DERBYSHIRE AND DERBY MINERALS LOCAL PLAN

Towards a Minerals Local Plan:

Winter 2021/2022 Consultation

Proposed Draft Plan

Background Paper
Unconventional Gas – Shale Gas

December 2021

DERBYSHIRE County Council

Derby City Council

Contents

1. Introduction and Background

1.1 This is one of a series of papers providing background information to accompany the preparation of the new Minerals Local Plan. The new Plan will include strategies and policies concerning the winning and working of hydrocarbon based energy minerals. This paper provides information about gas obtained from shale deposits (an unconventional source) whilst corresponding papers focus on oil and gas from conventional sources and gas obtained from within coal measures (an unconventional source). The production of separate papers reflects both the issues that have been raised and the response to comments received in previous consultation exercises and the views expressed to the County and City Councils in response to publicity for individual planning applications. Some of the issues and legislative provisions are common to all three forms of hydrocarbon developments and therefore there is some level of duplication in the papers but this is necessary to ensure that each one provides a comprehensive review of the issues for those who read them individually.

Conventional and Unconventional Hydrocarbons

1.2 Hydrocarbon is a compound of hydrogen and carbon. Hydrocarbons are of great importance as they include minerals such as oil and gas which provide a significant proportion of our energy supplies. They are also used as raw materials for the petro-chemicals industry and in the manufacture of drugs and plastics. The geological conditions where these resources are found, and the methods used to extract them have resulted in two categories of hydrocarbons, conventional and unconventional.

1.3 Conventional deposits are contained in porous rocks with interconnected spaces, such as limestone and sandstone. These interconnected spaces give rise to permeability that allows oil or gas to effectively flow through the reservoir to the well. Conventional reserves therefore can usually be exploited by drilling a well, with oil or gas then flowing out under its own pressure. Unconventional oil and gas deposits are contained in impermeable rocks, such as shale or coal deposits. In these cases, the oil or gas cannot easily flow through the reservoir.

1.4 To extract the oil and gases, techniques such as hydraulic fracturing (commonly referred to as fracking), coal bed methane dewatering or coal gasification are used. Hydraulic fracturing is the process of opening and/or extending existing narrow fractures or creating new ones in gas or oil-bearing rock, which allows gas or oil to flow into wellbores to be captured. Hydraulic fracturing is not limited to unconventional resources but is more likely to be required to extract oil and gas from those deposits. In calcareous conventional resources, such as limestone, fracturing may involve the use of an acidic fluid which dissolves the rock to open up fractures (acidisation fracturing). This paper focuses on shale gas and the issues associated with its extraction.

What is Shale Gas?

1.5 Shale is a common type of fine grained sedimentary rock formed from deposits of mud, silt, clay and organic matter. Through the application of heat and pressure over geological time, gas (predominantly methane) is produced from this organic matter. Methane is a 'natural gas' and is used to generate electricity and for domestic heating and cooking. Gas contained within shale is often referred to as 'unconventional gas' by contrast to 'conventional gas' obtained from sandstones or limestone. Conventional gas is found in reservoirs where it has migrated up from the source rock. In contrast shale gas has to be obtained directly from the source rock.

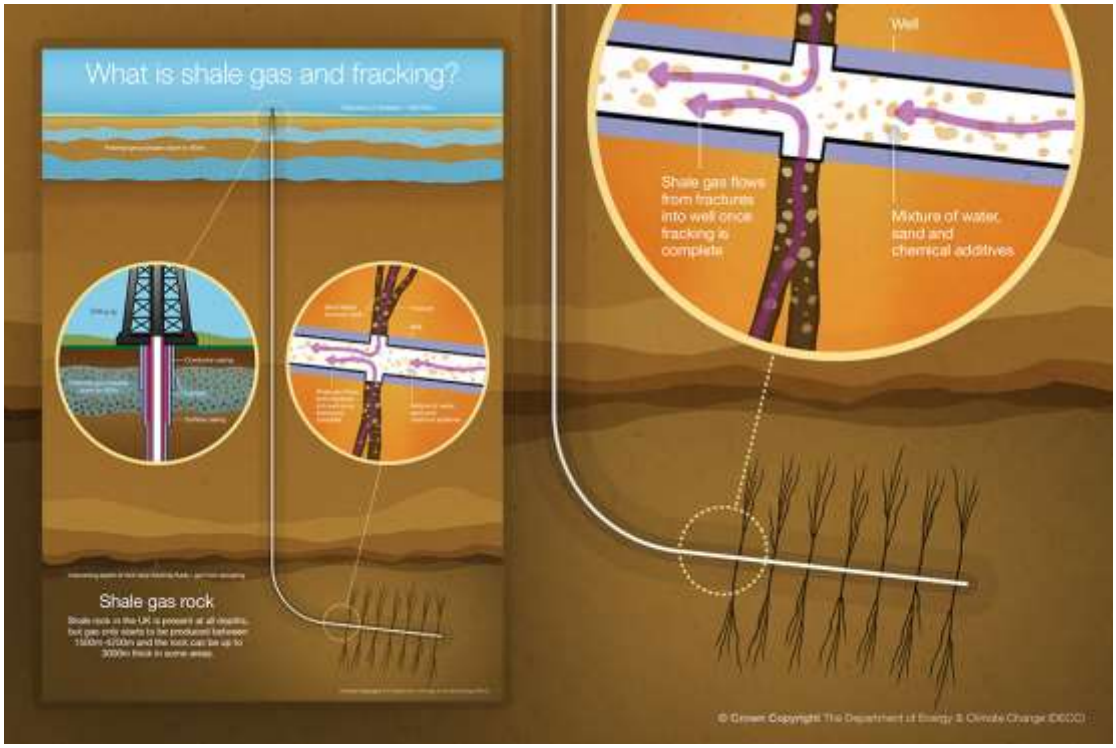
How is the Gas Extracted?

1.6 The techniques available to obtain the gas from conventional or unconventional sources are essentially the same but they have to be applied in a different way for shale gas as shales have a relatively low permeability and gas can only flow from them at very low rates. The shale has to be broken or opened to enable the gas to flow out and be captured.

1.7 All the techniques currently available involve drilling down to the shale beds. The drill shafts can consist of a single and direct vertical path to the shale bed. An alternative is Horizontal Drilling, in which the well trajectory is turned horizontally, sometimes running for thousands of feet along a layer of rock. A single horizontal well can access a much larger volume than a vertical well,

reducing the number of wells that need to be drilled, and thereby the overall cost of production.

1.8 Whereas conventional gas is found in reservoirs, shale gas is trapped in small gaps in the host shale. The shale therefore has to be broken down to allow access to these pockets of gas. Hydraulic fracturing or “fracking” is a relatively new technique for extracting gas from shale. It is a technique that uses fluid, usually water, pumped at high pressure into the rock to create narrow fractures which form pathways allowing the gas to flow into the well bore and up to the surface. The water normally contains small quantities of other substances to improve the efficiency of the operation. Sand is often pumped into the fractures to keep them open and allow the gas to flow out. The fluids pumped into the shale are referred to as proppants (props to keep it open) and can include small quantities of chemicals. The fractures extend a few hundred metres into the rock and the newly created fractures and other fluids in addition can be pumped into the well to maintain the pressure so that fracture development can continue and the proppant can be carried deeper into the formation.



Source: DBEIS, Guidance on fracking: developing shale gas in the UK, March 2019.

1.9 A well may be too long to maintain sufficient pressure to stimulate fractures across its entire length. If so, plugs may be inserted to divide the well into smaller sections ('stages'). Stages are fractured sequentially, beginning with the stage furthest away and moving towards the start of the well. After fracturing, the plugs are drilled through and the well is depressurised. This creates a pressure gradient so that gas flows out of the shale into the well. Fracturing fluid flows back to the surface ('flowback water') but it now also contains saline water with dissolved minerals from the shale formation ('formation water'). Fracturing fluid and formation water returns to the surface over the lifetime of the well as it continues to produce shale gas ('produced water'). Although definitions vary, flowback water and produced water collectively constitute mining waste and require an environmental permit for appropriate disposal.

1.10 The most recent Government publication specifically containing information about hydraulic fracturing can be obtained from the Department for Business, Energy & Industrial Strategy (DBEIS), Guidance on fracking: developing shale gas in the UK, March 2019.

2. Geology

2.1 Oil and natural gas originate in petroleum source rocks, i.e. sedimentary rocks that were deposited in very quiet water, usually in still swamps on land, in shallow quiet marine bays, or in deep submarine settings. Source rocks are comprised of very small mineral fragments. In between the mineral fragments, are the remains of organic material, usually algae, small wood fragments, or pieces of the soft parts of plants. When these fine-grained sediments are buried by depositions of later, overlying sediments, the increased heat and pressure resulting from the burials turns the soft sediments into hard rock strata. If further burial ensues, then temperatures continue to increase. When temperatures of the organic-rich sedimentary rocks exceed 120^{o} Centigrade, the organic

remains within the rocks begin to be ‘cooked’ and oil and gas are formed from the organic remains expelled from the source rock. It takes millions of years for these source rocks to be buried deeply enough to attain these maturation temperatures and additional millions of years for sufficient volumes of oil and gas to form commercial accumulations as the oil and gas are expelled from the source rock into adjacent reservoir rocks. Oil and gas formed in this manner are referred to as thermogenic oil and gas.

2.2 If the organic material within the source rocks is mostly wood fragments, then the primary hydrocarbon generated is natural gas. If the organic material is mostly algae and the soft parts of land plants, then both oil and gas are formed. By the time the source rock is buried deeply enough so that temperatures are above 150^{o} Centigrade, the organic remains have produced most of the oil they are able to. Above these temperatures, any oil remaining in the source rock or any oil that has been trapped in adjacent reservoirs will be broken down into natural gas.

2.3 Some organic-rich sedimentary rock can generate gas through bacterial processes at shallow burial depths before thermal maturation temperatures are attained. In this process, referred to as biogenic gas generation, the organic-rich source rocks are never buried deeply enough and do not attain temperatures necessary for the thermogenic production of gas. Instead, anaerobic bacteria generate gas in shallow source rocks that are generally located around the basin margins. Biogenic processes produce less gas per unit of sediment than thermogenic processes. Gas wells associated with biogenic gas are usually low volume. Most accumulations of biogenic gas occur at depths of less than 200 feet.

2.4 Oil and gas reservoir rocks are porous and permeable. They contain interconnected passageways of microscopic pores or holes that occupy the areas between the mineral grains and the rock. When oil and gas have been naturally expelled from the source rocks, they enter or migrate into the adjacent reservoir rocks. Most oil and gas reservoir rocks are sandstones, limestones or dolomites.

2.5 Large areas of the United Kingdom are underlain by shales (see Figure 1). The body of shale which is of particular interest in Derbyshire is that known as the Bowland-Hodder shale resource (see Figure 2). This area extends from Lancaster in the north-west across to Scarborough in the north-east. The broadly rectangular area extends as far south as Derby and Loughborough. These marine shales were deposited in a complex series of tectonically active basins across central Britain during the Visean and Namurian epochs. The shales attain thicknesses of up to 5,000 metres in the basin depocentres.

2.6 Not all shales are capable of producing gas. The presence of gas within the shale is a function of the organic content of the rock and how the shale was formed. Some shales did not contain enough organic material when first buried, some have not been sufficiently buried and heated whilst some hold gas but cannot sustain sufficiently high rates to be commercial. The organic content of the Bowland-Hodder shales is typically 1 to 3% but can reach as high as 8%. The Bowland-Hodder shale study[1] classified the shales into two areas in terms of geology and resource estimation, depicted in Figure 2; the Upper unit prospective (maturity for gas (R>1.1%) and depth < 5000 ft) and the Lower unit prospective (maturity for gas (R>1.1%) and depth > 5000 ft). Accordingly the area is considered to have a very high potential for shale gas prospects.

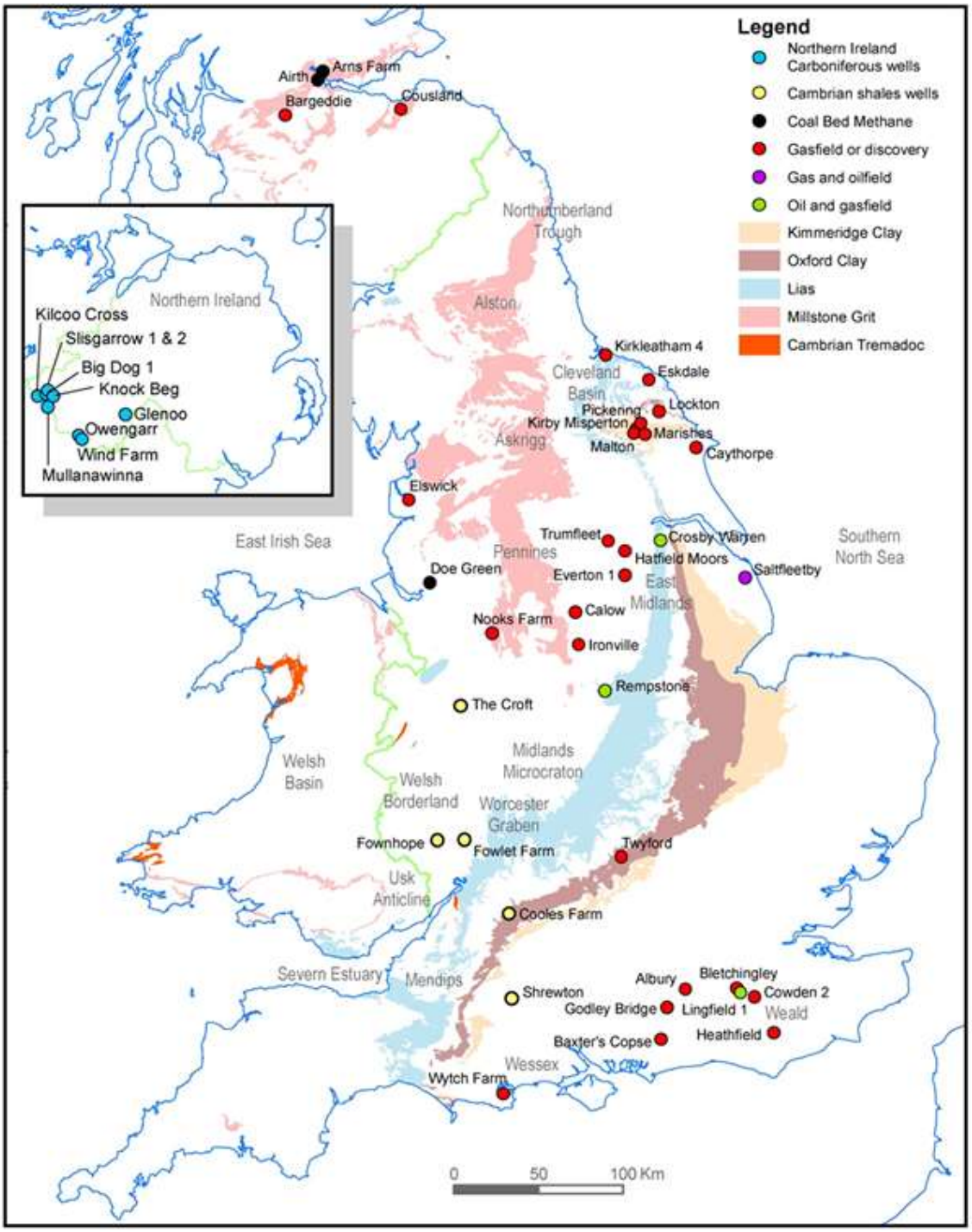
2.7 The Jurassic Weald basin in the south of England is also known to contain commercially viable reserves. Other geological areas with commercial potential include the Kimmeridge Clay of the Weald Basin, the deeper Dinantian shales in the Pennine Basin and possibly the Oil-Shale Group of the Midland Valley of Scotland. Further reserves may be found in the Upper Cambrian source rocks on the Midland Microcraton – although it has not been severely tectonised and the Upper Cambrian has not sourced conventional fields. The risk attached to black shales within the Caledonian and Variscan fold belts is likely to be unacceptably high. These fold belts have high organic carbon, but are strongly

[1] DECC-BGS The Carboniferous Bowland-Hodder Shale Gas Study 2013

tectonised (affected by thrusts, cut by igneous intrusions and converted to slates), and they have no overlying fields.

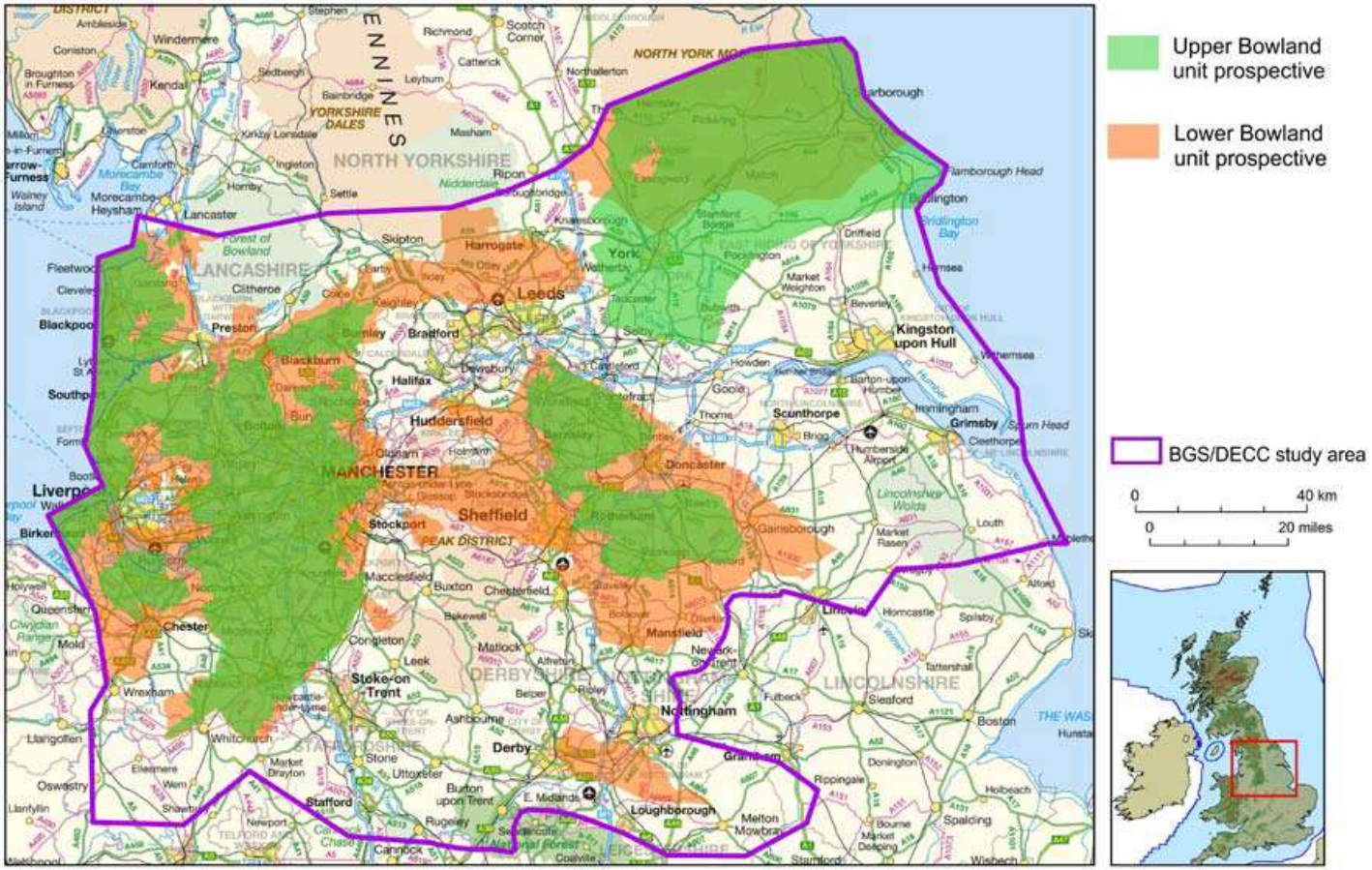
Figure 1: Principal UK Onshore Hydrocarbon Provinces 2010[2]

Outcrop of main black shale formations in UK and selected oil and gas wells and gas fields



[2] **DECC, Hydrocarbon Prospectivity of Britain's Onshore Basin, 2010**

Figure 2: Summary of areas prospective for gas in the upper and lower parts Bowland-Hodder unit in relation to the urban areas of central Britain, 2013[3]



[3] Figure 44, The Carboniferous Bowland Shale gas study: geology and resource estimation, BGS, DECC, 2013

3. National and Local Policy and Guidance

National Planning Policy

3.1 Government policy and guidance relating to the extraction of all forms of hydrocarbons, including shale gas, is developing rapidly in response to the discovery of new resources, the emergence of new techniques for working those resources and the impact of those technologies. The Minerals Local Plan will have to take account of this emerging guidance and the policies that develop. The following section reviews the main publications which currently apply and the guidance they provide on future hydrocarbon developments. Some of the guidance relates to hydrocarbons in general whilst much of the new and developing guidance relates to shale gas specifically. This review focuses on the aspects of guidance which are pertinent to town and country planning and the production of the Minerals Local Plan rather than the wider, more technical aspects.

National Planning Policy Framework

3.2 National guidance for the extraction of minerals, including hydrocarbons, is set out in the National Planning Policy Framework (NPPF)[4]. In general terms, the NPPF recognises the important contribution of minerals to our way of life. It states at paragraph 209 that, *'It is essential that there is a sufficient supply of minerals to provide the infrastructure, buildings, energy and goods that the country needs. Since minerals are a finite natural resource, and can only be worked where they are found, best use needs to be made of them to secure their long-term conservation*.' The policy advice on mineral development generally (paragraph 210) includes that mineral planning authorities should have planning policies that '*a) provide for the extraction of mineral resources of local and national importance*,' and '*f) set out criteria or requirements to ensure permitted and proposed operations do not have unacceptable adverse impacts on the natural and historic environment or human health, taking into account the cumulative effects of multiple impacts from individual sites and/or a number of sites in a locality.'* Paragraph 211 requires '*when determining planning*

[4] National Planning Policy Framework, July 2021, Paragraph 215

applications, great weight should be given to the benefits of mineral extraction, including to the economy.'

3.3 Specific guidance on hydrocarbons is set out in Paragraphs 215 and 216. Paragraph 215 states that, "Minerals Planning Authorities should:
a) when planning for on-shore oil and gas development, clearly distinguish between, and plan positively for, the three phases of development (exploration, appraisal and production), whilst ensuring appropriate monitoring and site restoration is provided for;

b) encourage underground gas and carbon storage and associated infrastructure if local geological circumstances indicate its feasibility; and

d) encourage the capture and use of methane from coal mines in active and abandoned coalfield areas.

3.4 The NPPF published in 2012 required MPAs to address constraints and processing within areas that are licensed for oil and gas exploration or production but this requirement was removed in both the 2018 and 2019 publications of the NPPF as well as the latest 2021 publication. (The Planning Practice Guidance (PPG), published in 2014, does not repeat or expand on the 2012 requirement).

3.5 Paragraph 216 states that '*When determining planning applications, mineral planning authorities should ensure that the integrity and safety of underground storage facilities are appropriate, taking into account the maintenance of gas pressure, prevention of leakage of gas and the avoidance of pollution.'*

Planning Practice Guidance, March 2014 (PPG)

3.6 In July 2013 the Department for Communities and Local Government published new guidance relating to onshore oil and gas developments (Planning Practice Guidance for Onshore Oil and Gas). This has now been superseded although most of the advice and guidance it contained has been incorporated into the PPG which contains guidance for oil and gas developments from both

conventional and unconventional sources in the section headed Planning for Hydrocarbons. This is an iterative form of guidance that is updated and amended periodically.

3.7 The PPG[5] states that, as an emerging form of energy supply, there is a pressing need to establish through exploratory drilling, whether or not there are sufficient recoverable quantities of unconventional resources such as shale gas and coal bed methane present to facilitate economically viable full scale production. In terms of the guidance, the PPG[6] encourages mineral planning authorities to make appropriate provision for hydrocarbons in local mineral plans, based on emerging information, to allow them to highlight areas where proposals for extraction may come forward, as well as managing potentially conflicting objectives for the use of land.

3.8 Where mineral planning authorities consider it is necessary to update their local plan and they are in a Petroleum Licence area, the PPG[7] states that they are expected to include Petroleum Licence Areas on their policies maps and include criteria-based policies for each phase; that is exploration, appraisal and production, setting clear guidance for the location and assessment of hydrocarbon extraction within those areas. Mineral planning authorities may identify specific sites for hydrocarbon extraction through the site allocation process should the oil and gas industry wish to promote specific sites[8]. In contrast to the practice established for other minerals resources, the guidance[9] does not advocate the creation of formal safeguarding areas for hydrocarbons due to the depth of those reserves, the ability to use drilling equipment and the small surface area required for the installations.

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[5] PPG Minerals Paragraph: 091 Reference ID: 27-091-20140306 Revision date 06 03 2014

[6] PPG Minerals Paragraph:105 Reference ID: 27-105-20140306 Revision date 06 03 2014

[7] PPG Minerals Paragraph: 106 Reference ID: 27-106-20140306 Revision date: 06 03 2014

[8] PPG Minerals Paragraph: 107 Reference ID: 27-107-20140306 Revision date: 06 03 2014

[9] PPG Minerals Paragraph: 108 Reference ID: 27-108-20140306 Revision date: 06 03 2014

3.9 The PPG provides a description of the different operations involved in the three phases, the technical issues associated with hydrocarbon working and the planning issues which arise from hydrocarbon developments. It includes an explanation of the role of the planning system in obtaining permission together with a summary of the role of the other official regulators also involved in the process.

3.10 With regard to the determination of development proposals, mineral planning authorities are advised[10] to assess applications for each phase on their respective merits and applications for the exploratory stage of development should not involve the consideration of the potential impacts of extraction. Mineral planning authorities should take account of Government energy policy, which indicates a preference for energy supplies to be obtained from a variety of sources, including onshore oil and gas[11]. Mineral planning authorities should use appropriate conditions, having regard to the issues for which they are responsible, to mitigate against any adverse environmental impact.[12] The PPG, at Annex C, provides some examples of model conditions. It states that above ground separation distances would be acceptable in specific circumstances where it is clear that, based on site specific assessments and other forms of mitigation measures (such as working scheme design and landscaping) a certain distance is required between the boundary of the minerals site and the adjacent development.[13] Operators and mineral planning authorities are also encouraged to seek appropriate restoration schemes for sites once mineral extraction is completed.[14]

3.11 Appendix A of the guidance relates to shale gas, coalbed methane and underground coal gasification. The main aspects of this guidance are covered in the summary of the individual extraction methodologies below.

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[10] PPG Minerals Paragraph: 120 Reference ID: 27-120-20140306 Revision date 06 03 2014

[11] PPG Minerals Paragraph: 124 Reference ID: 27-124-20140306 Revision date 06 03 2014

[12] PPG Minerals Paragraph: 125 Reference ID: 27-125-20140306 Revision date: 06 03 2014

[13] PPG Minerals Paragraph: 126 Reference ID: 27-126-20140306 Revision date: 06 03 2014

[14] PPG Minerals Paragraph: 127 Reference ID: 27-127-20140306 Revision date: 06 03 2014

DECC and DCLG Written Ministerial Statement (WMS) September 2015, 'Shale Gas and Oil Policy'

3.12 The WMS sets out that there is a national need to explore and develop our shale gas and oil resources in a safe, and sustainable and timely way. It states that, '*Having access to clean, safe and secure supplies of natural gas for years to come is a key requirement if the UK is to successfully transition in the longer term to a low-carbon economy. The Government remains fully committed to the development and deployment of renewable technologies for heat and electricity generation and to driving up energy efficiency, but we need gas - the cleanest of all fossil fuels – to support our climate change target by providing flexibility while we do that and help us to reduce the use of high-carbon coal*. *Natural gas is absolutely vital to the economy. It provides around one third of our energy supply. About one third of gas supply is used for industry and services, not just for power or heating but also as feedstock, e.g. for chemicals; one quarter is used for electricity generation; and the remainder is used in domestic households for heating and cooking*[15]*.'*

3.13 **'***Since 2004, the UK has been a net importer of gas due to the rapid decline of production from the UK Continental Shelf· Last year around 45% of UK gas supply was made up of net imports*[16]*. Our projections suggest that domestic production will continue to decline and, without any contribution from shale gas, net imports could increase to 75% of the gas we consume by 2030. Domestic oil production has also declined since reaching a peak in 1999. Currently net imports comprise around 40% of the oil we use and DECC projections suggest net imports could increase to 73% by 2030.*[17]

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[15] DECC, Digest Of UK Energy Statistics, July 2015

[16] DECC, Digest Of UK Energy Statistics, July 2015

[17]DECC, UK Oil and Gas Production Projections, March 2015 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/414172/Production_projections.pdf

3.14 The WMS adds that developing the UK shale industry could reduce our dependence on imports and improve energy resilience. It could also lead to economic benefits in developing a new industry in terms of investment and jobs. It notes that the full scale of the UK's shale resource is unknown including how much can be extracted technically or economically. BGS estimates that the shale gas resource in the Bowland-Hodder basin could be 1300 trillion cubic feet (tcf)[18], compared to current UK annual gas consumption of around 2.5 tcf[19].

3.15 The WMS states that, '*Shale gas can create a bridge while we develop renewable energy, improve energy efficiency and build new nuclear generating capacity. Studies have shown that the carbon footprint of electricity from UK shale gas would be likely to be significantly less than unabated coal and also lower than imported Liquefied Natural Gas*.'[20]

3.16 The WMS emphasises the need to explore and test shale potential adding that, '*Safety and environmental protection will be ensured through responsible development and robust regulation.'*

Infrastructure Act 2015

3.17 The Act, via the non-issue of hydraulic fracturing consents, prohibits 'associated hydraulic fracturing' activity taking place anywhere at a depth of less than 1000 metres below the ground surface. The 1000 metre restriction is unlikely to be an issue in practice, given the depth at which most shale gas resources lie in the UK. Associated hydraulic fracturing is defined as hydraulic fracturing of

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[18]BGS/DECC, Bowland Shale Gas Study, June 2013
https://www.gov.uk/government/publications/bowland-shale-gas-study

[19] Based on DECC, Digest of UK Energy Statistics, July 2015

[20] Mackay-Stone report (requested by DECC), Potential Greenhouse Gas Emissions Associated with Shale Gas Extraction and Use, Sept 2013
https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/237330/MacKay_Stone_shale_study_report_09092013.pdf

shale or strata encased in shale which is carried out in connection with the use of the relevant well to search or bore for or get petroleum, and involves, or is expected to involve, the injection of more than 1,000 cubic metres of fluid at each stage, or expected stage, of the hydraulic fracturing, or more than 10,000 cubic metres of fluid in total.

The Onshore Hydraulic Fracturing (Protected Areas) Regulations 2016

3.18 This secondary legislation to the Infrastructure Act 2015 ensures, via the hydraulic fracturing consent regime that 'associated hydraulic fracturing 'cannot take place within 1,200 metres beneath the surface of 'protected groundwater source areas' and other 'protected areas' Protected groundwater source area is any land at a depth of less than 1,200 metres below a relevant surface area defined as (a) within 50 metres of a point at the surface at which water is abstracted from underground strata and is used to supply water for domestic or food production purposes, or (b) within or above a zone defined by a 50-day travel time for groundwater to reach a groundwater abstraction point that is used to supply water for domestic or food production purposes. Protected areas include National Parks, AONBs, the Broads and World Heritage Sites.

The Petroleum Licensing (Exploration and Production) (Landward Areas) (Amendment) (England and Wales) Regulations 2016

3.19 These regulations amend model clauses on new PEDLs to prohibit 'relevant hydraulic fracturing' operations from taking place from new or existing wells drilled at the surface in the protected areas defined in the 'The Onshore Hydraulic Fracturing (Protected Areas) Regulations 2016' i.e. National Parks, the Broads, Areas of Outstanding Natural Beauty, World Heritage Sites and areas that are most vulnerable to groundwater pollution (Groundwater Protection Zone 1). The surface restrictions also apply to Sites of Special Scientific Interest, Ramsar sites and European sites (as defined by regulation 8(1) of the Conservation of Habitats and Species Regulations 2010, including Natura 2000 sites protected under the Habitats Directive and sites protected under the Wild Birds Directive. Relevant hydraulic fracturing means hydraulic fracturing of shale or strata encased in shale and is defined as hydraulic fracturing which involves or is expected to involve the injection of more than

1,000 cubic metres of fluid at any stage, or expected stage, of the hydraulic fracturing, or more than 10,000 cubic metres of fluid in total. For existing PEDLS the DECC issued a policy statement[21] which states that save in wholly exceptional circumstances Hydraulic Fracturing Consent will not be granted in protected areas.

National Energy Policy

3.20 There have been several important stages in the evolution of current national energy policy, incorporating the need to adapt to climate change whilst securing energy supplies. The Department of Trade and Industry paper, Meeting the Energy Challenge, 2007[22] states that England, Wales and Scotland's substantial remaining coal resources, including gas contained within the coal, have the potential not only to help meet our national demand for coal and to reduce our dependence on imported primary fuels, but also to contribute to the economic vitality and skills base of the regions where they are found.

3.21 Energy policy since 2008 has been influenced by The Climate Change Act 2008 which set in legislation the UK's approach to tackling and responding to climate change. It introduced the UK's long-term legally binding 2050 target to reduce greenhouse gas emissions by at least 80% relative to 1990 levels and introduced 'carbon budgets' which cap emissions over successive 5-year periods which must be set 12 years in advance.

3.22 The draft National Policy Statement for Energy, published in 2009, built on the 2007 Energy White Paper. Together they formed an evolving international and domestic energy strategy in response to the changing circumstances in global energy markets. They set out to address the long-term energy challenges of security of supply, whilst acknowledging the implications of climate change. Whilst recent emphasis has been on the development of renewable energy supplies the Government recognised the important and continuing role that

[21] Surface Development Restrictions for Hydraulic Fracturing Appendix A, DECC June 2016

[22] Meeting the Energy Challenge, A White Paper on Energy, DTI, May 2007

indigenous sources of coal, oil and gas will play in meeting national energy requirements. This was reaffirmed in the Overarching National Policy Statement for Energy[23], published in July 2011, which provided further clarification of the Government's plans for a transition to a low carbon economy and in the Gas Generation Strategy 2012[24] which makes it clear that gas will continue to play a major role in the UK electricity mix over the coming decades, alongside low-carbon technologies as the electricity system is decarbonised.

3.23 This policy is set against the background of changes in the sources of our energy requirements. By 2004 the United Kingdom became a net importer of natural gas and a net importer of oil in 2010. By 2020, it was then estimated that the UK is likely to be importing about three-quarters of its energy supplies.

3.24 In December 2013[25] the Government announced its long-term infrastructure investment plan which included the development of unconventional shale gas as one of its priorities. The plan identified a package of reforms to facilitate shale gas exploitation. It reiterated that the role for gas is consistent with the need to decarbonise our economy and that it was regarded by the Government as the cleanest fossil fuel, and that much of the new gas capacity that was needed would be replacing the ageing coal capacity. Gas was also seen as important for balancing the increasing levels of intermittent and inflexible low-carbon energy in the system.

3.25 The facilitation of unconventional gas exploration included, in December 2012, the establishment of the Office for Unconventional Gas and Oil, with the aim of promoting the safe, responsible, and environmentally sound recovery of the UK's unconventional reserves of gas and oil, including shale gas. The Government consulted on a proposed tax regime for shale gas, including a new shale gas 'pad' allowance, and it announced plans to streamline the permitting process to provide more certainty to industry as well as publishing new planning

[23] DECC, Overarching National Policy Statement for Energy (EN-1), July 2011

[24] DECC, Gas Generation Strategy, December 2012

[25] HM Treasury, National Infrastructure Plan, December 2013

guidance to clarify the process for developers. The Government also worked with industry on a scheme[26] which would require operators to engage with local communities from an early stage and which would ensure that local communities benefit from hosting shale projects, with operators providing at least £100,000 in benefits per fracked well site during exploration/appraisal stage and 1% of revenues at production stage. In 2014 it introduced the Shale Wealth Fund whereby a percentage of revenues arising from shale gas production would be used for the benefit of communities which host shale sites.

Energy Act 2013

3.26 The Energy Act received Royal Assent on 18 December 2013. The Act has several objectives and in relation to hydrocarbons it seeks to make provision for the setting of a decarbonisation target range and duties in relation to it; or in connection with reforms to the electricity market for purposes of encouraging low carbon electricity generation, or ensuring security of supply. It is also about the designation of a strategy and policy statement concerning domestic supplies of gas and electricity. It does not actually prescribe a new strategy or policy at this stage but instead sets the procedural requirements for doing so. It is likely however that future policy and strategy will reflect the overall objective of the Act to reduce our carbon footprint and in turn this will affect the future demand for minerals including fossil fuels.

DECC Written Ministerial Statement November 2015, 'Priorities for UK Energy and Climate Change Policy'

3.27 This WMS was presented to Parliament in November 2015 by the Secretary of State for Energy and Climate Change. The WMS does not change national planning policy or guidance but it does set out Government thinking on the approach to energy supply. The Secretary of State stated that "*Affordable, reliable clean energy is critical to our economy, our national security, and to family budgets. We need secure energy so people can get on with their lives and businesses can plan for the future. Affordable energy so the people that*

[26] UKOOG Community Engagement Charter 2103

foot the bill get a good deal, and clean energy to safeguard our future economic security and ensure we can meet our climate change commitments." She added "*New nuclear and gas will be central to our energy secure future and we are encouraging investment in our shale gas exploration so we can add new sources of home-grown supply to our real diversity of imports*." The WMS goes on "*one of the greatest and most effective contributions we can make to emissions from electricity generation is by replacing coal-fired power stations with gas*." The programme was to be subject to consultation but indicated a restriction on the use of coal by 2023 and the possible closure of all coal-fired power stations by 2025. This was subject to the development of the infrastructure to enable the shift to take place. This could have implications for the UK onshore oil and gas industry and the utilisation of indigenous resources.

DBEIS Written Ministerial Statement HCWS690 May 2018, - Energy Policy

3.28 This WMS was presented to Parliament in May 2018 by Greg Clerk Secretary of State for Business, Energy and Industrial Strategy. It states that, '*there are potentially substantial benefits from the safe and sustainable exploration and development of our onshore oil and gas resources. It adds that The UK must have safe, secure and affordable supplies of energy with carbon emissions levels that are consistent with the carbon budgets defined in our Climate Change Act and our international obligations. We believe that gas has a key part to play in meeting these objectives both currently and in the future. In part as a result of the UK's diverse range of energy sources, which include natural gas, we have had competitively-priced energy since 1990 whilst reducing carbon emissions across the economy by 49% – a leading performance among developed nations. Gas still makes up around a third of our current energy usage and every scenario proposed by the Committee on Climate Change setting out how the UK could meet its legally-binding 2050 emissions reduction target includes demand for natural gas. As set out in the Clean Growth Strategy, innovations in technologies such as Carbon Capture Usage and Storage (CCUS) have the potential to decarbonise this energy supply still further and prolong its role in our energy mix.*

3.29 *However, despite the welcome improvements in efficiency and innovation from companies operating in the North Sea, the ongoing decline in our offshore gas production has meant that the UK has gone from being a net exporter of gas in 2003 to importing just under 50% of gas supplies in 2017 and estimates suggest we could be importing 73% of our gas by 2035*[27]*. Our current import mix, via pipelines from Norway and Continental Europe and LNG terminals that can source gas from around the world, provides us with stable and secure supplies. However, the Government believe that it is right to utilise our domestic gas resources to the maximum extent and explore further the potential for onshore gas production from shale rock formations in the UK, where it is economically efficient, and where environment impacts are robustly regulated.'*

3.30 In relation to planning policy and guidance the Statement goes on to say,
'*This Statement is a material consideration in plan-making and decision-taking, alongside relevant policies of the existing National Planning Policy Framework (2012), in particular those on mineral planning (including conventional and unconventional hydrocarbons).Shale gas development is of national importance. The Government expects Mineral Planning Authorities to give great weight to the benefits of mineral extraction, including to the economy. This includes shale gas exploration and extraction. Mineral Plans should reflect that minerals resources can only be worked where they are found, and applications must be assessed on a site by site basis and having regard to their context. Plans should not set restrictions or thresholds across their plan area that limit shale development without proper justification. We expect Mineral Planning Authorities to recognise the fact that Parliament has set out in statute the relevant definitions of hydrocarbon, natural gas and associated hydraulic fracturing. In addition, these matters are described in Planning Practice Guidance, which Plans must have due regard to. Consistent with this Planning Practice Guidance, policies should avoid undue sterilisation of mineral resources (including shale gas).'*

[27] DBEIS factsheet 1: Shale gas and energy security 2018

3.31 Other measures referred to in the statement include setting up a new single Shale Environmental Regulator (currently three regulators are involved – the Environment Agency, the HSE and the OGA) and a commitment to improve the community benefits payments available to communities hosting shale gas developments (currently worth up to £10 million for a typical site). It also made commitments to provide a shale support fund and planning brokerage service to help facilitate timely decisions making.

The UK's Draft Integrated National Energy and Climate Change Plan (NECP) January 2019

3.32 In the context of planning ahead for withdrawal from the EU the draft stated that, '*On energy, the UK is seeking co-operation with the EU to support the delivery of cost efficient, clean and secure supplies of electricity and gas, based on competitive markets and non-discriminatory access to markets*.' On climate change it stated, '*that the UK recognises the shared interest in global action on climate change and the mutual benefits of a broad agreement on climate change co-operation*.'

3.33 The paper provides a review of important statements on energy and climate change (for example the Clean Growth Strategy October 2017) which set the framework, objectives and targets. It reaffirms the need to ensure energy security and energy efficiency, the approach to decarbonisation and the policies and measures relating to these and other issues. Whilst it addresses a wide range of energy and climate change issues the only direct minerals reference is to unconventional gas resources, including shale gas development. It states '*The UK Government is committed to a low carbon and affordable future for our energy. Gas, the least polluting fossil fuel, still meets a third of our energy demand and we will need it for many years to come. In May 2018, the UK Government reiterated its view that there are potentially substantial benefits from the safe and sustainable exploration and development of our onshore shale gas resource'.* The paper also reiterated Government statements that shale gas development must be safe and environmentally sound and the continued need for tough regulations for all on-shore and off-shore oil and gas

developments to ensure on-site safety, prevent water contamination, and mitigate seismic activity and air pollution.

Department for Business, Energy & Industrial Strategy, Guidance on fracking: developing shale gas in the UK, March 2019

3.34 This statement was first issued on 13 January 2013. The most recent statement reiterates the Government view that shale gas has the potential to provide the UK with greater energy security, growth and jobs and that it is encouraging safe and environmentally sound exploration to determine its potential. It cites the reasons why we require gas and indicates that off-shore gas production has been in decline since 2000 with the UK having gone from a net exporter to importing 53% of our supplies by 2017, adding that imports could reach 72% by 2030. It describes what shale gas is and how it is extracted. It reviews the regulatory regime and includes a review of evidence on safety and the environment.

The Climate Change Act 2008 (2050 Target Amendment) Order 2019

3.35 The Act originally committed the UK to cut its emissions by at least 80% below the 1990 baseline level by 2050. Following the declaration of a climate change emergency, this target was amended, on 27 June 2019[28], committing the UK to a legally binding target of net zero emissions by 2050, set on a whole-economy basis with an interim target of a 57% reduction by 2030. (For carbon dioxide, methane and nitrous oxide the baseline is 1990. For hydrofluorocarbons, perfluorocarbons, sulphur hexafluoride and nitrogen trifluoride the base year is 1995.)

3.36 The Climate Change Act 2008 also introduced legally binding 'carbon budgets' which cap emissions over successive 5-year periods which must be set 12 years in advance to allow, policy makers, businesses and individuals enough time to prepare. The first five carbon budgets cover the period 2008-2032. The UK is currently in the third carbon budget period with the sixth carbon budget

[28] The Climate Change Act 2008 (2050 Target Amendment) order 2019

(2033-2037) legislated on 23 June 2021. The table below shows the progress made to date:

Budget	**Carbon Budget Level MtCO2e**	**Reduction below 1990 levels**	**Met?**
1st budget (2008-2012)	3,018	25%	Yes
2nd budget (2013-2017)	2,782	31%	Yes
3rd budget (2018-2022)	2,544	37% by 2020	On track
4th budget (2023-2027)	1950	51% by 2025	Off track
5th budget (2028-2032)	1725	57% by 2030	Off track
6th budget (2033-2037)	965	78% by 2035	Legislated on 23 June 2021
Net Zero Target		At least 100% by 2050	

DBEIS Written Ministerial Statement HCWS68 Energy Policy Update, 4th November 2019

3.37 The Statement was issued to provide an update on the Government's policy regarding shale gas exploration. It states that, "*the Government continues to recognise the importance of natural gas as a source of secure and affordable energy as we aim to reach net zero emissions by 2050*". The Statement sets out that the CCC predicts that we will still be consuming about 70% of the gas that we consume today in 2050 under our net zero target as significant

reductions across building, industry and power are offset by demand for gas to produce hydrogen and therefore, continued good access to natural gas from both domestic and international markets is seen as critical. In terms of shale gas the statement notes that it has the potential to provide a new source of domestic energy but at present it is in an exploration phase. The Government stresses its commitment to only allow shale gas development in a way which is safe and sustainable both for the environment and local people. It notes that a precautionary, evidence-based approach has been adopted towards exploring its potential underpinned by world-leading environmental and safety regulations.

3.38 The Statement goes to explain that safety regulations in relation to seismic activity have led to the development of a 'traffic light system' which requires hydraulic fracturing to be suspended in the event of specified levels of activity. Following seismic events at Cuadrilla's Preston New Road site, Lancashire in 2018 and 2019 hydraulic fracturing has been suspended at the site. The OGA has been analysing data from the PNR1z well which was fracked in 2018 and resulted in induced seismic activity. The OGA summary report amongst other conclusions states that, *'while we cannot draw definitive comparisons between this site specific evidence and other prospective shale gas sites, the limitations of current scientific evidence mean it is difficult to predict the probability and maximum magnitude of any seismic events, either at the Preston New Road site or in other locations.'*

3.39 The OGA intends to commission further research to incorporate new data from Cuadrilla's more recent 2019 operations which resulted in the highest level of hydraulic fracturing seismic activity to date. The OGA has made clear that it cannot evaluate with confidence whether a proposal to resume hydraulic fracturing at the Preston New Road site, or to start operations elsewhere, will not cause unacceptable levels of seismicity and therefore it is unlikely to approve future Hydraulic Fracture Plans unless new evidence is presented.

3.40 The WMS therefore reiterates, '*The Government has always been clear that it will take a precautionary approach and only support shale gas exploration if it*

can be done in a safe and sustainable way, and that we will be led by the science on whether this is indeed possible. It remains our policy to minimise disturbance to those living and working nearby, and to prevent the risk of any damage. *On the basis of the current scientific evidence, the Government has confirmed that it will take a presumption against issuing any further Hydraulic Fracturing Consents. This position, an effective moratorium, will be maintained until compelling new evidence is provided which addresses the concerns around the prediction and management of induced seismicity. While future applications for Hydraulic Fracturing Consent will be considered on their own merits by the Secretary of State, in accordance with the law, the shale gas industry should take the Government's position into account when considering new developments*.'

3.41 The WMS concludes that the Government will not be taking forward proposed planning reforms in relation to shale gas that were subject to consultation in 2018. These include the proposals on the principles of a permitted development right for non-hydraulic exploratory shale gas development; making community pre-application consultation compulsory for shale gas development; and proposals to bring shale production development into the Nationally Significant Infrastructure Projects (NSIP) regime.

National Grid: Future Energy Scenarios July 2020

3.42 National Grid, which operates GB's electricity and gas networks, produce an annual report on Future Energy Scenarios which suggests four credible pathways for the future of energy to 2050. Each scenario considers how much energy we might need and where it could come from. Three of the four scenarios achieve the net zero greenhouse gas emission target by 2050 i.e. a 100% reduction compared to 1990 levels. The fourth scenario labelled 'Steady Progression' achieves a 68% reduction; the use of shale gas is only present in this scenario. The report notes that shale gas is not present in the three net zero scenarios due to reduced support from government and consumers.

Local Planning Policy

Derby and Derbyshire Minerals Local Plan

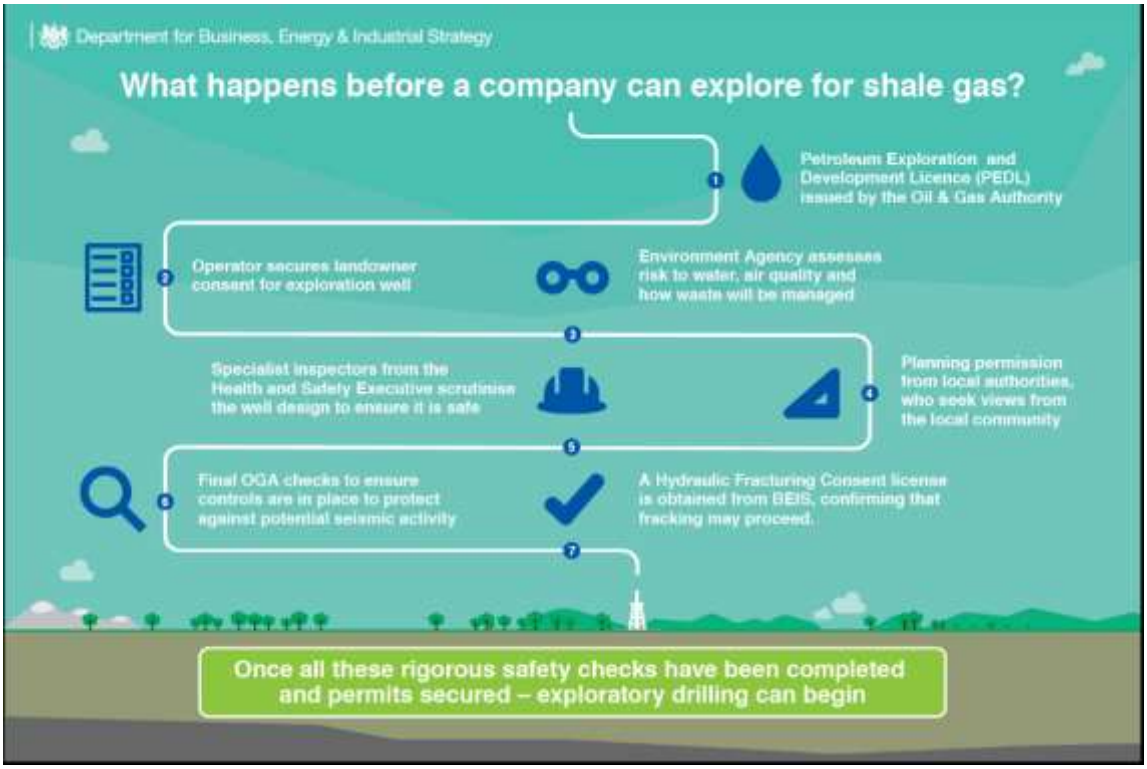
3.43 The current Minerals Local Plan, adopted in 2002, states that all proposals for the extraction of oil and gas will be considered against the general policies set out in the Plan, and the detailed criteria in Policy MP35 Oil and Gas which states that:

3.46 Proposals for the development of oil and gas, including facilities associated with the production, processing or transporting of oil or natural gas will be permitted only where they can be carried out in an environmentally acceptable way, and provided that:

- any irreparable damage to interests of acknowledged environmental importance is outweighed by a proven need for the development in its proposed location
- the proposal is consistent with an approved overall scheme for the appraisal of, or production from the area
- the proposed location of the development is the best having regard to geological, technical and environmental considerations
- satisfactory arrangements have been made for the avoidance of seepage pollution, the off-site disposal of drilling mud and other drilling residues and the flaring and disposal of unwanted gas.

4. Regulatory System

4.1 Before any shale operation can begin in the UK, operators must pass rigorous health and safety, environmental and planning permission processes.



Source: DBEIS Guidance on fracking: developing shale gas in the UK (updated 12 March 2019

Key Regulators

4.2 Anyone seeking to carry out operations for the extraction of hydrocarbons, including gas from shale, has to obtain approval from the appropriate regulatory bodies. The key regulators for all hydrocarbon extraction operations are identified below. Licencing and working issues are addressed in other sections of the paper.

- **Oil and Gas Authority** - The OGA regulates the licensing of exploration and development of England's onshore oil and gas resources. The OGA issues well consents, development programme approvals, completion of work programme approvals and production consents. Before a company can carry out onshore exploration for oil and gas, a company needs to apply to the OGA for a Petroleum Exploration & Development License (PEDL). As part of the OGA's regulation of onshore

hydraulic fracturing operations, it has stringent controls in place to ensure that operators manage the risk of induced seismicity from such operations. If hydraulic fracturing is proposed, operators are required to undertake detailed geological studies and submit a Hydraulic Fracture Plan (HFP) setting out how they will control and monitor the fracturing process and assess the risk of induced seismic events.

- **Mineral Planning Authorities** – grant planning permission for the location of any wells and well pads, and impose planning conditions to ensure that the impact on the use of the land is acceptable.

- **Environment Agency** – The EA ensures that any shale gas operations are conducted in a way that protects people and the environment. The Environment Agency's environmental permitting regulations cover:
  protecting water resources (including groundwater aquifers) as well as assessing and approving the use of chemicals which from part of the hydraulic fracturing fluid; ensuring appropriate treatment and disposal of mining waste produced during the borehole drilling and hydraulic fracturing process including waste water; ensure suitable treatment and management of any naturally occurring radioactive materials (NORM), the disposal of waste gases through flaring and emissions to air. The EA is a statutory consultee on planning applications and provides the MPA with advice on potential risks to the environment form individual gas exploration and extraction sites.

- **Health and Safety Executive** – the HSE regulates the safety aspects of all phases of extraction, in particular responsibility for ensuring the appropriate design and construction and upkeep of a well casing for any borehole.

- **Department for Business, Energy and Industrial Strategy** – the DBEIS issues Hydraulic Fracturing Consent (HFC) required before hydraulic fracturing can take place. Hydraulic fracturing consent (HFC) will not be issued unless 13 conditions are met and DBEIS is otherwise

satisfied that it is appropriate. The conditions relate to a variety of environmental and social factors including emissions and community benefits. The operator must also demonstrate its financial resilience prior to HFC being granted. The operator then seeks final well consent from the OGA.

4.3 The Shale Environmental Regulator Group (SERG) was launched on 5th October 2018. It brought to together the onshore oil and gas regulators EA, HSE and the OGA together as a virtual regulatory group for the environmental aspects of shale gas exploration and production.

4.4 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 and which has responsibility for any subsidence in ex-mining areas
- **Natural England**, which may need to issue European Protected Species Licences in certain circumstances
- **the British Geological Survey**, which needs 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**, which may need to provide hazardous substances consents.

Additional consents and orders, such as stopping up rights of way or temporary road orders, may also be required.

Obtaining Planning Permission and Other Approvals

4.5 Apart from a few exceptions, all works associated with the extraction of hydrocarbons require planning permission. The process of obtaining planning permission to drill a well is currently the same whether the well is targeted at conventional gas resources or unconventional gas such as shale gas. The process involves three separate stages; exploration, appraisal and extraction,

and planning permissions are required for each stage, although an applicant can seek approval for two or more stages in one application.

4.6 The exploratory phase seeks to acquire geological data to establish whether hydrocarbons are present. The appraisal stage takes place when the existence of gas (or oil) has been confirmed, but where the operator needs further information about the extent of the deposit or its characteristics to establish whether it can be economically extracted. The production stage normally involves the drilling of a number of wells and may also involve the installation of ancillary equipment such as pipelines, processing facilities and storage tanks.

4.7 Before a company can carry out onshore exploration for oil and gas, it needs to apply to the OGA for a Petroleum Exploration & Development License (PEDL). Licences are issued in competitive offerings (Licence Rounds). They do not give permission for drilling or any other operations; rather, they grant exclusivity to licensees, in relation to hydrocarbon exploration and extraction (including for shale gas but also for other forms), within a defined area.

4.8 The DBEIS Regulatory Roadmap England: Onshore Oil and Gas Exploration in the UK: Regulation and Best Practice, December 2015 (with updates to 2018), contains the following checklist which identifies that before commencing drilling operations for all onshore oil and gas development the operator must have:

- obtained a petroleum exploration and development licence (PEDL) from the OGA
- secured a lease from the landowner
- submitted relevant Petroleum Operations Notices (PON) to OGA
- secured planning permission from MPA/LPA/DOE
- discharged any relevant conditions placed on the planning permission
- obtained a permit from the Coal Authority if the well will encroach on coal seams
- informed the British Geological Survey BGS of the intention to drill

- completed the necessary consultation process with all the statutory/relevant consultees
- obtained the necessary permits from the Environment Agency
- notified HSE of the intention to drill (minimum 21 days' notice)
- provided HSE with details of the proposed well design that have been examined by an independent and competent well examiner (minimum 21 days' notice)
- agreed data-reporting methods with the OGA
- agreed a method for monitoring induced seismicity and fracture growth height with the OGA (where hydraulic fracturing is planned)
- received consent from DBEIS to drill and frack (referred to as Hydraulic Fracturing Consent).

Further details of this process are summarised below.

4.9 The submission of an application to the mineral planning authority triggers the need to determine if an Environmental Impact Assessment (EIA) is required. An EIA will be required if the scale of the proposed development exceeds certain thresholds, or if, depending on the nature, scale and location, the development may have significant environmental impacts. If an EIA is required, it must be completed by the applicant and submitted to the mineral planning authority before the authority decides on the application. Operators are encouraged to engage in pre-application discussions with the mineral planning authority where the need for an EIA and the matters to be addressed in it can be determined before an application is prepared and submitted. Government policy also encourages would-be applicants to undertake community engagement. Applicants are advised to inform local communities about their proposals and, where appropriate, amend those proposals in response to the feedback they receive. A commitment to pre-application engagement is set out in UKOOG's[29] Community Charter.

[29] UKOOG – the trade body for companies developing shale gas and oil

4.10 Following a consultation in September 2013 and the Government response in January 2014, changes were made to the system of how landowners and tenants should be notified by applicants of applications for onshore oil and gas development. The requirement to serve notice on individual owners and tenants of land on the above ground area where works are required was retained, but the requirement for owners of land beyond this area i.e. the owners of land where solely underground operations may take place, was removed. This was implemented by the Town and Country Planning (Development Management Procedure and Section 62A Applications) (England) (Amendment No.2) which came into force from 13 January 2014.

4.11 Once the MPA has granted planning permission to drill, and at least 21 days before drilling is planned, the Health and Safety Executive (HSE) must be notified of the well design and operation plans to ensure that major accident hazard risks to people from well and well-related activities are properly controlled, and are subject to the same stringent regulation as any industrial activity. HSE regulations also require verification of the well design by an independent third party. Notification of an intention to drill has to be served to the environmental regulator under S199 of the Water Resources Act, 1991.

4.12 If hydraulic fracturing is intended, the OGA will require that a hydraulic fracturing plan (HFP) is submitted setting out how the operator will control and monitor the fracturing process and address the risk of induced seismicity. The HPF will require approval by EA with HSE having an opportunity to comment. The OGA requires operators to adhere to certain controls before, during and after hydraulic fracturing operations. The details of these controls are set out in the operator's HFP and will be based on a real-time "traffic light system", describing in detail the operator's monitoring and operational precautions in response to seismic events.

4.13 Hydraulic Fracturing Consent (HFC) was introduced as an additional step to the existing regulatory and permitting regime. Before issuing a HFC, DBEIS must be satisfied that a list of specific conditions have been met. It also requires that the financial resilience of companies proposing to carry out hydraulic

fracturing operations is taken into account as part of the consent process. Pre-conditions for a HFC are set out below:

- The environmental impact of the development which includes the relevant well has been taken into account by the local planning authority;
- Appropriate arrangements have been made for the independent inspection of the integrity of the relevant well;
- The level of methane in groundwater has, or will have, been monitored in the period of 12 months before the associated hydraulic fracturing begins;
- Appropriate arrangements have been made for the monitoring of emissions of methane into the air appropriate arrangements have been made for the publication of the results of the monitoring;
- The associated hydraulic fracturing will not take place within protected groundwater source areas;
- The associated hydraulic fracturing will not take place within other protected areas;

  In considering an application for the relevant planning permission, the local planning authority has (where material) taken into account the cumulative effects of— (a) that application, and (b) other applications relating to exploitation of onshore petroleum obtainable by hydraulic fracturing;
- The substances used, or expected to be used, in associated hydraulic fracturing— (a) are approved, or (b) are subject to approval, by the relevant environmental regulator;
- In considering an application for the relevant planning permission, the local planning authority has considered whether to impose a restoration condition in relation to that development;
- The relevant undertaker has been consulted before grant of the relevant planning permission;
- The public was given notice of the application for the relevant planning permission;
- A scheme is in place to provide financial or other benefit for the local area.

4.14 If the operator wishes to drill an appraisal well or propose to start production operations, they start again with the process described above; the landowner's

consent, permissions and planning consent, (which may require EIA and approval from the EA, the HSE, OGA and DBEIS).

4.15 The planning and other regulatory regimes are separate but complementary. The planning system controls the development and use of the land in the public interest and, this includes ensuring that new development is appropriate for the location taking account of the effects, including cumulative effects, of pollution on health, the natural environment, general amenity and the potential sensitivity of the area or proposed development to adverse effects from pollution (see paragraph 185 of the NPPF). The focus is on whether the development is an acceptable use of the land, and the impacts of those uses, rather than the control of the processes involved and health and safety. The information above briefly outlines the regulatory responsibilities for these issues.

4.16 All planning applications have to be assessed on the individual merits of the case, taking account of national and local policy. This applies to all proposals for oil and gas extraction from both conventional and unconventional sources using traditional or new techniques. Decisions will therefore be based on an assessment of the proposal against the policies of local plans and the National Planning Policy Framework and any other material considerations.

4.17 In the early part of 2013 media coverage of proposals for hydraulic fracturing for shale gas led to concerns that such developments would be dealt with by the fast-track route for nationally significant business and commercial development proposed in the Growth and Infrastructure Bill by submitting applications to the Planning Inspectorate rather than to local councils. However, on 19 July 2013 in a Ministerial Statement, Baroness Hanham confirmed that "… responsibility for the determination of planning applications for onshore oil and gas, including for the exploration of shale gas, will be with the local authority.

4.18 The situation changed following the publication on 13 August 2015 of a joint Ministerial Statement from the Department of Energy and Climate Change and

the Department for Communities and Local Government in which the new measures include:

- The Communities Secretary actively considering calling in on a case by case basis shale planning applications and considering recovering appeals
- Identifying councils that repeatedly fail to determine oil and gas applications within the 16 week statutory timeframe requirement (unless applicants agree to a longer period). Underperforming councils gas and oil planning applications could be determined by the Communities Secretary
- Adding shale applications as a specific criterion for recovery of appeals, to ensure no application can ‘fall through the cracks’
- Ensuring planning call ins and appeals involving shale applications are prioritised by the Planning Inspectorate
- Taking forward work on revising permitted development rights for drilling boreholes for groundwater monitoring.

4.19 In Summer 2018 the Government consulted on potential changes in procedures for shale gas developments involving permitted development rights for the exploration for shale gas and transferring determination of shale gas production proposals to the National Infrastructure Project system. No decision has been made on these issues.

4.20 Coverage of recent hydrocarbon operations in the press and media, especially those involving hydraulic fracturing, have focused on a number of important issues, including seismic risks and the chemical content of hydraulic fracturing fluid. The National Planning Practice guidance states that whilst these issues may be put to the mineral planning authority, the responsibility for assessment rests with other regulators. Mineral planning authorities have to assume that these other regulators will carry out their duties and responsibilities. They do not have to undertake their own assessments and should rely on the assessments of these regulators. Prior to granting planning permission,

however, the mineral planning authority will need to be satisfied that these issues can and will be adequately addressed by taking advice from the appropriate regulator.

5. Licensing of Oil and Gas Exploration and Development

5.1 The Petroleum Act 1998 vests all rights and ownership of the petroleum resources (oil and gas) of Great Britain and the United Kingdom territorial waters in the Crown. At the time, the Secretary of State for Trade and Industry (DTI) was responsible for granting licences to persons that confer exclusive rights to 'search and bore for and get' these resources. The Department for Energy and Climate Change (successor to DTI) had a regular timetable of licencing rounds, with generally one onshore round per year. Licences are awarded to those bids promising to optimise the exploitation of the UK's petroleum resources. This function has now passed to the OGA which has published guidance[30] on the current licencing system.

5.2 The main objectives of the licencing regime are to secure the comprehensive exploration and appraisal of UK oil and gas resources and the economic development of discovered reserves. The rights granted by landward licences do not include any rights of access, and the onus is upon the licensee to obtain all the relevant authorisations and planning permissions from the respective authorities and landowners.

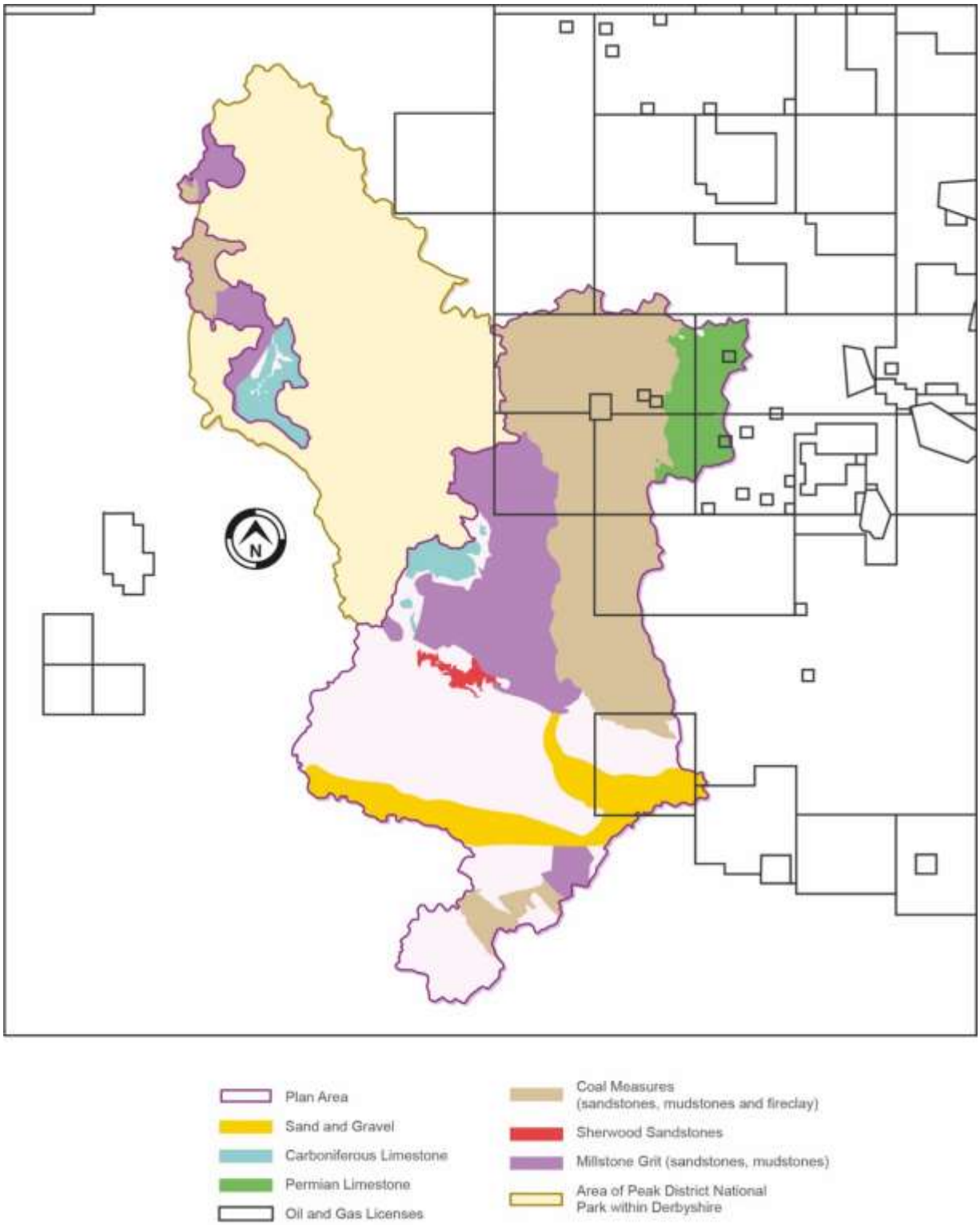
5.3 As a result of the long history of legislation, several types of onshore licence existed. To simplify things, the DTI in 1996 commenced the issue of Petroleum Exploration and Development (PEDL) Licences at the 8th Licensing Round. These carry a three-term lifetime: a six-year Initial Term allows completion of an agreed Work Programme, which is a pre-condition of entry into the five-year Second Term. Successful completion and approval of a development plan is a pre-condition of entry to the Third Term for production, which is granted for a

[30] OGA Consolidated Onshore Guidance Version 2.2 June 2018

period of 20 years, although the Secretary of State has the discretion to extend this period if production is continuing.

5.4 Following the announcement of a new round of licensing offers, applications are made for a PEDL over unlicensed areas (blocks) which correspond to the 10 km by 10 km Ordnance Survey grid. Many licences cover more than one block. Licensees are entitled to surrender a Licence, or part of the acreage covered by it, at any time after the Initial Term and the Work Programme have been completed, with a minimum relinquishment required at the end of the Initial Term. Details of the existing licence areas and those conferred under the 14th Onshore Oil and Gas Licensing Round are shown in Figure 3.

Figure 3: Current PEDL areas within the Plan area



6. Exploration, Assessment, Working and Reclamation

6.1 The production of oil and gas is subject to the same planning controls which are applicable to any other mineral development. The Planning Practice Guidance, March 2014 (as updated), provides a comprehensive summary of the latest planning procedures relating to the winning and working of oil and gas from both conventional and unconventional sources and the inter-relationship of the planning regime with other regulatory systems which have a role in the overall determination of such proposals (see Regulatory System above).

6.2 The three phases of all hydrocarbon extraction operations are exploration, appraisal and production. Planning permission is required for each phase, although some initial preparatory work may have deemed planning consent. The provisions of the Town and Country Planning (General Permitted Development) (England) (Amendment) Order 2016 allow during a period not exceeding 28 consecutive days the drilling of boreholes for the purposes of (a) carrying out groundwater monitoring; (b) seismic monitoring or (c) locating and appraising the condition of mines, in each case, which is preparatory to potential petroleum exploration. This right is subject to a number of exceptions (for example where drilling would be carried out within a National Park or protected groundwater source area) and a number of conditions (including no operations between 6pm-7am, and notification to the Environment Agency). This work can be carried out to establish baseline information on the groundwater environment without the need for planning permission, although other regulatory consents, such as a PEDL, would still be required.

For consistency the following review is a general one applying to oil and gas developments.

Exploration

6.3 The exploratory phase seeks to acquire geological data to establish whether hydrocarbons are present. The main method of determining whether an area has potential traps for petroleum is seismic exploration. Seismic sections provide images of the sub surface. Once detected, a potential trap can be

mapped in detail using 3-D seismic data to define its shape and thickness of petroleum-bearing parts of the reservoir. Porosity and permeability of the reservoir rock determined by direct measurements of exploration-well samples then allow the volume of oil and gas that can be recovered to be estimated.

6.4 Geological data can also be obtained by exploratory drilling. For on-shore situations, exploratory drilling is a short-term, but intensive activity. Typically, site construction drilling and site clearance (if no further development) will take between 12 to 25 weeks. Oil drilling rigs are generally capable of drilling through several thousand metres of rock. They require a power source to rotate the drill and drive the pumps needed to circulate drilling mud (slurry) through the drill bit, allow the well casing to cool and remove the rock cuttings while a well is drilled.

Appraisal

6.5 The appraisal phase takes place following exploration when the existence of oil or gas has been proved, but the operator needs further information about the extent of the deposit or its production characteristics to establish whether it can be economically exploited. This phase can take several forms, including additional seismic work, longer-term flow tests, or the drilling of further wells. This may involve additional drilling at another site away from the exploration site or additional wells at the original exploration site.

Working (extraction)

6.6 The production phase normally involves the drilling of a number of wells. This may be wells used at the sites at the exploratory and/or appraisal stages, or from a new site. Associated equipment such as pipelines, processing facilities and temporary storage tanks are also likely to be required.

6.7 Primary recovery of oil occurs in two stages; 1) the oil flows to the surface through natural reservoir pressure and 2) following initial flow and after the natural pressure is depleted, oil is pumped to the surface, often using the familiar beam pumping units, commonly referred to as ‘nodding donkeys’.

Primary recovery methods produce up to 30% of the oil present but normally this method retrieves only 10% of the oil.

6.8 Secondary recovery refers to simple water flood to displace and drive out remaining oil, or reservoir pressure maintenance through re-injection of natural gas often produced at the same time. Water or gas is injected as a continuous force to the reservoir formation to maintain reservoir pressures. Many oilfields now routinely inject sour gas (containing a proportion of H_2S) back into the reservoir to enhance oil recovery. A growing option is the injection of gases such as nitrogen and CO_2. These dissolve in the oil, lowering the viscosity and increasing mobility. These techniques can boost oil recovery to about 20%.

6.9 A third stage (Tertiary) of enhanced oil recovery may be carried out, potentially increasing the proportion extracted to 30 to 60%. This is a more expensive and utilises less conventional techniques, including thermal recovery (steam injection), chemical injection to increase the effectiveness of water flood or the use of detergents.

6.10 Gas is also obtained by drilling into the host rock. This is accompanied by a variety of techniques to help release the gas from the rock and to create the pressure required to drive the gas up the drill hole to the surface. One method is to re-inject dried gas free of condensate to maintain underground pressure and allow re-evaporation and extraction of more gas. Another method is to send electric charges down the well, which affect the rock around it. After the charges are set off, a highly pressurised liquid fracking solution is sent down the well which breaks up the rocks, releasing the gas.

Restoration

6.11 When all the reserves have been extracted the equipment has to be removed and the site has to be restored to an appropriate condition and a beneficial use. The responsibility for restoration and subsequent aftercare rests with the operator and is normally a requirement of the relevant planning permission or as stipulated in a legal agreement such as a Section 106 Agreement.

6.12 The form of restoration is determined on a site-by-site basis where the original conditions and uses will be important factors. Typical restoration forms include the creation of new habitats and biodiversity, uses for agriculture or forestry or recreational activities.

Processing

6.13 Crude oil (see terminology below) is essentially a mixture of hydrocarbons with varying molecular weights and differing from one another in structure and properties. These various forms are separated into groups, or fractions by a process of distillation called oil refining. The oil is first heated to a vapour, and then passed upwards through a tower containing trays at various levels. The vapours are very hot at the bottom, but become cooler as they rise, so that different fractions condense in the trays at different heights. The lighter the fraction the higher it condenses. On average, crude oil fractions, beginning with the lightest, are: dissolved gases, petroleum ether, gasoline, kerosene, gas oil, lubricating oils, fuel oils and asphalt.

6.14 Further breaking down of the larger heavier molecules of the heavier fractions can be achieved in a process called 'cracking', whereby these fractions are subjected to higher temperatures and pressure or a chemical catalyst. This enables the creation of high octane blending components from low octane naphtha's (e.g. paraffin and olefins).

6.15 At the end of 2020, five major and one minor refineries were in operation in the UK, with a combined capacity of approximately 91 million tonnes per year[31] (the equivalent of 456.25 million barrels).[32] The refineries occupy large sites strategically distributed around the coast where they can receive large oil tanker ships. The network of storage facilities is more urban based, closer to the product users.

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[31] https://knowledge.energyinst.org/search/record?id=58933

[32] Oil and Gas Journal 2018

6.16 Gas extracted from the ground normally contains some impurities which have to be removed to ensure a consistent product in a usable condition. Impurities include water and water vapour and carbon dioxide which affect the calorific value of the gas. Some natural gases (sour gas) contain hydrogen sulphide. The gas has to be processed to remove these impurities. An initial stage of processing is undertaken at the well head to remove free liquid water and gas condensate. The gas is then normally transported via a pipeline to a larger, industrial scale processing plant to remove any further impurities.

7. Economic, Social and Environmental Issues

7.1 The section above on Regulatory Controls identifies the issues that a mineral planning authority may have to take into account when determining planning applications for shale gas developments. The issues are of relevance to the mineral planning authority because they relate to potential adverse economic, social and environmental impacts and the assessments undertaken on these issues help determine whether or not a proposed development is acceptable.

7.2 Some of these potential impacts are ones which would be common to most other minerals developments, including other forms of hydrocarbon developments. For example, issues such as the levels of noise and dust that would be generated, the impact on the landscape, the volume of traffic and how these impacts are to be controlled.

7.3 The PPG advises that the principal issues (potential impacts) that mineral planning authorities can and should address, bearing in mind that not all issues will be relevant at every site, to the same degree, are those which have been identified in the Local List (Local list of information requirements required to support planning applications). The issues identified in the Local List of Information Requirements operative in Derbyshire and Derby address the following topics:

- Noise associated with the operation.
- Dust.
- Air quality, including odour emissions.

- Lighting.
- Visual intrusion into the local setting and the wider landscape caused by the placement of any building or structure within the application site area.
- Landscape character.
- Archaeological and heritage features.
- Traffic.
- Water and water resources, including foul and surface water drainage.
- Risk of contamination to land.
- Soil resources.
- The impact on the 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.

7.4 In addition there are other potential impacts that will influence the decisions of other regulators and which fall outside the sphere of the planning system. There are however some issues and impacts which are particularly relevant to hydraulic fracturing. These are addressed below using information and opinion obtained from Government publications. They are included as a general background introduction to the issues.

Water Use

7.5 Large quantities of water are required during the hydraulic fracturing process. It is estimated that a typical well could use between 10,000 to 30,000 cubic metres of water (2 – 6 million gallons) which is enough to fill 12 Olympic swimming pools[33].

[33] EA Facts about fracking: water 2017

7.6 Concerns have been raised that this usage could result in the depletion of water within local eco-systems and damage to their integrity and function. All proposals for the abstraction of surface or ground waters are regulated by the Environment Agency who should take account of such potential impacts before issuing a permit. An added concern is the impact on drinking water supplies, especially in periods of drought. This will also be addressed by the Environment Agency with reference to its Water Resources Strategy. Water companies must produce, and then update every 5 years, a long-term plan with contingency reserves in case of a drought. Water companies will assess the amount of water available before providing it to operators.

Impacts on Ground Water

7.7 One of the major concerns is the potential risk of contamination of ground water. The process involves the use of fluids containing potential pollutants which are injected into the ground, where they may enter into the ground water system. The presence of water containing other fluids could also mobilise natural substances in the ground that could then cause pollution. The assessment of these risks is a matter for the EA under the Environmental Permitting Regulations 2010 (EPR). Where approved, the permit would specify any limits on the activity, any requirements for monitoring, the chemicals which may be used and any limits on permissible concentrations. If the activity poses an unacceptable risk the EA would not issue a permit. If the EA decides that the activity could not affect ground water, a permit would not be necessary. In the event that a risk or impact becomes apparent, the EA could issue a notice requiring the operator to obtain a permit, or in extreme situations, issue a notice prohibiting the operation.

7.8 The EA notes[34] that shale gas deposits are found at depths thousands of metres deeper than rivers, lakes and aquifers that provide our drinking water. Above the shale rock there are many layers of impermeable rock which will block gas or other pollutants from travelling upwards to groundwater.

[34] EA Facts about fracking: water, 2017

Additionally high pressure volume fracking is banned[35] at depths of less than 1000 metres; drinking water supplies are typically found up to about 250 metres. Furthermore fracking is not permitted[36] within 1,200 metres beneath areas that are most vulnerable to groundwater pollution.

7.9 Concerns have been raised about the chemicals used in hydraulic fracturing and the potential to pollute the water environment. The EA requires that only chemicals that are not hazardous to ground water can be used. The names and quantities of the chemicals must be provided to and approved by the EA. Many of the approved chemicals used in frack fluids are already used by other industries including farming, food and drinking water industry and the cosmetics industry. The chemicals used by Cuadrilla, the only company so far to have carried out hydraulic fracturing for shale gas are listed as:

- 99.75% of the fluid is made up of water and sand
- 0.075% polyacrylamide friction reducers commonly used in cosmetics and facial creams
- 0.125% hydrochloric acid frequently used in swimming pools and drinking water wells
- 0.005% biocide used on rare occasions when the water provided from a local supplier needs to be purified further.

7.10 Regulation in England requires baseline monitoring of a range of chemicals and methane in groundwater before any hydraulic fracturing takes place in order to obtain baseline information against which to assess any impacts.

Seismic Activity

7.11 One of the main concerns is the potential for fracking to result in seismic activity which could result in damage to property and land. The Government introduced a ‘traffic light system’, administered by the OGA, of control over seismic activity

[35] Under provisions of the Infrastructure Act 2015

[36] Under the provisions of the Onshore Hydraulic Fracturing (Protected Areas) Regulations 2016

in which green is for events of up to 0ML and injections proceed as normal, amber refers to events between 0M and 0.5ML where injections proceed with caution, possibly at reduced rates, and red for events over 0.5ML where an operator must suspend injections, reduce pressure and monitor seismic activity and ground motion for any further events before potentially resuming.

7.12 Seismic activity associated with mineral operations is not uncommon in the UK. There are many recorded incidences of seismicity induced by coal mining activities or the settlement of abandoned mines. British Geological Survey records indicate that coal mining-related seismicity is generally of smaller magnitude than natural seismicity and no larger than 4 ML.

7.13 The risk of seismic activity is the responsibility of the Oil and Gas Authority (OGA) through the licence consent regime. It requires an applicant to provide an assessment of the geology of an area to establish geological conditions, risk of seismic activity and mitigation measures to be put in place for all hydraulic fracturing processes.

Wastes including Methane Release and Leakage

7.14 Concerns exist around potential wastes produced from fracking both in terms of the escape of gases from the well and shale gas hydraulic fracturing fluids into the air, and the need to dispose of shale gas hydraulic fracturing drilling muds and wastewater. The EA is primarily responsible ensuring the control and management of waste.[37]

7.15 Waste material includes solids, liquids and gases. The solid materials are pieces of rock from the drilling of the borehole, known as drill cuttings. Waste liquids come from the discarded fluids used to help the drilling process, known as drilling muds, and the waste water that returns to the surface after fracking, known as flowback fluid. Waste gas is gas that cannot be used and needs to be collected.

[37] EA , Facts about fracking: waste 2017

7.16 The waste is regulated through environmental permits from the EA and, as part of the permit, operators must have an approved Waste Management Plan which sets out how the operator will control wastes on-site to ensure that they do not escape and cause pollution.

7.17 The drilling muds transport cuttings from the well back to the surface to prevent clogging of the well. At the surface the cuttings are separate from the drilling mud. Drilling mud can be reused by the operator to reduce waste, or returned to the mud producer for reuse elsewhere. If the drilling mud cannot be used again it is usually transported off site in skips by an authorised contractor and taken to a licensed waste facility.

7.18 Waste gas is captured and can then be used to generate energy although at the exploration stage this is unlikely to be cost effective if the site is temporary and without a connection to the grid. In this situation the operator will need to safely dispose of the gas using a flare. The flare should be enclosed to burn methane efficiently and reduce air, noise and light pollution. Venting and flaring of gases are regulated by the OGA as part of licence conditions which require that such activities are kept to the minimum that is technically possible.

7.19 Unplanned releases of gas, for example, leaks from valves and well heads and from the well casing underground are strictly controlled through conditions in the environmental permit which require the operator to monitor for leaks. A programme of monitoring must be set out in an Emissions Monitoring Plan which requires approval by the EA.

7.20 The wastewater or flow back fluid that returns to the well is likely to contain high quantities of natural minerals and metals that have dissolved in the water from the shale or other rock formations. The fluid may also contain naturally occurring radioactive material (NORM) and a small proportion of the non-hazardous chemicals added during the fracking process. Waste water will need to be treated off-site at a Waste Water Treatment Works which will require an appropriate permit from the EA. Operators accumulating and storing NORM

waste are required to have a Radioactive Substances environmental permit. The waste must then be treated at a permitted treatment facility, also regulated by the Environment Agency, which specialises in removing and disposing of NORM safely.

8. Production, Consumption and Reserves

Global

8.1 For geological reasons, shale gas resources are often synonymous with sources of conventional hydrocarbon resources of oil and other gases. There are believed to be large resources of shale gas (unproved technically recoverable)[38] in China (1,115 trillion cubic feet), Argentina (802 TCF), Algeria (707 TCF), USA (623 TCF), Canada (573 TCF) and Mexico (545 TCF). In Europe extensive reserves can be found in Poland (146 TCF) and France (137 TCF).

8.2 The working of shale to obtain gas to date has largely been concentrated in the United States (US) where it has been extracted using various techniques but production on a lower scale has recently commenced in Canada and China. The earliest workings were in 1821 in Fredonia, New York where shallow shales were exploited. The technique of horizontal drilling began in the 1930s and a well was first 'fracked' in 1947. Production of gas using the modern methods of hydraulic fracturing generated 1,293 billion cubic metres in 2007, rising to 7,994 billion cubic metres by 2011 and again to 18,589 billion cubic metres by 2017. As a result of this domestic production gas imports to the US fell by 55% between 2007 and 2012. Since 2016 the US has been a net exporter of gas.

National

8.3 The British Geological Survey study estimated that the reserves in the Bowland-Hodder study area to be in the order of 1,300 trillion cubic feet[39] but it

[38] US Energy Information and Administration, World Shale Resource Assessments, 2015

[39] BGS DECC Bowland Shale Gas Report 2013

is not yet possible to provide a reliable estimate of the volume that could be commercially viable. The Government has acknowledged that only when empirical data is available from production sites will the figures on genuine resource availability be finalised. The Government's Gas Generation Strategy[40] states that, '*overall, it is likely the pace of development of shale gas in the UK will be slower than has been seen in the United States. If exploration is successful, early production is likely to be seen in the second half of this decade, but any substantial contribution to the UK's gas supply is unlikely until further into the 2020s*.'

8.4 At the time of writing hydraulic fracturing for shale gas has only taken place at two sites Preese Hall and Preston New Road, both in Lancashire and operated by Cuadrilla Resources Ltd. In 2011, Cuadrilla completed drilling of Preese Hall 1, the first onshore shale gas exploration well in the UK to investigate the resource potential of the Bowland Shale. The well was drilled vertically to a total depth of 2740 metres, and a number of potentially prospective shale horizons were identified, for which initial estimates indicated a potentially significant shale gas resource. A total of six zones in the Bowland shale were perforated for hydraulic fracturing, which commenced on 26 March 2011.

8.5 Six stages were hydraulically fractured during these operations, with the largest stage, stage 2 using treatment volumes of approximately 2250 m3 of slick water, and placing 117 tons of proppant. On the 1 April 2011, 10 hours after stage 2, a magnitude 2.3 ML seismic event was detected by seismic monitoring in the area and was felt by local people. Following the completion of stage 5, on the 27 May 2011, a further magnitude 1.5 ML seismic event occurred. These events were suspected to be associated with the hydraulic fracturing at Preese Hall, and operations were therefore suspended by the company. Additionally, the government imposed a temporary moratorium on hydraulic fracturing whilst these seismic events were investigated.

[40] DECC Gas Generation Strategy, December 2012

8.6 Following extensive investigation the government, in December 2012, lifted the moratorium on fracking subject to new regulatory requirements concerning seismic activity including the Traffic Light System (TLS). In 2017, Cuadrilla commenced exploratory drilling at Preston New Road. A vertical pilot well was drilled which was then deviated horizontally (PRN1z) through the upper most section of the Bowland Shale. A second horizontally deviated well (PRN2) was drilled through the lower section of the Bowland Shale. In September 2018, the OGA agreed the required Hydraulic Fracture Plan for the hydraulic fracturing of the PNR1z well, in which Cuadrilla proposed to fracture up to 41 stages along the horizontal well, using up to 765 m3 of slick water fluid to place 75 tonnes of proppant per stage.

8.7 Following hydraulic fracturing of PRN1z some 57 seismic events were recorded of which nine were reported as 'traffic light system (TLS)' events (greater than 0 ML) by the operator, and six exceeding the magnitude 0.5 ML threshold. The largest was 1.5ML which resulted in a cessation of 48 hours. Operations were resumed but due to the TLS events just 14% of the intended proppant was injected into the formation. Hydraulic fracturing of the well ended in December 2018. The OGA[41] has used the data collected from this well to study in depth the linkages between hydraulic fracturing and seismic events.

8.8 A Hydraulic Fracture Plan was agreed in August 2019 to fracture the second well at Preston New Road (PNR2). The planned operations for PNR2 were to hydraulically fracture up to 45 stages, using 765 m3 of fluid to place 75 tonnes of proppant. The plan introduced options to use either slick water, gel or a hybrid frac fluid as a mitigation against induced seismicity. Only 6 stages have been fractured and only 13% of the intended volume of proppant. By stage 7 a number of red TLS events have occurred the largest of these measuring 2.9ML which reportedly caused potential superficial damage to buildings. Operations were suspended on 23 August 2019 following which the OGA announced that the suspension would remain whilst investigations were conducted into these

[41] OGA Interim report of the scientific analysis of data gathered from Cuadrilla's operations at Preston New Road, November 2019

events, including the consideration as to whether the assumptions and mitigations in Cuadrilla's PNR2 Hydraulic Fracture Plan continue to be appropriate to manage the risk of induced seismicity at the Preston New Road site.

8.9 Cuadrilla has stated that results from flow testing PNR2 confirm that natural gas of the highest quality sampled to date in the Lancashire Bowland Shale is present. Sampled gas contained 89 per cent methane, 6 per cent ethane and 2 per cent propane, with virtually no impurities. Natural gas flowed to the surface from a total of just six propped fracture stages. A total volume of some 1.3 million cubic feet of natural gas was recovered and gas flowed at a peak rate of over 275 thousand cubic feet per day data with stable flow rates of between 60 and 100 thousand cubic feet per day.

Derbyshire

8.10 The Bowland-Hodder study area included most of Derbyshire but it does not contain any specific information or estimates of the level of reserves in the area. It does indicate however, that parts of the County may prove to be underlain by commercially viable reserves of shale gas. Exploratory seismic survey work[42] has been undertaken by INEOS Upstream Ltd in four PEDL areas in the north east of the County. Planning permission has been granted, on appeal, for the exploration of shale gas at one site Bramleymoor, in the north east of the County, operated by INEOS Upstream Ltd. The proposal involves the erection of a 60 metre tall drilling rig to drill around 2,400 metres below the ground to investigate the suitability of the rock for hydraulic fracturing. This planning permission expired in August 2021.

[42] Permitted development under Part 17, Class K of Schedule 2 of the Town and Country Planning (General Permitted Development) (England) Order 2015 (GPDO).