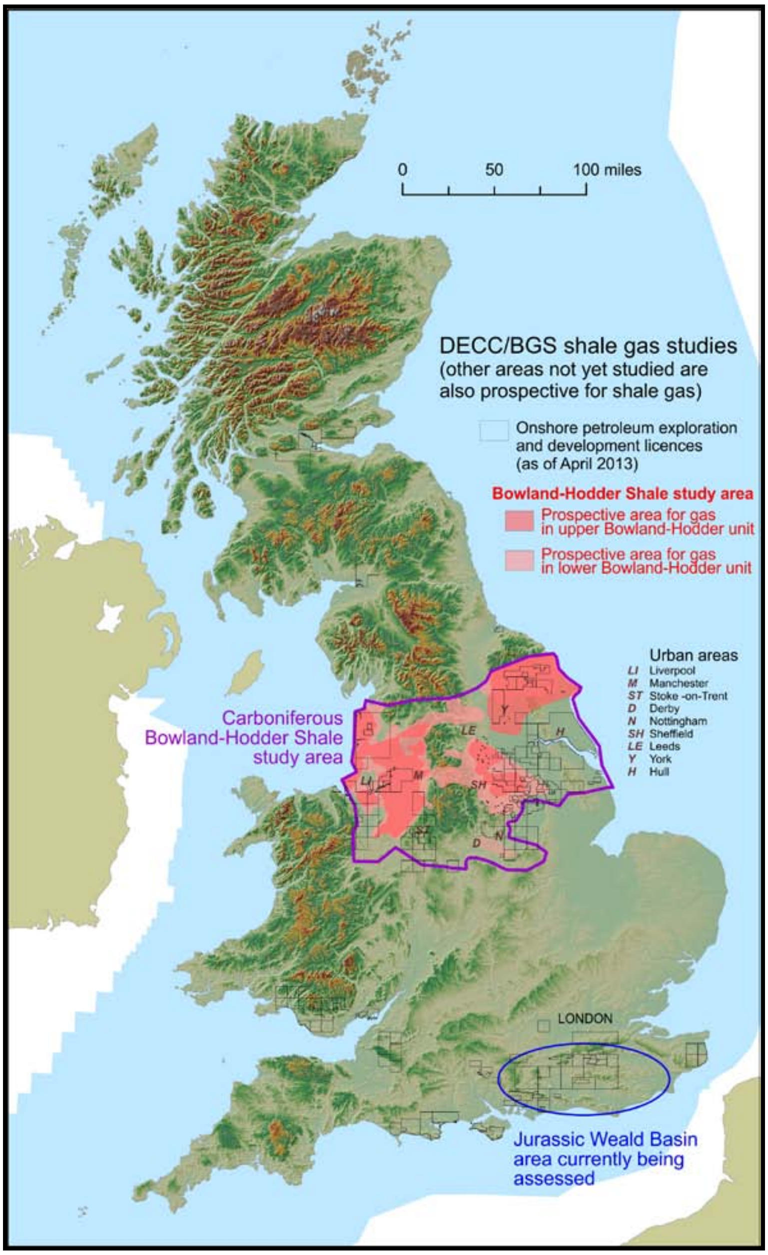
The Carboniferous Bowland Shale gas study: geology and resource estimation



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Foreword

This report has been produced under contract by the British Geological Survey (BGS). It is based on a recent analysis, together with published data and interpretations.

Additional information is available at the Department of Energy and Climate Change (DECC) website. https://www.gov.uk/oil-and-gas-onshore-exploration-and-production. This includes licensing regulations, maps, monthly production figures, basic well data and where to view and purchase data. Shale gas related issues including hydraulic fracturing, induced-seismicity risk mitigation and the information regarding the onshore regulatory framework can also be found on this webpage.

Interactive maps, with licence data, seismic, relinquishment reports and stratigraphic tops for many wells are available at www.ukogl.org.uk.

A glossary of terms used and equivalences is tabled at the end of the report (see page 48).

All of the figures in this report are attached in A4 or larger format; thumbnails are also included in the text for reference.

Acknowledgements

The author would like to thank the many contributors to this report, most notably Sue Stoker[1], Kevin Smith[3], Nigel Smith[4], Mike Sankey[3], Chris Vane[4], Mike McCormac[3], Ceri Vincent[4], Vicky Moss-Hayes[4], Toni Harvey[2] and Joy Gray[2], and reviewers Al Fraser[5], Nick Riley[4] and Don Cameron[3].

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1. Summary

The assessment of shale gas resources in the UK is in its infancy. This report summarises the background geological knowledge and methodology which has enabled a preliminary in-place gas resource calculation to be undertaken for the Bowland-Hodder (Carboniferous) shale gas play[1] across a large area of central Britain (Figure 1).

Marine shales were deposited in a complex series of tectonically active basins across central Britain during the Visean and Namurian epochs[2] of the Carboniferous (c.347-318 Ma). In all of these basins, deep-water marine shales pass laterally into shallow-water shelf limestones and deltaic sandstones. Contemporary basins extend offshore beneath the East Irish Sea and the Southern North Sea.

The marine shales attain thicknesses of up to 16,000 ft (5000 m) in basin depocentres (i.e. the Bowland, Blacon, Gainsborough, Widmerpool, Edale and Cleveland basins), and they contain sufficient organic matter to generate considerable amounts of hydrocarbons. Conventional oil and gas fields around most of these basins attest to their capability to produce hydrocarbons.

The organic content of the Bowland-Hodder shales is typically in the range 1-3%, but can reach 8%.

The maturity of the Bowland-Hodder shales is a function of burial depth, heat flow and time, but subsequent uplift complicates this analysis. Where they have been buried to sufficient depth for the organic material to generate gas, the Bowland-Hodder shales have the potential to form a shale gas resource analogous to the producing shale gas provinces of North America (e.g. Barnett Shale, Marcellus Shale). Where the shales have been less-deeply buried, there is potential for a shale oil resource (but, as yet, there is inadequate geotechnical data to estimate the amount of oil in-place).

In this study, shales are considered mature for gas generation (vitrinite reflectance > 1.1%) at depths greater than c. 9500 ft (2900 m) (where there has been minimal uplift). However, central Britain has experienced a complex tectonic history and the rocks here have been uplifted and partially eroded at least once since Carboniferous times. Because of this, the present-day depth to the top of the gas window is dependent on the amount of uplift, and can occur significantly shallower than 9500 ft.

The total volume of potentially productive shale in central Britain was estimated using a 3D geological model generated using seismic mapping, integrated with outcrop and deep borehole information. This volume was truncated upwards at a depth of 5000 ft (1500 m) below land surface (a suggested US upper limit for thermogenic shale gas production) or the depth at which the shale is mature for gas generation (whichever was the shallowest).

The volume of potentially productive shale was used as one of the input parameters for a statistical calculation (using a Monte Carlo simulation) of the in-place gas resource (see Appendix A).

[1] The Bowland-Hodder shale gas play (or Bowland-Hodder shales) is the term used in this report for an amalgamation of shales of Visean to early Namurian age that includes the Bowland Shale Formation (and its equivalents) together with older shales which equate to the Hodder Mudstone Formation. The definition of the unit is discussed in more detail within this report.

[2] See Section 5 for a comparison of the Carboniferous chronostratigraphies used by European and North American/international geologists.

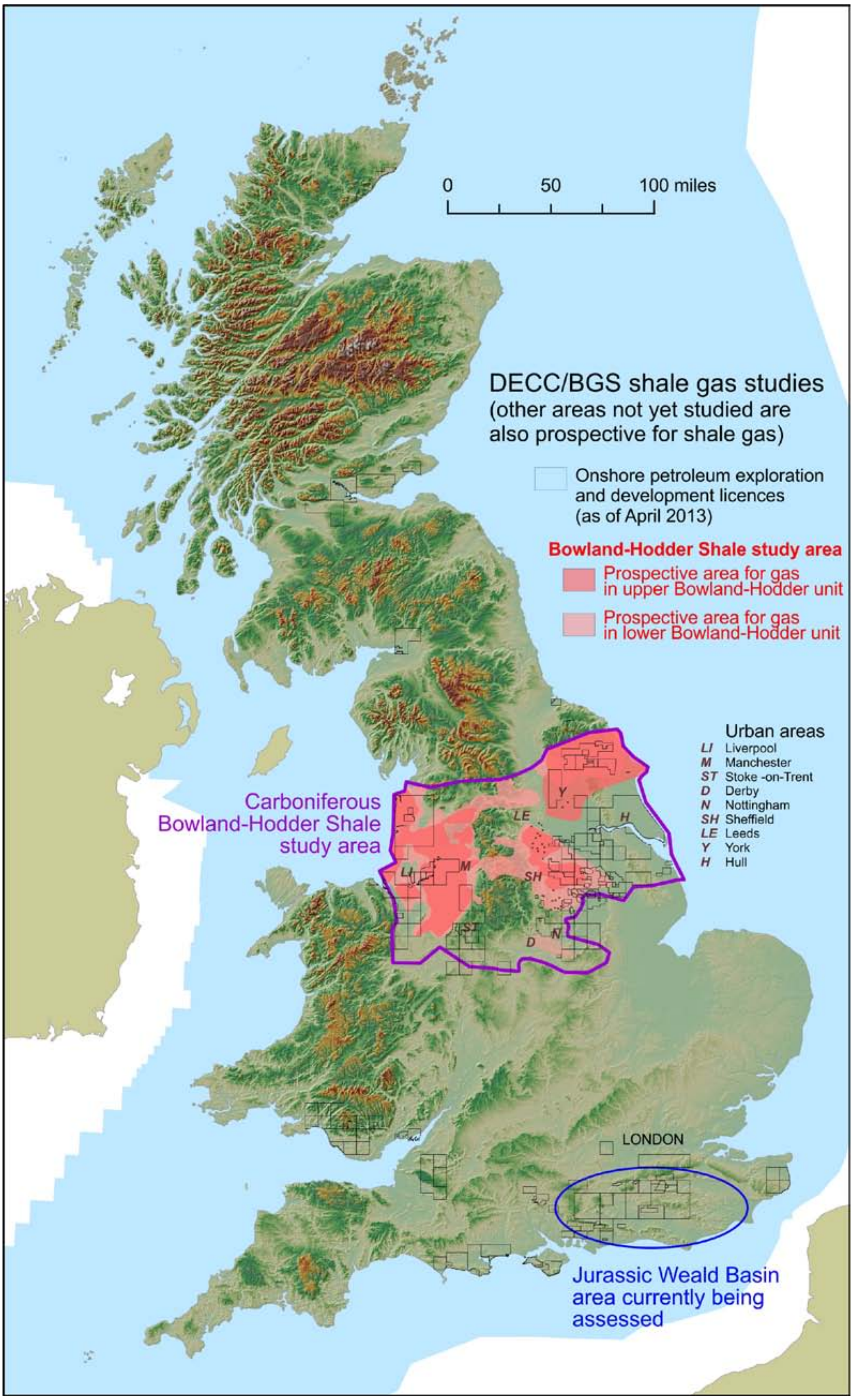


Figure 1. Location of the DECC/BGS study area in central Britain, together with prospective areas for shale gas, currently licensed acreage and selected urban areas. Other shale gas and shale oil plays may exist.

For the purposes of resource estimation, the Bowland-Hodder unit is divided into two units: an upper post-rift unit in which laterally contiguous, organic-rich, condensed zones can be mapped, even over the platform highs, and an underlying syn-rift unit, expanding to thousands of feet thick in fault-bounded basins, where the shale is interbedded with mass flow clastic sediments and re-deposited carbonates.

The upper unit is more prospective, primarily due to the better well control which demonstrates its closer resemblance to the prolific North American shale gas plays, in which the productive zones are hundreds of feet thick. The lower unit is largely undrilled, but where it has been penetrated it contains organic-rich shale intervals, whose lateral extent is unknown.

This study offers a range of total in-place gas resource estimates for the upper Bowland-Hodder unit shales across central Britain of 164 – 264 – 447 tcf (4.6 – 7.5 – 12.7 tcm) (P90 – P50 – P10). It should be emphasised that these ‘gas-in-place’ figures refer to an estimate for the entire volume of gas contained in the rock formation, not how much can be recovered.

There is considerable upside potential in the lower unit, but the resource estimation for this unit has a much higher uncertainty due to the paucity of well data so far and potentially less favourable lithologies. The estimated range of gas in place for this thick unit is 658 – 1065 – 1834 tcf (18.7 – 31.2 – 51.9 tcm). The total range for estimated gas in place is 822 – 1329 – 2281 tcf (23.3 – 37.6 – 64.6 tcm) (P90 – P50 – P10) for the combined upper and lower parts of the Bowland-Hodder unit.

	Total gas in-place estimates (tcf)			Total gas in-place estimates (tcm)		
	Low (P90)	Central (P50)	High (P10)	Low (P90)	Central (P50)	High (P10)
Upper unit	164	264	447	4.6	7.5	12.7
Lower unit	658	1065	1834	18.6	30.2	51.9
Total	822	1329	2281	23.3	37.6	64.6

This large volume of gas has been identified in the shales beneath central Britain, but not enough is yet known to estimate a recovery factor, nor to estimate potential reserves (how much gas may be ultimately produced). An estimate was made in the previous DECC-commissioned BGS report (2010a) that the Carboniferous Upper Bowland Shale, if equivalent to the Barnett Shale of Texas, could potentially yield up to 4.7 tcf (133 bcm) of shale gas. In the absence of subsurface volumes of potential gas-bearing shale, this early estimate was based on the relative areal extent of the basins. Now, after detailed subsurface analysis, a “bottom-up” resource assessment of gas in-place has be made, which more accurately reflects the area’s shale gas potential. However, it is still too early to use a more refined methodology, like the USGS’s Technically Recoverable Resource “top-down” estimates which require production data from wells. In time, the drilling and testing of new wells will give an understanding of achievable, sustained production rates. These, combined with other non-geological factors such as gas price, operating costs and the scale of development agreed by the local planning system, will allow estimates of the UK's shale gas reserves to be made.

Other areas in the UK have shale gas and shale oil potential, and later in 2013 the Jurassic shales in the Weald Basin of southern England will be the subject of a further BGS/DECC study.

2. Introduction to shale gas and resource estimation

2.1. History of oil and gas exploration and production in the UK

Exploration for oil and gas in the UK began onshore in the late 19th century, but subsequent land-based activity has been episodic, with six principal phases yielding variable success (Evans 1990, Decc 2010b). The earliest reports of hydrocarbons date from 1836, and a well drilled at Heathfield in Sussex in 1895 produced sufficient gas to fuel a gas light for the railway station. The history of exploration through subsequent decades is detailed in DECC (2010b), with the largest gas fields discovered being Saltfleetby (Lincolnshire) and Kirby Misperton (North Yorkshire). Wytch Farm with associated gas (Dorset), Welton (Lincolnshire), Stockbridge (Hampshire) and Eakring (Nottinghamshire) have produced the most oil (DECC 2010b). Wytch Farm is the largest onshore oil field in Europe, but the total onshore production is small compared with offshore production and contributes only 1.5% of overall UK oil and gas total. Over 2100 wells have been drilled onshore for oil and gas. There are currently (April 2013) 30 oil fields and 8 gas fields producing onshore, plus 3 coalbed methane and 18 vent gas (extraction of methane from abandoned coal mines) fields producing gas.

In recent years (Figure 2), there has been a decline in the number of exploration and appraisal wells drilled for conventional oil and gas onshore, with a shift to coalbed methane (CBM), vent gas and most recently, to wells drilled for shale gas exploration.

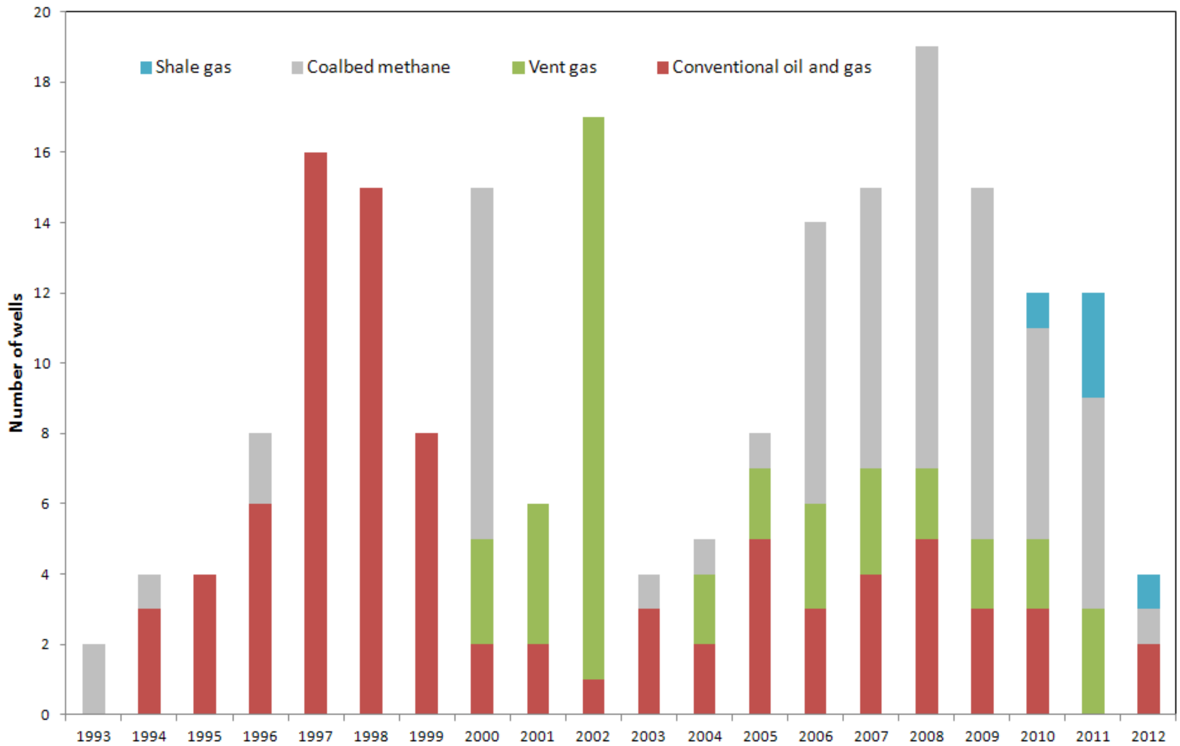


Figure 2. Numbers of onshore exploration and appraisal wells drilled in the past 20 years.

Within the study area, significant amounts of gas have been discovered in conventional plays in the Bowland, Cleveland, Edale, Gainsborough, Humber and Widmerpool basins (Figure 3). There was also a natural build-up of methane in the Wyresdale Tunnel, Lancashire, which lead to the fatal Abbeystead explosion in May 1984 (Wilson *et al*. 1985, Smith *et al*. 2010). These occurrences provide evidence for working petroleum systems in all of the sub-basins and the expulsion of gas from source rocks which have reached the gas window in the vicinity of the fields.

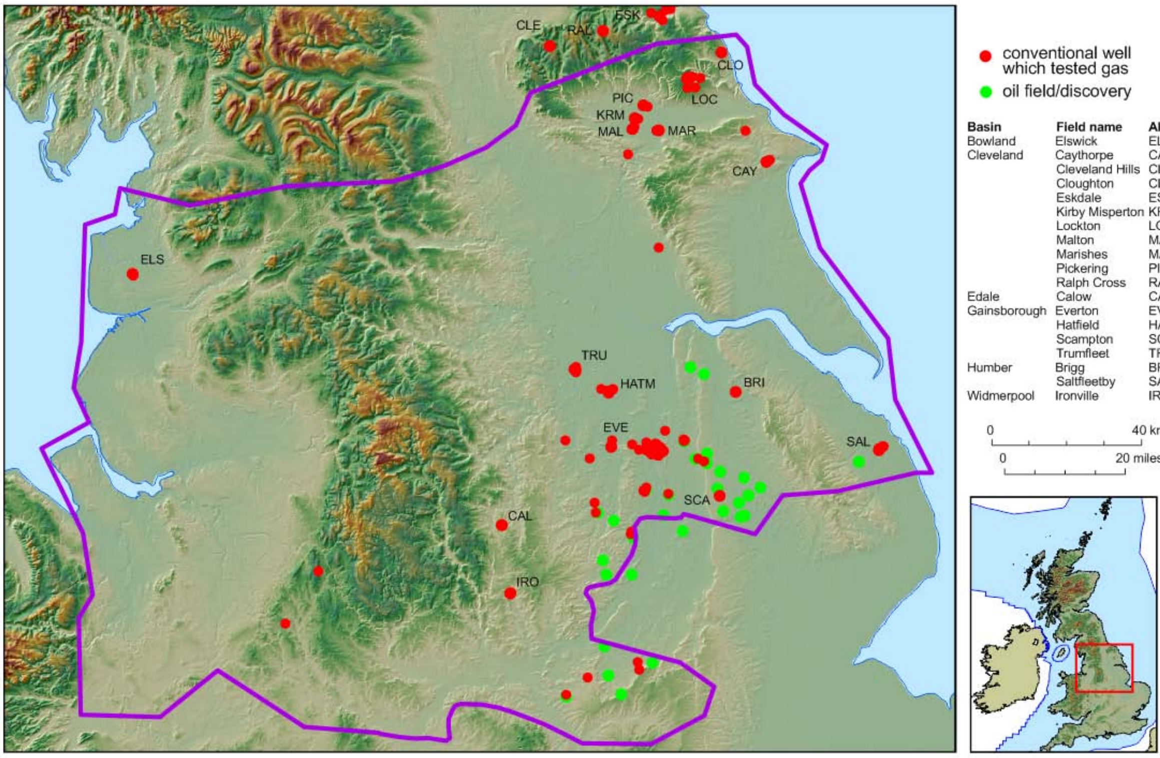


Figure 3. Distribution of wells (not including coal-related CBM or vent gas) which have tested gas and oil in central Britain (from DECC data).

Oil was commercially produced from Carboniferous oil shales in West Lothian between 1859 and the 1940s, and although shale gas potential was highlighted in the 1980s (Selley 1987, 1996, 2005) it was only in the 13th Onshore Licensing Round in 2008 that companies specifically sought to explore for shale gas. Only one shale gas well has been hydraulically fractured, Cuadrilla's Preese Hall 1 well during 2011, but that test was suspended before completion of the fracturing programme after two small earthquakes were induced (Green *et al*. 2012).

2.2. Resources vs. reserves

In simple terms, the resource estimate for any shale gas play is the amount of gas in the ground (some of which might never be produced), while the reserve estimate is a more speculative measure which describes the amount of gas that you might be able to extract given appropriate technology, economics and other factors. The recovery factor is an estimate of the proportion of the total gas resource that might be extracted, and it is generally expressed as a percentage. Recently, the Parliamentary Office of Science and Technology published a POSTbox note for policymakers to address the distinction between reserves and resources, which have often been confused by the media (POSTbox 2013).

To some extent our ability to obtain reserve or resource figures in any hydrocarbon province is determined by the stage of exploration and the degree of production uncertainty. Gas in-place (GIP), original gas in-place (OGIP) or gas initially in-place (GIIP) are all the same estimate and these figures are normally derived early in an exploration phase perhaps even before drilling takes place, for the benefit of shareholders and investors. These speculative values often find their way into the media. When substantive data from drilling and production rates become available, more reliable figures for reserves and resources can be estimated. But if only a few wells are drilled, there is a risk that the data they reveal may not be representative of large undrilled areas. A large variability in shale gas well productivity has been experienced in North America, where the gas from wells in 'sweet spots' far exceed the average recovery from wells across the play area.

A third measure of the amount of gas is the concept of 'technically recoverable resources' (TRR) which the US Geological Survey (e.g. Charpentier & Cook 2011) use to estimate how much gas is likely to be extracted. The USGS methodology was modified for coalbed methane and shale gas and oil to use well production information (estimated ultimate recovery and well spacing) to better constrain estimates of recoverable volumes compared with their previous recovery factor based methodology used for conventional oil and gas. The US Energy Information Administration (EIA) estimates of TRR for shale gas and tight oil have changed significantly in recent years as new well performance data and USGS resource assessments have been integrated (USEIA 2012). However, a wide variety of other methodologies of estimating resource and reserve potential have been used by other organizations and these described by Pearson *et al.* (2012) along with the factors determining the viability of development. Technically or economically recoverable resources will fluctuate in time according to technological advances and commercial factors.

In the US, the SPE Petroleum Resource Management System nomenclature (Figure 4, SPE 2007) defines total petroleum initially-in-place as that quantity of petroleum that is estimated to exist in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to 'total resources') and goes on to describe 'contingent resources' for which key conditions or contingencies that prevent commercial development must be clarified or proved to be viable.

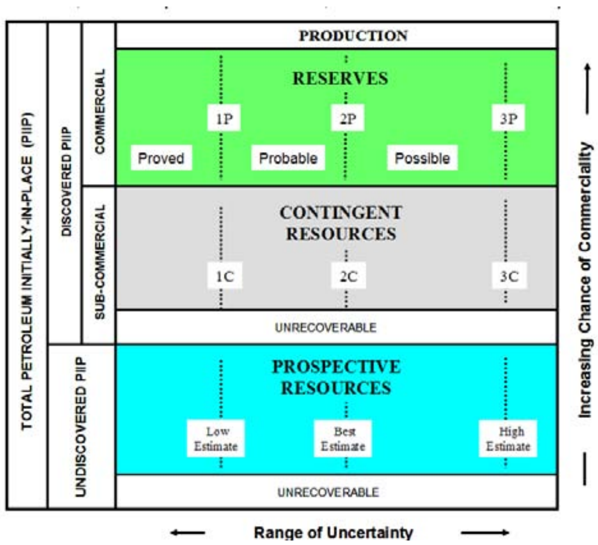


Figure 4. The Society of Petroleum Engineers' framework for petroleum resource classification (SPE 2007).

For the Bowland-Hodder shale, a number of hurdles must be overcome to economically produce gas. A way to describe the current state of understanding is illustrated by the diagram presented by the IEA (2011) (Figure 4a) which indicates five factors determining the viability of commercial development, or reserves. This report addresses only the resource size, the first stage of this process.

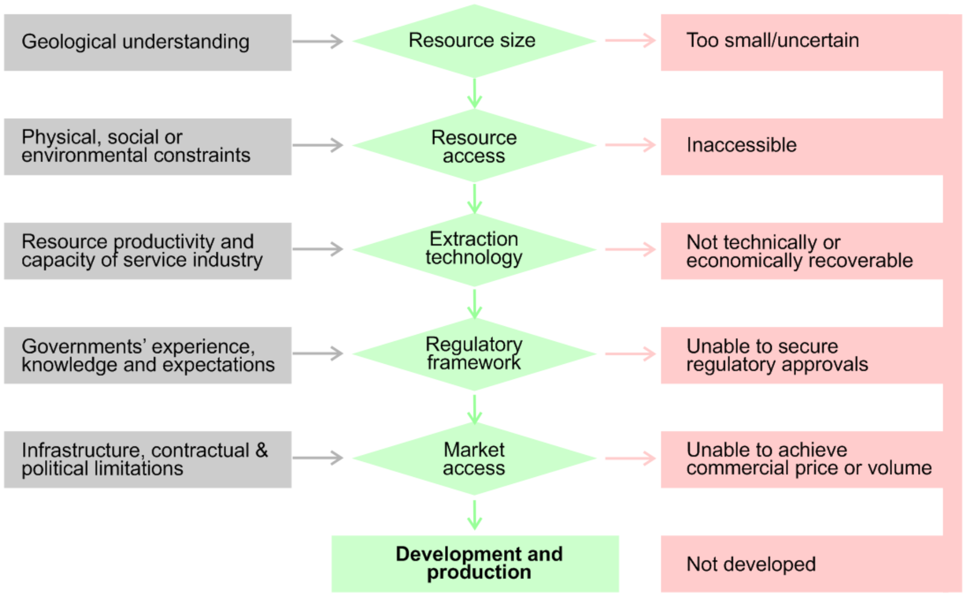


Figure 4a. Factors determining the viability of natural gas developments (IEA 2011).

2.3. Shale as a source and reservoir rock

In conventional oil and gas accumulations, shales comprise the source rock from which hydrocarbons are generated following burial. Through geological time, these hydrocarbons migrate from the source rock, through carrier beds and ultimately accumulate in porous reservoirs (typically sandstone or carbonate) in discrete traps. These traps are typically located in structural highs on the margins of the basin centres.

In the case of unconventional hydrocarbon accumulations (such as shale gas), this perceived wisdom is turned on its head – with shales acting as both source and reservoir rock, and the extensive basin centres becoming the exploration targets. Also, it is only within the last few decades that technology has enabled shale gas reservoirs to be exploited more economically.

Exploration for shale gas presents a series of new challenges; not least the collection of a different suite of geological, petrophysical and geotechnical data across previously little understood and poorly studied parts of hydrocarbon provinces.

In shale gas plays, biogenic[3] or thermogenic gas is present as two components: either adsorbed onto kerogen or clay particles, or present as free gas in pore spaces and natural fractures.

Shale is predominantly comprised of very fine-grained clay particles deposited in a thinly laminated texture, but shale gas production may also come from layers of re-deposited limestone or thin clastic beds within the gross shale sequence. The clay particles fall out of suspension and become interspersed with organic matter, which is measured as the rock's total organic carbon content (TOC). Through deep burial these muddy strata are compacted, and the pore water is expelled, resulting in a low-permeability layered rock called 'shale', which describes the very fine-grained and laminar nature of the sediment, not the rock composition, which is layered. Each of these layers creates a barrier to fluid migration, and this stacked system, called 'composite layering' is an effective vertical seal.

Matrix permeabilities (the ability of fluids to pass through them) of typical shale are very low compared to conventional oil and gas reservoirs (<0.1 mD in shales versus >1 mD in conventional reservoir sandstones) which means that, in shale, hydrocarbons are effectively trapped and unable to flow or be extracted under normal circumstances, and they are usually only able to migrate to conventional traps over geological time.

2.4. What defines a shale gas play?

Table 2 summarises some of the most important geological, geochemical and geotechnical criteria that are widely used to define a successful shale gas play; some criteria are essential, others are desirable. The criteria are based on data from analogous shale gas plays in the USA, which are known to vary considerably from one another.

Criteria	**Range of data and definitions**	**UK data (availability and gaps) and definitions used in this report**
Organic matter content (TOC)	Shales should be rich in organic matter, with total organic carbon (TOC) values > 2% (TNO 2009, Charpentier & Cook 2011, Gilman & Robinson 2011). >4% (Lewis *et al*. 2004). Jarvie (2012) uses a cut-off of just 1% present-day TOC, and quotes averages for the 10 top US systems as 0.93-5.34% TOC.	Some legacy data available, augmented by data from a study commissioned by DECC (Appendix B). A cut-off of TOC > 2% is used for a potentially viable shale gas resource.
Gamma-ray values	High gamma radiation is typically an indication of high organic carbon content. Gamma log response should preferably be 'high' (Charpentier & Cook 2011); 20 API above shale baseline (Schmoker 1980); >230 API (NPC 1980); >180 API (DECC 2010a); >150 API, but lower if TOC is demonstrably high (D. Gautier, USGS, pers. comm.).	The cut-off used has been selected on a well-by-well basis taking into account TOC and background shale gamma-log values, but is typically in the range 150 to 200 API.

[3] Natural gas can be created by two mechanisms: biogenic and thermogenic. Biogenic gas is created by micro-organisms that produce methane as a metabolic by-product in anoxic conditions such as in marshes, bogs, landfills, and shallow sediments. At depth, at greater temperature and pressure, thermogenic gas is created through the maturation of buried organic material. Biogenic gas can be encountered even if the underlying source rocks have not entered the thermogenic gas generation window.

Criteria	**Range of data and definitions**	**UK data (availability and gaps) and definitions used in this report**
Kerogen type	Kerogen should be of Type I, II or IIS (Charpentier & Cook 2011). Ideally, II (Jarvie 2012). This indicates a planktonic, marine origin.	Information on kerogen type is incomplete. Ewbank *et al*. (1993) identify Type II and III kerogen in various basins. Note: immature Type II kerogen can plot in the Type III field when matured for gas generation (Jarvie *et al.* 2005).
Original hydrogen index (HI_o)	HI_o preferably >250 mg/g (TNO, 2009, Charpentier & Cook 2011); 250-800 mg/g (Jarvie 2012). Note: it is important to have information on original, rather than present day, HI values. This conversion relies heavily on kerogen type.	Only present day HI values are available for UK basins.
Mineralogy/clay content	Clay content should be low (< 35%) to facilitate fracking and hence gas extraction. Jarvie (2012) stresses the requirement of a significant silica content (>30%) with some carbonate, and presence of non-swelling clays.	USEIA (2011a) quote 'medium/high' clay contents. There is scope for further work to bring together data from disparate sources and for new analyses.
Net shale thickness	Moderate shale thicknesses are considered ideal; >50 ft (15 m) (Charpentier & Cook 2011); >20 m (TNO 2009); >150 ft (Jarvie 2012). Conventional wisdom is that the 'thicker the better', but this may not necessarily be the case (Gilman & Robinson 2011); >25 m in <200 m gross section (Bent 2012). Thick shale sequences (100s of metres) tend to be regarded as 'basin centre gas' plays rather than shale gas plays.	Net potentially productive shale in the upper Bowland-Hodder unit is 200-3000 ft (60-900 m) thick; the lower Bowland-Hodder unit is up to 10,000 ft (3000 m thick) (with the possibility of thin units of higher-than-background TOC). These latter thicknesses are much greater than in the US analogues.
Shale oil precursor	A shale oil precursor should ideally be identified.	Oil and gas fields sourced from the Bowland-Hodder unit are both present in central Britain.
Thermally maturity	The shale should be mature for gas generation; R_o = 1.1 – 3.5% is widely accepted as the 'gas window'. Charpentier & Cook (2011) use a cuff-off of R_o >1.1%. Smith *et al*. (2010) use 1.1% as it demarcates the prospective area in the Fort Worth Basin; Jarvie (2012) quotes a higher cut-off of R_o >1.4%; 1.2 – 3.5% (BGR 2012); <3.3% (TNO 2009). Conventional wisdom is 1.25 – 2%, but 'empirical wisdom' is 1.75 – 3% (Gilman & Robinson 2011).	In this study, the shale is considered to be mature for gas generation above an R_o value of 1.1%.
Gas content/saturation	Gas should be present as free gas (in matrix and fractures) and adsorbed gas. Gas contents should be 60-200 bcf/section (Bent 2012) or >100 bcf/section (Jarvie 2012).	There is no published information on gas contents. Data from US analogues has been used.
Depth minimum	Depth >5000 ft (>1500 m) (Charpentier & Cook 2011). Lower pressures generally encountered at shallower depths result in low flow rates.	Shale resources shallower than 5000 ft (1500 m) below land surface have been excluded from this study.
Shale porosity	Typically 4-7%, but should be less than 15% (Jarvie 2012).	Not known.
Overpressure	Slightly to highly overpressured (Charpentier & Cook 2011, Jarvie 2012). The Barnett Shale is slightly overpressured (Frantz *et al.* 2005).	Not known, but Smith *et al*. (2010) mention 'the lack of overpressure' in the Bowland Shale. However, recently-uplifted shales in central England should in theory be mildly overpressured. In resource calculations the pressure is assumed to be hydrostatic to give a conservative estimate of gas in place.
Tectonics and burial history	Preferably in large, stable basins, without complex tectonics (Charpentier & Cook 2011). Wells should be drilled away from faults where possible.	Britain is located at the junction of several structural terrains and has undergone a complex geological history; the basins are also generally small. Locally, faulting occurs at high densities.

Table 2. Criteria that are widely used to define a successful shale gas play.

2.5. Shale gas around the world

Figure 5. Estimates of technically recoverable shale gas resources (tcf) for selected shale formations in 32 countries (USEIA 2011a; Bickle et al. 2012). Note: data were not available for Russia, Central Asia, Middle East, South-east Asia and central Africa. The figure of 20 tcf for the UK includes 19 tcf for the Bowland Shale and 1 tcf for the Liassic shales of the Weald Basin.

The distribution of potential shale gas plays covers the globe (Figure 5), but it is only within North America that large-scale commercial extraction has been achieved to date. In the USA, ten shale gas plays hold the vast majority of the country's technically recoverable reserves, and these are the only shale gas plays currently being exploited (USEIA 2011b, Jarvie 2012).

2.6. How to estimate how much gas?

Two fundamentally different methodologies are used to assess shale gas basins worldwide:

1. In-place resource estimates based on a geological model, volumetrics and gas contents ('bottom-up approach', as used by TNO and BGR), and

2. Technically recoverable resource estimates based on well technology, well performance, well density ('top-down approach', as used by the USGS).

In-place estimates with a robust connection to geological studies are widely considered an excellent tool for initial estimates, and BGS/DECC have employed this methodology. TNO (2009) and BGR (2012) also used this approach to make their preliminary assessments of shale gas resources in the Netherlands and Germany. While the second approach has been shown to be more reliable based on the US experience, no shale gas production data are yet available in the UK.

USEIA (2011a) subsequently de-risked their equivalent gas in-place figure by a factor that 'account[s] for the current level of knowledge of the resource and the capability of the technology to eventually tap into the resource'. This approach is not followed here because of the relative infancy of the UK shale gas industry.

3. Estimating the total in-place gas resource of the Bowland-Hodder unit in central Britain

3.1. Introduction

Carboniferous organic-rich basinal marine shales are present across a large part of central Britain and the study area extends from Merseyside to Humberside and Loughborough to Pickering (Figure 6). The shales are either buried at depth or occur at outcrop. These organic-rich shales are recognised to be excellent source rocks, in which oil and gas matured before some of it migrated into conventional oil and gas fields (e.g. UK Midlands area, East Irish Sea) (DECC 2010b). The Bowland shale gas study area is bounded by complete erosion of the potentially prospective shales over highs to the south, by uplift in several areas where the prospective units are at outcrop, and by a facies change in the north and north-east to contemporary deltaic deposits.

Figure 6. Location of the BGS/DECC shale gas study area, central Britain. Contains Ordnance Survey data © Crown copyright and database right 2013.

3.2. Seismic, well and outcrop data

This assessment of the Carboniferous basin shales of central Britain is based upon detailed seismic mapping using all available hydrocarbon well and stratigraphic borehole information along with outcrop geology.

Although several thousand wells and boreholes have been drilled within the assessment area, only 64 of these reached sufficient depths to record more than 50 ft (15 m) of net shale in the Early

Carboniferous section (Figure 7). Very few wells have drilled more than 1000 feet (300 m) of the section of interest. Key wells are discussed further in Section 3.6.

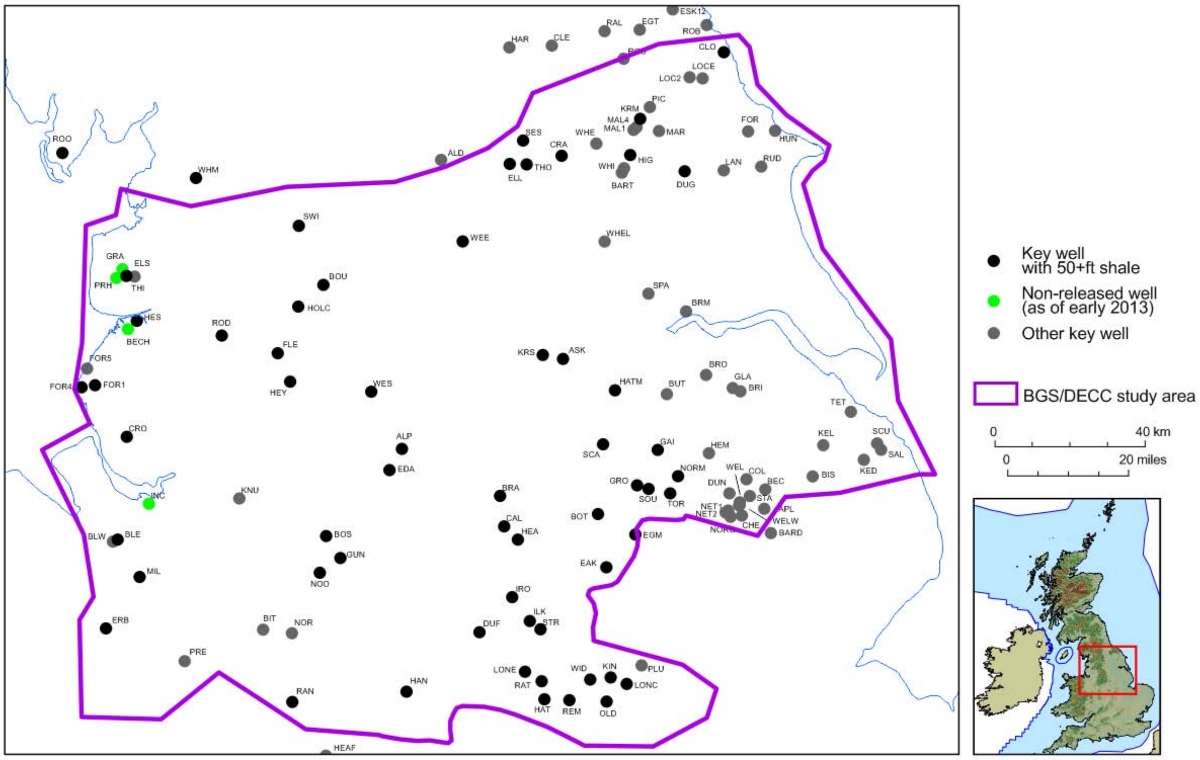


Figure 7. Location of key wells, non-released wells and other wells providing important stratigraphic information used to assess the shale gas potential of central Britain. See Appendix C for details of well name abbreviations and stratigraphic information.

All of the available seismic data was obtained from the UK Onshore Geophysical Library (UKOGL www.ukogl.org.uk). A total of c. 23,500 km (14,700 miles) of 2D and 1000 km² (390 mile²) of 3D seismic data (Figure 8) was loaded on an interpretive workstation. This mixed vintage data is of variable quality and often short line lengths (because seismic data onshore UK can only be shot over extant licences). An iterative approach was employed, finding seismic lines with the good evidence for horizon mapping, then circling back through the poorer quality lines, with an interpretation that was consistent with the detailed BGS outcrop mapping and the geological model.

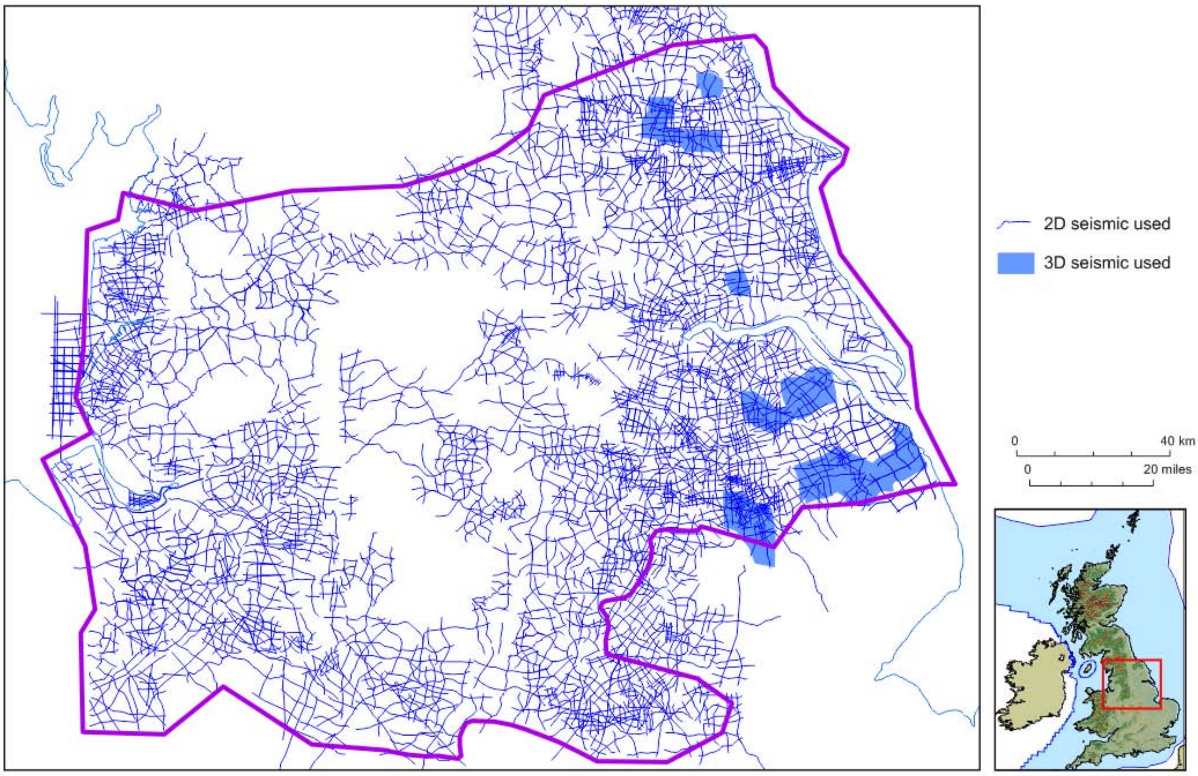


Figure 8. Location of 2D seismic profiles and 3D surveys used to assess the shale gas potential of central Britain.

The Bowland-Hodder shales (of the Craven Group, see section 3.4) are at outcrop in the Lancashire Forest of Bowland, Derbyshire Peak District, North Wales, at Gleaston (Cumbria) and a small area near Harrogate (Figure 9). These outcrops fringe areas where post-Carboniferous uplift has brought older rocks to the surface (e.g. the Derbyshire Dome and the Clitheroe and Slaidburn anticlines). These have been mapped by the BGS over a period of c.150 years and a large amount of literature has been published, but this has often concentrated on the sandstones, fossils and bed-by-bed stratigraphy. Since 2000, BGS has published three subsurface memoirs within the study area (Kirby *et al.* 2000, Smith *et al.* 2005, Pharaoh *et al.* 2011) (Figure 10).

Lee (1991) and others have interpreted the regional gravity and magnetic data (Figures 11 and 12). In the northern half of the area, gravity lows correlate more closely with known rift basins, such as the Widmerpool and Edale gulfs and the Gainsborough Trough (GL7, GL8 and GL9 respectively). Anomaly GL 10, however, is thought to be related to the postulated concealed Market Weighton Granite adjacent to the lineaments associated with known basement highs, such as the Nocton and Askern-Spital highs, and ESE-trending lineaments associated with faults which controlled sedimentation, such as the fault on the southern margin of the Widmerpool Gulf. Licence operators have acquired proprietary high-resolution gravity gradiometry surveys which better image the structural fabric of the Carboniferous rift basins, but these are not yet in the public domain.

Although the shales are widely distributed, their outcrops are not extensive and occur mainly in river and road cuttings (Figure 13).

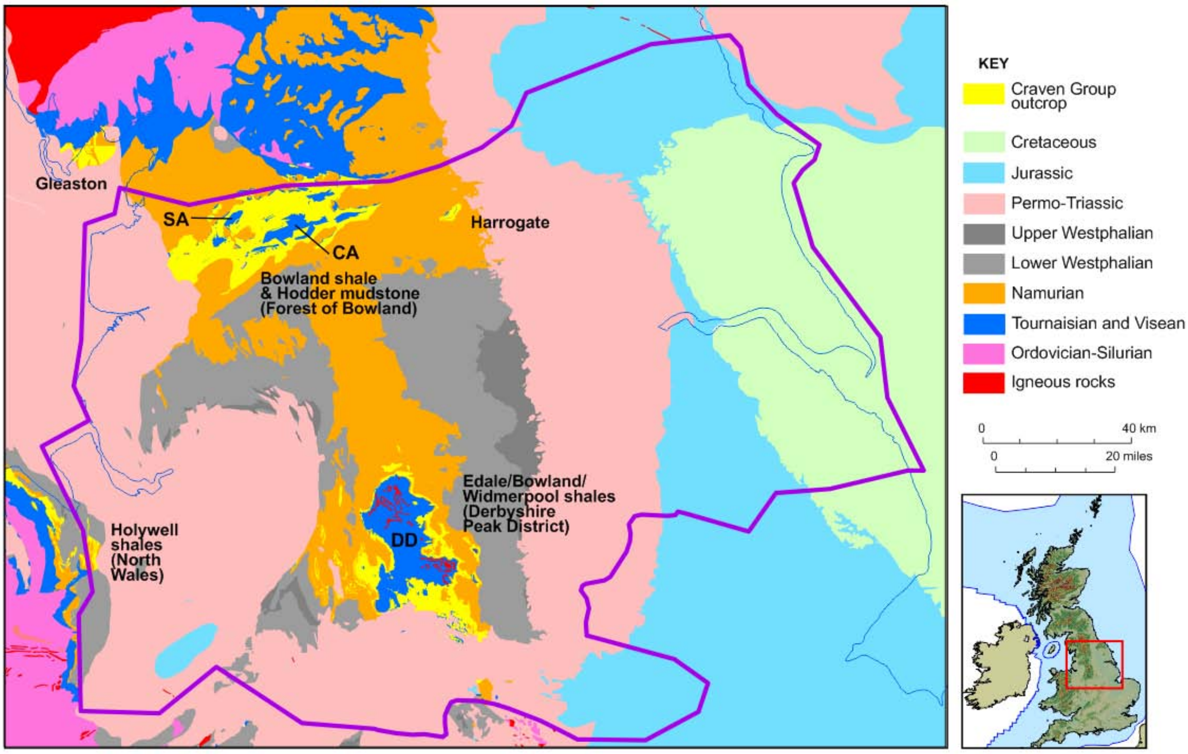


Figure 9. The five main Craven Group outcrops in central Britain (from BGS 1:50,000 mapping). DD = Derbyshire Dome; CA = Clitheroe Anticline; SA = Slaidburn Anticline.

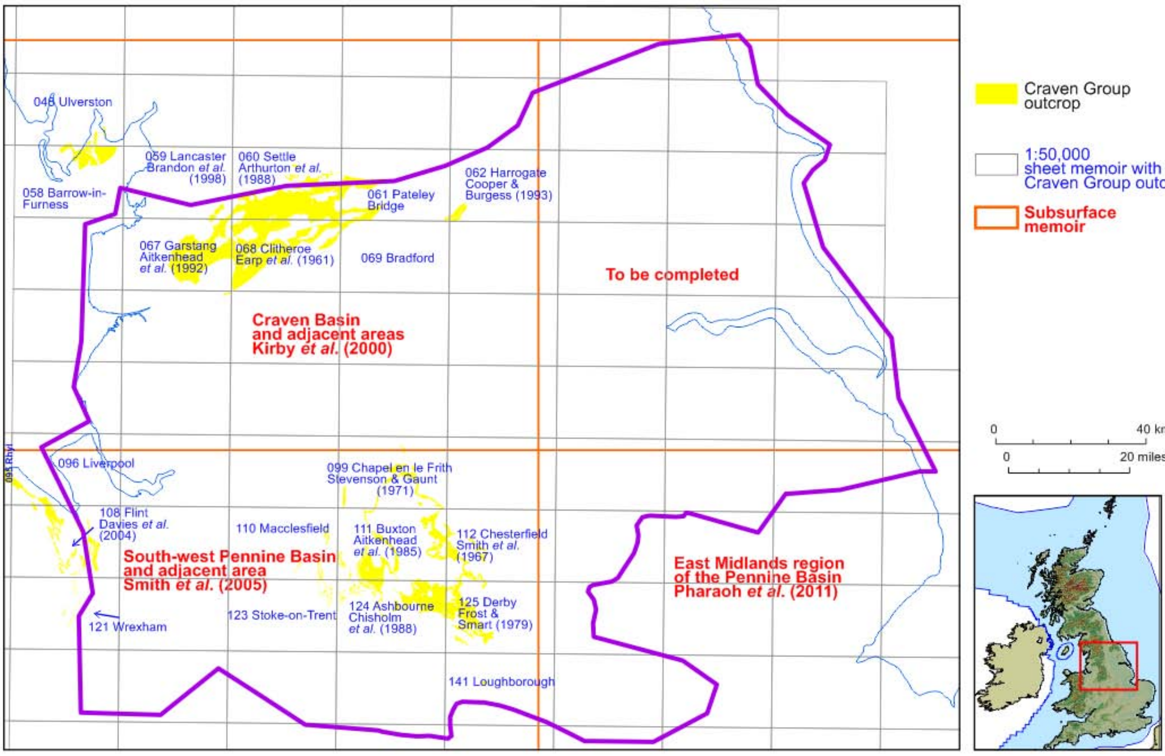


Figure 10. Location of relevant BGS map sheets and memoirs across central Britain. See references for further details.

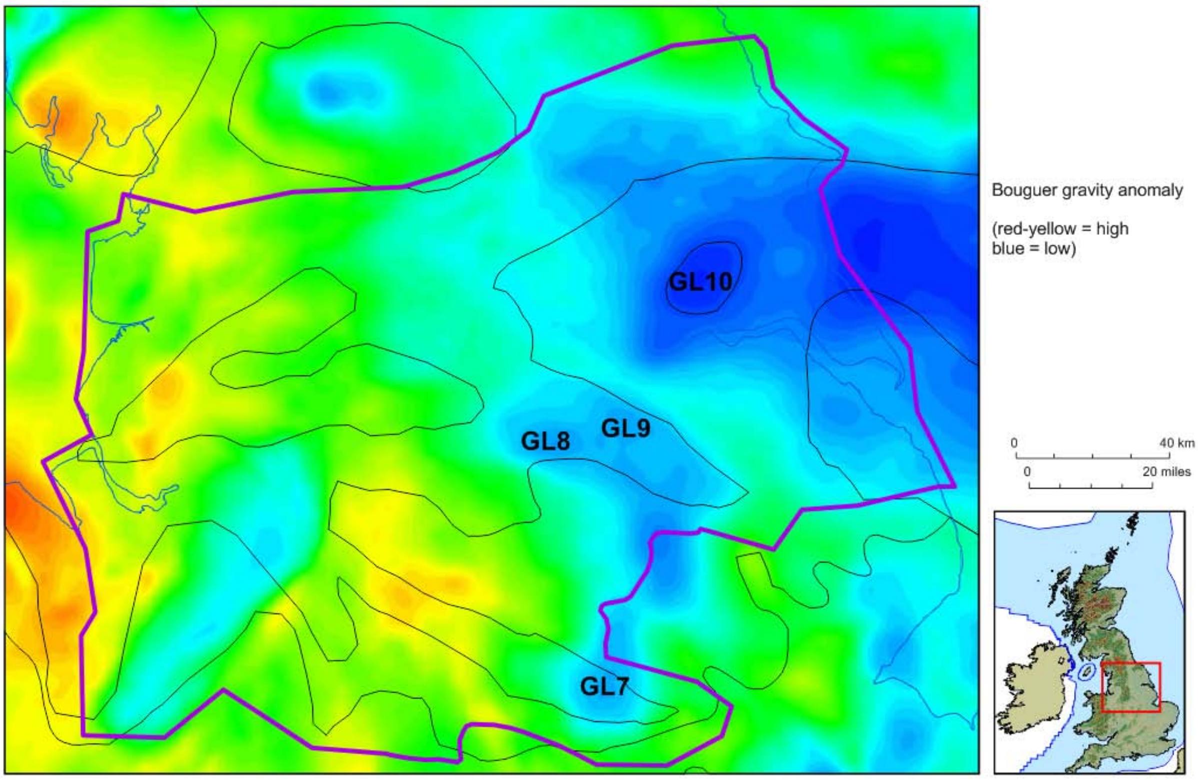


Figure 11. Bouguer gravity anomaly map for central Britain (from BGS mapping). Gravity low (GL) numbering from Lee et al. (1991). The Early Carboniferous structural framework lines are from Figure 14.

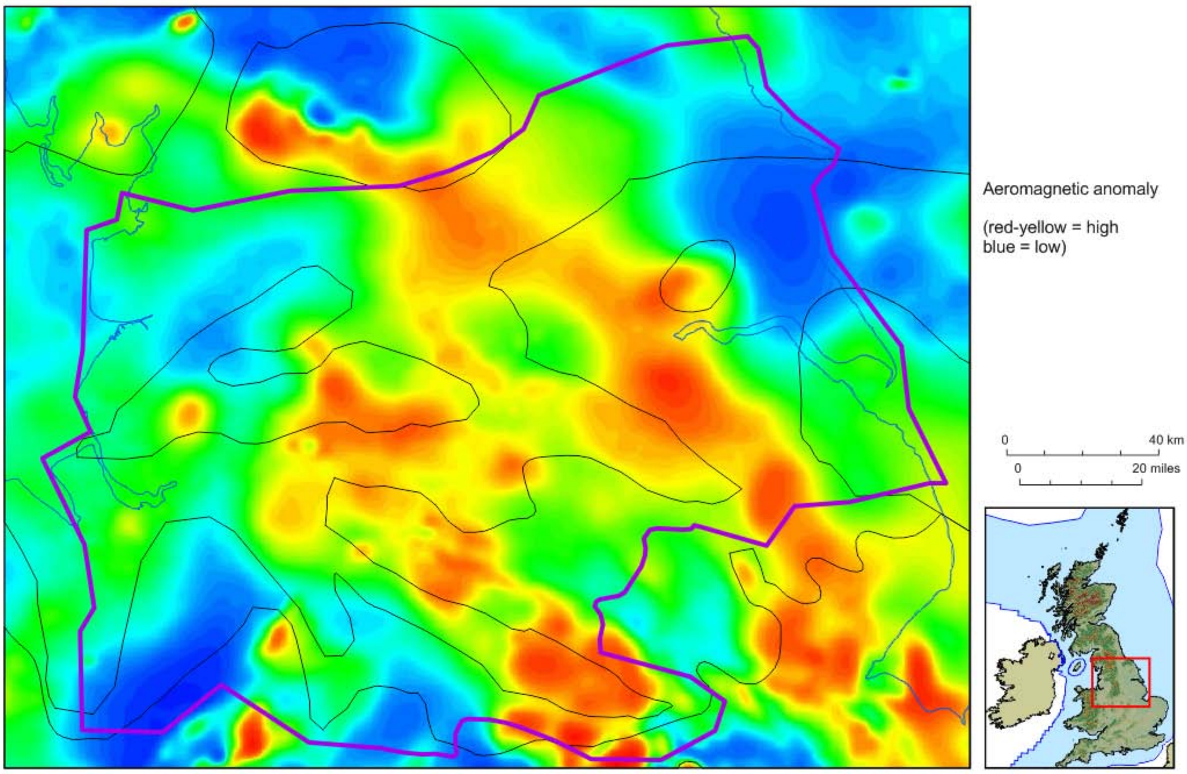


Figure 12. Magnetic anomaly map for central Britain (from BGS mapping). The Early Carboniferous structural framework lines are from Figure 14.

Figure 13. Typical outcrop of shale showing a slope deposit comprising imbricated rafted blocks of Hodder Mudstone Formation (Arundian age) on the flank of Ashnott High, Bowland Basin, Lancashire. © N.J. Riley/BGS

3.3. Paleogeography and basin inversion

Palaeomagnetic evidence suggests that Britain was situated in near-equatorial latitudes during Visean times, and the Carboniferous was a period of glacial eustasy, with sea-level fluctuations likely to have had a significant impact on deposition. Marine shales were deposited in a complex series of tectonically active basins across central Britain during the Visean and Namurian. A phase of Late Devonian to Early Carboniferous rifting produced a marked palaeo-relief with numerous basins occupying subsiding grabens and half-grabens and emergent highs associated with horsts and tilt-block highs (Leeder 1982, 1988) (Figure 14). In general terms, hemipelagic marine shales (with mass flow deposits) were deposited in the basins and these pass laterally into extensive platform carbonates over the East Midlands Shelf and Derbyshire High. Equivalent basins occur offshore beneath the East Irish Sea (Jackson *et al.* 1995) and the Southern North Sea (Cameron *et al.* 1992). Cessation of most rifting processes occurred across large parts of the UK in the late Visean to be followed by a period of regional subsidence during which the pre-existing basins were generally filled in completely by more widespread marine deposition.

The Early Carboniferous basin model has become increasingly well defined, with supporting evidence coming from both the interpretation of seismic data and well penetrations (e.g. Kent 1966, Leeder 1982, 1988, Smith *et al*. 1985, Fraser *et al.* 1990, Fraser & Gawthorpe 1990, 2003). The exceptions are the basin beneath the Permo-Triassic Cheshire Basin[4] where the thickness is unconstrained and in the Humber Basin, where the interpretation is tenuous due to the lack of well penetrations and poor seismic control (Figure 14).

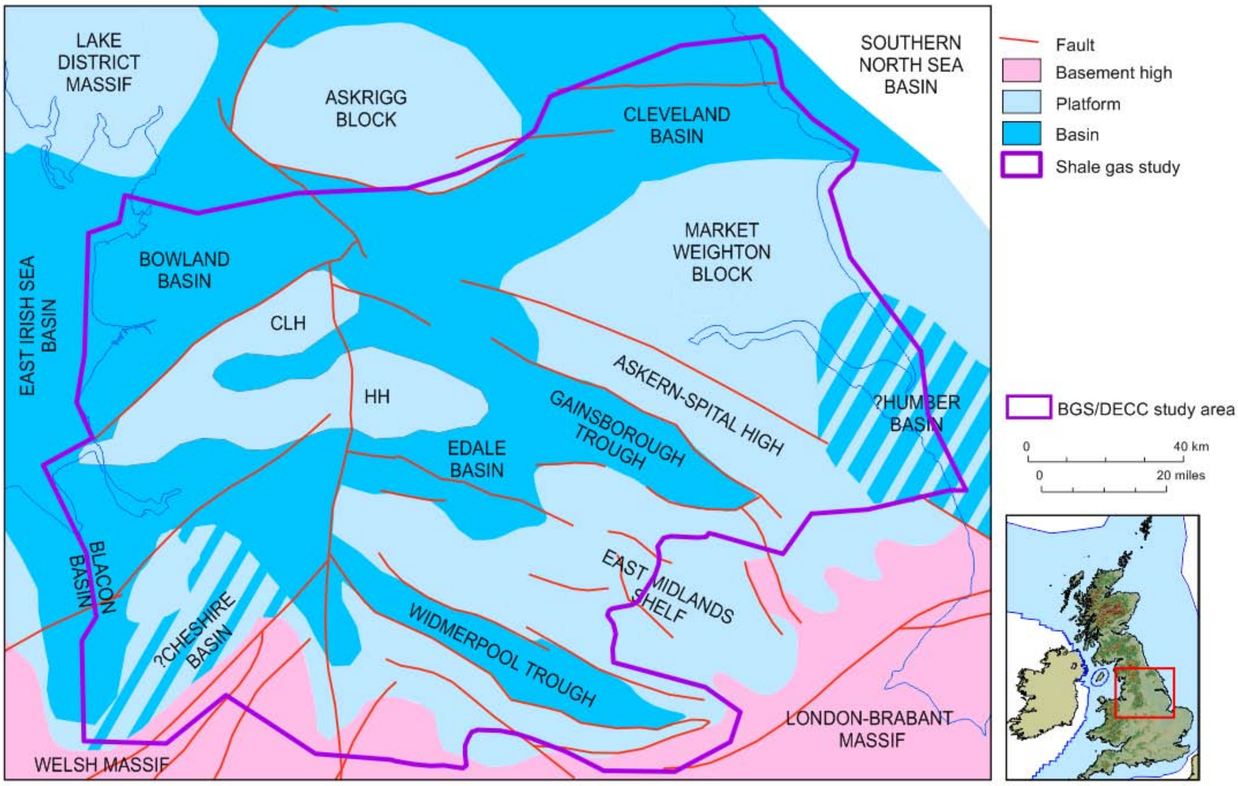


Figure 14. The Early Carboniferous basins and platforms of central Britain (modified after Fraser et al. 1990, Kirby et al. 2000). CLH = Central Lancashire High; HH = Holme High. Note: the presence of Early Carboniferous basins beneath the Permo-Triassic Cheshire Basin (Smith et al. 2005 cf. Waters et al. 2009) and a putative Humber Basin (Kent 1966, Hodge 2003) are both debatable (see text).

The Blacon East 1 and Milton Green 1 wells in the Blacon Basin penetrate basinal facies of late Visean, Brigantian age (Smith *et al.* 2005) and Davies *et al.* (2004) indicate basinal facies extending south as far as the Dee Estuary and Wirral. There are no well data further east and the seismic data is of insufficient quality to provide evidence for the thickness of the unit. Smith *et al.* (2005, Fig. 27) show that deep-water sediments with limestone turbidites were deposited across the Cheshire Basin area during the Asbian-Brigantian, with platform carbonates to the west and also south-east of the Red Rock Fault. On the other hand, Mikkelsen & Floodpage (1997) and Fraser & Gawthorpe (2003) show carbonate shelf facies extending broadly across an area that Waters *et al.* (2009; Fig. 1) label as the 'Holme High'. To avoid confusion, this report introduces the term 'Blacon Basin' for the Early Carboniferous basin which lies beneath the western part of the Permo-Triassic Cheshire Basin.

[4] The term Cheshire Basin is restricted to the Permo-Triassic basin; the presence of a poorly-defined Carboniferous depocentre, offset to the west, informally referred to as the 'Blacon Basin', is postulated.

The Humber Basin was first mentioned by Kent (1966) and is shown by Fraser & Gawthorpe (2003) and Hodge (2003). There are no well or seismic data to support this suggestion. Seismic interpretation reveals the presence of a Namurian-Westphalian thickening in the vicinity of the Tetney Lock 1 well. It could be interpolated that the Visean exhibits similar depositional thickening in this area, but importantly there is no evidence from the seismic data for a large-scale Visean half-graben (although seismic data quality is poor at this level). Hodge (2003) alluded to basinal shales being the source for the gas in the Saltfleetby field; this could be the most compelling evidence for the existence of the Visean-Namurian Humber Basin. More well penetrations or better seismic resolution will be necessary to assess the extent of the prospective shale in the Humber Basin.

The Bowland Basin[5] is one of the largest basins in the assessment area (Figure 14), and it continues westwards beneath the Irish Sea. Near the coast the Bowland Basin is buried beneath a layer of thick Permo-Triassic rocks, whilst farther east, the centre of the same basin has been uplifted and eroded such that rocks of the Bowland-Hodder unit crop out at the surface. The Edale Basin is a fault-bounded structure (Gutteridge 1991) that has a preserved cover of Millstone Grit and a relatively thin overlying unit of late Carboniferous Coal Measures locally also. The Gainsborough and Widmerpool troughs are broadly similar faulted basins to the Edale Basin, but the western, deepest part of the Widmerpool Trough was inverted and partially eroded prior to deposition of Permo-Triassic rocks. Over the crest of the Widmerpool Trough basin inversion, all of the overlying Coal Measures and Millstone Grit sections were eroded along with the uppermost part of the Bowland-Hodder unit (see Figure 24).

Late Carboniferous uplift occurred in a number of phases across central Britain, associated with the Variscan orogeny. The areas of greatest uplift largely followed the axis of the earlier depocentres, so that, for example, the oldest basinal strata of the Bowland-Hodder unit are exhumed in the centre of the inversion axis in the Bowland Basin.

3.4. Stratigraphy

Historically, the Early Carboniferous organic-rich basin shales have been given many names (e.g. Bowland Shale, Hodder Mudstone, Worston Shales, Widmerpool Formation, Sabden Shale, Caton Shale, Long Eaton Formation, Edale Shales, Lask Edge Shales and Holywell Shales etc.), and all of these shale units are now encompassed within the Craven Group (Waters *et al.* 2009) (Figure 15).

The interval mapped in this study is of Visean to early Namurian age, and has been interpreted on the seismic data in terms of sequence boundaries, and therefore includes both shales and laterally-equivalent platform limestones (Figures 15 and 16). The non-prospective platform deposits were subsequently excluded from the model using estimated net shale mapping (see Section 3.7).

In this study, this interval of interest is informally termed the 'Bowland-Hodder unit' (Figures 15 and 16) since this is the key stratigraphic interval within the Bowland Basin that was targeted by the Preese Hall 1 well in western Lancashire (Figure 7), the UK's first shale gas exploration well.

The age of the Bowland-Hodder unit extends from the late Chadian to the Pendleian (and locally Arnsbergian), within the Visean and Namurian epochs.

[5] The term Bowland Basin is used in this report in preference to the synonym Craven Basin (Hudson 1933). It was formerly known as the Bowland Trough (e.g. Kent 1966).

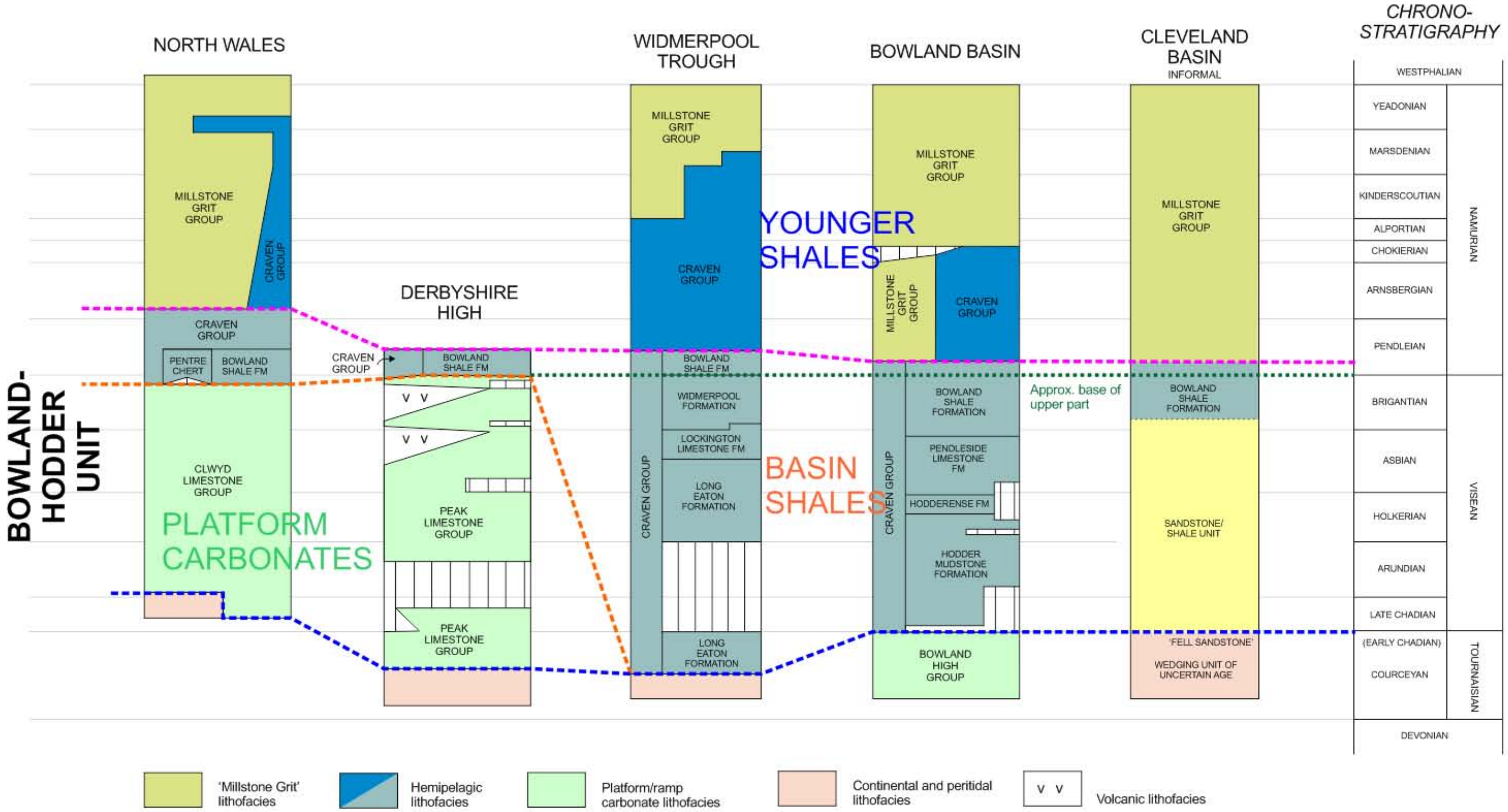


Figure 15. Lithostratigraphical framework of the Bowland-Hodder unit in central Britain (after Waters et al. 2009). Note: away from the outcrops, the platform carbonates in the Wessenden 1 and Roddlesworth 1 boreholes are termed Holme High Group and Trawden Group respectively (Waters et al. 2011). No formal lithostratigraphic framework has yet been applied to strata in the subsurface Cleveland Basin. In pre-2009 terminology, the Craven Group equates to the combined Worston Shale and Bowland Shale groups, excluding the Clitheroe Limestone Formation. Note: the use of Upper Chadian follows Riley (1990), but the Chadian has been partly redefined by Waters et al. (2011). Also, the Cleveland Basin sequence is poorly known and it is likely to have non-sequences that are not yet unrecognized.

The base of the Bowland-Hodder unit is defined in the basins as the top of the 'EC2/Chadian' carbonates identified in the Widmerpool Trough (Fraser *et al.* 1990). Outside this half-graben, it has only been penetrated on the highs and platforms. In the Cleveland Basin, the Kirby Misperton 1 well terminated in a sandstone (termed the 'Fell Sandstone' on the company log), the top of which is taken to approximately equate to the base of the Bowland-Hodder unit. The overlying shales have been only imprecisely dated using palynology , but on regional sequence stratigraphical grounds it is likely that the top of the Fell Sandstone is overlain by Holkerian strata, with the equivalent boundary being the top of the Ashfell Sandstone (Stainmore Trough) and Twiston Sandstone in the Bowland Basin.

The top of the Bowland-Hodder unit corresponds to the base of the sandstone-dominated Millstone Grit sequences. In outcrop, the Bowland Shale – Pendle Grit (oldest Millstone Grit unit) boundary is gradational and rather arbitrary, being part of an upward-coarsening sequence (Brandon *et al.* 1998). It is taken at either the base of the first massive sandstone, or where the sandstones predominate over siltstones and mudstones. This transition is younger in the north, due to the progradation of deltaic sequences from the north and north-east.

It should be noted that younger potential shale gas units, such as the Arnsbergian-Kinderscoutian Sabden Shale in Lancashire and much of the 'Holywell shales' in North Wales, which occur within Millstone Grit sandstone sequences, are excluded from this study (Figure 6). The Sabden Shale reaches a thickness of 1300 ft (400 m) in the Ribchester Syncline (Aitkenhead *et al.* 1992) and 2000 ft (610 m) south-east of Clitheroe (Earp *et al.* 1961), but it is not sufficiently deeply buried onshore to be considered as a source of shale gas.

Older 'limestone-with-shales' of Courceyan age are also excluded from the Bowland-Hodder unit, and these represent the deposits of the initial phase of rifting within the basin. These include the Haw Bank Limestone-with-Shales (Hudson 1944, Arthurton *et al.* 1988), the Gisburn Cotes Beds (Earp *et al.* 1961) and 2156 ft (657 m) of undated muddy limestones in the Swinden 1 borehole (Charsley 1984). They may reach a thickness in excess of 10,000 ft (3000 m) based on geophysical modelling (Arthurton *et al.* 1988). This depocentre coincides with the location of the greatest uplift and inversion and where the Bowland High Group crops out in the core of the anticline.

The integration of outcrop, well and seismic data has shown that the Bowland-Hodder unit can be divided into lower and upper parts (Figure 16). These correspond respectively to the EC3-EC6 syn-rift sequences and part of the LC1 post-rift sequence of Fraser *et al.* (1990). This subdivision provides a useful framework for the breakdown of the resource estimation into the less understood (and higher risk) lower unit and the better well-controlled (and lower risk) upper unit (see Section 5). It should be noted that although this division is valid as a generalized model, there is evidence that local syn-depositional faulting continued into the Arnsbergian (e.g. Brandon *et al*. 1998 p.55).

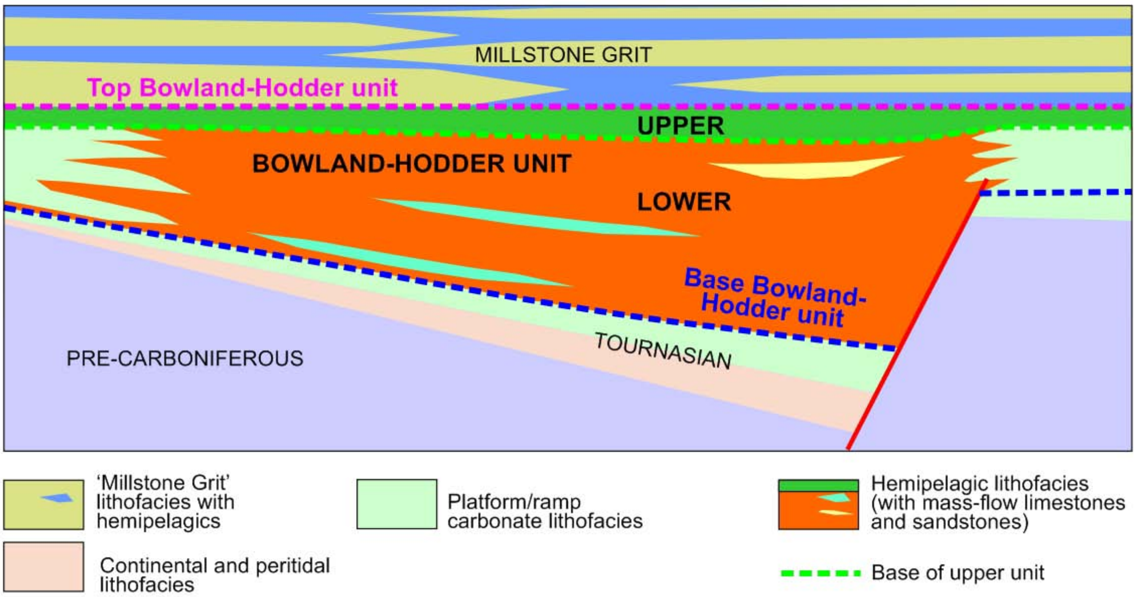


Figure 16. Schematic diagram showing the relationship between hemipelagic basinal shales and platform carbonates within the Bowland-Hodder unit. Note that basin shales also occur interbedded with the sandstones of the overlying Millstone Grit.

The lower part of the Bowland-Hodder unit comprises a thick, syn-rift, shale-dominated facies which passes laterally to age-equivalent limestones that were deposited over the adjacent highs and platforms (Figure 16). The presence of slumps, debris flows and gravity slides (Gawthorpe & Clemmey 1985, Riley 1990) are evidence for relatively steep slopes, which may have been the result of instability induced by tectonic activity. A combination of syn-depositional tectonics, fluctuating sea levels, climate change, and evolution of the carbonate ramps/platforms surrounding the basin resulted in a variety of sediments being fed into the basin at different times. Localised breccias are present close to the basin-bounding faults (Smith *et al*. 1985, Arthurton *et al*. 1988). This lower unit is dated as late Chadian to Brigantian in age.

There is some evidence that marine transgressions, represented by high gamma, high TOC intervals, also occasionally flooded the platform highs (e.g. Arundian shales in the Plungar 8A well). However, there is so little well control for the lower unit in the deep basins, that it is unclear how regionally correlative these intervals are.

The upper part of the Bowland-Hodder unit comprises basinal shales that were deposited both in the basins and across most of the platforms, following the drowning of the highs. These condensed zones are laterally continuous, rather than enclosed within basins, but are considerably thicker and richer in organic material within the basins which had a stratified water column. Within the Bowland Basin, individual beds can be easily correlated between (currently unreleased) wells, providing further evidence of relative stability in the upper unit. This unit is dated as latest Brigantian to Pendleian (locally up to Arnsbergian) in age.

Evidence as to whether the onset of high-gamma shale deposition is always coincident with the Visean-Namurian boundary (*Emstites leion* Marine Band) requires further research. In most cases, there is a good correlation between these boundaries. However, in several wells, Brigantian ages have been assigned to the lowest part of the upper unit.

In the Harrogate outcrop (Cooper & Burgess 1993) and wells in the Cleveland Basin (this study), the boundary between the lower and upper parts of the Bowland-Hodder unit (and the top of the Visean) is taken near the base of the Harrogate Roadstone (of the Pendleton Formation).

Biostratigraphic control will be particularly important in interpreting the depositional controls on shale gas prospectivity and obtaining a terminal core to constrain the maximum stratigraphical penetration is most desirable. Cores of shale over zones of interest can be used not only for gas desorption tests and analysis, but also to gain the high resolution stratigraphical knowledge and geophysical log/seismic calibration necessary to inform subsequent exploration and development (e.g. prediction of shale net to gross, lithological and diagenetic controls on shale characterisation, lateral distribution of most productive zones and identify faults and their displacement).

3.5. Regional depth and isopach maps

The top of the Bowland-Hodder unit lies at depths of up to 16,000 ft (4750 m) across the assessment area (Figure 17), with the greatest depth of burial occurring in the Bowland Basin of Lancashire, beneath the Permo-Triassic Cheshire Basin and in eastern Humberside.

The thickness of the Bowland-Hodder unit (Figure 18) mirrors the regional Early Carboniferous structural configuration (Figure 14), with greatly expanded sections in the syn-rift basins.

From outcrop data, the Bowland Basin is estimated to contain up to 880 ft (268 m) of Bowland Shale (Brandon *et al*. 1998) and 3000 ft (900 m) of Hodder Mudstone (Riley 1990). In the subsurface, seismic interpretation suggests the complete Bowland-Hodder unit reaches a thickness of up to 6300 ft (1900 m) (Figure 18) in the same basin. This may be a conservative approximation, as Kirby *et al.* (2000) and Aitkenhead *et al.* (2002) estimated Tournaisian-Visean thicknesses of 13,000 ft (4000 m) and 8200 ft (2500 m) respectively (although both apparently include the Courceyan Chatburn Limestone Group and are thus not directly comparable to the Bowland-Hodder unit). The Thistleton 1 well drilled 2911 ft (887 m) of the Bowland-Hodder unit, but terminated in Brigantian-aged shales and sandstones (N.J. Riley pers. comm.) and the lower part of the unit was not reached.

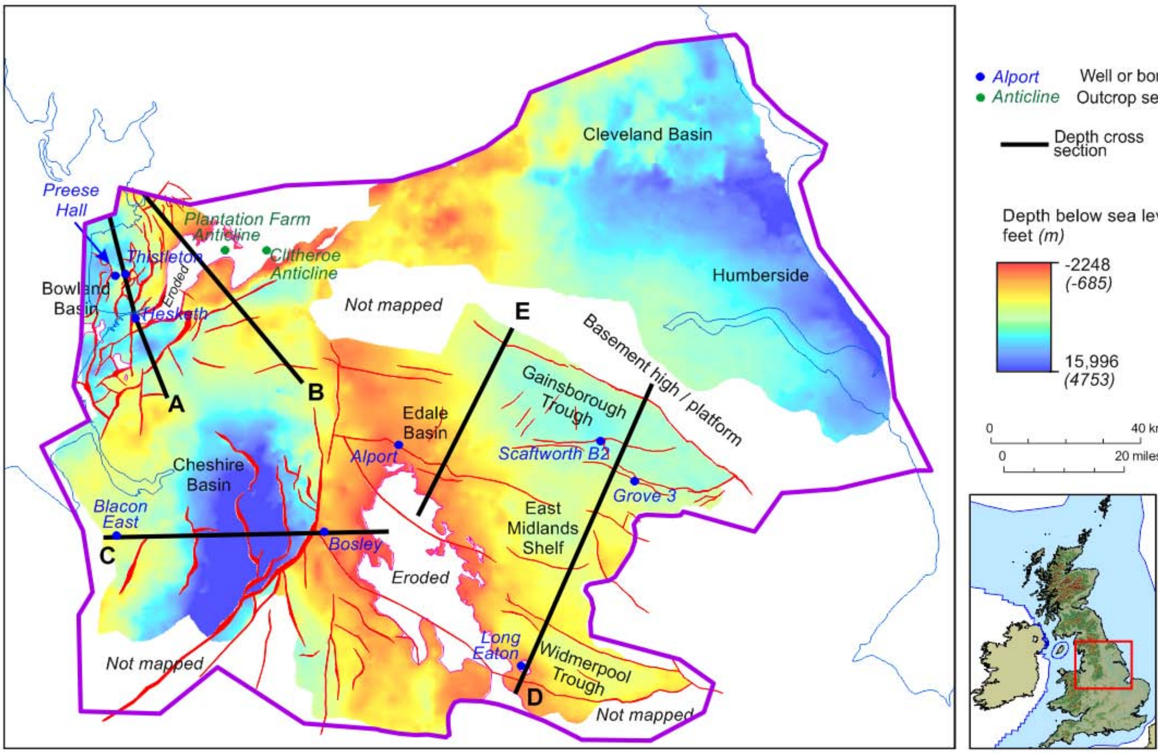


Figure 17. Depth (ft) to the top of the Bowland-Hodder unit, central Britain. The location of regional cross-sections is indicated (see Figure 19).

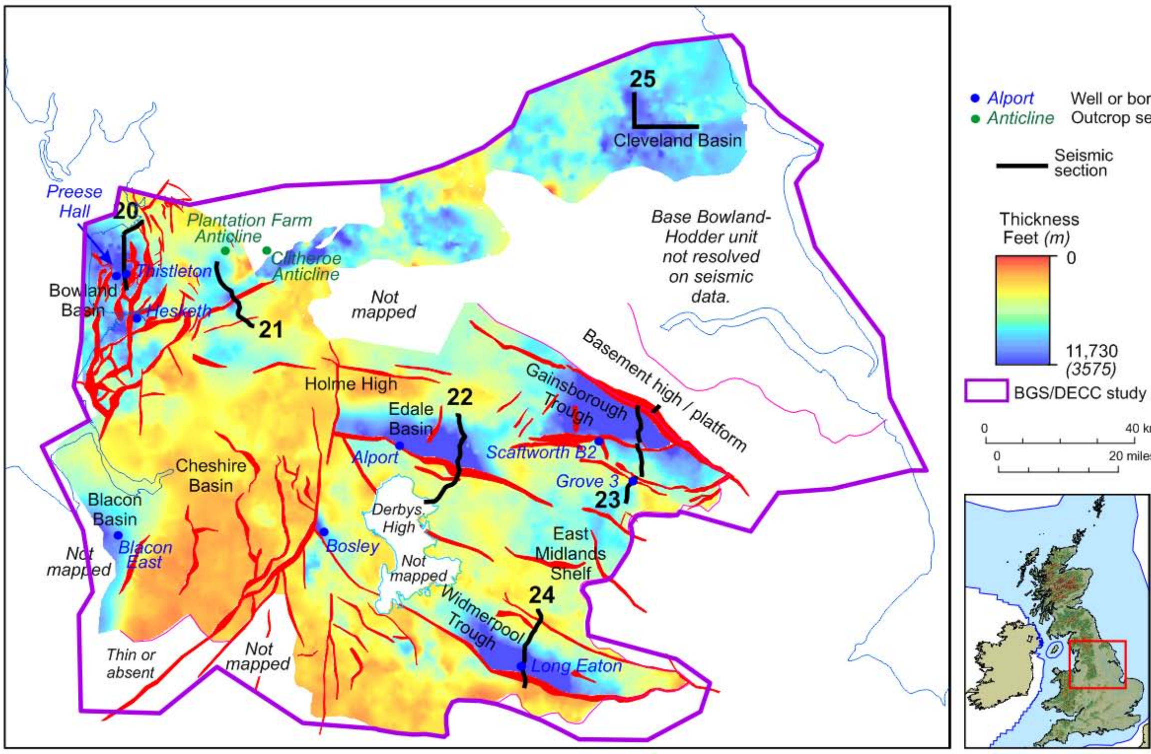


Figure 18. Thickness (ft) of the Bowland-Hodder unit, central Britain. The interval was not mapped across the Derbyshire High where there are no seismic data (and the unit comprises platform carbonate rocks) (see Figure 19C & E). The location of example seismic profiles is indicated (see Figures 20-25).

The Bowland-Hodder unit is equally thick, or thicker, within the narrow, fault-bounded Gainsborough, Edale and Widmerpool basins (Figure 18) with up to 10,000 ft (3000 m), 11,500 ft (3500 m) and 9500 ft (2900 m) respectively. The Cleveland Basin maintains a more uniform thickness, with the distribution of net shale controlled by facies changes to the north and south. Kirky Misperton 1 drilled a complete Bowland-Hodder unit thickness of 4598 ft (1401 m).

The organic-rich upper part of the Bowland-Hodder unit is typically up to c.500 ft (150 m) thick, but locally reaches 2900 ft (890 m). The syn-rift lower part of the Bowland-Hodder unit is considerably thicker, reaching 10,000 ft (3000 m) in the depocentres.

A selection of seismic-based depth cross-sections (Figure 19) and example seismic profiles (Figures 20-25) illustrate various aspects of the deep geology of the study area. Expanded captions provide additional information.

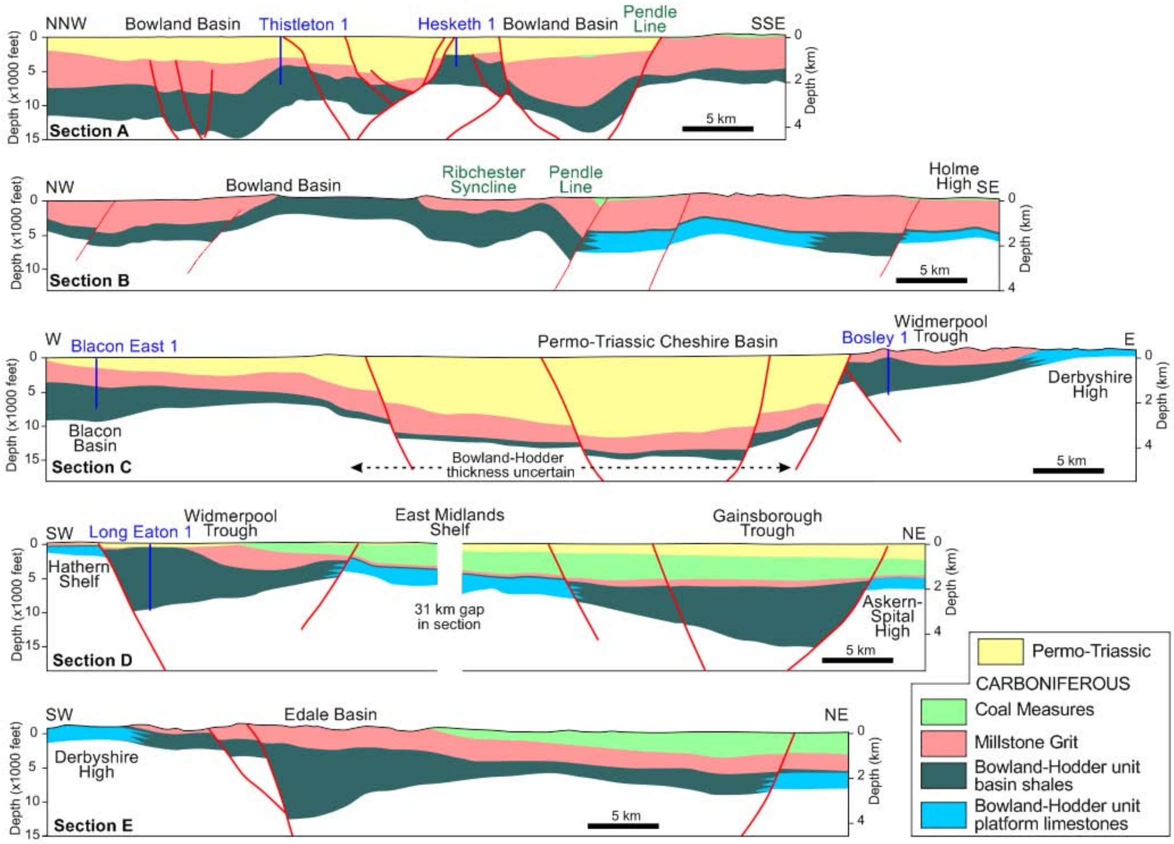


Figure 19. Generalised depth cross-sections through the Bowland Basin, Cheshire Basin, Widmerpool Trough, Gainsborough Trough and Edale Basin. For location of the sections, see Figure 17.

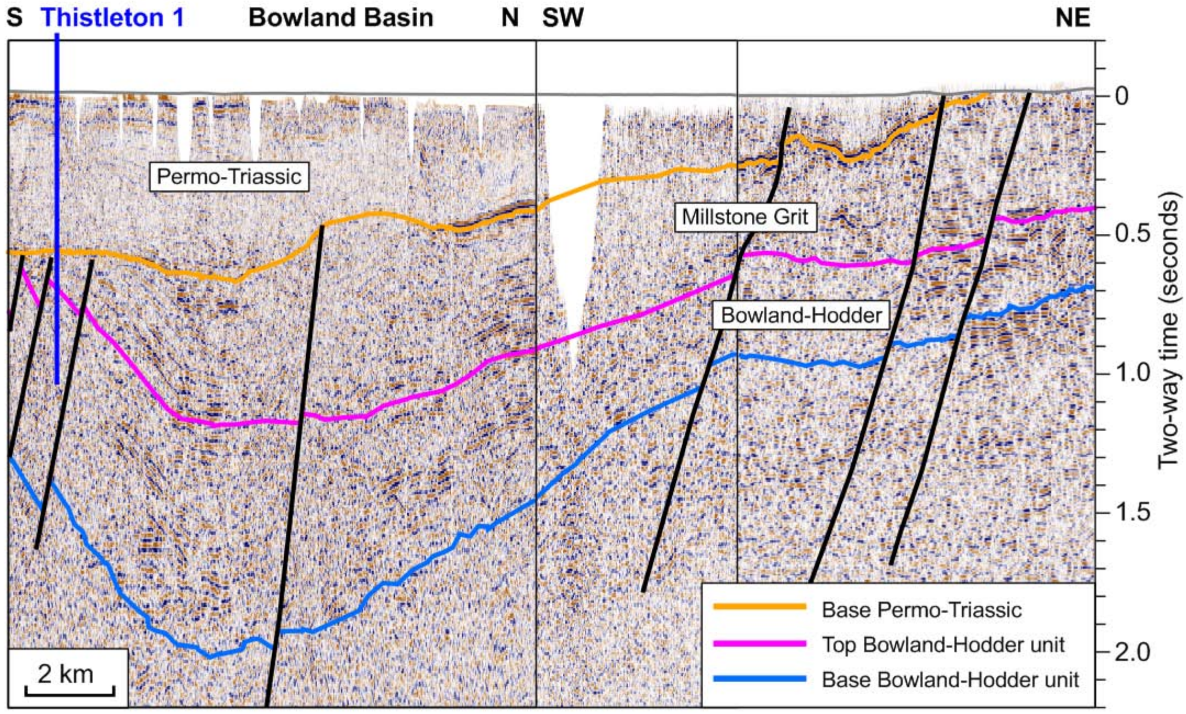


Figure 20. Seismic example across the deepest-buried part of the Bowland Basin showing thickening of the Bowland-Hodder unit towards the basin depocentre. The Thistleton 1 well terminated in Brigantian-aged shales and sandstones and the lower Bowland-Hodder unit was not reached. However, the Hodder Mudstone Formation is at least 3000 ft (900 m) thick in the Plantation Farm Anticline outcrop section located 25 km ENE of Thistleton 1 (Riley 1990), and a section of similar thickness is expected to be present in the area overlain by Permo-Triassic strata. For location of the section, see Figure 18.

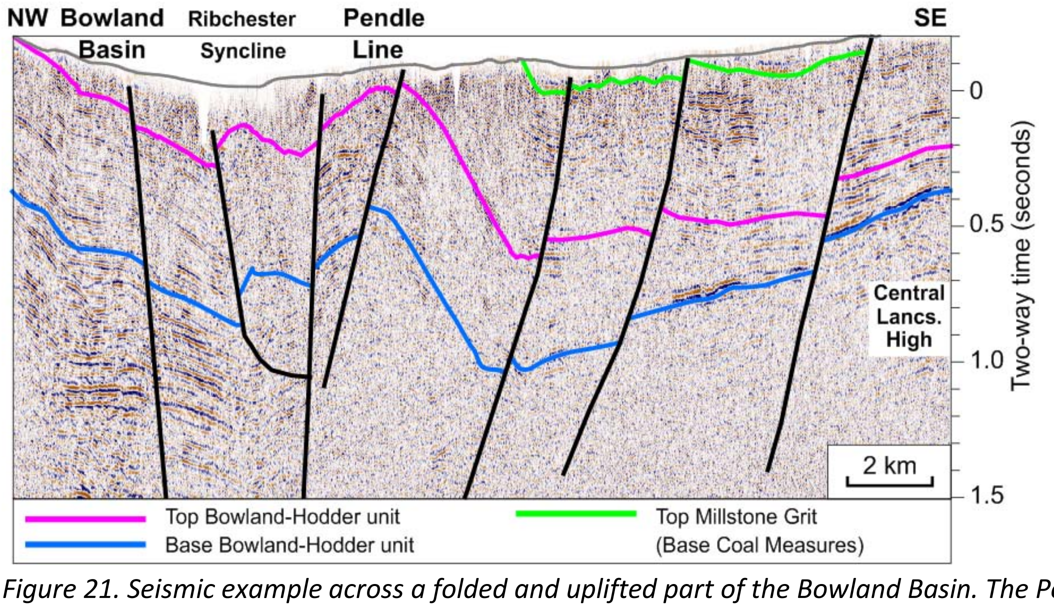


Figure 21. Seismic example across a folded and uplifted part of the Bowland Basin. The Pendle Line and associated monocline mark the southern boundary of the Bowland Basin; Westphalian Coal Measures crop out in the south-east. For location of the section, see Figure 18.

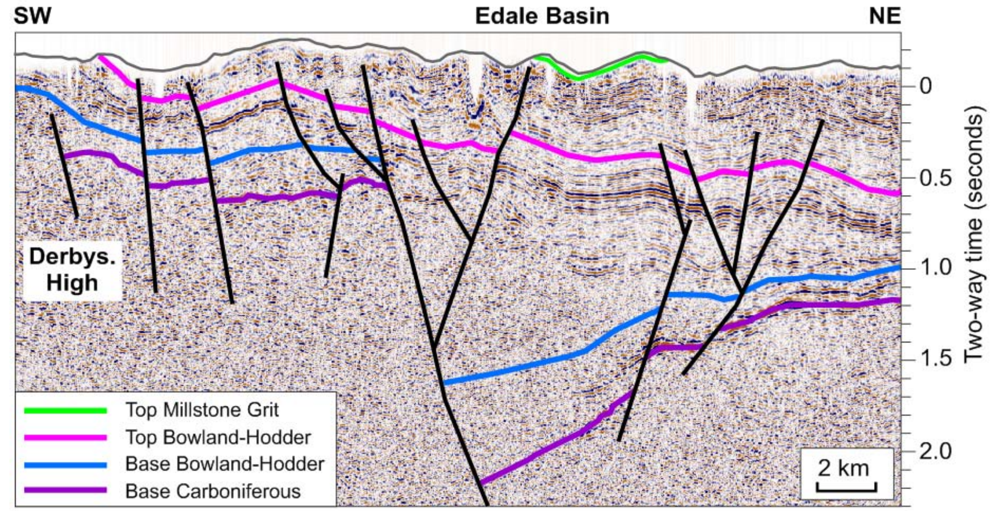


Figure 22. Seismic example across the Edale Basin where very thick basinal shales are interpreted. On the adjacent Derbyshire High, the Bowland-Hodder unit comprises platform carbonates topped by relatively thin upper Bowland-Hodder shales. For location of the section, see Figure 18.

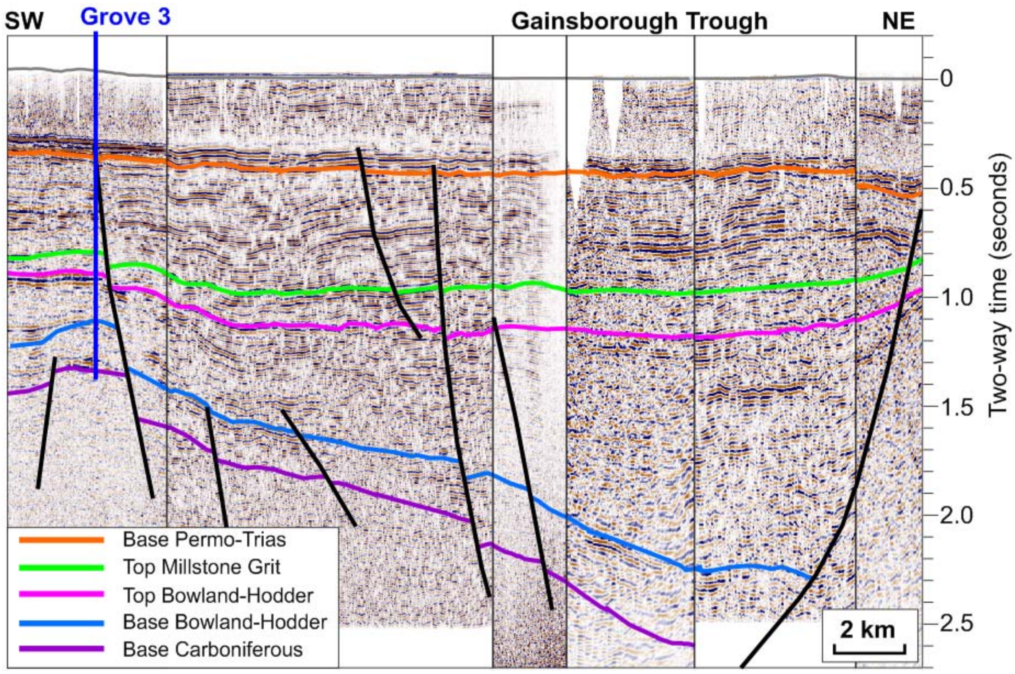


Figure 23. Seismic example across the Gainsborough Trough. The Grove 3 well is located on the East Midlands Shelf and illustrates the platform limestone-dominated nature of the Bowland-Hodder unit that was deposited on an Early Carboniferous platform high area. For location of the section, see Figure 18.

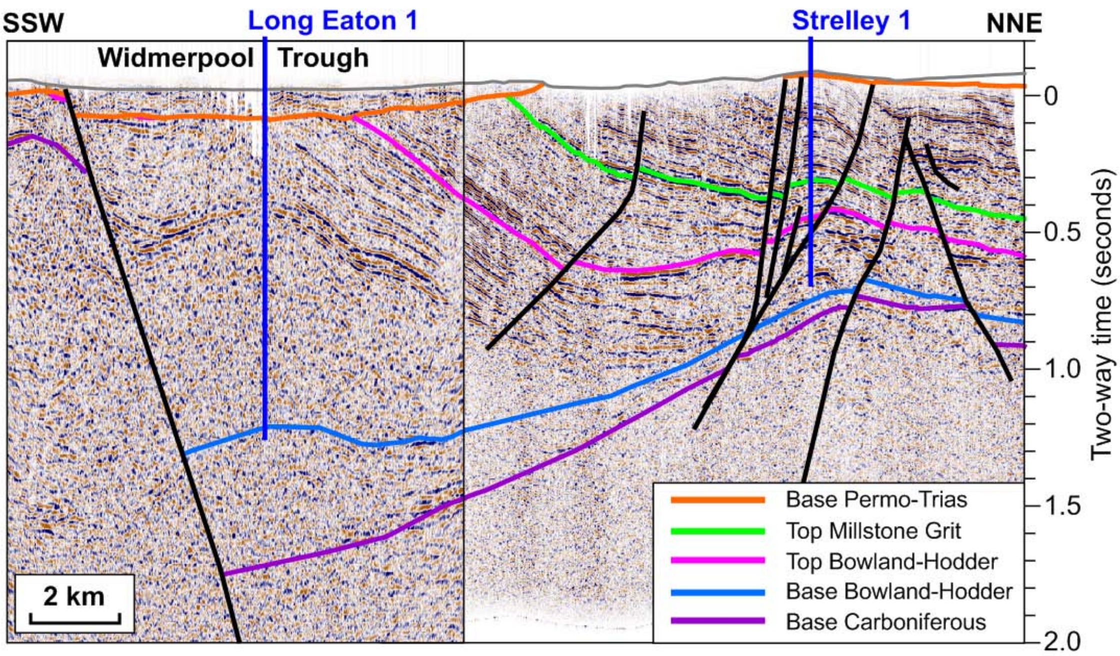


Figure 24. Seismic example across the Widmerpool Trough, showing inversion of the basin depocentre and localised erosion of the upper part of the Bowland-Hodder unit beneath the base Permian unconformity. The Long Eaton 1 well penetrated 8028 ft (2447 m) of the Bowland-Hodder unit before reaching a limestone of possible Chadian age. For location of the section, see Figure 18.

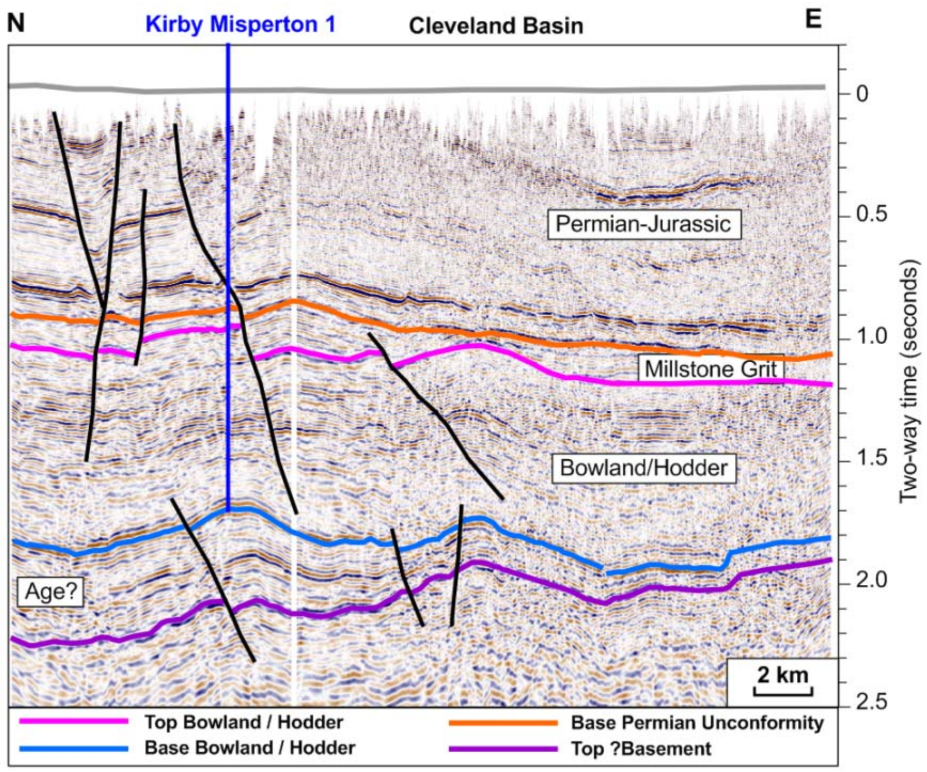


Figure 25. Seismic example across the Cleveland Basin, showing the presence of older wedging strata (of unknown age) beneath the Bowland-Hodder unit. The Kirby Misperton 1 well terminates in the 'Fell Sandstone', but the older part of the Bowland-Hodder unit is also sand-prone in this well. For location of the section, see Figure 18.

3.6. Key wells

Of the many wells drilled within the assessment area, only 64 reached sufficient depths to record more than 50 ft (15 m) of net shale in the Early Carboniferous section (Figures 7, 26 and 28, Appendix C).

Few wells have penetrated the full Bowland-Hodder succession within the deep basins, but several have drilled sections of more than 5000 ft (1500 m). Detailed well correlations are included in Appendix D (Figure 26) and Figure 27 compares the sections encountered in some of the key wells and outcrops in the study. Note that most wells do not encounter the base of the unit, and only a few penetrate significantly into the lower Bowland-Hodder unit.

In addition to wells drilled under hydrocarbon legislation, there are a number boreholes drilled for mineral and geothermal investigation which are relevant to the understanding of the Bowland-Hodder shale play. For example, the BGS Duffield (Aitkenhead 1977) and Roosecote boreholes, the Cominco boreholes described by Arthurton *et al*. (1988), the BP minerals boreholes described by Aitkenhead *et al*. (1992) and Brandon *et al*. (1998) and the unpublished BGS Clitheroe geothermal borehole (SD 755 409). Note also, that many borehole samples, thin sections and macrofossil (ammonoids, bivalves) and microfossil (conodonts, foraminifera and palynology) preparations are held in the biostratigraphy/palaeontology collections at BGS. Contact *enquiries@bgs.ac.uk* for further details.

Dating and correlation of the Bowland-Hodder unit requires a multidisciplinary approach. Standard industry techniques such as palynology are of limited use due to the poor preservation of miospores in the hemipelagic marine shales and the broad stratigraphic range of the miospore zones. The highest resolution stratigraphy is provided by glacio-eustatic flooding surfaces. These form the backbone for all the marine event stratigraphy and biostratigraphic correlation through the Bowland-Hodder unit, particularly in the upper part (Bowland Shales). Major flooding surfaces successively introduce new marine faunas, especially ammonoids (hence the need to take cores for definitive dating). Accessory taxa, such as hemipelagic bivalves, trilobites, foraminifera and conodonts, provide additional tools for correlation and understanding depositional environments, as well as elucidating the interplay between basinal facies and sediments sourced from surrounding areas (with implications on predicting shale quality and distribution). This knowledge is particularly important in deciphering the origin, cause and distribution of gravity-fed deposits within the hemipelagic sequence, and corresponding carbonate, silicate and organic-rich zones.

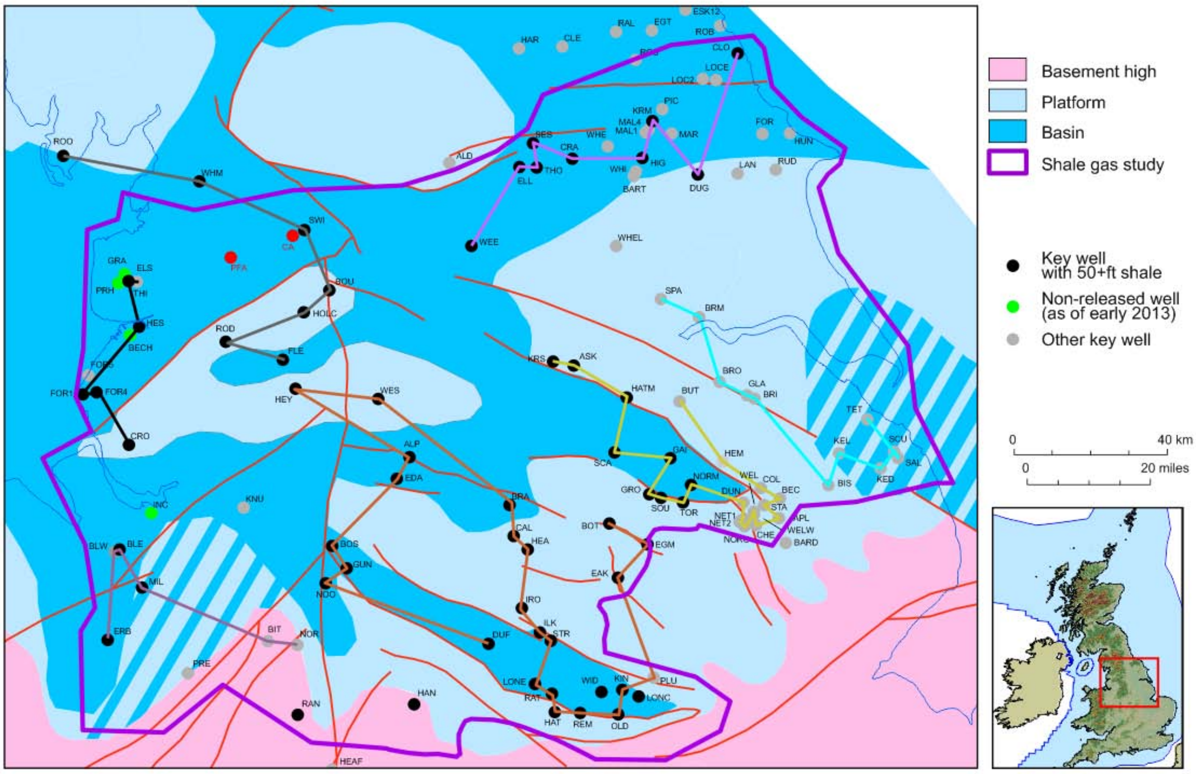


Figure 26. Location of well correlation lines included in Appendix D.

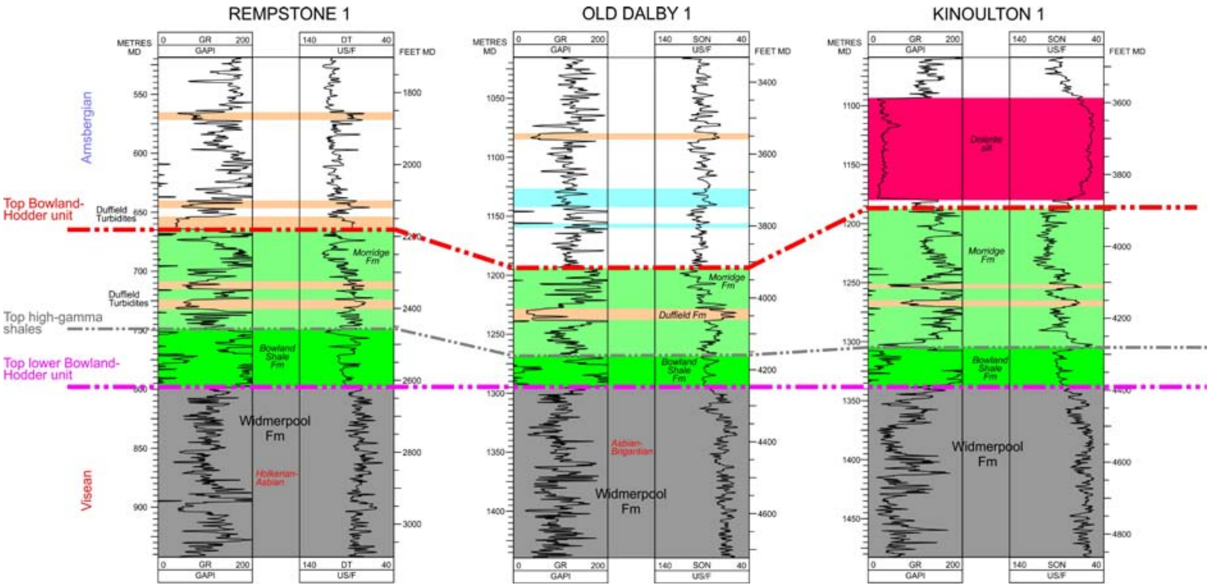


Figure 27. Geophysical well-log correlation of the upper Bowland-Hodder unit between Rempstone 1, Old Dalby 1 and Kinoulton 1 located in the Widmerpool Gulf (see Appendix D iv for the complete correlation diagram). The upper part of the Bowland-Hodder unit contains correlateable units.

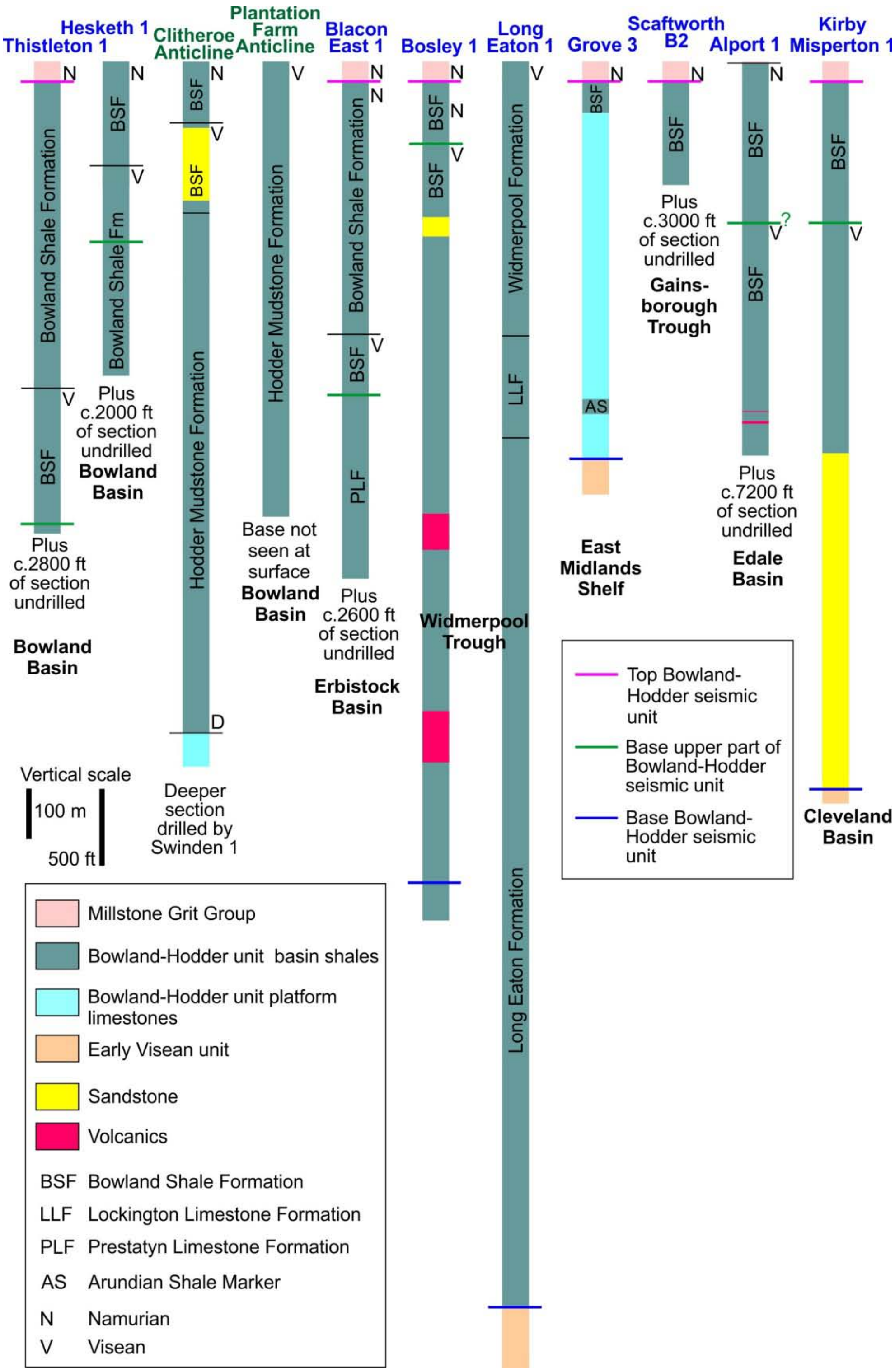


Figure 28. Craven Group basinal shale sections recorded from wells and outcrops, central Britain. At the Clitheroe and Plantation Farm anticlines, the outcrop section has been measured along the ground. In the wells, only the part drilled down from just above the top of the Bowland-Hodder unit is shown. See Figure 26 for the location of the wells and outcrop localities. The estimated thickness of the unit which remains undrilled below the terminal depth of each well is also indicated; this is based on seismic interpretation. Note the early incoming of clastic sediments in the northernmost well, Kirby Misperton 1.

3.7. Regional distribution of shale

The mapping of the Bowland-Hodder interval as a seismically defined unit necessitated the use of a sequence stratigraphic approach. As a result, the mapped unit is constrained by time lines, between which there are a variety of basinal and platform facies. To ensure that the 3D volume model used to calculate the potential amount of gas in-place within the Bowland-Hodder unit only included shale lithologies (and not the platform limestones, nor sandstones and limestone turbidites within the basins), it was necessary to map the predicted lateral variation in shale percentage. The distribution of shale in the lower part of the Bowland-Hodder unit (Figure 29) was mapped using a shale analysis of key wells (using an appropriate gamma log cut-off) integrated into the regional palaeogeographic model (Figure 14). The distribution of shale in the upper part shows little variation across the study area.

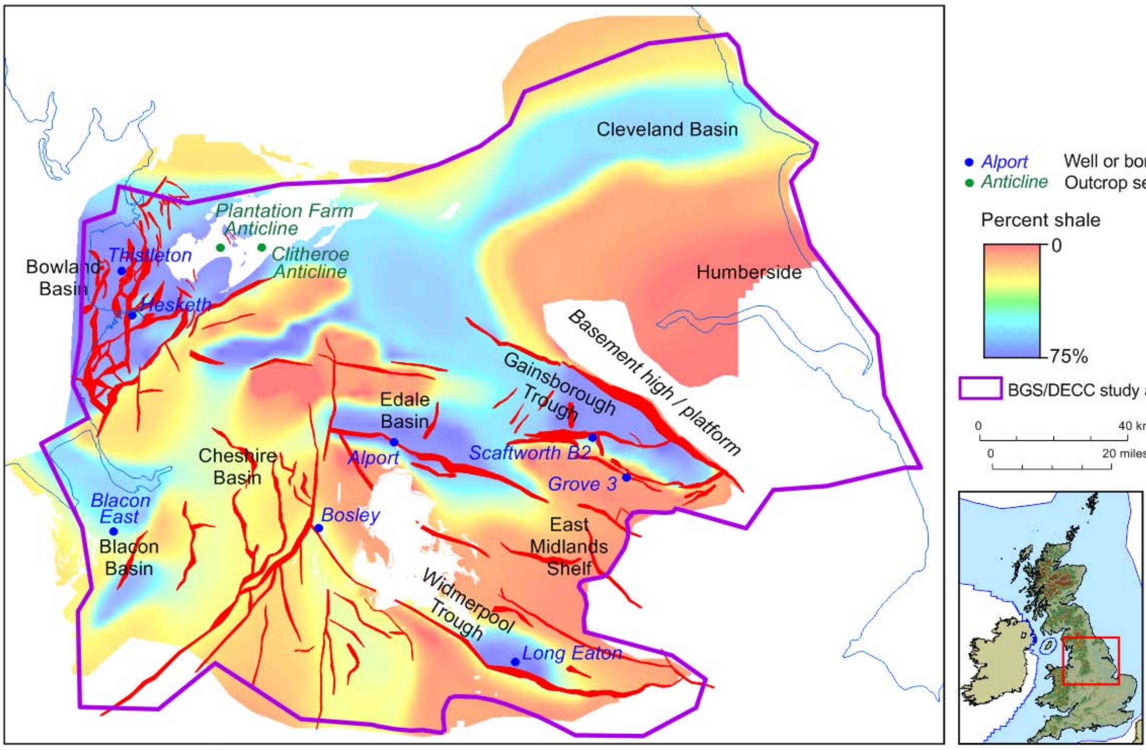


Figure 29. Predicted shale percentages within the lower part of the Bowland-Hodder seismic unit used to condition the 3D volume during the calculation of in-place gas resources.

3.8. Geochemical evaluation

Many central Britain outcrop, core and cuttings samples of Visean and Namurian shales have undergone geochemical analysis, mainly when studying source rocks in conventional petroleum systems. Relatively little analysis has specifically targeted its shale gas plays.

Data from 161 well and outcrop locations (3420 samples) were available to this study. Many reports are available through the general release of hydrocarbon well data from DECC's data release agents. Data has also been extracted from Petra-Chem (1983a, b, c) and RRI (1987). Rock-Eval analysis of an additional 109 core samples was commissioned as part of this study (Appendix B). Confidential data available to DECC was integrated into the study, but it is not published in this report. Under UK onshore licence terms, well data is held confidential for four or five years before it can be released into the public domain by DECC's release agents.

Geochemical data were also available from strata higher in the Carboniferous succession, and these have proved useful in determining maturation trends with depth and burial history.

Organic carbon content

There are only limited published data on organic carbon contents in the Bowland-Hodder unit (DECC 2010a, Smith *et al*. 2010). These published data suggest that Namurian marine shales have generally higher TOC values (average 4.5%) compared to non-marine shales, which have an average value of 2.7% (Spears & Amin 1981). Maynard *et al.* (1991) found that two thin Namurian black shale marine bands have a TOC of between 10 and 13%, whereas values within interbedded strata ranged between 2 and 3%. The Namurian Holywell Shale of North Wales has TOC values in the range 0.7-5%, with an average of 2.1% (Armstrong *et al.* 1997). More recently, the Ince Marshes 1 well encountered shales with TOC values of 1.18 – 6.93% (average 2.73%) in the 'Bowland Shale' (iGas 2012). Könitzer *et al.* (2011) record Arnsbergian shales with 1-7% TOC in the Carsington C4 borehole [SK 251 530].

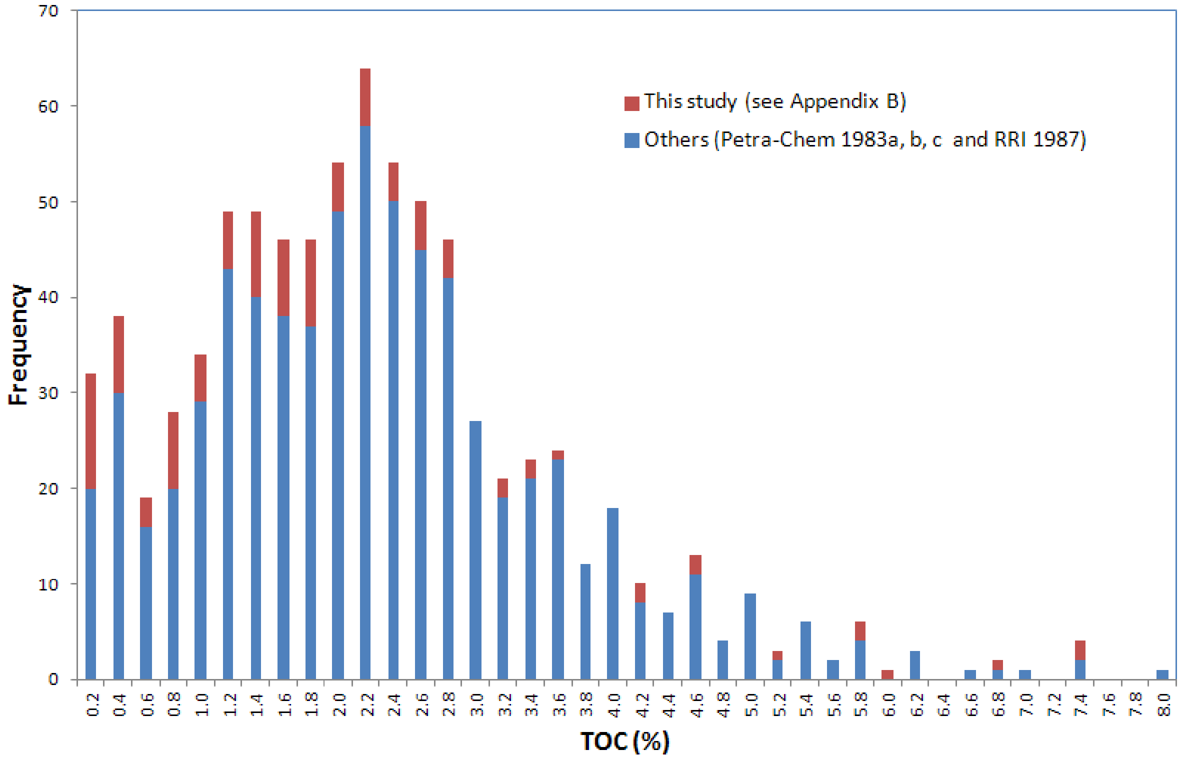


Figure 30. Summary of total organic carbon analyses from the Bowland-Hodder unit in central Britain. There are seven data points with TOC >8%. Some data may be from adjacent horizons and some non-shale lithologies are included.

A review of all available total organic carbon data from the Bowland-Hodder unit in central Britain is summarised in Figure 30. Most samples are from the upper part of the Bowland-Hodder unit. Values fall in the range >0.2 to 8%, with most shale samples in the range 1-3% TOC. Smith *et al*. (2010) give a similar range up to 10%. The results of the new Rock-Eval analyses commissioned as part of this study (shown in red on Figure 30 and listed in full in Appendix B) mirror this conclusion.

For comparison, USEIA (2011a) quote an 'average TOC' for the Bowland shale play of 5.8%.

The down-hole gamma-log response is generally considered to be a good proxy for organic carbon content where geochemical analyses are lacking. TOCs in excess of 1-3% typically correlate with gamma log values of greater than 150 API.

The gamma-log responses of the shales within the upper Bowland-Hodder unit indicate significant intervals having >2% TOC (see well correlations in Appendix D).

While there are some data for the lower Bowland-Hodder unit, the well penetrations are mostly within the uppermost 100 feet, so few wells sample the full expanded section in the narrow rifted basins. The exceptions indicate consistently high TOC values in the Widmerpool Gulf, with average TOCs of 3.5%, 4.9% and 5% over sampled intervals in Old Dalby 1, Ratcliffe-on-Soar 1 and Rempstone 1 respectively (Appendix B). There are no analysed samples from the lower unit in the Gainsborough Trough.

The observed range of TOC values in the Bowland-Hodder unit (average 1-3%, maximum 8%) is comparable to many of the producing North American shale-gas analogues (Table 3).

Formation	Age	HI_o (mg/g)	TOC_{pd} Low (wt. %)	TOC_{pd} High (wt. %)	TOC_{pd} Average (wt. %)
Barnett	Early Carboniferous	434	0.02	9.94	3.74
Fayetteville	Early Carboniferous	404	0.71	7.13	3.77
Woodford	Devonian	503	0.26	11.27	5.34
Bossier	Late Jurassic	419	0.46	4.11	1.64
Haynesville	Late Jurassic	722	0.23	6.69	3.01
Marcellus	Devonian	507	0.41	9.58	4.67
Muskwa	Devonian	532	0.01	5.97	2.16
Montney	Triassic	354	0.01	4.78	1.95
Utica	Ordovician	379	0.19	3.06	1.33
Eagle Ford	Late Cretaceous	411	0.58	5.6	2.76

Table 3. Comparison of present-day total organic carbon contents (TOC_{pd}) for the top 10 shale gas plays in North America (Jarvie 2012).

Kerogen type

Four basic categories of kerogen are recognised in organic matter (Tissot *et al*. 1974). Type I and II kerogens have the potential to generate both oil and gas. Type III kerogens mainly generate gas, with only a small amount of oil, while Type IV kerogens have little or no remaining potential to generate hydrocarbons.

The type of kerogen present is also an indication of the environment in which the interval was deposited. Algae seen in Type I samples indicate a lacustrine (or marine environment), whereas Type II is deposited exclusively in marine conditions and contains plant spores, exines, resins and bacterially degraded algal matter. During initial maturation, Type II source rocks generate mainly oil and only a limited amount of gas. As maturation proceeds through higher temperatures, secondary cracking in these source rocks cracks the generated oil into gas. Type III organic material is comprised of vitrinite and is typically woody material found in continental rocks deposited in rivers and deltas, but it can also be found in marine environments where it is washed in from a nearby shelf. Type IV contains inertinite, where oxidation of woody material has occurred, either before it is deposited or in situ.

Ewbank *et al*. (1993) reported Type II kerogen in the Widmerpool Gulf, Edale Basin, Goyt Trough and mudstones interbedded with carbonates on the Derbyshire High; Type III was also present. However, little additional data are available to establish the original composition of the kerogen in the Bowland-Hodder unit. The identification of kerogen type using geochemical cross-plots is complicated by the fact that various ratios can reduce during the maturation process (Jarvie *et al.* 2005, 2008). A significant number (but still a minority) of samples plot in the Type II field (Figure 31; Appendix B) which is in general agreement with the deep-water marine, hemipelagic depositional environment of the Bowland-Hodder unit. One explanation as to why many samples plot as Type III is that their geochemistry has been altered during maturation.

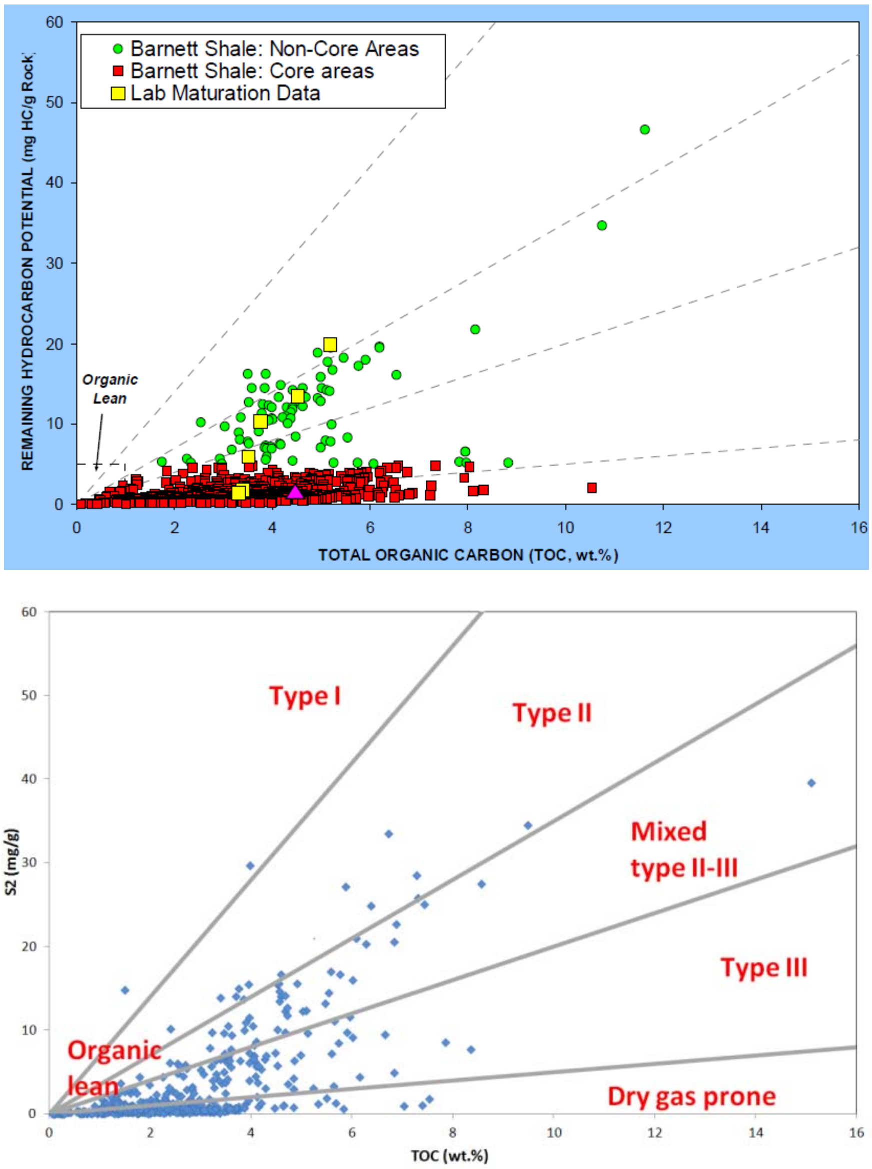


Figure 31. Remaining hydrocarbon potential (S2) versus TOC plot for (a) the Barnett Shale (from Jarvie 2008) and (b) all available data from this study. There are close similarities, although the larger range of TOCs in the Barnett Shale is evident.

Further data relevant to kerogen typing and maturation are shown in Figures 32 and 33.

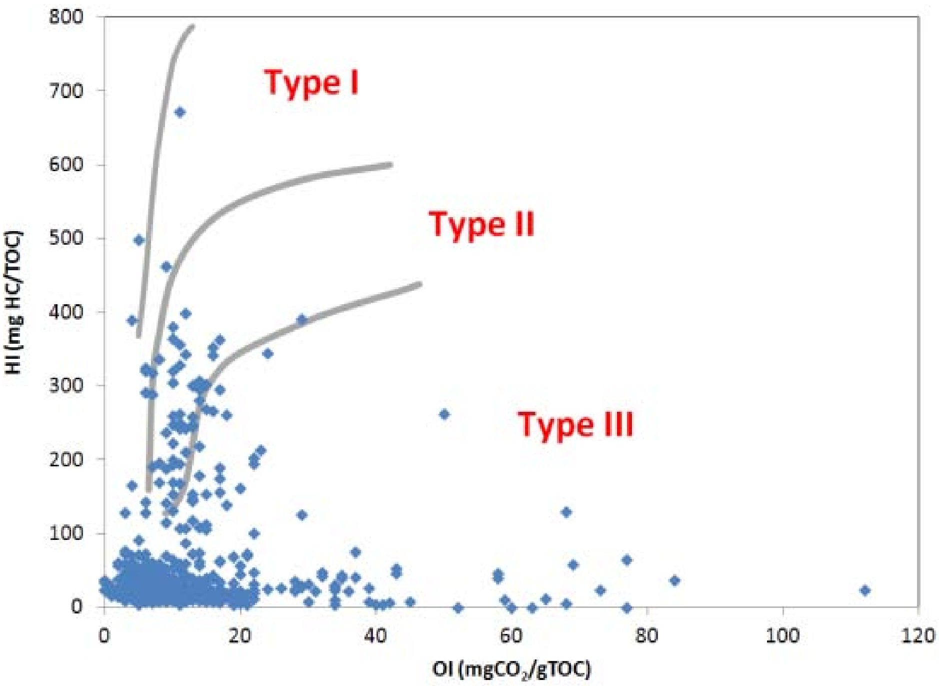


Figure 32. Modified van Krevelen diagram (HI versus OI plot) for all available data from this study. A significant number of samples fall in the Type II field.

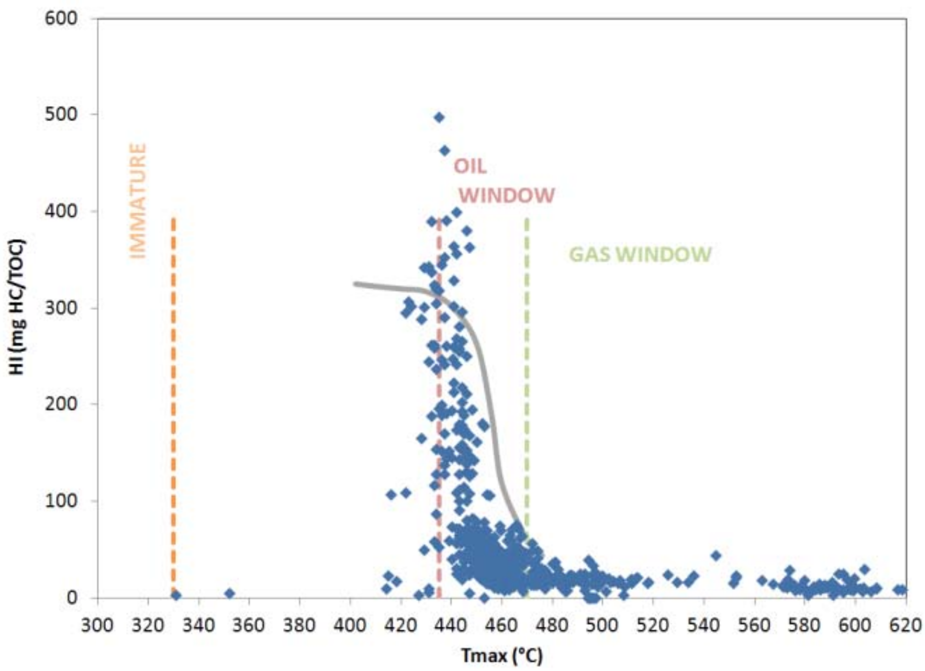


Figure 33. Hydrogen Index versus T_{max} plot for all available data from this study.

Thermal maturity and uplift

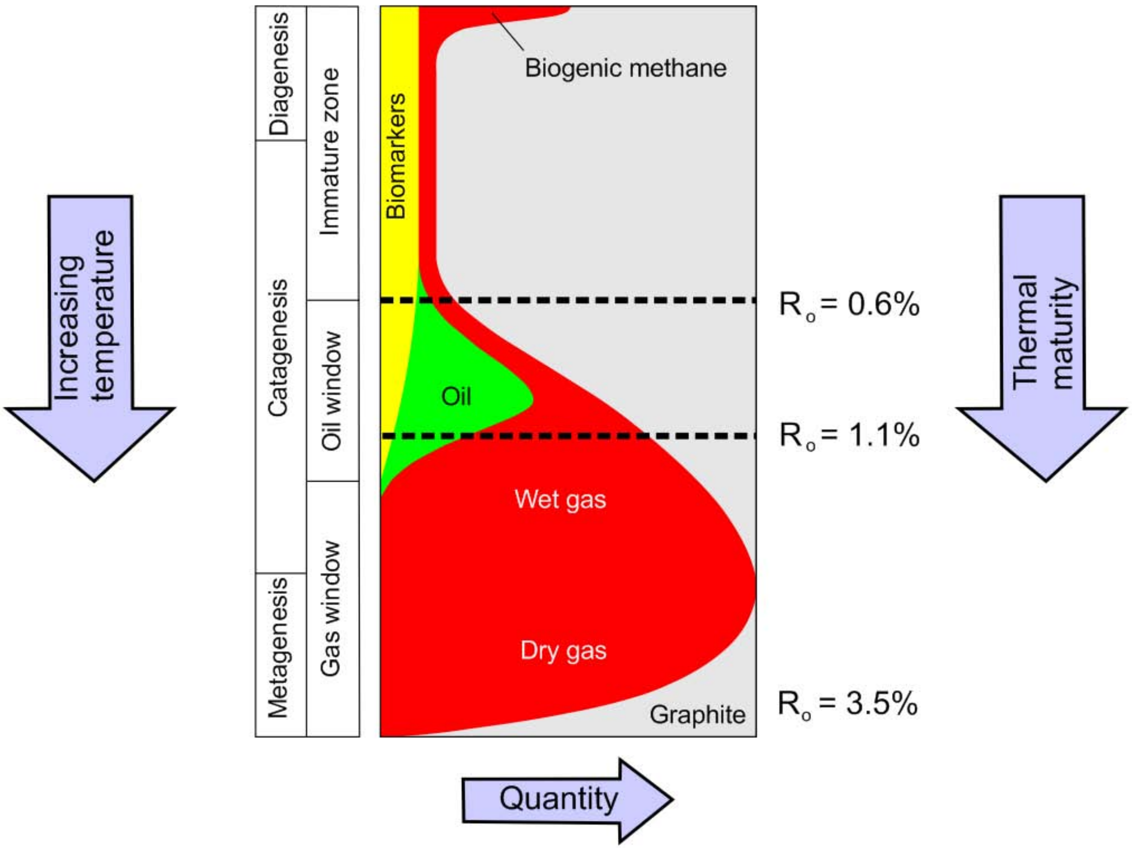


Figure 34. *Relationship between temperature, vitrinite reflectance of organic material and phases of hydrocarbon generation (modified from Tissot et al. 1974 and McCarthy et al. 2011).*

The thermal generation of oil and gas from organic material (Figure 34) generally takes place at temperatures between 50°C and 225°C. At lower temperatures, the organic material is immature and no oil or gas will be thermally generated from the source rock; at much higher temperatures, the organic material is overmature and all possible oil and gas will have been generated. The timing of generation is dependent on the kerogen type and the exact composition of the organic material.

Vitrinite reflectance (R_o) and measurements of the temperature of maximum release of S2 hydrocarbons (T_{max}) at outcrop and in boreholes provide a widely accepted proxy for thermal maturity and extent of hydrocarbon generation. An equivalent to R_o can be calculated from T_{max} using the following formula (Jarvie *et al.* 2001):

$$T_{maxeq}\%R_o = 0.018(T_{max}) - 7.16 \qquad \text{[where } T_{max} \text{ is in °C]}$$

From an analysis of all available maturity data of the Bowland-Hodder unit in the study area, it can be deduced that an R_o of 1.1% (equating to the onset of significant gas production) can be reached at a present-day depth of anything between outcrop and 9500 ft (2900 m) (Figure 35). This variability occurs because the simple R_o vs. depth relationship is overprinted by the multiphase subsidence and inversion experienced across the study area.

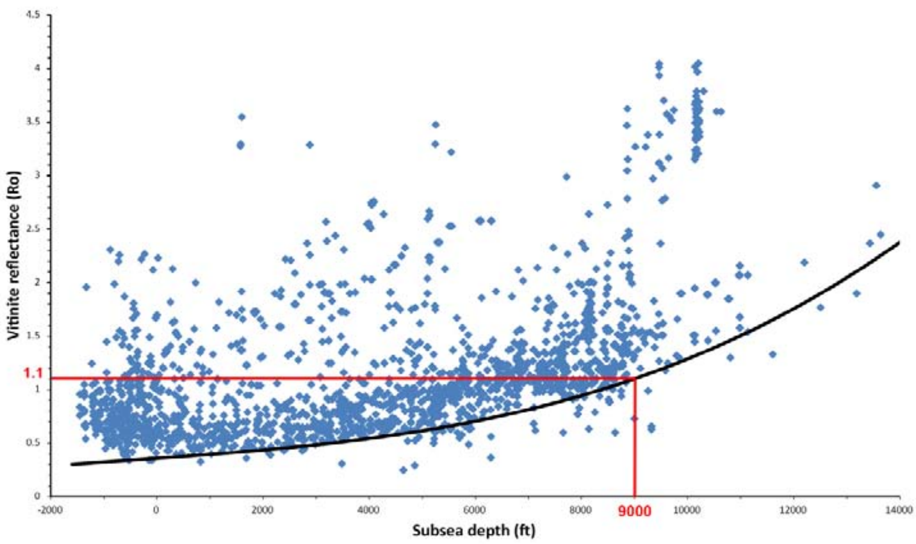


Figure 35. Chart showing all available vitrinite reflectance data (R_o and equivalent data calculated from T_{max}) plotted against present-day sub-sea depth for the Bowland-Hodder unit (and some younger strata) across central Britain. The curve shows a conservative best-fit baseline (i.e. a minimal uplift baseline); data points lying well above the baseline are affected by the highest amounts of uplift.

In the absence of quantitative data on uplift, the data summarised in Figure 35 have been used to set a baseline with minimal uplift to subsequently obtain a best-guess estimate of uplift at well locations. Data points lying above the baseline are primarily affected by uplift, so by adjusting the best-fit baseline curve to fit the data for a given well, the depth at which this curve intersects R_o = 1.1% can be identified (Figure 36).

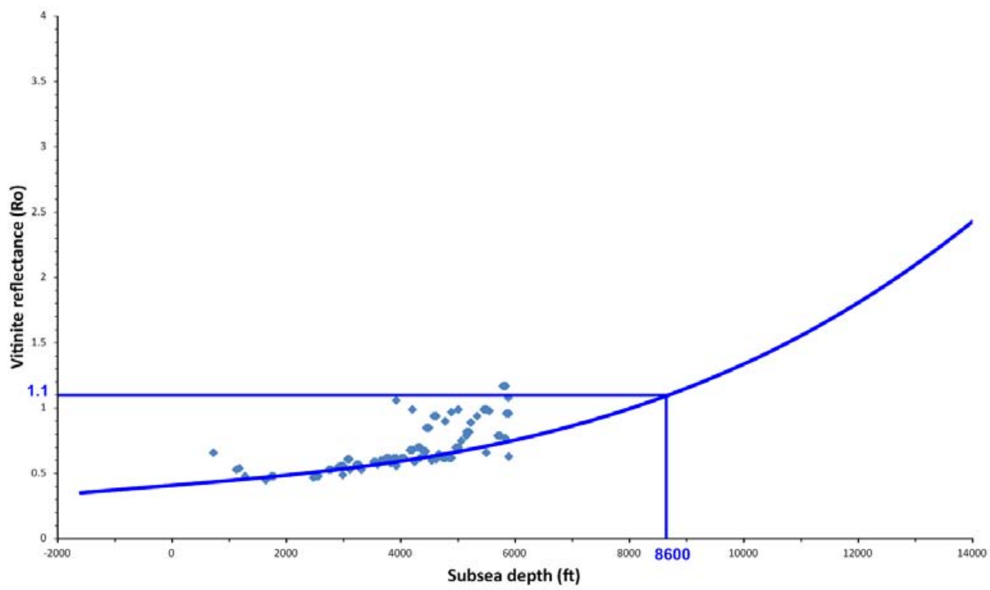


Figure 36. Chart showing the vitrinite reflectance data from Widmerpool 1. The baseline from Figure 35 has been adjusted upwards to fit the spread of the data. The depth at which R_o is expected to reach 1.1% is 8600 ft, i.e. the top of the gas window lies at c.8600 ft at this well location.

This approach is qualitative and should be treated with considerable caution, but it achieves some credence in its broad geographical conformance to other uplift models (e.g. Fraser *et al.* 1990, Kirby *et al.* 2000). At least two phases of uplift have been recognised: the first during the latest Carboniferous and early Permian (Variscan uplift) and the second during the Tertiary (Alpine uplift).

Appendix E contains details of a 1D and 2D basin modelling study, which includes uplift curves for wells and maturity models for 2D profiles. An example from the Kirk Smeaton 1 well is shown as Figure 37.

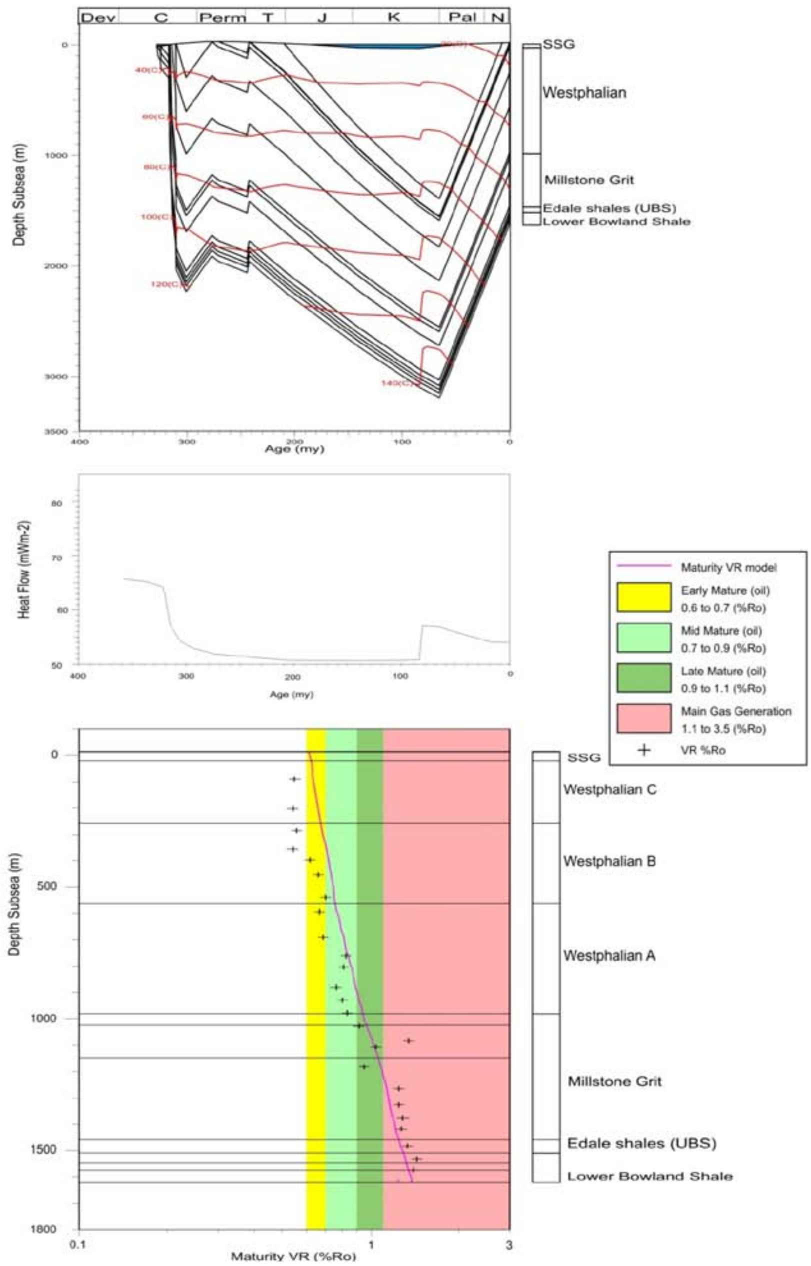


Figure 37. 1-D basin model for the Kirk Smeaton 1 well taken from Appendix E. (top) shows the depositional history, (centre) shows the modelled palaeo-heat flow and (bottom) shows the modelled vitrinite reflectance (VR) maturity curve and raw VR data.

This procedure was carried out for all well and outcrop data and the resulting depths contoured to derive a depth surface to the top of the gas window throughout the study area (Figure 37).

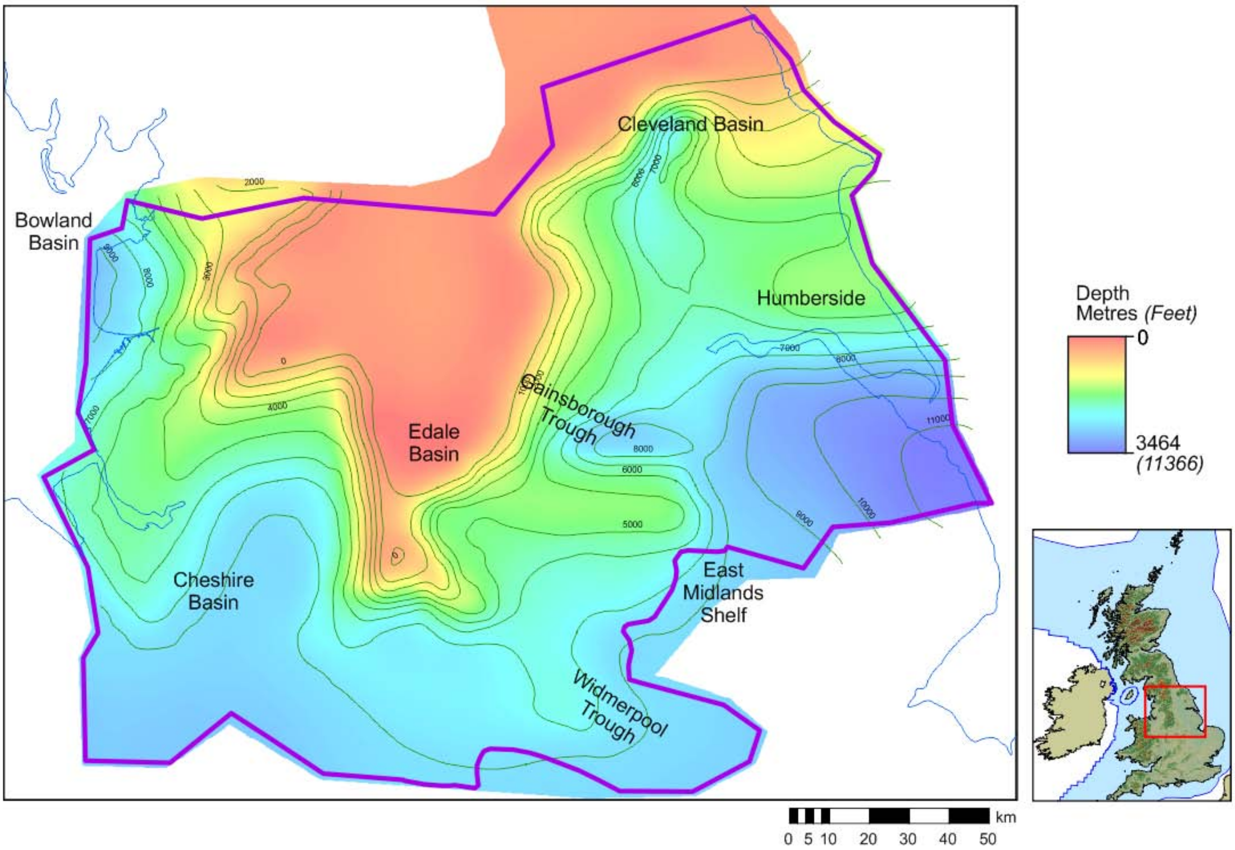


Figure 38. Estimated present-day depth (feet) to the top of the gas window (R_o = 1.1%), central Britain. Note: the shallowest colour includes areas where this isomaturity surface is above sea-level and also above the land surface.

3.9. Calculating gas-mature shale volumes

The work flow used to estimate the in-place gas resource in this study is shown in Figure 39. This shows the processes (large arrow) as well as the data sources (in blue). Some data was not available from the study area, so data from US analogies was used. There is a significant range of uncertainty of the shale volume, and greater uncertainty in the range of free and adsorbed gas used to calculate the total in-place gas volume. No attempt was made to estimate the potential liquid resource, for which the thermal maturity criteria would result in a different gross rock volume.

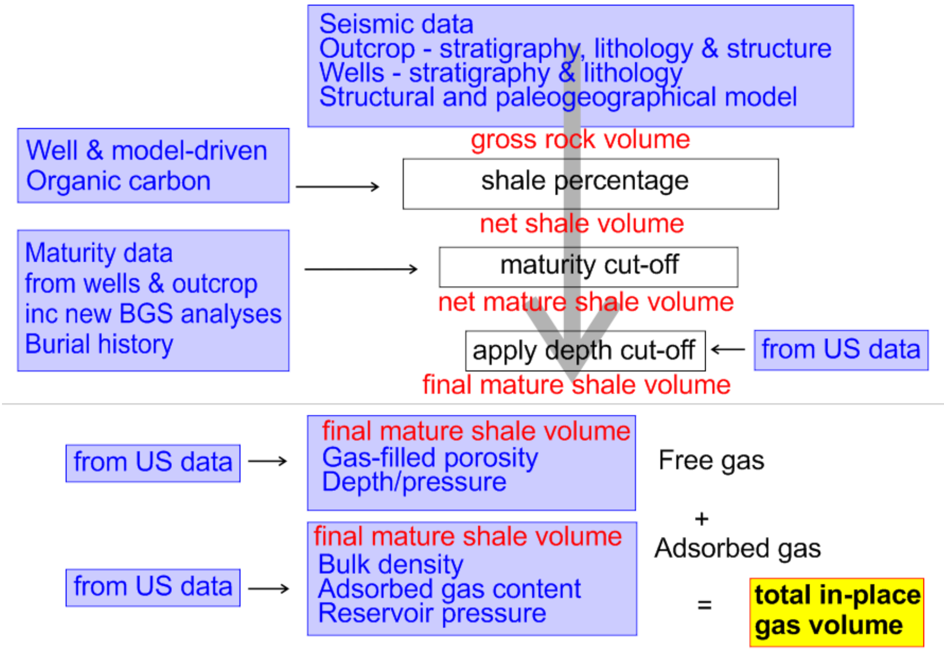


Figure 39. Workflow used in this study to estimate the in-place shale gas resource.

The calculation of the net gas-mature shale volume in the study area used the following basic screening criteria:

Identification of potentially prospective shale gas units from well information

- Mapping the top and base of units to enter into a 3D model
- Mapping the shale component as a proportion of the seismically mapped unit
- Minimum depth cut-off of 5000 ft (1500 m) below land surface
- Minimum cut-off where $R_o > 1.1\%$ (max cutoff of $R_o > 3.5\%$ never exceeded)

The volumes of shale in the upper and lower parts of the Bowland-Hodder unit were calculated using the following formula:

Net shale volume (m^3) = gross rock volume[1] (m^3) x proportion of shale

[1] below the depth where $R_o = 1.1\%$ or 5000 ft, whichever is the deeper.

The thermal maturity surface (Figure 38) was integrated with the depth structure mapping and shale proportion distribution (Figure 29) to calculate the volume of Bowland-Hodder shale in the gas window. Areas where the Bowland-Hodder shale is less than 5000 ft (1500 m) below the land surface were removed from the potentially prospective volume. North American experience has shown that there is not adequate pressure to economically produce shale gas at shallow depths (with the exception of the biogenic gas in the Antrim Basin in Michigan).

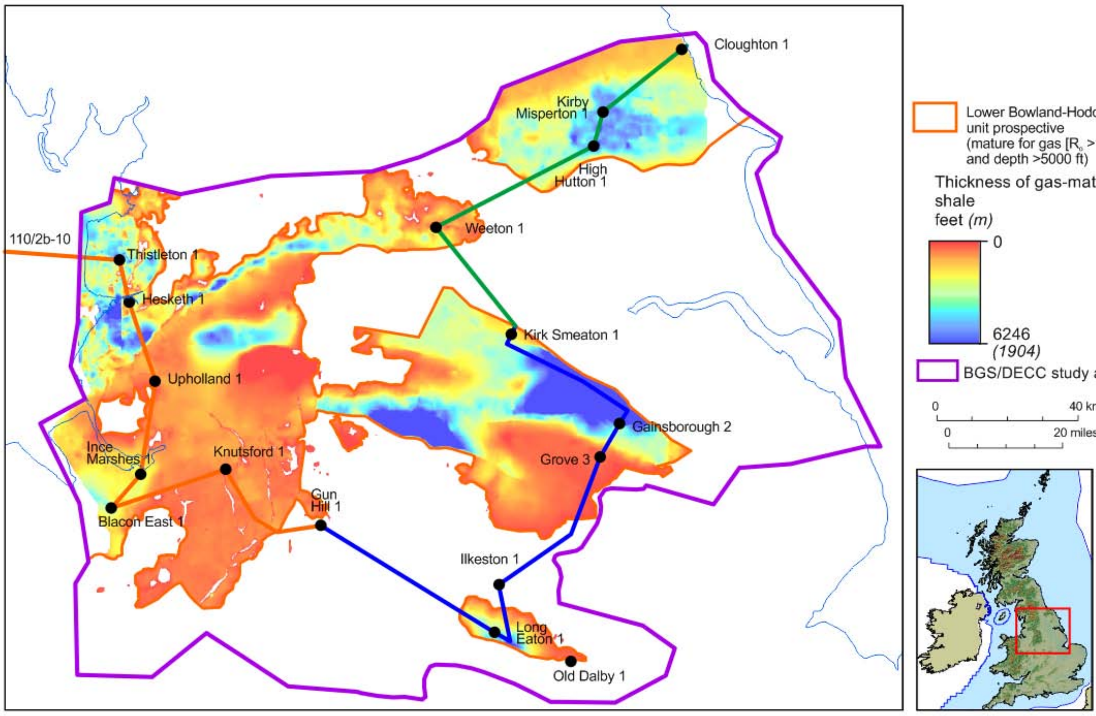


Figure 40. Thickness and distribution of shales of the lower Bowland-Hodder unit that are within the gas window and at a depth greater than 5000 ft.

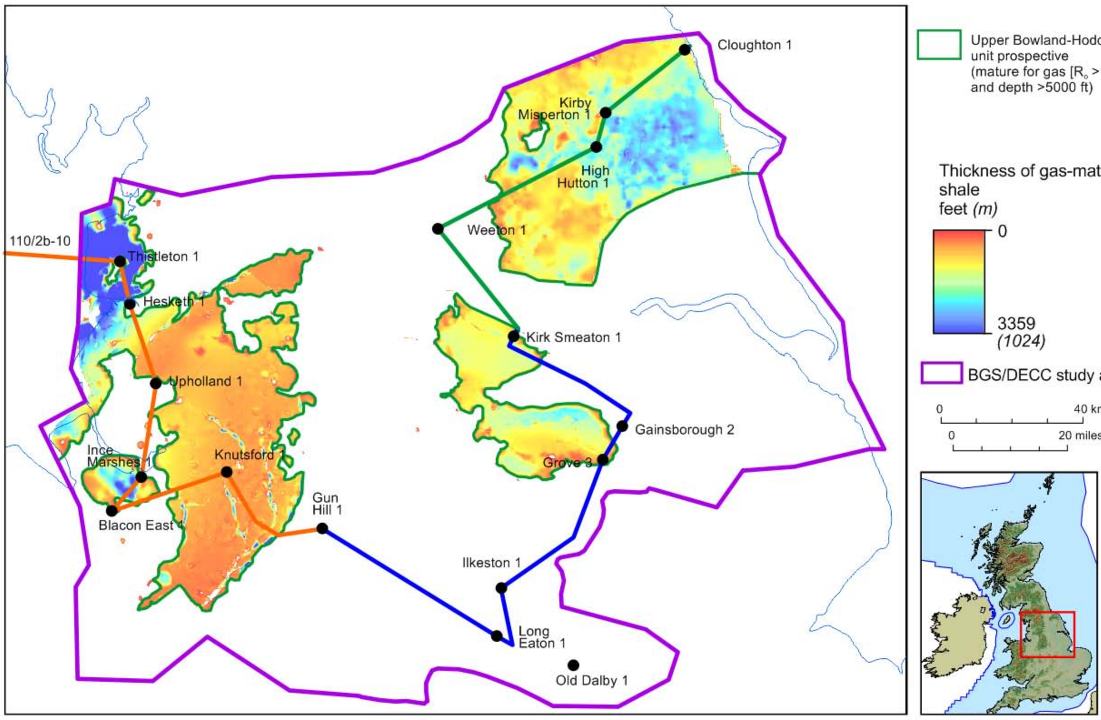


Figure 41. Thickness and distribution of shales of the upper Bowland-Hodder unit that are within the gas window and at a depth greater than 5000 ft.

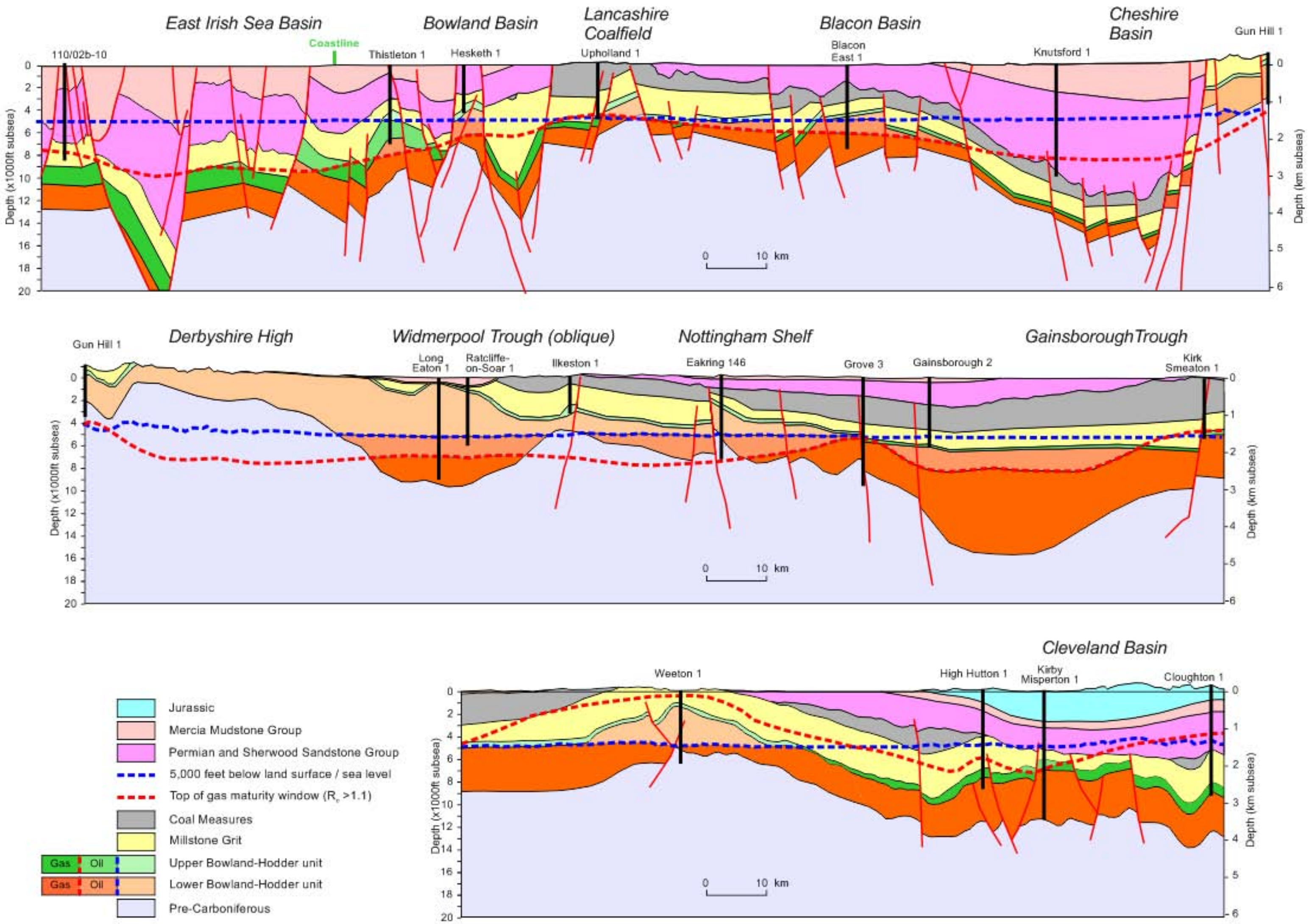


Figure 42. Schematic geological cross-sections indicating where the Bowland-Hodder unit might be considered a shale gas target (labelled 'Gas' in the key). Liquids potential, where not thermally mature for gas (labelled "Oil"), are not considered within the scope of this study. For location of the section, see Figure 40 or 41.

This interpretation is consistent with the detailed core analysis from wells (see Appendix B). In Old Dalby 1 in the Widmerpool Trough, high organic contents and high hydrogen indices (interpreted as Type II kerogen) are encountered, but the calculated R_o values of 0.6-0.7% at 4239-4450 ft sub-sea indicate that the lower Bowland-Hodder shales are immature for gas generation (Figure 40).

In Blacon East 1, in the Blacon Basin, the calculated R_o values of 1.0-1.1% at 6075-6100 ft sub-sea and 1.6-1.9% at 7423-7433 ft indicate that the upper shales are at the lower limit of the gas window, whilst the lower unit is within the gas window (Figures 40 and 41). In Grove 3, located on the East Midlands Shelf, a shale within the lower unit carbonates is also within the gas window (calculated R_o values of 1.8% at 7354-7384 ft sub-sea) (Figure 40).

The resultant maps and cross-sections show the areal extent of the upper and lower shale gas plays together with the estimated thickness of gas-mature shale (Figures 40-42). There are indications that there is a significant volume of gas-mature Bowland-Hodder shale in the Bowland, Cleveland, Edale and Blacon basins and the Gainsborough Trough. The shales in the Widmerpool Trough and Nottingham Shelf are not mature for gas, but contain a significant volume of shale that is thermally within the oil window, where liquids may be prospective, but this is outside the scope of this study.

While liquids associated with shale gas are highly sought after in North America, the recovery of liquids is lower yield than gas and therefore with the current high gas price in Europe it is anticipated that shale gas will be more commercially viable than producing liquids. However, the economics of both plays need more study once the results of wells are available.

Figure 43 shows that there is extant acreage which falls into the highly prospective areas for shale gas, so shale gas drilling and testing does need not wait upon the award of new licences. An update to DECC's 2010 Strategic Environmental Assessment is currently being undertaken and a full consultation is planned to form the basis for the next onshore licensing round.

Some of the most prospective areas are in environmentally sensitive areas or under urban centres. Exploration and potential development will likely progress at a much slower pace to fully consider how adverse impacts can be mitigated and to obtain surface landowner access permissions (both for well sites and under the path of all deviated wells), but shale gas development of the Barnett Shale in the densely populated Dallas-Fort Worth Basin proves that it is not impossible.

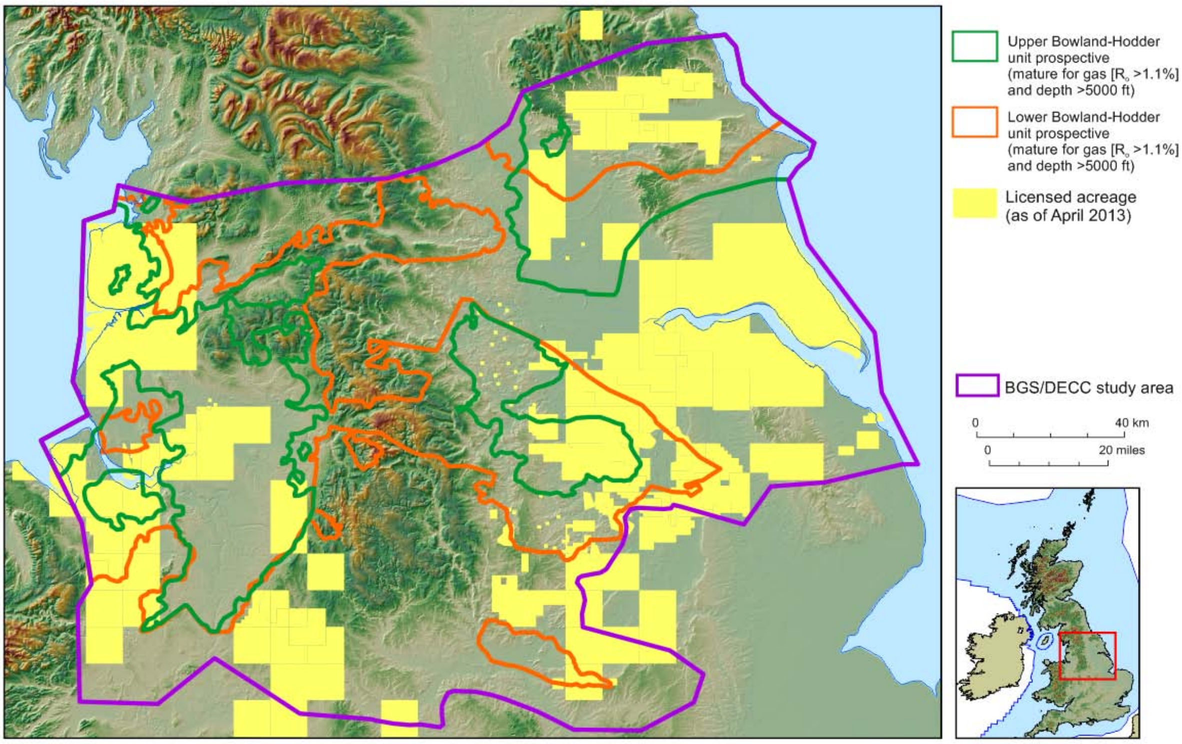


Figure 43. Summary of areas prospective for gas in the upper and lower parts Bowland-Hodder unit in central Britain with currently licensed acreage shown.

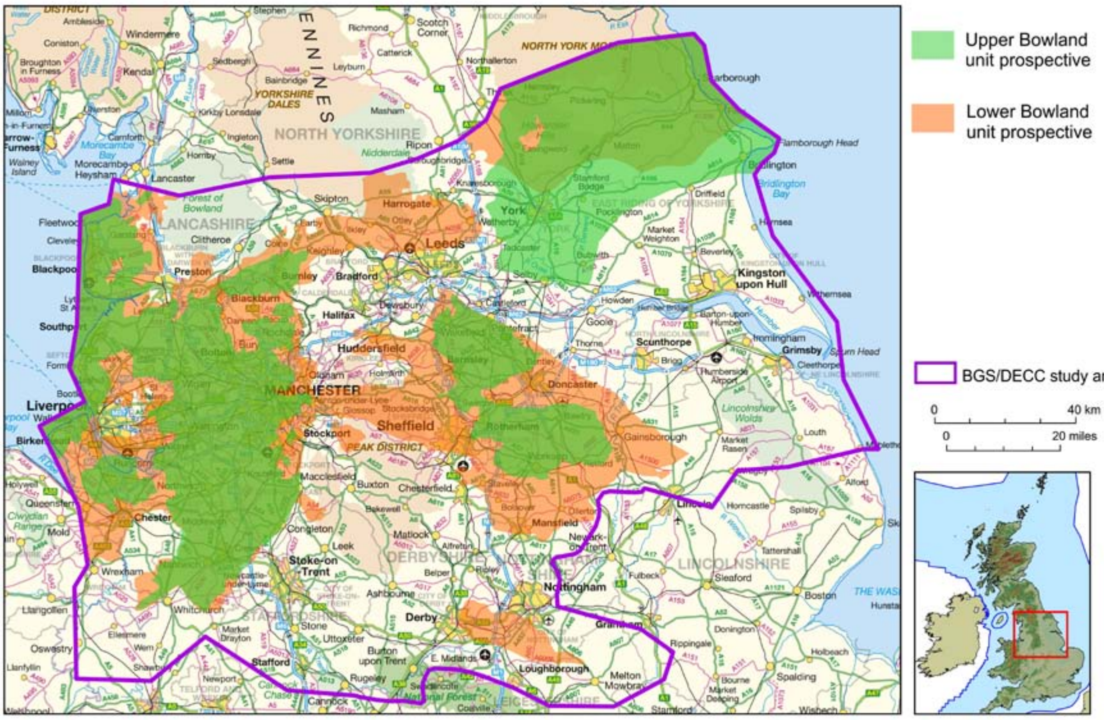


Figure 44. Summary of areas prospective for gas in the upper and lower parts Bowland-Hodder unit in relation to the urban areas of central Britain. Contains Ordnance Survey data © Crown copyright and database right 2013.

4. Resource estimation

In 2010, a DECC-commissioned BGS study estimated that, by a simple scaled basin-size analogy with similar producing shale gas plays in North America, that the UK Carboniferous Upper Bowland Shale (i.e. upper Bowland-Hodder unit) gas play, if analogous to the Barnett Shale of Texas, could potentially yield up to 4.7 tcf of gas or if analogous to the Antrim Shale, 2.1 tcf (DECC 2010a, BGS 2012).

Now, based on this detailed work undertaken in 2012-13, a rigorous gas-in-place resource estimation can be made for the Bowland-Hodder unit in central Britain. The details of this study's calculation and its results are presented in Appendix A.

This study concludes that the stacked Bowland-Hodder unit can be separated into two genetically defined intervals, with different probabilities of success, largely due to the limited well penetrations of the deeper interval. The upper unit is well constrained with borehole penetrations, core analyses and moderate seismic control. It is a condensed interval characterised by high organic content, with evidence of gas in boreholes and high gamma ray signature in well logs which can be correlated over a large area, even flooding over the carbonate platforms at the basin margins. There are a number of intervals greater than 200 ft thick that could potentially be developed using horizontal drilling technology. **The estimated range of Gas in Place (GIIP) for the upper Bowland-Hodder unit is 164 – 264 – 447 tcf.**

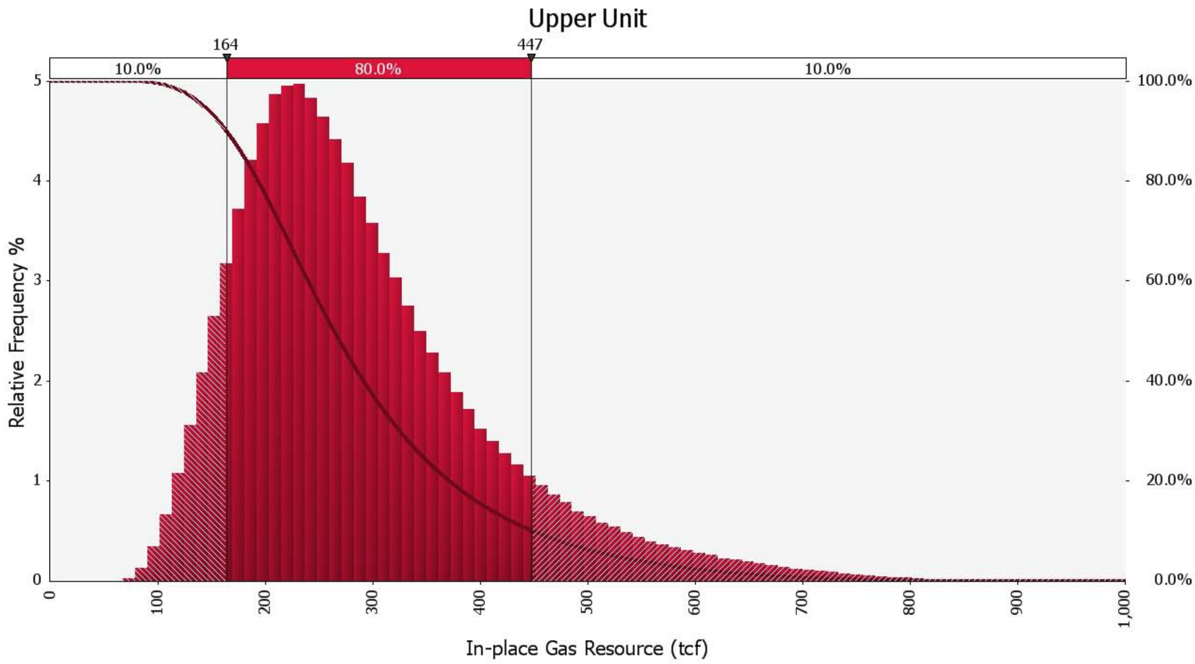


Figure 45. Probabilistic distribution and cumulative probability curve representing the result of a Monte Carlo analysis for the in-place resource estimation of shale gas in the upper Bowland-Hodder unit.

The lower unit's expanded sequence must be viewed as a higher risk resource as it is much less explored – there are few well penetrations and it is poorly imaged on seismic data in the deepest, potentially most prospective basins (Widmerpool Gulf, Edale Basin and Gainsborough Trough), where thicknesses can reach 10,000 ft. The few deep well penetrations do show some high organic content, high gamma log prospective intervals that may prove to be laterally contiguous. The presence of large-scale slumps in the lower unit may also present challenges for shale gas exploration and production. In addition, the lower unit thickness, complex syn-rift structure and stratigraphy do not have any producing analogies in North America. Consequently, the estimated range of gas in-place for this thick sequence is 658 – 1065 – 1834 tcf, with a lower assumption of gas yield than the upper unit.

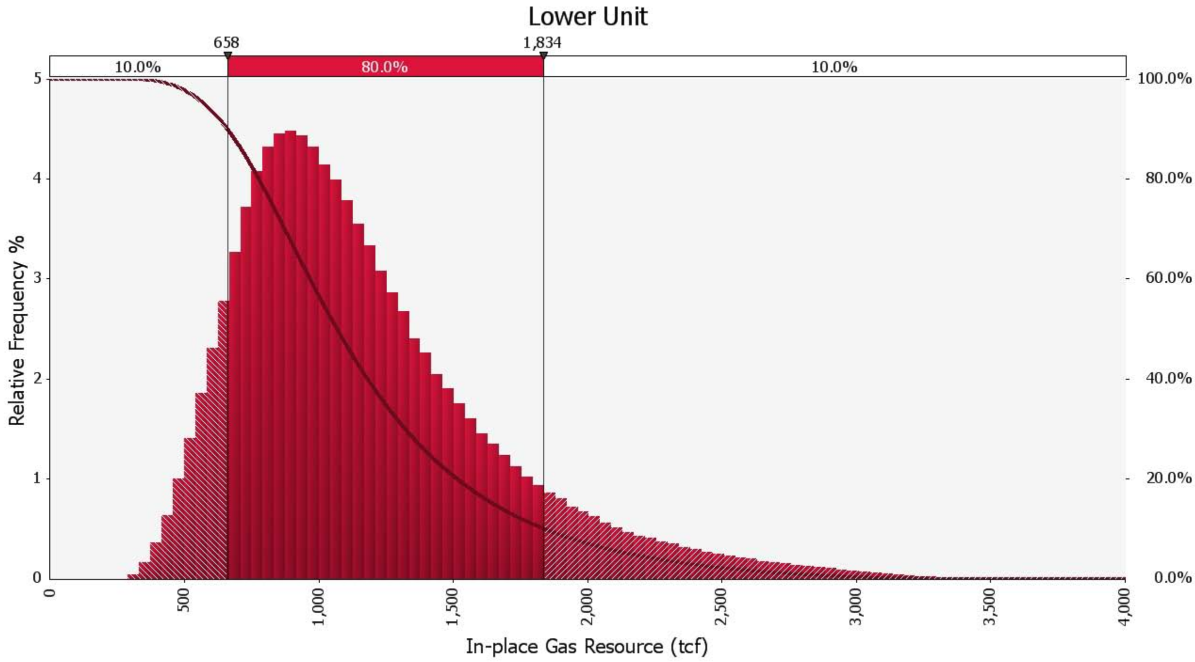


Figure 46. Probabilistic distribution and cumulative probability curve representing the result of a Monte Carlo analysis for the in-place resource estimation of shale gas in the lower Bowland-Hodder unit.

The total range of estimated gas-in-place for the combined upper and lower units is 822 – 1329 – 2281 tcf. No estimate is made for the potential for liquid hydrocarbons, which is outside the scope of this study.

	Total gas in-place estimates (tcf)			Total gas in-place estimates (tcm)		
	Low (P90)	Central (P50)	High (P10)	Low (P90)	Central (P50)	High (P10)
Upper unit	164	264	447	4.6	7.5	12.7
Lower unit	658	1065	1834	18.6	30.2	51.9
Total	822	1329	2281	23.3	37.6	64.6

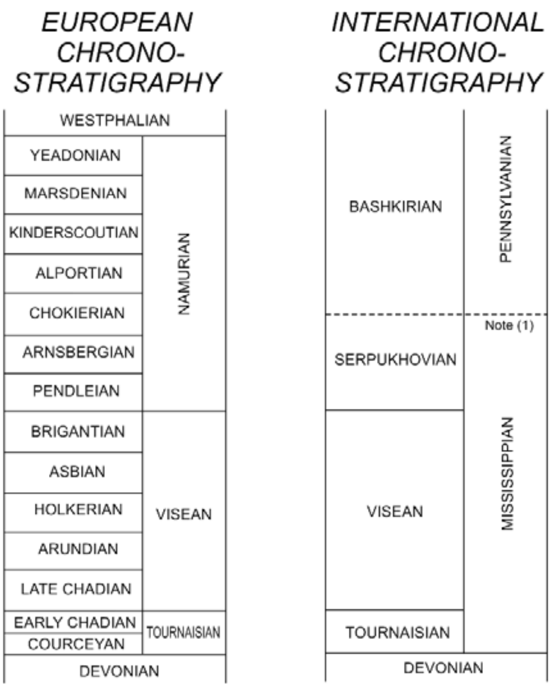
This estimate is a gas in-place (GIP) estimate, because a reliable estimate of recoverable shale gas cannot be made at this time (see Section 2.2). DECC does not include any onshore or offshore shale gas potential in the published estimates for Undiscovered Resources , where detailed mapping has identified undrilled prospectivity in basins where the uncertainties in evaluating prospectivity are much better understood.

It must be noted that this Bowland Shale gas in-place (GIP) estimate is very large when compared with the total ultimate recovery of gas (i.e. gas reserves plus cumulative production) from the offshore UK, which is currently estimated at 92.7 - 101.4 - 109.0 tcf. Of this total, the cumulative amount of gas produced to the end of 2011 was 84.0 tcf. (See https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/16096/6313-appendix-1-reserves-2012l.pdf)

However, only with further shale gas exploration drilling and testing over an extended period, and optimization of the extraction process, will it be possible to determine whether this identified shale gas prospectivity can be exploited commercially – and how significant a contribution it could make to the future UK energy mix.

5. Glossary

Unit/abbreviation	Full name
API	standard (American Petroleum Institute) measure of natural gamma radiation typically in a borehole
bcf	billion (10^9) cubic feet
B_g	gas expansion factor
ft	foot/feet
ft^3 or scf	(standard) cubic foot/feet
GIIP	gas initially in place
HI_o	original hydrogen index
HI_{pd}	present-day hydrogen index
km	kilometre(s)
km^2	square kilometre(s)
m	metre(s) (1 m = 3.28084 ft)
m^3	cubic metre(s) (1 m^3 = 35.31467 ft^3)
Ma	million years before present
mD	millidarcy
MPa	megapascal(s) (1 MPa = 145 psi)
mmcfd	million (10^6) cubic feet of gas per day
$mile^2m$	a volume occupying an area of 1 square mile with a thickness of 1 metre (1 $mile^2m$ = 2,589,988 m^3)
R_o	vitrinite reflectance (in oil) (%)
tcf	trillion (10^{12}) cubic feet
tcm	trillion (10^{12}) cubic metres
TOC	total organic carbon (%)



Note (1) As the Global Stratotype for the base Pennsylvanian contains numerous non-sequences (Barnett & Wright 2008), precise correlation is not possible.

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