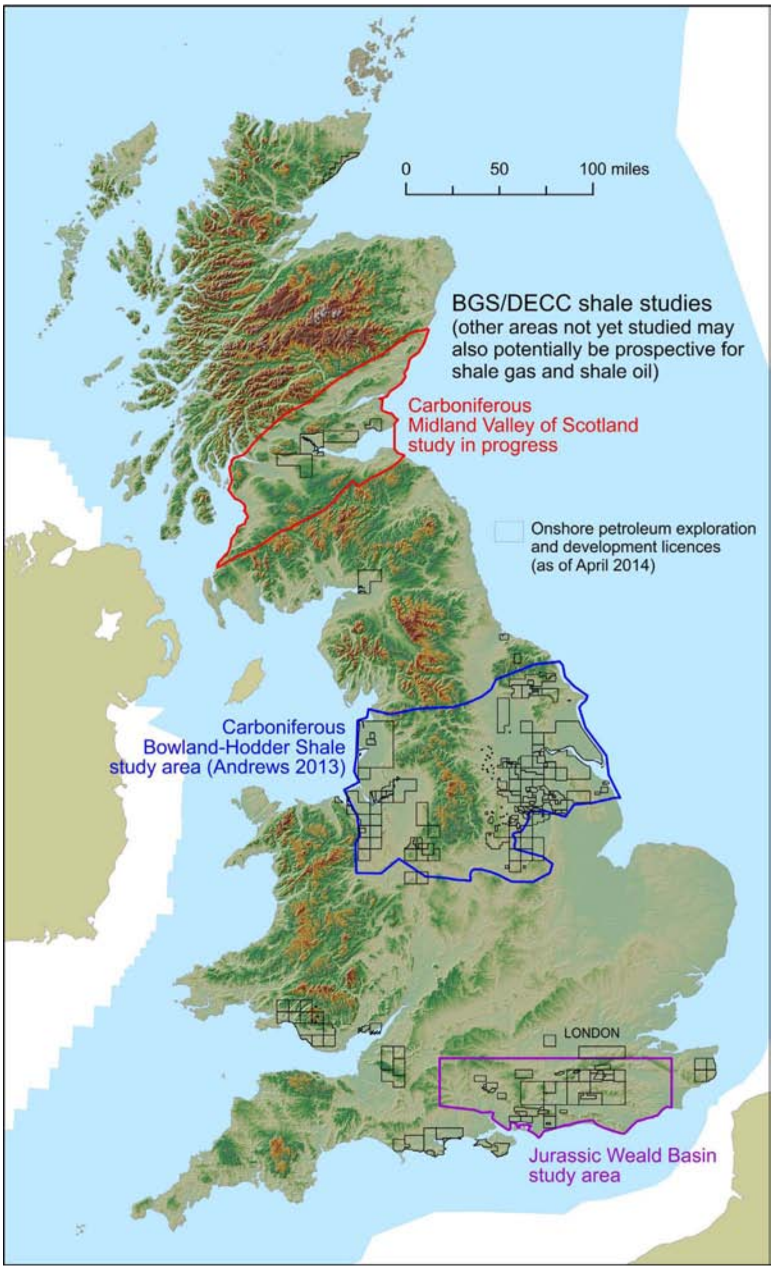
The Jurassic shales of the Weald Basin: geology and shale oil and shale gas resource estimation



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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 65).

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

Acknowledgements

The author would like to thank the many contributors to this report, most notably Alick Leslie[1], Kirstin Johnson[3], Don Cameron[3], Mike Sankey[3], Mike McCormac[1], Nigel Smith[4], Chris Gent[4], Sarah Hannis[4], Chris Vane[4], Vicky Moss-Hayes[4], Simon Kemp[4], Ian Mounteney[4], A. Chaggar[4] and Toni Harvey[2], and reviewers Dick Selley[5] and Andrew Aplin[6]. Rob Ward[4], Ian Davey[7] and Alwyn Hart[7] contributed Section 3.3 (aquifers and groundwater).

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1 Summary

Following the publication of shale gas resource estimates for the Carboniferous Bowland-Hodder shales (Andrews 2013), this report is the second to address the potential distribution and in-place resources of unconventional oil and gas contained in shales beneath the UK. It summarises the background geological knowledge and methodology that have enabled a preliminary in-place oil resource calculation to be undertaken for the Weald Basin and adjacent areas in southern Britain (Figure 1). No significant shale gas resource is recognised in the Jurassic of the Weald Basin.

Marine shales were deposited in the Weald Basin at several intervals during the Jurassic (c.145-200 Ma). The basin is composed of several fault-controlled sub-basins, which form part of a wider basin that extended into northern France. It is geologically distinct from the Wessex Basin which lies to the south-west, outside the study area.

Five units within the Jurassic of the Weald Basin contain organic-rich, marine shale: the Mid and Upper Lias Clays (Lower Jurassic) and the Oxford Clay, Corallian Clay and Kimmeridge Clay (Upper Jurassic). These attain gross shale thicknesses of up to 300 ft (90 m), 220 ft (67 m), 500 ft (150 m), 260 ft (80 m) and 1,800 ft (550 m) respectively in the Weald Basin depocentre, and they contain varying amounts of organic matter. Conventional oil and gas fields in the basin attest to the capability of some of these units to produce hydrocarbons. It is possible that oil could have been generated from any or all of the five shales, but in the current model even the deepest Jurassic unit is not considered to have been sufficiently deeply buried to have generated significant amounts of gas. Some gas has been generated in association with oil and shallow biogenic gas may also be present.

Organic-rich shales occur at two levels in the Lias (Lower Jurassic) of the Weald; these have direct equivalents in the Paris Basin, although in the Weald they fail to reach the richness found in France. In a third Lias unit, the Blue Lias (Lower Lias), total organic carbon (TOC) reaches 8% further west in shales in the Wessex Basin, where it sources the Wytch Farm oilfield, but organic carbon contents are typically well below 2% in the equivalent limestones and shales of the study area. This contrast in organic content may result from differences in palaeogeography and organic input or preservation between the basins. The most significant organic-rich shales in the Weald Basin occur in the lowermost Oxford Clay (TOC up to 7.8%) and middle Kimmeridge Clay (TOC up to 21.3%) and these represent potential 'sweet-spots' worthy of further investigation.

None of the Jurassic shales analysed by Rock-Eval methodology in the Weald Basin has an 'oil saturation index' (S1*100/TOC) of greater than 50, i.e. much of the 'oil' may be physically associated with kerogen, rather than present in pore space. This is low in comparison to shale oil producing areas in North America, so it may be that only limited amounts of shale within the Jurassic of the Weald Basin have any potential to produce oil in commercial quantities. However, after correcting for the evaporation of light hydrocarbons since the sample was taken, it may be that some horizons within the Mid and Upper Lias, lower Oxford Clay and Kimmeridge Clay exceed the 100 required for the oil to be 'producible.' Also, the fact that oil has migrated into conventional reservoirs suggests that optimum conditions are reached at least locally within the basin. Interpreting the presence of producible oil in the organic-rich shales allows for an in-place resource volume to be calculated with a broad range of probabilities.

The maturity of the shales is a function of burial depth, heat flow and time. In this study, the Jurassic shales are considered mature for oil generation (vitrinite reflectance, R_o, values between 0.6% and 1.1%) at depths between approximately 7,000-8,000 ft (2,130-2,440 m) and 12,000-13,000 ft (3,660-3,960 m) (where there has been minimal uplift). However, southern Britain experienced a phase of significant uplift in Cenozoic times, due to basin inversion, that has raised the mature shales by up to 6,750 ft (2,060 m) to shallower present-day depths than would otherwise be expected. However, even the Lias shales are unlikely to have attained sufficient maturity to allow for significant gas generation.

Where they have been buried to a sufficient depth for the organic material to generate oil, all five prospective shales are considered to have some potential to form a shale oil resource analogous, but on a smaller scale, to the producing shale oil provinces of North America (e.g. Barnett, Woodford and Tuscaloosa).

Hybrid conventional/shale oil plays with low-porosity and impermeable rocks juxtaposed against mature shales may also represent a favourable exploration target in the Weald Basin; these have also proven successful in the North America (e.g. the Bakken oil system). The oil resources potentially present in these plays are not included in the in-place oil volumes in this report.

The total volume of potentially productive shale in the Weald Basin was estimated using a 3D geological model generated using seismic mapping, integrated with borehole information. This gross volume was then reduced to a net mature organic-rich shale volume using a maximum, pre-uplift burial depth corresponding to a vitrinite reflectance cut-off of 0.6% (modelled at 7,000 ft/2,130 m, and 8,000 ft/2,440 m). This volume was further truncated upwards at two alternative levels - firstly, at a depth of c.3,300 ft (1,000 m) (as proposed by USEIA 2013) and secondly at a depth of c.5,000 ft (1,500 m) below land surface (as proposed by Charpentier & Cook 2011 for shale gas). This is a regionally applied cut-off; the depth at which shale oil (or shale gas) productivity becomes an issue in terms of pressure and hydrogeology will need to be addressed locally.

The volumes of potentially productive shale and average oil yields were used as the input parameters for a statistical calculation (using a Monte Carlo simulation) of the in-place oil resource (see Appendix A). Two scenarios were modelled for each shale unit (Table 1).

	Total oil in-place estimates (billion bbl)		**Total oil in-place estimates (million tonnes)**	
	With top of oil window at 7,000 ft (2,130 m) maximum burial depth	With top of oil window at 8,000 ft (2,440 m) maximum burial depth	With top of oil window at 7,000 ft (2,130 m) maximum burial depth	With top of oil window at 8,000 ft (2,440 m) maximum burial depth
Kimmeridge Clay	0.41 – 2.03 – 4.77	0.11 – 0.61 – 1.44	55 – 270 – 636	15 – 81 – 192
Corallian Clay	0.20 – 0.52 – 1.04	0.11 – 0.30 – 0.61	27 – 69 – 139	15 – 40 – 81
Oxford Clay	0.59 – 1.39 – 2.46	0.41 – 0.96 – 1.70	79 – 185 – 328	55 – 128 – 227
Upper Lias Clay	0.28 – 0.63 – 1.05	0.22 – 0.52 – 0.85	37 – 84 – 140	29 – 69 – 113
Mid Lias Clay	0.33 – 0.79 – 1.43	0.27 – 0.64 – 1.15	44 – 105 – 191	36 – 85 – 153
All Jurassic clay units	**2.2 – 4.4 – 8.6**		**293 – 591 – 1,143**	

Table 1. Estimates of the total potential in-place shale oil resource in the Jurassic Weald study area. P90, P50 and P10 values are given for each unit, where P10 is the most optimistic scenario. This estimate only covers unconventional oil, and excludes volumes in potential tight conventional or hybrid plays.

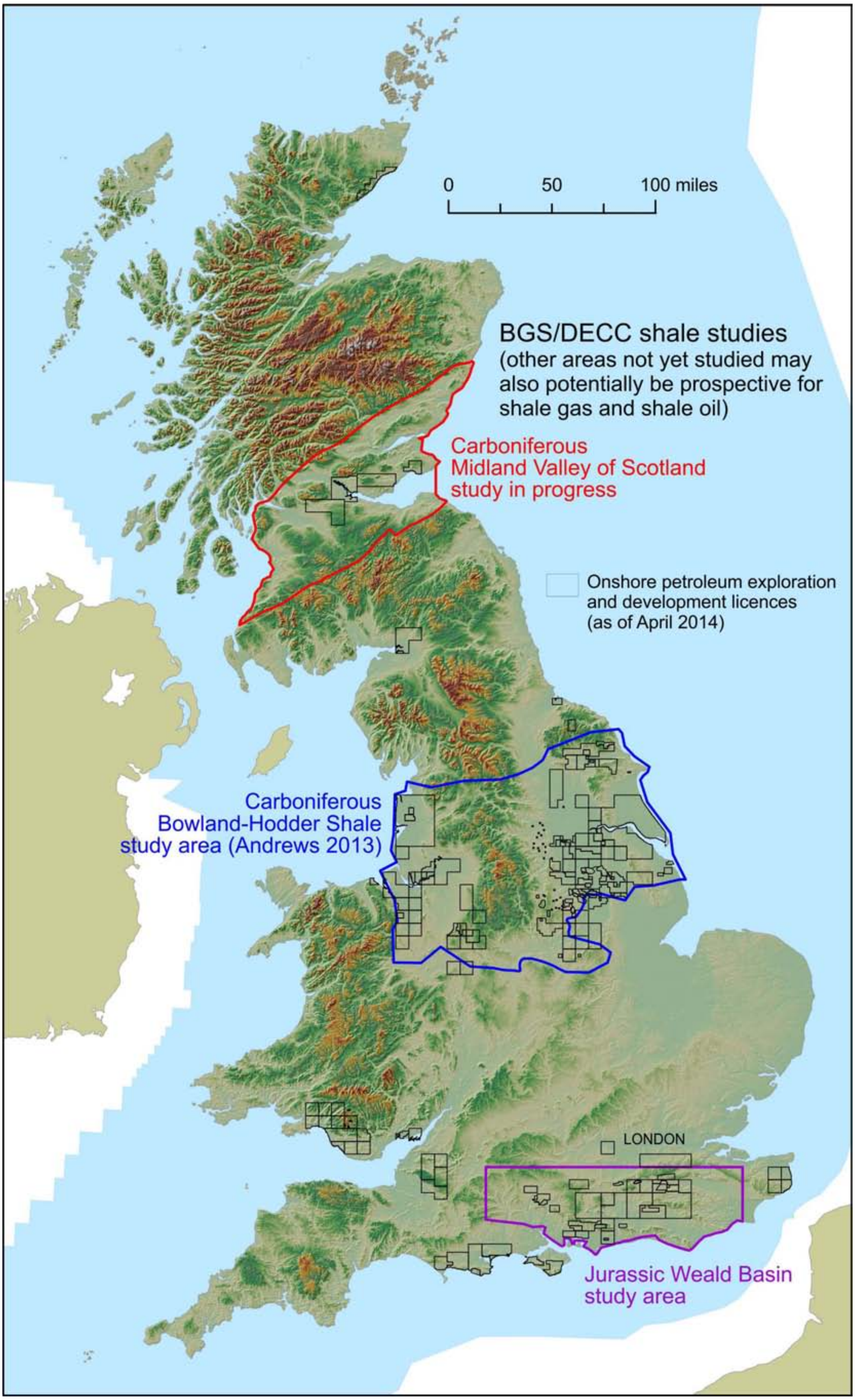

Figure 1. Location of the BGS/DECC Weald study area in southern Britain, together with prospective areas for shale gas in northern Britain and currently licensed acreage. Other shale gas and shale oil plays may exist.

This study offers a range of total in-place oil resource estimates for the various Jurassic shales of the Weald Basin of 2.2 – 4.4 – 8.6 billion bbl (0.29 – 0.59 – 1.14 billion tonnes) (P90 – P50 – P10) (Table 1). It should be emphasised that these 'oil-in-place' figures refer to an estimate for the entire volume of oil contained in the rock formation, not how much can be recovered. 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 oil price, operating costs and the scale of development agreed by the local planning system, will allow estimates of the UK's producible shale oil reserves to be made.

There is a high degree of uncertainty in these figures. Indeed, there is a chance that there may be little or no 'free oil', given that the 'oil saturation index' is considerably less than 100 (see Jarvie 2012b) and what oil there is could be located entirely within the kerogen particles and would thus require heating/retorting to extract it. In these circumstances, the resource could no longer be categorised in terms of 'shale oil'. The potential for hybrid plays in which oil might have migrated into tight reservoirs adjacent to mature shale is acknowledged, but the potential volumes of oil trapped in such plays is not addressed in this report.

Other areas in the UK have shale gas and shale oil potential, and later in 2014 the Carboniferous shales of the Midland Valley of Scotland will be the subject of a further BGS/DECC report.

2 Introduction to shale gas, shale oil and resource estimation

2.1 Shale as a source and reservoir rock

Shales have long been recognised as the source rocks from which most oil and gas has been generated. This mechanism allows for a proportion of the generated oil and gas to be expelled and to migrate into conventional reservoirs over geological time. The fact that some hydrocarbons, particularly oil, are retained in the fine-grained lithologies has now taken on a new significance. Some of these hydrocarbons occur as free oil in the shale, whilst some remain bound with the kerogen and require the shale to be retorted (i.e. heated to >350°C) to extract it. This is the basic distinction between shale oil and oil shale (see Section 2.2 below).

2.2 Shale oil vs. oil shale

The terms 'shale oil' and 'oil shale' are both applied to organic-rich source rocks, but the hydrocarbons are present in very different scenarios. Shale oil is mature and can be found in association with shale gas plays if the source rocks have been buried to sufficient depths. On the other hand, oil shale is immature and can either be mined at or near the surface or retorted *in situ* at depth. Such oil shale extraction techniques make it very unlikely that it might be exploited at depth in the Weald Basin.

The differences between shale oil and oil shale are presented below (Table 2).

Oil shale	**Shale oil (this report)**
Kerogen-rich shale, i.e. organic matter still in its solid state. Does not contain liquid oil. The source rock for conventional oil fields. Grades to carbonaceous shale [i.e. rich in carbon] and cannel coal. Torbanite is a lacustrine type of oil shale.	Oil occurs in liquid form in largely impermeable lithologies. These can be shale, but also adjacent siltstone, sandstone, limestone etc (note that non-shales are not specifically modelled in this report). Also known as 'tight shale oil', 'tight light oil (TLO)', 'tight oil', 'oil-bearing shale' or 'shale-hosted oil'.
Oil is extracted by (a) in-situ heating of shale at depth or (b) mining of shale at/near the surface which is then retorted. Yields of 15+ gallons/ton are considered viable (25+ gallons/ton is high grade) (see Birdwell *et al.* 2013)	**Oil is extracted by horizontal drilling and hydraulic fracturing.**
Kerogen is **immature** for oil generation.	Kerogen is **mature** and oil has been generated.
The hydrocarbons are essentially retained within the kerogen of the immature source rock. Oil has to be artificially generated by retorting, i.e. by accelerating the natural maturation process. Confusingly, oil produced by retorting shale can also been called 'shale oil'.	Oil, essentially light oil, has already been generated and some is retained in microscopic pore spaces within the shale rather than being associated with kerogen. It is this oil that is regarded as 'producible' in the sense that it could potentially flow after fracture stimulation. The remainder of the oil may have migrated into carrier beds and subsequently reservoir rocks.
<u>Examples</u>: the Green River Formation in the western USA, Ordovician deposits in Estonia and Sweden, the Tertiary deposits in Queensland, Australia, the El-Lajjun deposit in Jordan, and deposits in France, Germany, Brazil, China, southern Mongolia and Russia. Historical mining in West Lothian, Scotland.	<u>Examples</u>: the Bakken Shale, the Niobrara Formation, Barnett Shale, and the Eagle Ford Shale in the USA, R'Mah Formation in Syria, Sargelu Formation in the northern Gulf of Arabia region, Athel Formation in Oman, Bazhenov Formation and Achimov Formation of West Siberia in Russia, in Coober Pedy in Australia, Chicontepec Formation in Mexico, and the Vaca Muerta oil field in Argentina.
In-place resource from Rock-Eval S1+S2	In-place resource from Rock-Eval S1
S2 : the amount of hydrocarbons generated through thermal cracking of non-volatile organic matter (kerogen) when the sample temperature is increased to 550°C. S2 is an indication of the quantity of hydrocarbons that the rock may potentially produce should burial and maturation continue.	**S1** : the amount of hydrocarbons already generated in the rock. These are the free and sorbed hydrocarbons (oil) already present in the sample, which are volatalised from the sample by the initial heating to a temperature of 350°C.

Table 2. Criteria that differentiate a shale oil from an oil shale.

2.3 Resources vs. reserves

The important distinction between (in-place) resources and (recoverable) reserves is discussed in detail by Andrews (2013).

The aim of this report is to use all available geological information to provide, if sufficient data are available, in-place shale oil and shale gas resource estimates for the Weald Basin. Recovery factors, and hence recoverable reserves, are not discussed.

2.4 What defines a shale oil play?

Table 3 summarises some of the most important geological, geochemical and geomechanical criteria that are widely used to define a successful shale oil play; some criteria are essential, others are desirable. The criteria are based on data from shale plays in North America, which are known to vary considerably.

Criteria	**Range of data and definitions**	**Weald data (availability and gaps) and definitions used in this report**
Organic carbon 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 (2012a) used 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 new study commissioned by DECC (Appendix B). A cut-off of TOC > 2% is used for a potentially viable shale oil resource.
Gamma-ray values	High gamma radiation is typically an indication of high organic carbon content, especially in marine systems. 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.).	In the Weald area, the gamma log response generally indicates low radioactivity even where shales are organic-rich. 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 <100 API. This contrasts with the Upper Bowland-Hodder Unit of northern Britain, where high-gamma zones are widespread (Andrews 2013).
Kerogen type	Kerogen should be of Type I, II or IIS (Charpentier & Cook 2011). Ideally, Type II (Jarvie 2012a). This indicates a planktonic, marine origin.	Information on kerogen type is incomplete. Type I, II and III kerogens are described from the Weald Basin.
Original hydrogen index (HI_o)	HI_o preferably >250 (TNO 2009, Charpentier & Cook 2011); 250-800 mg/g (Jarvie 2012a). HI = [(S2 x 100)/TOC]. Note: it is important to have information on original, rather than present day, HI values. The conversion from present-day HI of mature rocks to original HI depends 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 oil or gas extraction. Jarvie (2012a) stresses the requirement of a significant silica content (>30%) with some carbonate, and presence of non-swelling clays.	Most samples with TOC>=2% have clay content of 33-51%. See Appendices B and C.
Net shale thickness	Moderate shale thicknesses are considered ideal; >50 ft (15 m) (Charpentier & Cook 2011); >20 m (TNO 2009); >150 ft (Jarvie 2012a). 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).	The thickness of net potentially productive shale in the five shale units of the Jurassic varies from 62 ft to 1,000 ft (19-300 m), with up to 229 ft (70 m) in the Oxford Clay and 1,000 ft (300 m) in the Kimmeridge Clay.
Thermal maturity	The shale should be mature for oil generation; R_o = 0.6 - 1.1% is widely accepted as the 'oil window'. 'The oil window does vary, depending on the source rock, although thermal maturity values from about 0.6 to 1.4% R_o are the most likely values significant for petroleum liquid generation' (Jarvie	In this study, the shale is considered to be mature for oil generation above an R_o value of 0.6%. Some minor amounts of gas will have also been generated in association with the oil.

Criteria	Range of data and definitions	Weald data (availability and gaps) and definitions used in this report
	2012a).	
Oil yields	'Free oil' content (S1 corrected for evaporative loss) should ideally be >2 mgHC/gRock, or equivalent yield of >50 bbl/acre-ft.	Average present-day S1 from Rock-Eval is only 0.42 mgHC/gRock. Even allowing for 50% evaporative loss, only 10% of Jurassic shales have >2 mgHC/gRock. Potential oil yields from Weald Basin samples are typically <50 bbl/acre-ft.
Oil saturation index	The oil saturation index [(S1 x 100)/TOC] should ideally be above 100 (Jarvie 2012b).	In the Weald area, the oil saturation index is typically < 35.
Depth minimum	Depth >5,000 ft (>1,500 m) (Charpentier & Cook 2011); >3,300 ft (>1,000 m) (USEIA 2013). Lower pressures generally encountered at shallower depths result in low flow rates.	Shale resources shallower than (a) 3,300 ft (1,000 m) and (b) 5,000 ft (1,500 m) below land surface have been excluded from this study in two alternative scenarios.
Shale porosity	Typically 4-7%, but should be less than 15% (Jarvie 2012a).	Not known.
Overpressure	Slightly to highly overpressured (Charpentier & Cook 2011, Jarvie 2012a). The Barnett Shale is slightly overpressured (Frantz *et al.* 2005).	Not known.
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. Faulting locally occurs at high densities.

Table 3. Criteria that are widely used to define a successful shale oil play (modified after Andrews 2013)

2.5 Shale oil around the world

One of the most prolific petroleum basins in the world, the West Siberian Basin, contains shale oil in the Bazhenov Formation of late Jurassic to early Cretaceous age (Ulmishek 2003). In the USA, the Bakken (Williston Basin), Niobrara (Colorado/Wyoming) and Eagle Ford (Texas) are major shale oil plays, although all are classed as hybrid systems[1] by Jarvie (2012b). Many other countries also have shale oil resources, such as China, Argentina, Libya and Australia (USEIA 2013).

See Andrews (2013) for examples of shale gas plays.

2.6 Estimation of oil volumes

The methodologies used to assess in-place and recoverable resources in shale gas basins are summarised in Andrews (2013). Analogous methods are used here for shale oil. The distinction between 'bottom-up' geological methods and 'top-down' production methods also holds true for

[1] hybrid systems contain juxtaposed organic-rich and organic-lean intervals (Jarvie 2012b).

estimating shale oil resources. In the absence of production data, a 'bottom-up' approach is used in this study.

The significant difference between shale gas and shale oil resource calculations is that in the case of gas, both free and adsorbed gas maybe extractable, whereas with oil, it is only the free oil component that is effectively producible.

Calculations to establish the volume of oil retained within a mature source rock that can be extracted without retorting/heating, i.e. the in-place shale oil resource, fall into two broad categories. Both involve calculating the volume of free oil per unit rock volume and then scaling it up to basin dimensions.

The various methodologies are summarised in Appendix A.

In the case of the Weald Basin, the paucity of data precludes a full understanding of free oil contents. However, with regards to the use of S1 to estimate oil-in-place, it is reasonable to model two end members (S1 and S2 are defined in Table 2):

1. Use Jarvie (2012b) and as 'S1*100/TOC' is less than 100, assume that most/all of the measured S1 is associated with kerogen. In this scenario, free oil will be negligible in the Weald area.
2. Assume that the sorbed oil is restricted to S2 and that all the S1 is free oil. It is then possible to correct the S1 for evaporative loss (see Michael *et al.* 2013) and use this to calculate the volume of free oil.

3 Estimation of the total in-place oil and gas resource in the shale of the Weald Basin in southern Britain

3.1 Introduction

The current study covers the assessment of the Jurassic shales of the Weald Basin for shale oil and shale gas. The study area covers 10,825 km^2 of southern Britain and extends from Salisbury (Wiltshire) in the west to Ashford (Kent) in the east; Southampton marks the south-western boundary (Figure 2). Geologically, this area corresponds to the area of the Weald Basin and the contiguous Pewsey Basin (see Section 3.5, Figure 18). For completeness, the mapped area extends southwards to the south coast (i.e. over the Portsdown-Middleton Fault that marks the structural limit of the Weald Basin, see Section 3.5.2).

Figure 2. Location of the BGS/DECC shale oil study area, southern Britain. Contains Ordnance Survey data © Crown copyright and database right 2014.

3.2 History of oil and gas exploration and production in southern UK

The Weald Basin has a long history of oil and gas exploration and there are currently 13 largely unobtrusive producing sites, some almost 30 years old (Figure 3). Oil and gas were first encountered by chance in the 19th century, but pulses of exploration activity since the 1930s have yielded variable success up to the present day (Evans 1990, DECC 2010b).

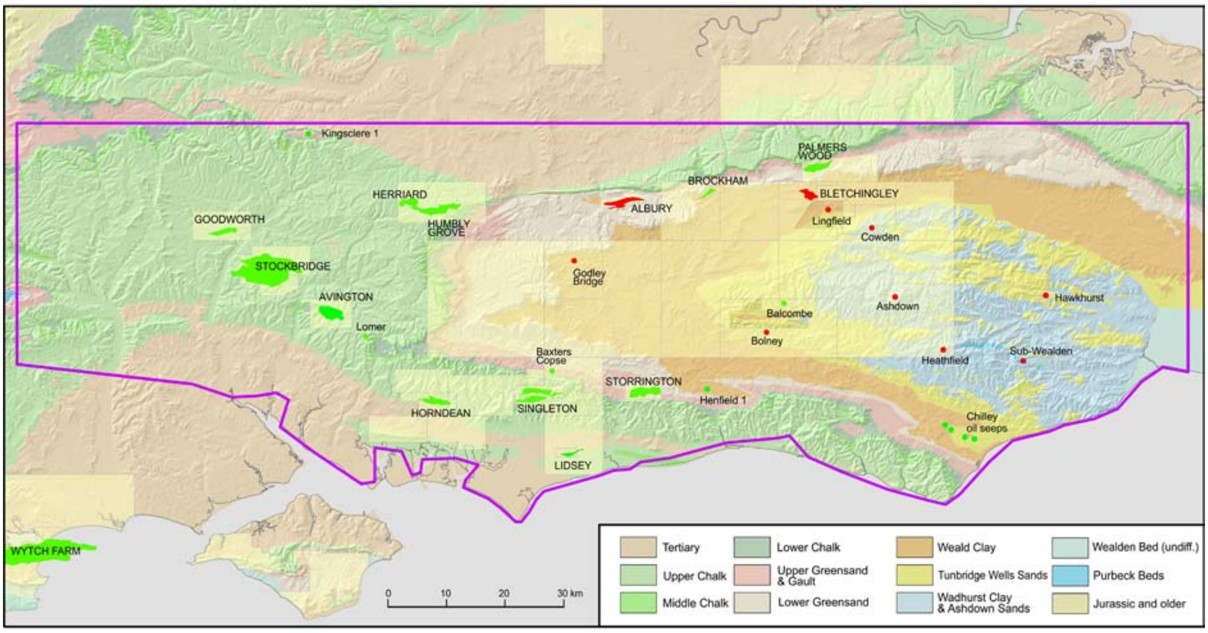

Figure 3. Distribution of producing oil and gas fields and other wells which have tested gas and oil in southern Britain (from DECC data). Green = oil, red = gas; capitals = producing, lower case = other discoveries. Minor surface oil seeps at Chilley (Sussex) are also indicated. Background is outcrop geology with hill shading, also showing petroleum licences as of April 2014.

Indications of hydrocarbons are common in cuttings and cores in many wells, and there is frequent evidence of methane and higher hydrocarbon isomers encountered while drilling. Hydrocarbons have been encountered at various levels throughout the stratigraphic section from the shallow Lower Cretaceous Ashdown Sands, through the Jurassic and even into the Upper Palaeozoic (Figure 4).

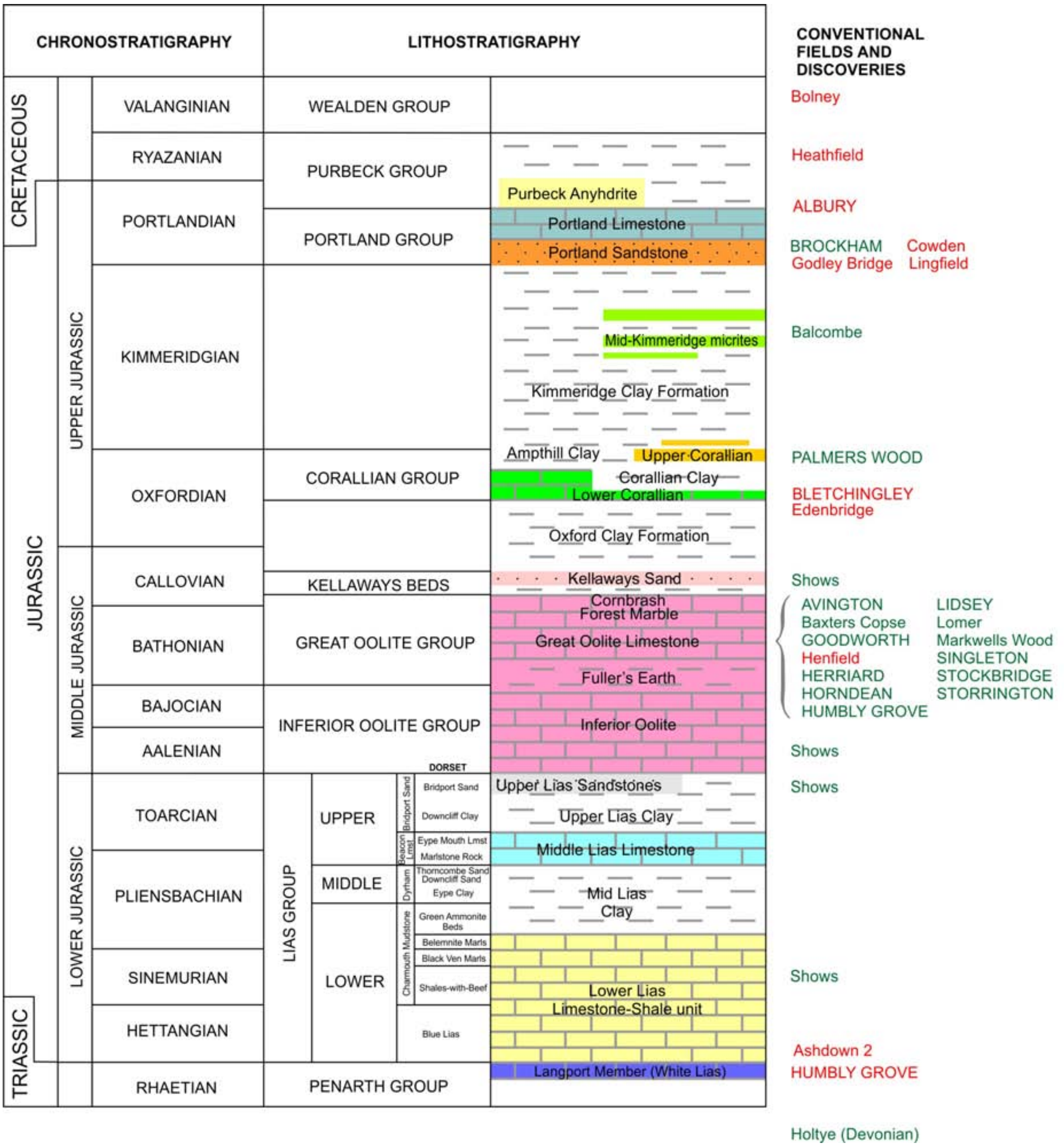

Figure 4. Generalised stratigraphic section for the Jurassic of the Weald area, showing the conventional oil (in green) and gas (in red) fields and other significant discoveries (see Table 4). The Lias stratigraphic names used in this study are informal.

Most of the early wells were drilled on structures with surface expression, before advances in seismic data acquisition and processing allowed the subsurface structure of the Weald area to be mapped. Each subsequent phase of exploration has used improved seismic reprocessing and the acquisition of new seismic data, with over c.16,500 km (10,300 miles) of 2D seismic data acquired in the study area to date (see www.ukogl.org.uk for location of lines and well control).

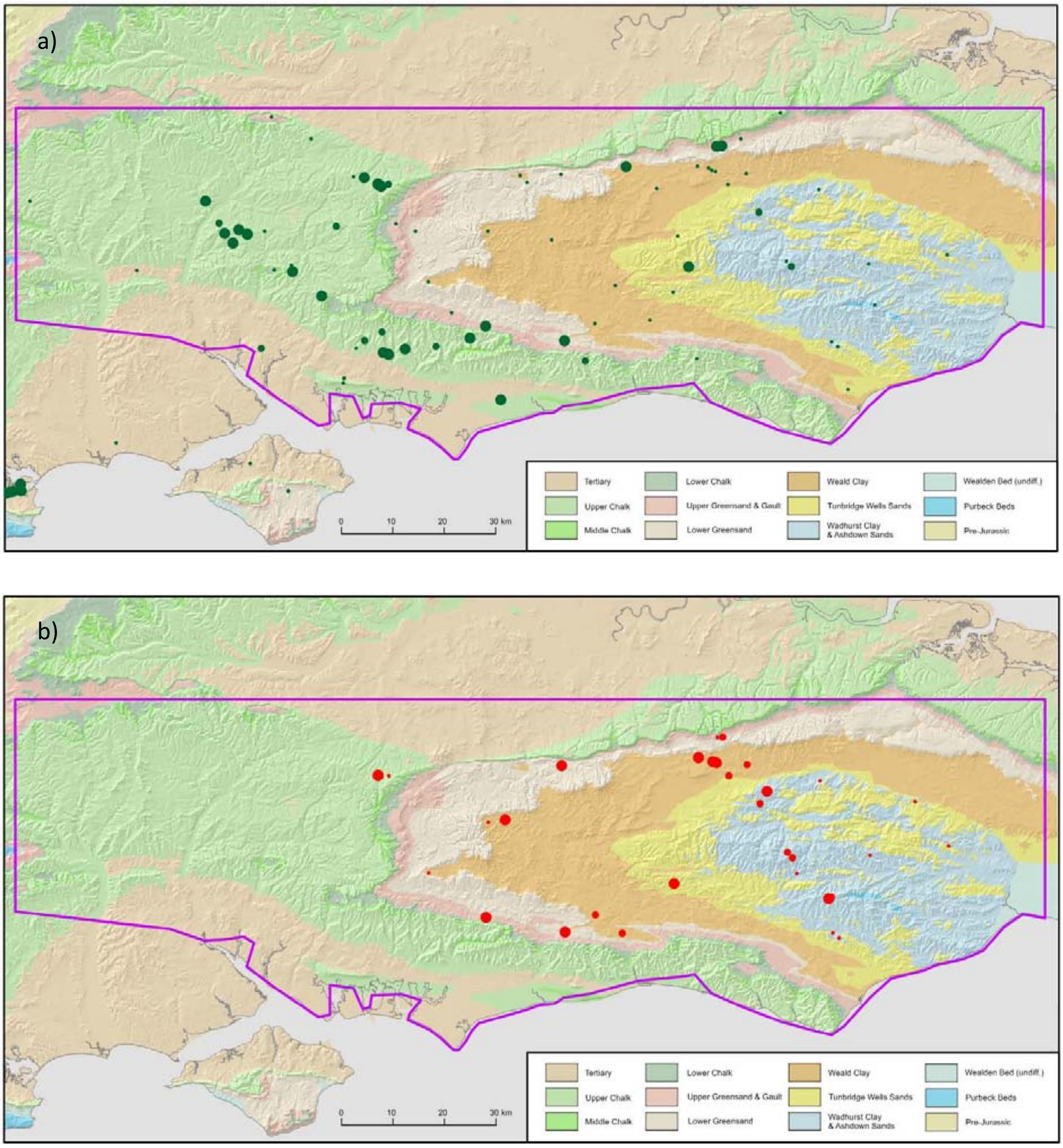

Figure 5. Distribution of (a) all oil and (b) all gas indications in wells in the Weald area, southern Britain. The dot size is proportional to the significance of the hydrocarbons present in each well (poor shows, good shows and discoveries). The distribution of oil and gas fields is shown in Figure 3.

3.2.1 Early encounters with oil and gas

Away from Dorset, surface oil shows are rare in southern England (Selley 1992). In the Weald area, the most significant is an oil sand located in the Lower Cretaceous Tunbridge Wells Sand at Chilley Farm near Pevensey, East Sussex (Figure 3). This was first noted by Mantell (1833), who indicated that the deposit had been used by the Romans. Lees & Taitt (1946) described these as “richly oil-impregnated sandstones”. Reeves (1948) also listed surface seepages associated with faults in the Tunbridge Wells Sand at three nearby locations (Figure 3).

The first mentions of natural gas in southern England come from East Sussex in the 19th century: gas caused a fatal explosion at a well at Hawkhurst in 1836, and “frequent outbursts and explosions of gas” occurred during the drilling of the Sub-Wealden wells near Netherfield in 1873-75 (Glen 1877, Willett 1878, Dawson 1898, Pearson 1905, Redwood 1913, Strahan 1920) (Figure 3). In the Sub-Wealden wells, the Kimmeridge Clay cores smelt strongly of oil, and gas was noted at various depths. Neither of these finds was followed up. Selley (2012) proposed the Sub-Wealden (Netherfield) 1 well as the first well to encounter shale gas in the UK.

More significant was the discovery of natural gas in a boring at Heathfield (East Sussex) (Dawson 1898, Pearson 1905, Strahan 1920, Milner 1922). In 1895, a water well (Heathfield 1) drilled at the New Heathfield Hotel encountered gas in the Lower Cretaceous at a depth of 228 ft (70 m). This was followed by the Heathfield Railway Station (Heathfield 2) well in 1896; “at 312 ft [95 m] gas came off in such abundance to give a flame of a height estimated at 16 ft [5 m]” (Strahan 1920). For three years, the discharge of gas continued and was “lit from time to time to gratify the curiosity of visitors” (Pearson 1905), but from 1899 it was put to use lighting the station. Subsequently, this gas was commercially exploited by Natural Gas Fields of England Ltd., who drilled six further boreholes on the Heathfield anticline. The reservoir was either within the Hastings Beds or the upper part of the Purbeck (Lees & Cox 1937). The gas was eventually not only used at the local railway station, but also in the surrounding villages and by ICI until the early 1960s (Lake *et al.* 1987). Heathfield 7 was drilled in this area by BP in 1955. This again produced gas from the Purbeck Beds, but not in sufficient quantities to warrant further development and the discovery was subsequently abandoned. Total gas production up to 1963 has been estimated at 20 mmcf (McEvoy *et al.* 2002).

3.2.2 Results of the first exploration wells

The Petroleum (Production) Act was passed in 1934, establishing the petroleum licensing regime, and the first licences were issued in December 1935 to D’Arcy Exploration Company Ltd, a subsidiary company of the Anglo-Iranian Oil Company (which became the British Petroleum Company in 1954). Since then, hydrocarbon exploration in the Weald area has been episodic, as illustrated by the histogram of drilling (Figure 6).

Lees & Cox (1937) were the first to propose the existence of a Mesozoic basin beneath the Weald. The first hydrocarbon well in the Weald Basin not only proved that the basin existed, but also encountered shows in a surface anticline at Henfield 1 in 1936-37. Later test wells at Grove Hill (1937) and Penshurst (1938) in the basin were unsuccessful, as was Kingsclere 1 (1937) on the basin margin (Lees & Cox 1937, Lees & Taitt 1946, Taitt & Kent 1958, Falcon & Kent 1960, Kent 1965).

In the 1950s, three D’Arcy wells found oil and gas shows in East Sussex: Ashdown 1 & 2 and Brightling 1. The Ashdown structure was originally mapped at the surface by Reeves (1948), but was further delineated by shallow boring and seismic reflection data prior to Ashdown 1 being drilled in 1954-55. This well found gas shows in the Portland Beds and Corallian Beds and gas and oil shows in the Kellaways Beds. A second well was drilled in 1955 one mile to the south-west, nearer the seismically defined crest of the structure. This well was drilled to Palaeozoic ‘basement’ and on test produced 750 gallons of oil per day and 12,000 ft^3 of gas per day from sandy limestones in the Lower Lias, but this was not considered sufficient to justify further development.

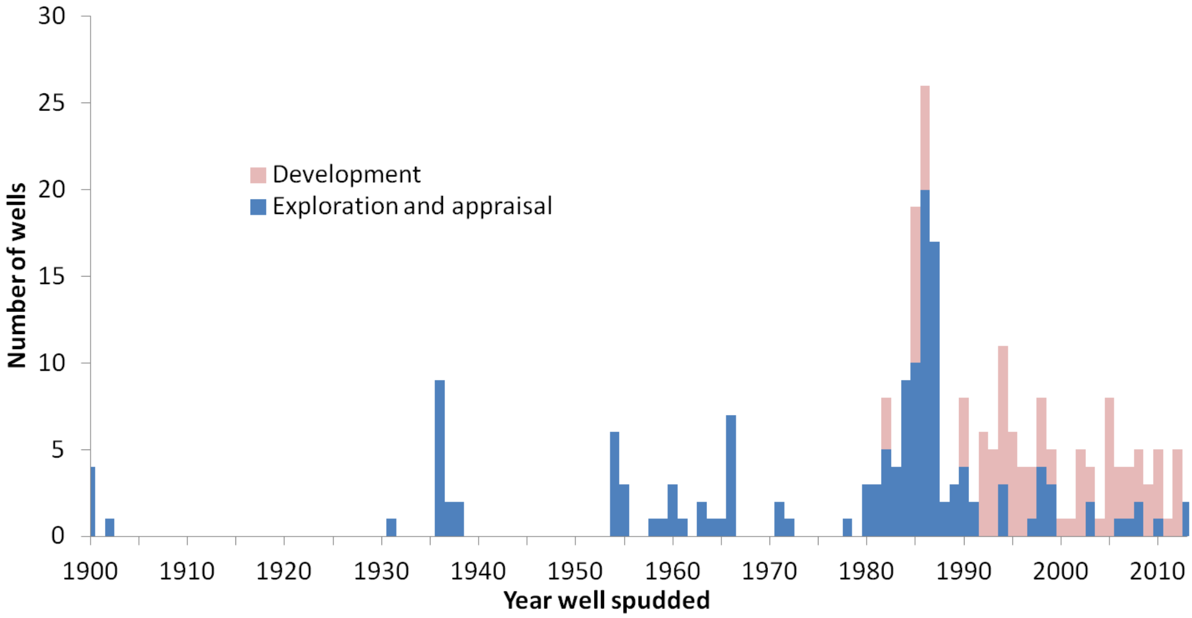

Figure 6. The number of wells drilled for hydrocarbons in the Weald area by year, 1900-2013. Data from DECC.

Esso used new reflection seismic data to locate six wells; the first resulted in the Bolney gas discovery in 1963 from shallow Wealden sands. Then in 1965 Esso discovered gas in Bletchingley 1, but the structure is complex, being cut by several faults. After the discovery well tested gas from the Corallian Beds, three further wells were drilled in an attempt to delineate the field. Despite initially promising results the discovery was temporarily abandoned and commercial production of the field was not established until 2009.

3.2.3 Main drilling phase

Following the oil price rises of the 1970s, a number of new XL and PL licences were granted, and drilling reached its peak when a total of 26 wells were spudded in 1986 (Figure 6).

Conoco drilled 28 exploration and appraisal wells in the 1980s and made six discoveries, testing gas at Godley Bridge 1 and Albury 1, and oil at Baxters Copse 1, Palmers Wood 1, Storrington 1 and Balcombe 1 (Trueman 2003).

Carless drilled 12 exploration wells; then as production started in 1985 on the Great Oolite oil discoveries, Humbly Grove 1 and Herriard 1 (Hancock & Mithen 1987), they followed with 17 appraisal wells. Carless encountered oil shows in Avington 1 in 1987, but the presence of hydrocarbons was not confirmed until Avington 2 was drilled by Pentex in 2003. Nearby, Lomer 1 had oil shows, but was not developed. The Horndean discovery was appraised and put on production in 1988. Carless drilled Lidsey 1, an oil discovery, in 1987. In 2000, an extended well test proved the viability of the field and it has been in production since 2008.

Amoco discovered oil in Stockbridge 1 in 1984 and drilled nine appraisal wells, but Stockbridge field production was not established until it was sold to Ultramar in 1990, although Amoco were able to start production on the Goodworth field just one year after its discovery in 1987.

BP drilled nine wells, including the Brockham 1 oil discovery in the Portland Sandstone, and encountered oil shows deep in the Devonian in Holtye 1 well.

In the 1990s and 2000s, about five wells were drilled per year, but many companies exited the Weald Basin because they viewed the resource sizes as too small, and development wells became increasingly problematic and expensive. Independent Energy tested gas in their Cowden 2 well, and encountered gas shows in Lingfield 1, both in 1999. Northern Petroleum drilled the Markwells Wood 1 oil discovery in 2010, finding live oil in Great Oolite cores along strike from Horndean. None of these recent discoveries has yet progressed to development.

Kelt drilled Singleton 1 in 1989 and then five appraisal wells before establishing production in 1991. The field contains the largest in-place oil volume of all the fields in the study area (Table 4). Star took over ownership in 2007; then it was purchased by Providence Resources in 2009 who drilled nine development wells before the field was sold to IGas in 2012. Following IGas's acquisition of Star in 2011, IGas became the operator of the majority of the fields in the Weald Basin.

Although the Wytch Farm oil field is situated in Dorset and falls outside the study area, it must be included in any exploration history of onshore UK. With 500 million bbl of recoverable oil, it is the largest onshore oil field in Europe and was discovered in the Lower Jurassic Bridport Sandstone in 1973, and in the deeper Triassic Sherwood reservoir in 1977 (Colter & Havard 1981). 90% of the reserves lie in the Sherwood Sandstone reservoir, strata which are largely absent in the Weald Basin.

3.2.4 Conventional success ratio

To date (February 2014), 117 exploration, 31 appraisal wells and 100 development wells have been drilled in the Weald area, and of these, 26 wells are classed as discoveries or had hydrocarbon indications (Table 4). Thirteen fields are currently in production, plus the historical oddity of Heathfield gas lighting the local rail station. Over the 24 years when exploration was most active (1980-2003), there were 72 exploration wells drilled and 18 discoveries made, 12 of which are now in production, so a 25% technical success ratio. Onshore exploration is significantly cheaper than offshore, and although this rate of success is comparable to the UKCS, the size of the discoveries is considerably smaller.

A creaming curve for the Weald Basin (Figure 7) does not exhibit the flattening-off characteristic of a mature basin. There has been little exploration drilling in recent years. Indeed, since 2004, only six appraisal wells have been drilled, along with 31 development wells. However, wells to test new play ideas with significant upside resource potential are now planned.

Well	Drilled by	DECC status	County	Main reservoir	Depth of resr (ft ss)	Discovery year	Production start year	Fluid type	GIIP (bcf)	STOIIP (mmbo)	Current licence	Current operator
Heathfield 1	-	FCP	E Sussex	Purbeck?	228	1885	1890	gas			PEDL247	Cuadrilla
Henfield 1	D'Arcy	HI	W Sussex	Great Oolite	3444	1937		gas			Open	
Ashdown 2	D'Arcy	HI	E Sussex	Lower Lias	4909	1955		gas	17?		PEDL247	Cuadrilla
Bolney 1	Esso	DIS	W Sussex	Wealden sandstone	203	1963		gas			PEDL244	Cuadrilla
Bletchingley 1	Esso	FIP	Surrey	Corallian limestone	3380	1965	2009	oil &gas	5.6	9.0	ML021/ ML018	IGas
Humbly Grove 1	Carless	FIP	Hants	Great Oolite; Rhaetic	3382	1980	1985	oil & gas	6.1	51.8	PL116	Humbly Grove Ltd
Baxters Copse 1	Conoco	DIS	W Sussex	Great Oolite	4706	1983		gas		34	PEDL233	IGas
Godley Bridge 1	Conoco	DIS	Surrey	Portland sandstone	2923	1983		gas	4		PEDL235	IGas
Herriard 1	Carless	FIP	Hants	Great Oolite	3267	1983	1985	oil		6.0	PL116	Humbly Grove Ltd
Horndean 1A	Carless	FIP	Hants	Great Oolite	4174	1983	1988	oil & gas	2.6	28.8	PL211	IGas
Stockbridge 1	Amoco	FIP	Hants	Great Oolite	3622	1984	1990	oil & gas	1.5	79.0	PL233 PL249 DL002	IGas
Lomer 1	Carless	DIS	Hants	Great Oolite	3870	1985		oil		nd	Open	
Balcombe 1	Conoco	DIS	W Sussex	Kimmeridge micrite	2128	1986		oil		nd	PEDL244	Cuadrilla
Palmers Wood 1	Conoco	FIP	Surrey	Corallian sandstone	2459	1986	1990	oil & gas	1.1	9.9	PL182	IGas
Storrington 1	Conoco	FIP	W Sussex	Great Oolite	3808	1986	1998	oil		10.7	PL205	IGas
Albury 1	Conoco	FIP	Surrey	Purbeck limestone	2112	1987	1994	gas	4.5		DL4	IGas
Brockham 1	BP	FIP	Surrey	Portland sandstone	1869	1987	2002	oil		2.4	PL235	Angus Energy
Goodworth 1	Amoco	FIP	Hants	Great Oolite	3409	1987	1998	oil		8.3	PEDL021	IGas
Holtye 1	BP	HI	E Sussex	Devonian	5727	1987		oil			PL241	Angus Energy
Lidsey 1	Carless	FIP	W Sussex	Great Oolite	3229	1987	2008	oil		9.2	PEDL247	Cuadrilla
Edenbridge 1	BP	HI	Surrey	Corallian limestone	3489	1987		gas			PEDL247	Cuadrilla
Singleton 1	Kelt	FIP	W Sussex	Great Oolite	4183	1989	1991	oil & gas	37	104.9	PL240	IGas
Cowden 2	Independent	DIS	Kent	Portland sandstone	955	1999		gas	nd		EXL189	Cuadrilla
Lingfield 1	Independent	HI	Surrey	Portland sandstone	1942	1999		gas			Open	
Avington 2	Pentex	FIP	Hants	Great Oolite	3620	2003	2009	oil		18.8	PEDL070	IGas
Markwells Wood 1	Northern	DIS	W Sussex	Great Oolite	4281	2010		oil		nd	PEDL126	Northern

Table 4. List of oil and gas discoveries, fields and hydrocarbon occurrences in the Weald area. FIP = field in production; DIS = discovery; HI = hydrocarbon indications; FCP = field ceased production. In-place resource figures (as of early 2014) are from current operators; nd = no data. Data from DECC.

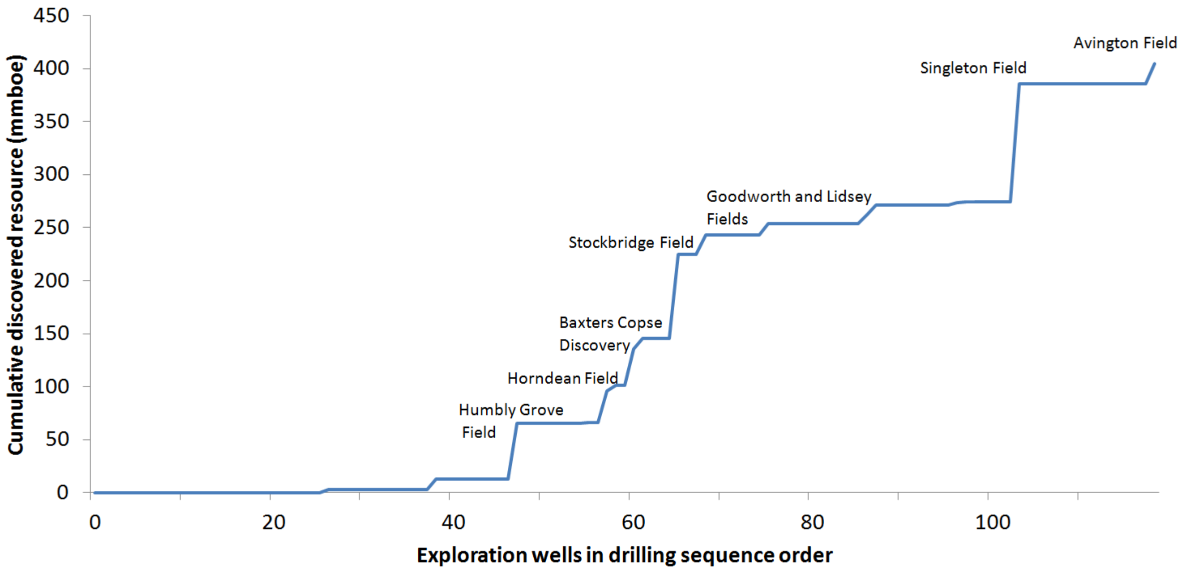

Figure 7. Creaming curve of oil and gas resources discovered by exploration wells in the Weald area since 1900.

3.2.5 Gas composition

The detailed composition of the gas in producing fields is poorly documented and only limited data are available (Conoco 1986, Celtique Energie & IGas pers. comm.). Several features are common to many samples: (a) many gases are methane-rich (i.e. dry gas), (b) nitrogen concentrations are often high, up to 19%, (c) other gases contain a wider range of hydrocarbons. It is of note that several of the gas samples are both dry and rich in nitrogen. H_2S is also present at Godley Bridge.

Some limited carbon isotope data is also available (Conoco 1986). The $\delta^{13}C$ values for seven methane samples all fall between -41 and -50 ‰: -45 to -48 (Godley Bridge), -42.5 to -43.5 (Baxters Copse) and -41.5 to -50 (Palmers Wood). This is a typical range for gas produced along with oil and condensate in the oil window rather than in the gas window (Stahl 1977) – see Section 3.7.10.2.

3.3 Aquifers and groundwater

3.3.1 Aquifer designations

The Environment Agency, responding to the Water Framework Directive (2000/60/EC), has identified several different types of aquifer across England (EA 2013a). These aquifer designations reflect the importance of aquifers in terms of groundwater as a resource for drinking water supply and their role in supporting surface water (rivers and lakes) and wetland ecosystems.

The aquifer designations are based on geological mapping and hydrogeological characterisation provided by BGS. Each geological formation has been designated as either principal aquifer, secondary aquifer or as unproductive strata (EA 2013a). Figure 8 illustrates the relationship between geological formations designated as principal aquifers and prospective shale gas and oil source rocks.

The aquifer designations principally takes into account the hydrogeological properties of the upper parts of the geological formations (<400 m/1,300 ft depth). At depths greater than 400 m (1,300 ft), the same geological formations that are considered as aquifers at shallower depths may have significantly different hydrogeological properties and poorer water quality, e.g. be highly mineralised (saline). In some locations, the geological formations designated as aquifers near the surface elsewhere may occur only at great depths and so have no direct connection to shallower aquifers or surface waters. Where these 'aquifer' formations retain sufficient permeability and porosity and are overlain by lower permeability (cap) rocks they may contain hydrocarbons (oil and gas) naturally and be potential hydrocarbon reservoirs. For example, the Permo-Triassic sandstone is the principal reservoir for oil and gas in the Irish Sea whereas the upper part of the same rock formation onshore is one of the UK's most important sources of drinking water.

This is also the case for the Great Oolite Formation. Where this formation occurs near the surface it can be a significant source of freshwater and so is designated as a principal aquifer. However, in the Weald Basin it only occurs at considerable depths (deeper than 1,300 ft/400 m) and is isolated from the surface by hundreds of metres of clay. At these depths, and across the Weald Basin, the Great Oolite Formation is known to contain naturally occurring hydrocarbons.

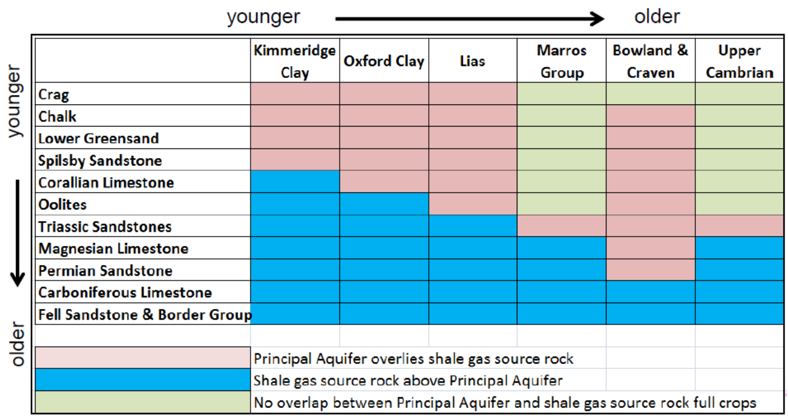

Figure 8. The stratigraphic relationship between principal aquifers and shale source rocks in England (from Bloomfield et al. 2014).

3.3.2 Groundwater Source Protection Zones

Source protection zones (SPZ) form part of the risk-based approach that the Environment Agency and Natural Resources Wales take to protect groundwater abstractions. They are areas defined around groundwater abstractions used for drinking water and other important abstractions such as those used for food production, within which potentially polluting activities should be controlled or prevented.

The full zones are based on the time it takes water to travel within the aquifer to the abstraction point (EA 2013b). Maps have been published that show the extent of zones at the ground surface and in some cases these have been drawn to take account of any natural protection afforded by clays or other rocks that overlie the aquifer. These zones are used primarily to respond to proposals for development at or near the ground surface as part of the statutory consultation to local planning authority consent decisions. For activities that take place at greater depth, such as well drilling, it is important also to consider the full travel time to abstractions.

Approximately 2,000 of the larger abstractions across England and Wales have bespoke modelled and mapped SPZs. However, all potable drinking water abstractions are protected and where no bespoke zone is available then a default 50 m radius zone applies.

Within the Weald Basin, the Upper Cretaceous Chalk is a principal aquifer and major water resource for the area with much of the outcrop covered by SPZs. The Chalk occurs only around the edge of the Basin. In the centre of the basin, there are a number of secondary aquifers that provide water supply locally and baseflow to rivers. There are a number of abstractions with mapped SPZs plus an unknown number of smaller private water supply abstractions.

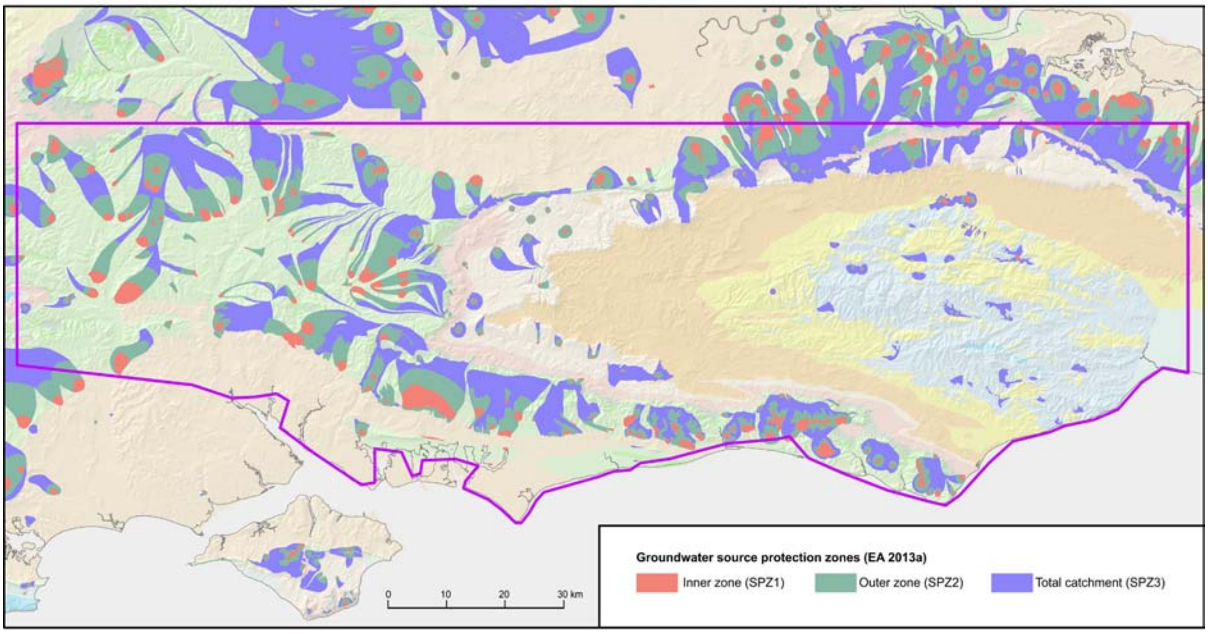

Figure 9. Map showing the groundwater source protection zones (SPZs) in the Weald area (from EA 2013a and maps.environment-agency.gov.uk).

The 'core mature area' for the shale mapped in this project (see Section 3.7, Figure 26) occurs in the core of the Weald Anticline, where the Chalk aquifer is absent and the other geological formations designated as principal aquifers are at depths greater than the 400 m (1,300 ft). It is generally recognised that at these depths in the Weald the fluids encountered will be highly mineralised (saline) and not be of potable quality. They may also contain significant amounts of hydrocarbons.

3.3.3 Methane in groundwater

Naturally occurring detectable methane is present in nearly all groundwater (BGS 2013a). BGS has been studying methane in UK groundwaters since the 1980s to investigate sources of methane in the subsurface, the hydrogeochemical controls on its fate and behaviour and potential for methane emissions from groundwaters (BGS 2013a). Methane in groundwater is formed by one of two processes: biogenic, which is produced by bacteria, and is often associated with shallow anaerobic groundwater environments, such as peat bogs, wetlands, lake sediments and landfills, although it is detectable in nearly all groundwater; also found is thermogenic methane, which is formed during thermal decomposition of organic matter at depth under high pressures, and is often associated with coal, oil and conventional gas fields.

Methane can migrate from the location at which it is formed either as free gas or dissolved in water (or other fluids). Thermogenic gas produced at considerable depths in deep basin shales can migrate upwards through more permeable geological formations. In some cases, it can become trapped below an impermeable cap rock to form a gas reservoir or it can continue to migrate towards the surface and enter shallow groundwater or appear as seepages at the surface. The presence of methane (CH_4) in groundwater is generally only of concern if it reaches concentrations that, if de-gassing should occur, it could reach explosive levels. Methane becomes an explosive hazard at concentrations of 5-15% by volume in air. Assuming complete outgassing from water, this requires a minimum dissolved methane concentration of 1,600 µg/l.

Initial results from a new baseline methane survey of UK groundwaters and a summary of existing data are available on the BGS website (BGS 2013b). The data show that methane is almost always detected in groundwater, but generally at low concentrations. Median concentrations in the areas sampled (underlain by potential shale gas source rocks) range from 0.21 to 34 µg/l. At a small number of locations, higher concentrations have been measured, but these are generally isolated and have been attributed, by isotopic analysis, to biogenic methane produced through the fermentation of acetate (Darling & Gooddy 2006).

This ongoing work will be augmented by the groundwater baseline monitoring and analysis that the UK Onshore Shale Gas Well Guidelines (UKOOG 2013) require as good oil field practice under a DECC oil and gas licence.

3.4 Seismic, well and outcrop data

This assessment of the Jurassic shales of the Weald Basin is based upon detailed seismic mapping integrated with all available hydrocarbon well and stratigraphic borehole information and outcrop geology.

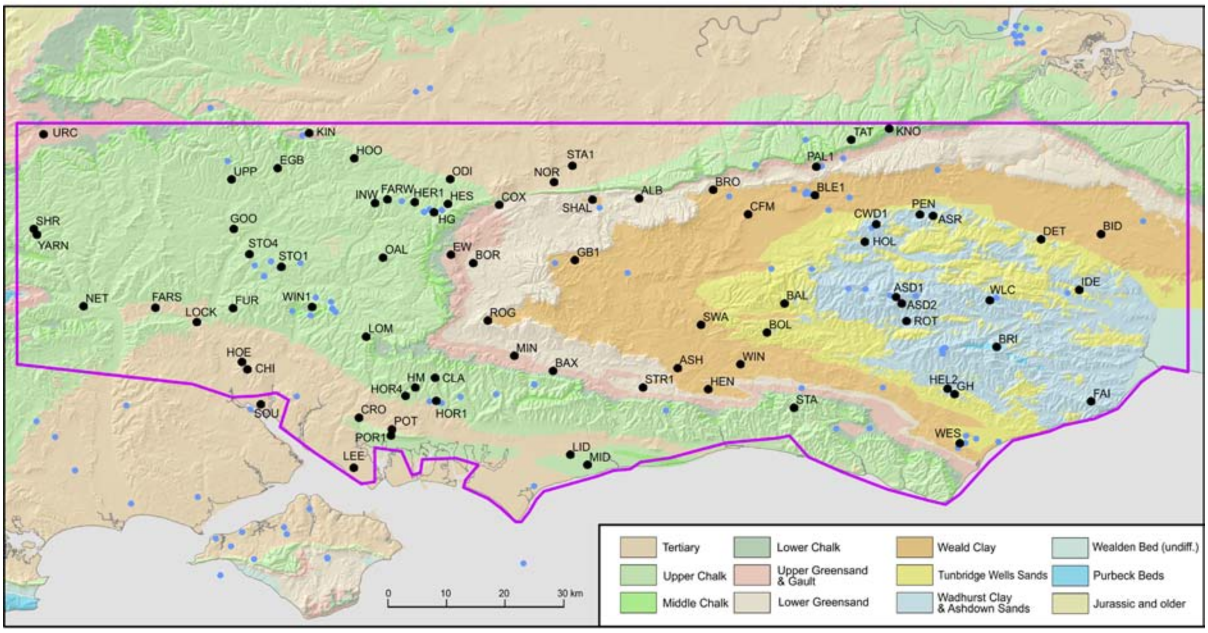

Figure 10. Location of key (black) and other deep wells (blue dots) used to assess the shale potential of the Weald area, southern Britain. See Appendix E for details of well name abbreviations and stratigraphic information.

Although several thousand wells and boreholes have been drilled within the assessment area, only 63 exploration wells reached sufficient depths to record the complete Jurassic section, with a further 15 terminating in the Lias (Figure 10). A selection of the key wells is illustrated in six correlation panels (Figure 11, Appendix F). The basin depocentre and key area of shale potential has poor well control, especially in the Lias, with no relevant stratigraphic or geochemical data in the area between Rogate 1, Godley Bridge 1 and Southwater 1 (Figure 10).

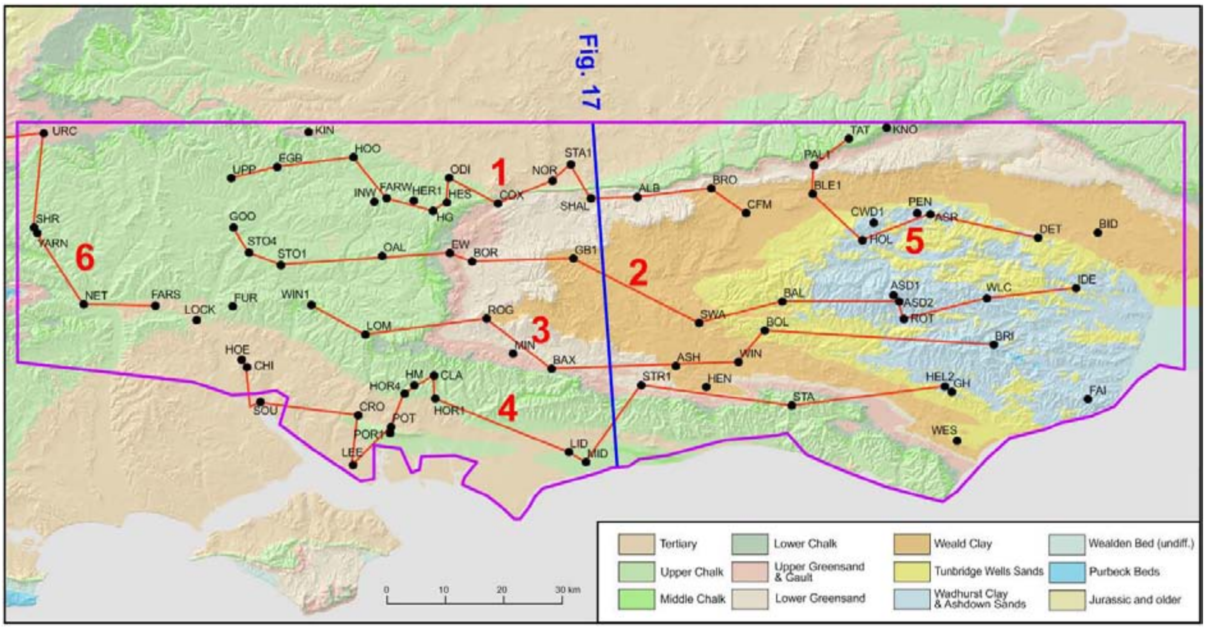

Figure 11. Location of well correlation lines included in Appendix F. See Appendix E for details of well name abbreviations. The location of the cross-section illustrated in Figure 17 is also indicated.

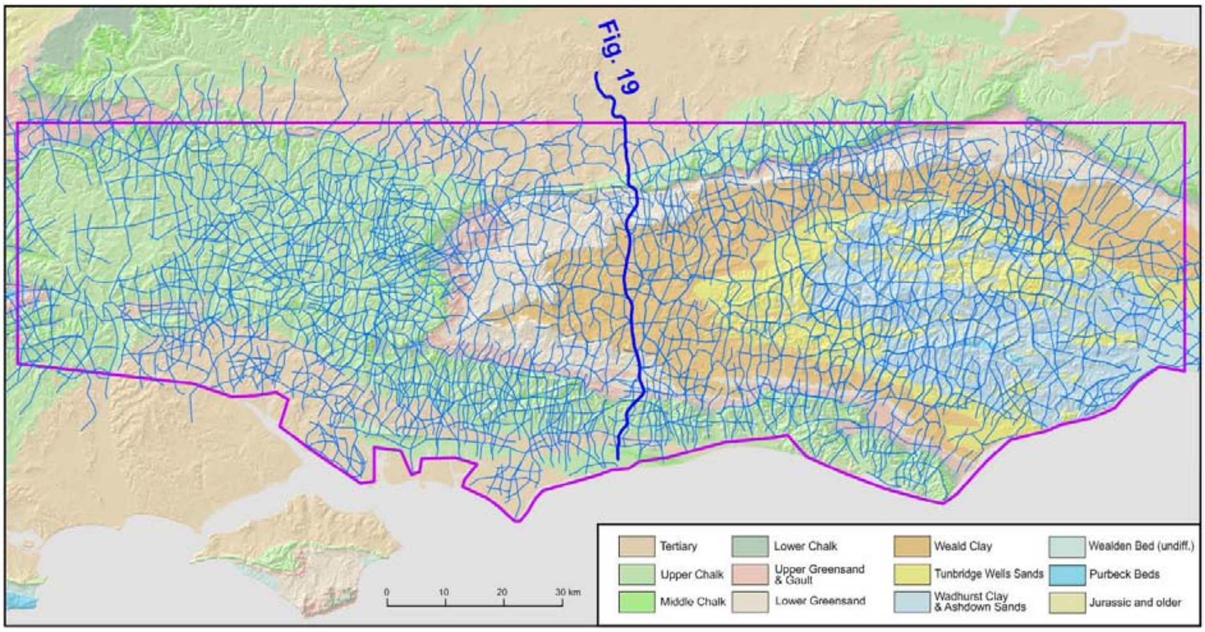

Figure 12. Location of 2D seismic profiles used to assess the shale potential of the Weald area, southern Britain. The location of the regional 2D line illustrated in Figure 19 is also indicated.

All of the available seismic data was obtained from the UK Onshore Geophysical Library (UKOGL www.ukogl.org.uk). A total of c. 12,200 km (7,600 miles) of 2D seismic data (Figure 12) 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 currently 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, with nearby wells, and with the geological model.

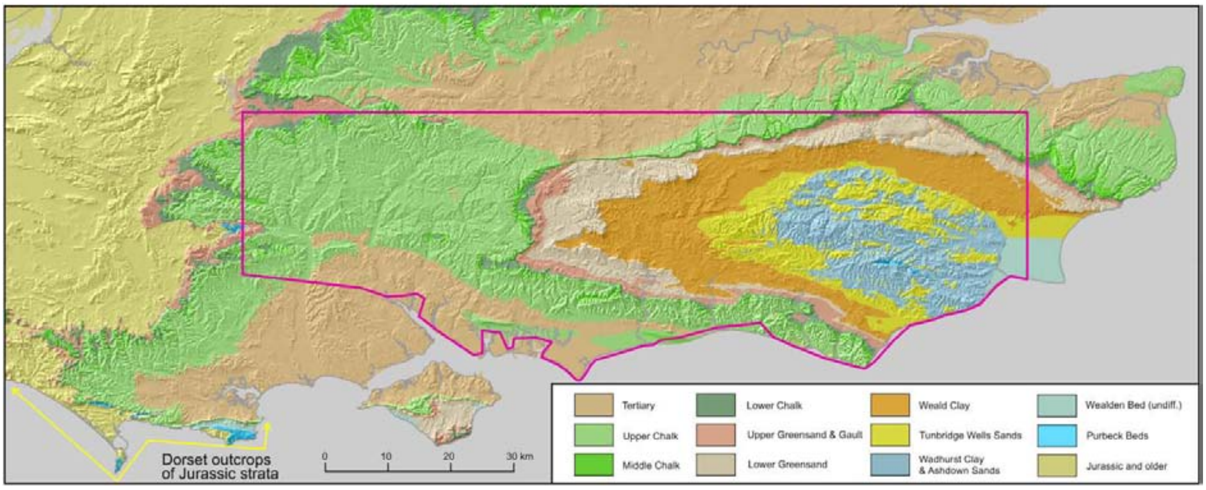

Figure 13. Surface geological map of southern Britain including the Weald study area and the coastal exposures of Jurassic strata in Dorset (from BGS 1:50,000 mapping).

It is important to note that none of the Jurassic shales crop out within the study area; they do however form part of the classic exposures along the Dorset coast 100 km (60 miles) to the south-west (Barton *et al.* 2011). The oldest rocks to crop out in the Weald area are the Purbeck Beds in the core of the Weald Anticline (Anderson & Bazley 1971) (Figure 13).

Depth structure maps to the top of the Kimmeridge Clay and the base of the Mid Lias Clay are included as Figures 14 & 15. These form part of the 3D geological model used in this study.

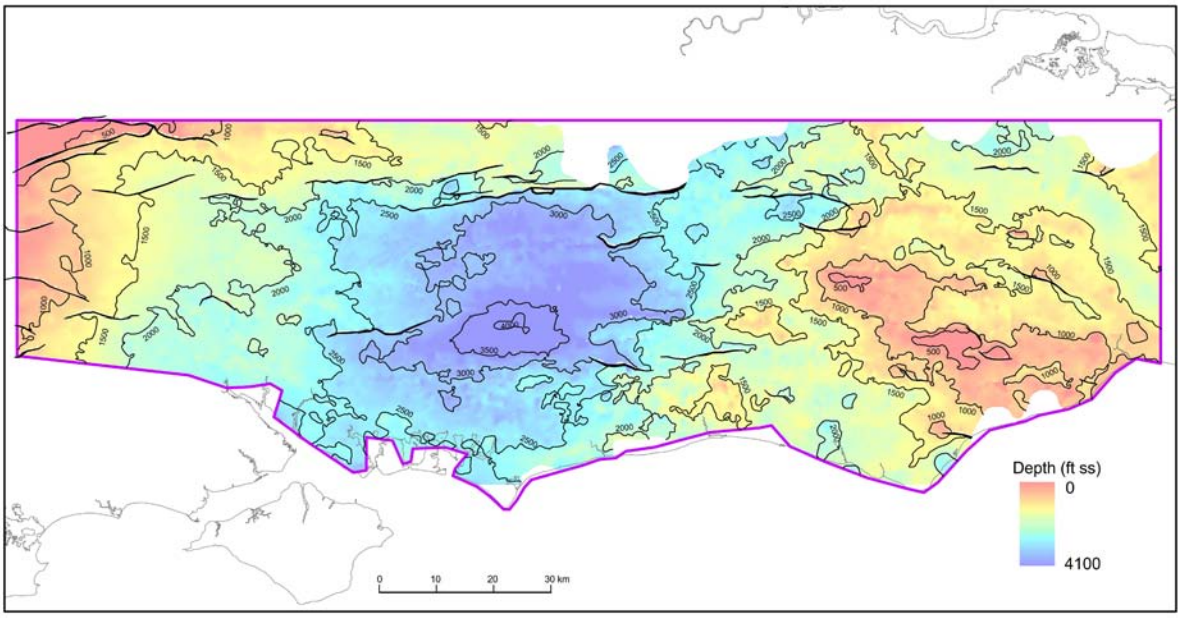

Figure 14. Depth (feet) to the Top Kimmeridge Clay as interpreted in this study.

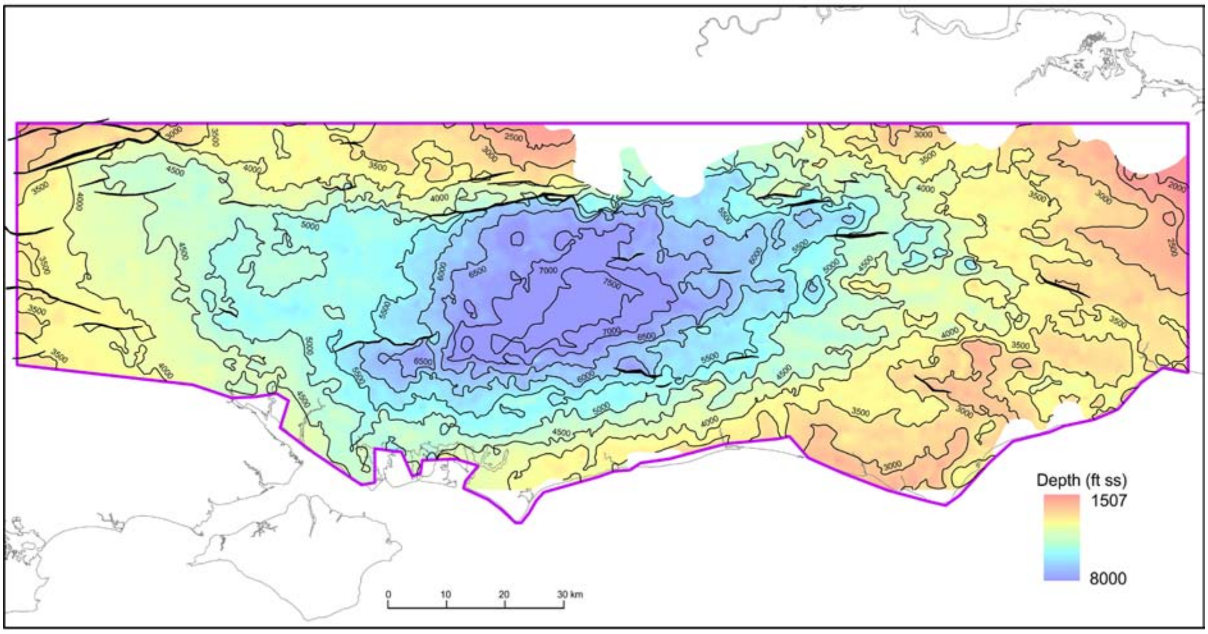

Figure 15. Depth (feet) to the Base Mid Lias Clay as interpreted in this study.

3.5 Basin development and subsequent inversion

The Weald Basin is a Permian to Cretaceous extensional basin, bounded by major east-west trending zones of *en échelon* syn-depositional normal faults (Chadwick 1993). Extension and basin formation has been linked to the reactivation of Variscan thrusts (Chadwick 1986, Hansen *et al*. 2002, Mansy *et al*. 2003) (Figure 16). The basin was inverted in Cenozoic times by compressive stresses oriented roughly north-south. The preserved sedimentary fill exceeds 8,200 ft (2,500 m) in thickness in the depocentre, thinning onto the London Platform to the north and north-east and to the south onto the Hampshire-Dieppe High. Considerable thicknesses have also been removed by erosion during the formation of the Weald-Artois Anticline (Figures 17 & 19). Estimates of the amount of sediment removed reach up to 7,000 ft (2,130 m) to the east of the basin centre (see Section 3.5.4).

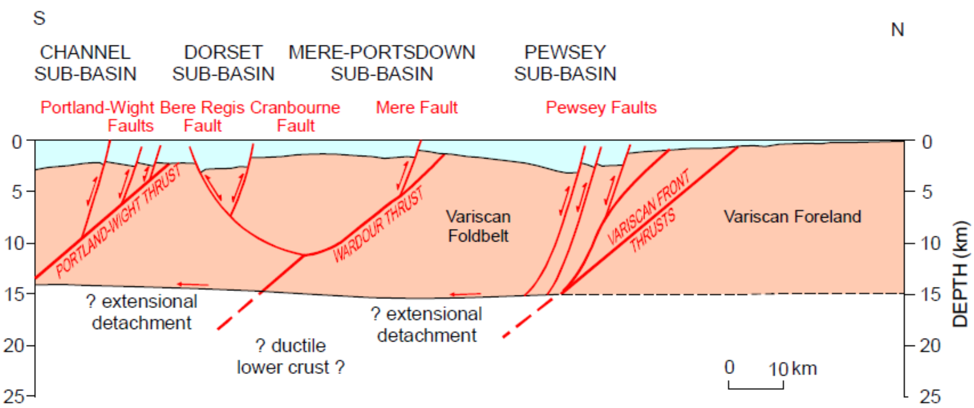

Figure 16. Crustal section across the Wessex and western Weald basins, illustrating the influence of extensional reactivation of Variscan thrusts (after Chadwick 1986). See Figure 18 for location.

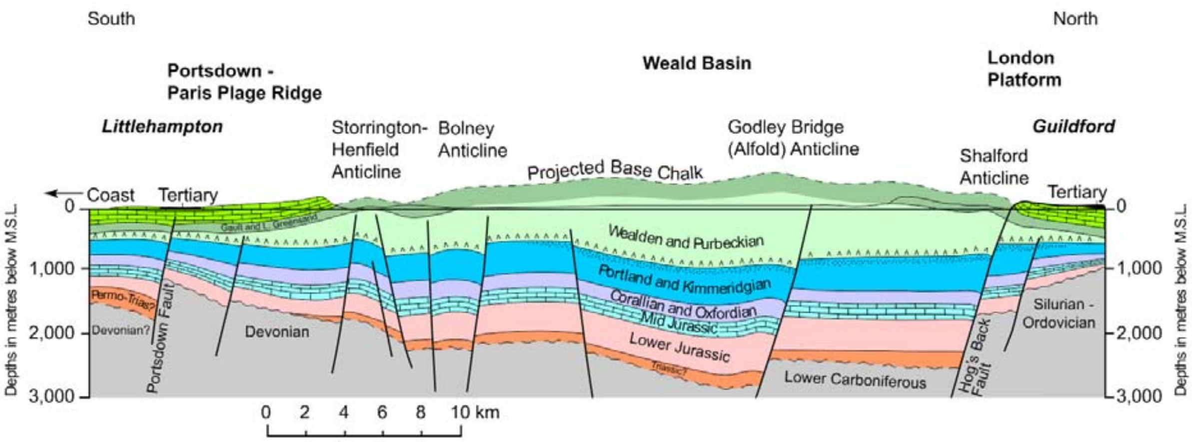

Figure 17. Simplified south-north geological cross-section through the central Weald Basin (from Butler & Pullan 1990). See Figure 11 for location.

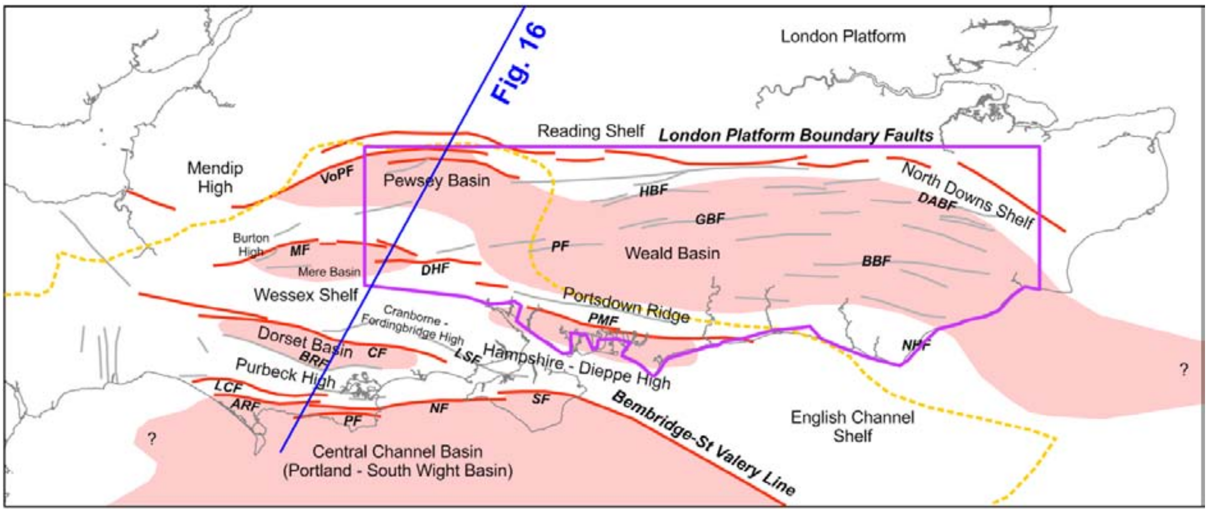

Figure 18. The major Mesozoic structural features of southern England. The location of the cross-section illustrated in Figure 16 is also indicated. Based on Stoneley (1982), Chadwick (1983), Lake (1985), Sellwood et al. (1985), Hancock & Mithen (1987), Butler & Pullan (1990), Butler (1998), Hawkes et al. (1998), Underhill & Stoneley (1998) and Chadwick & Evans (2005). Abbreviations: ARF = Abbotsbury – Ridgeway Fault; BBF = Brightling – Bolney Fault; BRF = Bere Regis Fault; CF = Cranborne Fault; DABF = Detention – Ashour – Bletchingley Fault; DHF = Dean Hill Fault; GBF = Godley Bridge Fault; HBF = Hog's Back Fault; LCF = Litton – Cheney Fault; LSF = Lymington – Sandhills Fault; MF = Mere Fault; NF = Needles Fault; NHF = Newhaven Fault; PF = Purbeck Fault; PMF = Portsdown – Middleton Fault; SF = Sandhills Fault; VoPF = Vale of Pewsey Fault(s). The term Purbeck – Isle of Wight Fault is used for the fault system extending from Purbeck and across the Isle of Wight. The Wessex Basin sensu *Underhill & Stoneley (1998) lies south-west of the orange dashed line; this report includes the Pewsey Basin in the Weald area.*

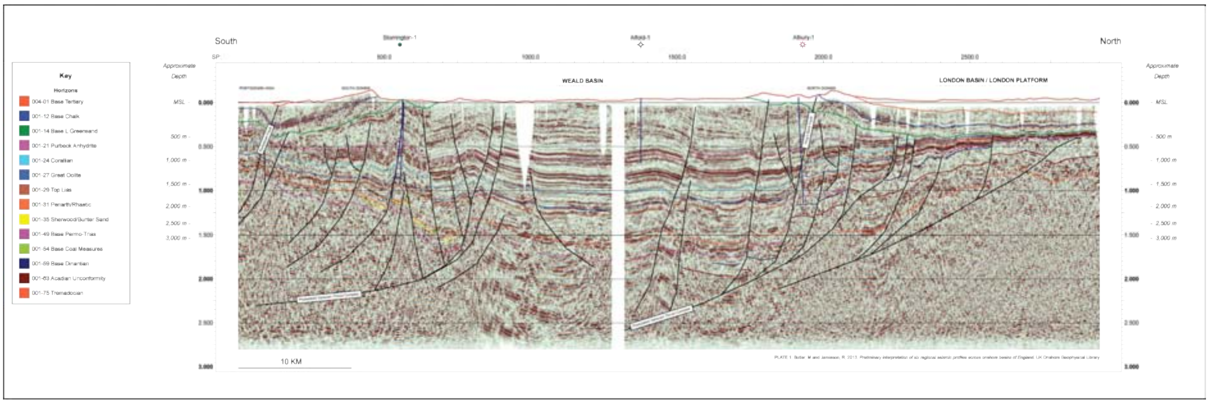

Figure 19. Regional 2D seismic line UKOGL-RG-001 across the central Weald Basin (from Butler & Jamieson 2013). See Figure 12 for location and Appendix G for a full-scale version.

3.5.1 Structural terminology

The term 'Wessex Basin' was introduced by Kent (1949) for the entire Mesozoic basin of southern England, despite the fact that the ancient kingdom of Wessex only covered the area centred on the present counties of Hampshire and Dorset. This terminology has been retained by many workers (e.g. Whittaker 1985, Penn *et al.* 1987, Chadwick 1993), although it is now known to contain several basins and highs, e.g. the Dorset, Weald and Pewsey Basins (which should strictly speaking be termed sub-basins).

Studying Corallian strata, Wilson (1968) demonstrated that there were two major sedimentary basins at this time: the Wessex Basin in the west and the Wealden Basin in the east, separated by the Portsdown 'swell'. This scenario had been first proposed by Taitt & Kent (1958) in so much as the "Paris Plage ridge [of which the Portsdown structure was the continuation] formed an incomplete barrier between the Wessex basin [*sensu* Kent 1949] and the channel".

As knowledge of the subsurface structure improved, this Wessex-Weald terminology was resurrected by Stoneley (1982), with subsequent refinement by Underhill & Stoneley (1998), restricting the term Wessex Basin to the area west of Portsmouth, but included the Pewsey [sub]Basin (Figure 19).

This duel definition of the term 'Wessex Basin' has led to confusion as to which area specific workers are referring to. A further complication arises because the Pewsey [sub]Basin, included in the Wessex Basin by Underhill & Stoneley (1998) (Figure 19), is essentially the westward continuation of the Weald [sub]Basin. In the absence of any intervening structural high or isopach thinning between the Weald Basin and the Pewsey Basin, this latter basin is included in this Weald Basin study area (see also map 9 of Whittaker 1985, Karner *et al.* 1987).

3.5.2 Sub-basins and intra-basinal highs

Note: the structural inversion of the Mesozoic extensional basins and associated highs has the potential to cause confusion in the naming of structural features, e.g. the Hampshire-Dieppe High (Jurassic) becomes the Hampshire Basin (Tertiary) and the Portsdown Fault (Jurassic) becomes the Portsdown Monocline (Tertiary).

The Weald Basin is bounded to the north by the London Platform Boundary Faults, which mark the southern limit of the London-Brabant Massif (or London Platform). The use of this generic term for the northern bounding fault system negates the need for such terms as the Ham – Kingsclere – Hog's Back – Bletchingley – Ashour – Detention fault (Sellwood *et al.* 1985). North of Bletchingley, Sellwood *et al.* (1985) label the 'North Downs Shelf' before the London Platform is reached. Hawkes *et al.* (1998) use the term 'Reading Shelf' fringing the London Platform.

To the WNW, the Pewsey Basin (Hawkes *et al.* 1998, Underhill & Stoneley 1998) (or Vale of Pewsey Basin of Whittaker 1985, Karner *et al.* 1987 or North Wessex Basin of Sellwood *et al.* 1985) is a half-graben controlled by the Devizes – Pewsey Fault to its north.

The southern margin of the Weald Basin is marked by a high on the upthrown side of the major down-to-the-south Portsdown – Middleton Fault (the Portsdown – Chichester Fault of Sellwood *et al.* 1985 or the Portsdown – Paris Plage Fault of Butler & Pullan 1990). This high was termed the Regnenses Hinge by Sellwood *et al.* (1985), Hancock & Mithen (1987) and Karner *et al.* (1987) and the Portsdown – Paris Plage Ridge by Butler & Pullan (1990). On the southern fringe of the study area lies a small un-named half-graben.

The Mere Basin lies south of the Mere Fault, which is the western continuation of this major ESE-trending Portsdown – Middleton fault zone. Seismic profiles show substantial thickening of the Lias across the Mere Fault, and reactivation produced the Wardour Monocline and the Vale of Wardour Anticline (Barton *et al.* 1998, Chadwick & Evans 2005).

To the SSE of the half-graben south of the Portsdown High, a further high (the South Hampshire – Isle of Wight High of Sellwood *et al.* 1985 or the Hampshire – Dieppe High of Underhill & Stoneley 1998) is situated on the upthrown side of the next major Mesozoic fault (the Bembridge – St Valery Fault/Line of Sellwood *et al.* 1985, Hawkes *et al.* 1998, or the Wight – Bray Fault of Hamblin *et al.* 1992). Further west, this high grades into the Cranborne – Fordingbridge High (Whittaker 1985, Butler 1998) or Wessex Shelf (Sellwood *et al.* 1985, Hawkes *et al.* 1998). During basin inversion, the former high developed into the Hampshire Basin.

Outside the current study area, the following structures are also noteworthy (Figure 18).

To the west, a narrow ENE-WSW symmetrical graben is defined by the Cranborne and Bere Regis faults. This is variously known as the Cerne Trough (Sellwood *et al.* 1985), the Dorset Basin (Whittaker 1985, Underhill & Stoneley 1998, Hawkes *et al.* 1998), the Winterborne Kingston Trough (Karner *et al.* 1987) or the Cerne – Winterborne – Christchurch Trough (Butler 1998). It lies to the north of a high also with varying terminology: the Mid Dorset High (Sellwood *et al.* 1985, Karner *et al.* 1987), Mid Dorset Platform (Butler 1998), South Dorset Shelf (Underhill & Stoneley 1998) or Purbeck High (Hawkes *et al.* 1998).

To the south of the Purbeck – Isle of Wight – Pays de Bray fault system lies the major half-graben variously known as the Central Channel Basin (Whittaker 1985), the Portland-Wight Basin (Underhill & Stoneley 1998), the Portland-South Wight Basin (Hawkes *et al.* 1998) or the South Wight Basin (Buchanan 1998).

3.5.3 Inversion features

In addition to the Weald-Artois Anticline itself, other compressional features formed during Cenozoic basin inversion include the Hog's Back Monocline (the reactivated Hog's Back Fault) and the Pewsey Anticline (the reactivated Pewsey Basin bounding fault). Two wells in the Weald area have encountered reverse faults, with repeat sections discernible in Brightling 1 and Detention 1 (see Appendix F).

Chadwick (1993) contrasts the Weald Basin with the Dorset and Pewsey basins, which do not show significant regional upwarp.

Outside the study area, other compressional features to the south-west include the Purbeck- Isle of Wight Monocline (Chadwick 1993, Chadwick & Evans 2005, Evans *et al.* 2011) and the Wardour Monocline (Chadwick 1993, Barton *et al.* 1998, Chadwick & Evans 2005).

Uplift was initiated during the early Paleocene (Cenozoic) and was related to Alpine tectonics further south (e.g. Chadwick 1993, Blundell 2002). Some authors, however, suggest that lower Tertiary strata extended across the Weald and that the most-significant inversion took place during the Miocene (e.g. King 1981, Butler & Pullan 1990, Jones 1999).

3.5.4 Estimation of the amount of inversion

3.5.4.1 Methodologies

Estimating the amount of inversion that has affected the various parts of the Weald Basin is fundamental in assessing the depth at which the oil and gas window currently occurs in the study area. This can be achieved using two main approaches: (a) stratigraphic restoration and (b) interval velocity comparisons (see Conoco 1986, Butler & Pullan 1990, Chadwick 1993 etc).

(a) Stratigraphic restoration relies on estimating the thickness of strata removed by erosion. In the case of the Weald area, this requires estimating the thickness of the eroded uppermost Jurassic, Cretaceous and Tertiary. This can be achieved by extrapolating isopach data from nearby wells across the area where the strata have been removed and incorporating established thickness trends.

(b) Sedimentary rock porosity decreases (and hence sonic velocity increases) with burial, and this decrease is largely irreversible with subsequent exhumation. An estimate of the amount of exhumation across the basin can thus be obtained from the sonic velocity of a (relatively) uniform shale unit (e.g. the Oxford Clay) in boreholes, by reference to an undisturbed compaction trend with depth. The geometry of this 'normal compaction trend' is critical to obtain best estimates and is controlled by wells where uplift is considered to have been minimal. Chadwick (1993) points out that this figure is somewhat less than that estimated from method (a).

There are also methods of estimating exhumation using Great Oolite porosity comparisons, palaeotemperature data from Apatite Fission-Track Analysis (AFTA) and vitrinite reflectance from wells. See Corcoran & Doré (2005) for a summary of methodologies.

3.5.4.2 This study

In this study, isopachs of the uppermost Jurassic, Wealden Beds, Lower Greensand, Gault Clay, Upper Greensand, Chalk and Tertiary were constructed by extrapolating well and outcrop thicknesses and their trends across to the area from where they have been subsequently eroded, building on the maps published by Sellwood *et al*. (1986). These were then summed to produce an aggregate layer that was added vertically to the depth-converted Kimmeridge micrite seismic reflector to produce a projected 'Top Tertiary' horizon. After subtracting the present-day depth to the Kimmeridge micrite below sea-level, the resulting map of uplift exhibits a maximum of 6,750 ft (2,060 m) in the vicinity of the Crowborough and Heathfield structures (Figure 20).

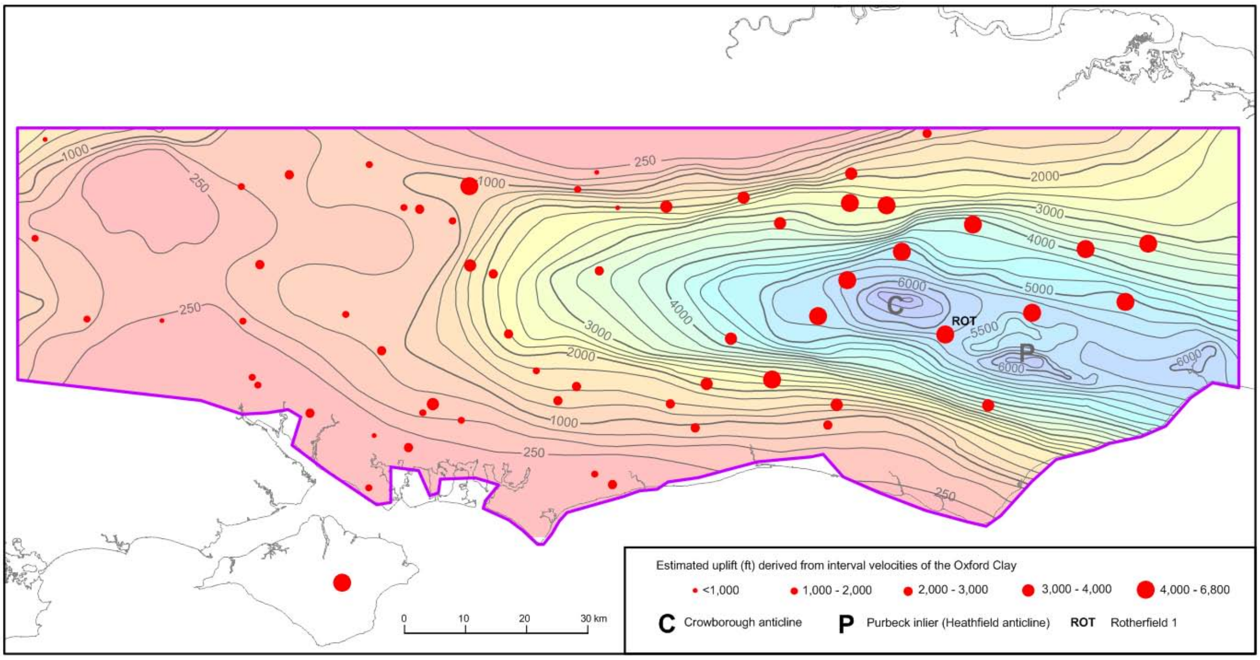

Figure 20. Approximate amount of Cenozoic uplift estimated using the stratigraphic reconstruction of missing strata (contours), with uplift figures at wells estimated using Oxford Clay interval velocities (red dots).

All available time-depth data for the Top Oxford Clay and Top Great Oolite (or equivalent horizons) were collated. This interval corresponds to the Oxford Clay, the same unit studied by Butler & Pullan (1990) (Note that Law (1998) and Hillis *et al.* (2008) used the broader Corallian to Oxford Clay interval in their studies). From these data, Oxford Clay interval velocities were calculated and plotted against the present-day true vertical depth to the mid-point of the unit (Figure 21).

A 'normal compaction trend' (purple line in Figure 21) was constructed using the available well data in areas considered to have experienced minimal uplift (e.g. Norton 1) and an evaluation of the curves used by Butler & Pullan (1990), Law (1998), Hillis *et al.* (2008) and Tassone *et al.* (2014). An estimation of the amount of uplift experienced at each well location results from the difference between the current mid-point depth and the depth predicted using the velocity measured in the well together with the 'normal compaction trend'.

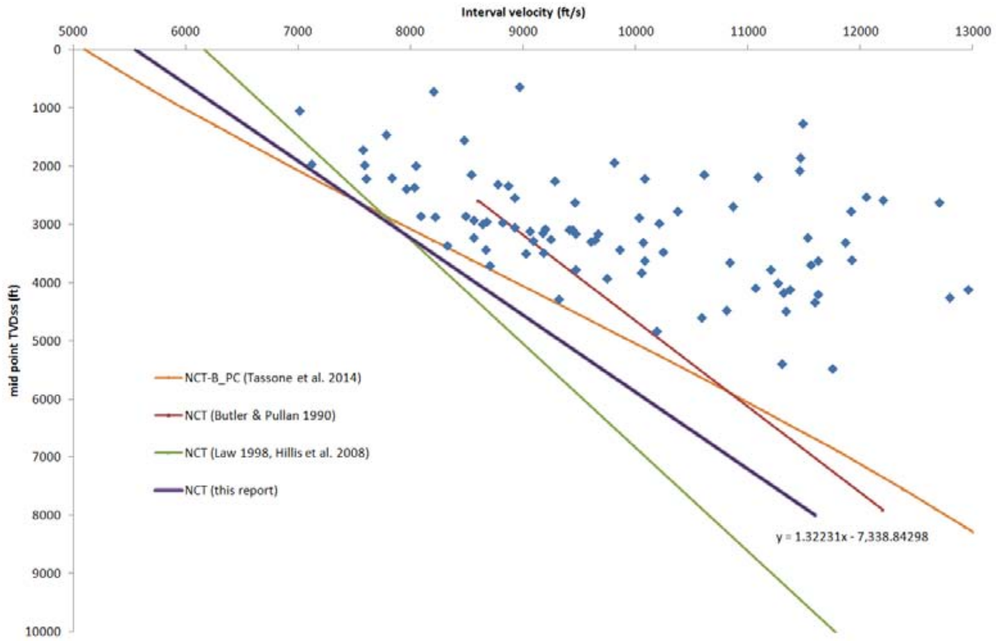

Figure 21. Plot of Oxford Clay interval velocity vs. present-day mid-point depth of the Oxford Clay in wells in the Weald study area and adjacent areas of Dorset. The 'normal compaction trends' (NCT) used in this study and by previous authors are also shown.

Bearing in mind the potential inaccuracies of each method (± 500 ft/150 m at least, see Law 1998), there is general agreement between the Cenozoic uplift figures calculated using these two methods (Figure 20).

In this study, vitrinite reflectance data have not been used as a guide to uplift due to the wide variability in the values, with much vitrinite being reworked from older, more mature strata, and some reflectance suspected of being suppressed (see Section 3.7.1).

3.5.4.3 Previous uplift/exhumation studies

Various authors have also attempted to quantify the amount of Cenozoic uplift/denudation/exhumation experienced in the central Weald Basin. Their deductions are summarised below in Table 5. The largest figures were published by Hillis *et al.* (2008), whose exhumation figures are up to 2,000-3,000 ft (c.600-900 m) greater than those calculated using the 'normal compaction trend' used by Butler & Pullan (1990) (note the steeper gradient on Figure 21).

Author(s)	**Method**	**Conclusion**	**Maximum uplift (ft)**
Jones (1980)	Stratigraphic reconstruction using published isopach data.	Crestal elevation of 3,900 ft (1,190 m).	3,900
Ebukanson & Kinghorn (1986a)	Stratigraphic reconstruction using regional isopach data from Gallois (1965).	Estimated that 5,500 ft (1,680 m) had been eroded from the site of the Penshurst 1 well, compared with 1,555 ft (470 m) at Winchester 1.	5,500
McLimans & Videtich (1987, 1989)	Fluid inclusion data from the Great Oolite limestones.	Estimated uplifts of about 1,500 ft (460 m) and 4,500 ft (1,370 m) respectively for the western and eastern parts of the Weald Basin.	4,500
Butler & Pullan (1990)	The addition of reconstructed isopach layers for the various eroded formations	Base Upper Chalk crestal elevation was c.4,000 ft (1,220 m) with a probable overall	5,000

Author(s)	**Method**	**Conclusion**	**Maximum uplift (ft)**
	to mapped surface and subsurface structure maps was used to compute a regional map of base Upper Chalk (sub sea-level). Then an estimated thickness was added for the Upper Chalk and any Lower Tertiary that might have been deposited over the Weald (say 700-1,500 ft).	Tertiary uplift in excess of 5,000 ft (1,520 m). Their interpretation placed the crest in the south-eastern part of the basin, specifically in the Crowborough-Heathfield-Battle area and extending offshore north of Hastings.	
Butler & Pullan (1990)	Oxford Clay interval velocity.	No specific data published, but 'very good agreement' with other methods.	
Butler & Pullan (1990)	Average porosity of the Great Oolite.	Their Fig. 8 suggests values of c.3,700 ft (1,130 m).	3,700
Chadwick (1993)	By mapping and extrapolating a base Chalk surface. Where the base Chalk surface has been eroded, seismically determined thickness trends were used.	The total (late Cretaceous to Miocene) relative uplift was estimated to be in excess of 4,100 ft (1,250 m) with an extrapolated maximum from this figure of 4,590 ft (1,400 m).	4,590
Chadwick (1993)	Comparison of sonic velocities of argillaceous rocks between a well which has suffered little uplift (Sandhills 1) and a well with a large amount of uplift (Detention 1).	A relative difference in uplift between these two wells was estimated to be c.2,950 ft (900 m).	2,950
Scotchman (1994)	Geochemical biomarker data.	At Warlingham and Palmers Wood 1, uplifts of 984 ft and 1,115 ft (300 m and 340 m respectively) were estimated using hopane, and 1,640 ft and 2,300 ft (500 m and 700 m) using sterane.	2,300
Law (1998)	Sonic velocity data from a unit comprising the Corallian and Oxford Clay (Top Corallian to Top Cornbrash interval).	In the adjacent English Channel area, the largest estimates of inversion were from the Purbeck-Isle of Wight fault zone, with 7,270 ft (2,216 m) at Arreton 2.	7,270
Jones (1999)	Stratigraphic reconstruction.	The removal of Mesozoic strata from the central Weald reaches an estimated 3,950 ft (1,205 m) at Ashdown, 4,177 ft (1,273 m) at Brightling and 4,216 ft (1,285 m) at Bolney. This suggested a broad, slightly asymmetrical upwarp with a maximum crestal elevation of 4,590 ft (1,400 m).	4,590
Jones *et al.* (2002)	Subsidence history modelling.	Estimated 4,920-6,560 ft (1,500-2,000 m) of Cenozoic denudation across south-east England, but with no indication of an uplift peak corresponding to the Weald Basin centre.	6,560
Hillis *et al.* (2008)	Oxford Clay interval velocity data from Butler & Pullan (1990) and a normal compaction trend from Law (1998) (S. Holford pers. comm.).	Maximum exhumation figures were 7,467 ft (2,276 m) at Wallcrouch 1 and 7,123 ft (2,171 m) at Ashour 1.	7,470
This study	Stratigraphic reconstruction using isopachs from boreholes and outcrop.	Areas with >6,500 ft (1,980 m) of removed strata occur on the Crowborough and Heathfield structures (Figure 20). The maximum is 6,750 ft (2,060 m) on the crest of the Crowborough anticline.	6,750
This study	Oxford Clay interval velocity.	The maximum eroded section occurring at a well is 6,835 ft (2,080 m) at Rotherfield 1 (Figure 20) (where 5,600 ft (1,710 m) is estimated using the reconstruction model).	6,835

Table 5. Summary of different estimations of the magnitude of Cenozoic uplift in the Weald area.

3.6 Stratigraphy - shales in the Jurassic succession of the Weald Basin

The Jurassic succession in the Weald Basin is a shale-dominated sequence with a relative paucity of interbedded limestones and sandstones. At least five fine-grained, potential source rock units occur in the Mid Lias, Upper Lias, Oxford, Corallian and Kimmeridge Clays (Figure 22).

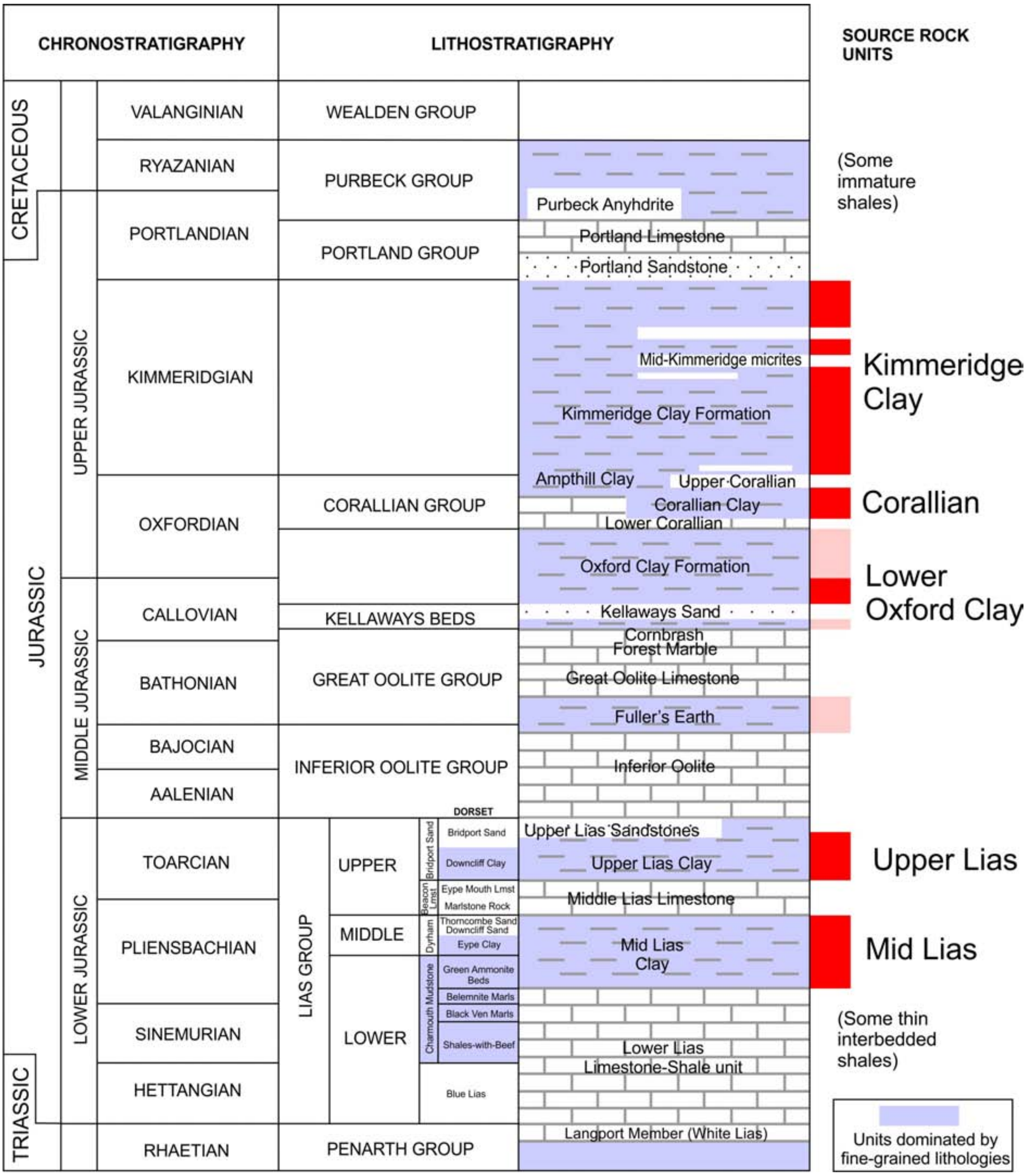

Figure 22. Lithostratigraphical framework of the Jurassic in the Weald Basin, showing the position of the five key argillaceous, source-rock units (in red). Other, potential source rocks are indicated in pink. The Lias stratigraphic names used in this study are informal. The inset of the Dorset Lias succession is taken from Barton et al. (2011).

3.6.1 Lower Jurassic on the Dorset coast

In Dorset, following the lithostratigraphic nomenclature of Cox *et al.* (1999) (Figure 22), the Blue Lias Formation (with its characteristic interbeds of bioturbated, oxic limestone and anoxic, laminated shale) is overlain by the Charmouth Mudstone Formation (Shales-with-Beef, Black Ven Marl, Belemnite Marl, Green Ammonite Beds) and together make up the Lower Lias. These beds are overlain by the Middle Lias Dyrham Formation, followed by the highly condensed Beacon Limestone Formation (Upper Lias). The Upper Lias continues with the Bridport Sand Formation commencing with the Downcliff Clay Member. Details of the Dorset outcrops are described in Barton *et al.* (2011).

Whittaker *et al.* (1985) correlated the subdivisions of the Lias northwards into nearby wells, but not as far as the Weald Basin. They divided the Lias into nine 'geophysical log units' (Lower Lias LL1-LL5, Middle Lias ML1-ML2, Upper Lias UL1-UL2). Of these, LL1 is equated with the Blue Lias and LL2-LL5 to the four Charmouth mudstone subdivisions. Bessa & Hesselbo (1997) further divided Whittaker *et al.*'s LL1-LL4 into 18 'spectral gamma-ray units' using a constructed gamma-log for the coastal section and nearby wells. From the constructed log, it is apparent that the division into Blue Lias and Charmouth Mudstone is not simply a limestone – mudstone boundary (as is implied by the lithostratigraphy, and as it appears in the distant Cooles Farm borehole, Whittaker *et al.* 1985) because the lowest gamma-log responses occur in the Shales-with-Beef and Belemnite Marls.

3.6.2 Lower Jurassic in the Weald Basin

Away from the coastal outcrops of Dorset, the detailed subdivisions of the Lias are soon replaced by a broader classification: a Lower Lias Limestone-Shales unit, the Mid Lias Clay, Middle Lias Limestone unit, Upper Lias Clay and Upper Lias Sandstones (Figures 22 & 23).

3.6.2.1 Lower Lias Limestone-Shale unit

In the Weald Basin wells, this sequence typically begins with a basal limestone unit that is up to 50 ft (15 m) thick and has a characteristically low gamma-log response. This bed is equated with the White Lias, known formally as the Langport Member of the Lilstock Formation (Penarth Group), in Dorset. This unit has been assigned a Rhaetian (Triassic) age, and it bed forms a lower reservoir in the Humbly Grove oil field. A basal low-gamma limestone (of putative Hettangian age) has been termed the 'Suttonstone equivalent' in Godley Bridge 1 (Figure 23). Further east, the base is diachronous and a basal sandstone facies becomes progressively younger approaching the London Platform (Holloway *et al*. 1983).

The remainder of the Lower Lias Limestone-Shales unit consists of interbedded limestones and subordinate shales (Figure 23).

A widespread geophysical log pattern in wells with 300-400 ft (90-120 m) of Lower Lias is a decreasing upwards signature in the lower two-thirds, followed by an upper third with a slightly higher gamma-log response indicating more argillaceous lithologies. This upper division may also show an upward-decreasing gamma-response, with lime-rich beds at the top (Figure 23). In wells where the unit is 200-300 ft (60-90 m) thick, this division is not apparent. There are significant differences between the log responses in Weald Basin wells and those in the Wessex Basin (Whittaker *et al.* 1985, Bessa & Hesselbo 1997).

There is some uncertainty as to how these beds equate with the Dorset outcrop. If the Mid Lias Clay which overlies them is early Pliensbachian in age and equate with the Green Ammonite Beds (as is often shown on composite logs), then the Lower Lias Limestone-Shales may equate with the Blue Lias and the remainder of the Charmouth Mudstones (Figure 22).

Many authors refer to the presence of a Lower Lias shale in the Weald Basin as well as in the Wessex Basin. Indeed, it is referred to as the prime source-rock candidate for the conventional oil fields in the Weald Basin (e.g. Butler & Pullan 1990, Burwood *et al*. 1991). However, there is also frequent, and somewhat contradictory, recognition that its source rock potential decreases eastwards into and across the Weald Basin (e.g. Scott & Colter 1987, Butler & Pullan 1990, Burwood *et al*. 1991, Hawkes *et al*. 1998, Ainsworth *et al*. 1998, Magellan Petroleum 2011, USEIA 2013). Also see Section 3.7.2.1 for a discussion of the geochemistry of this unit.

The current study does not recognise a significant Lower Lias shale unit in the Weald Basin. Although thin interbedded shales are certainly present, Weald Basin wells show that there is a higher proportion of limestone in the Lower Lias in the study area than in Dorset. It is possible that there may be thin shale beds that are below the resolution of the geophysical logging tools (c.6 ft, 2 m), but these would also have to be poorly sampled in cuttings. It should be noted that the Lias depocentre of the Weald Basin has yet to be drilled and it could prove to contain thicker and more organic-rich shales than current wells located towards the flanks of the basin, but there is no evidence for that trend from existing data.

3.6.2.2 Mid Lias Clay

In the subsurface of the Weald, there is a 100-375 ft-thick (30-110 m) shale between the Lower Lias Limestone-Shales unit and the Middle Lias Limestone (Figures 22 & 23). This unit is thickest in the Lockerley 1 well, but in the Wealden depocentre it is 125-300 ft (40-90 m) thick. It is represented by a fairly uniform shale lithology (confirmed by its uniform geophysical log responses) with some of the highest gamma-log responses of the entire Lias, and has been dated as Pliensbachian in age. The lower part is assigned an early Pliensbachian age on company composite logs; so strictly speaking the unit spans the uppermost Lower and lowest Middle Lias.

Several company logs equate this unit with the Green Ammonite Beds as found in Dorset (see Figure 23).

This unit contains 9-37% organic-rich shale in the ‘core mature area’ (see Section 3.7.2). In that area, total organic carbon contents of up to 2.07% have been recorded in Baxters Copse 1 (see Section 3.7.2.2)

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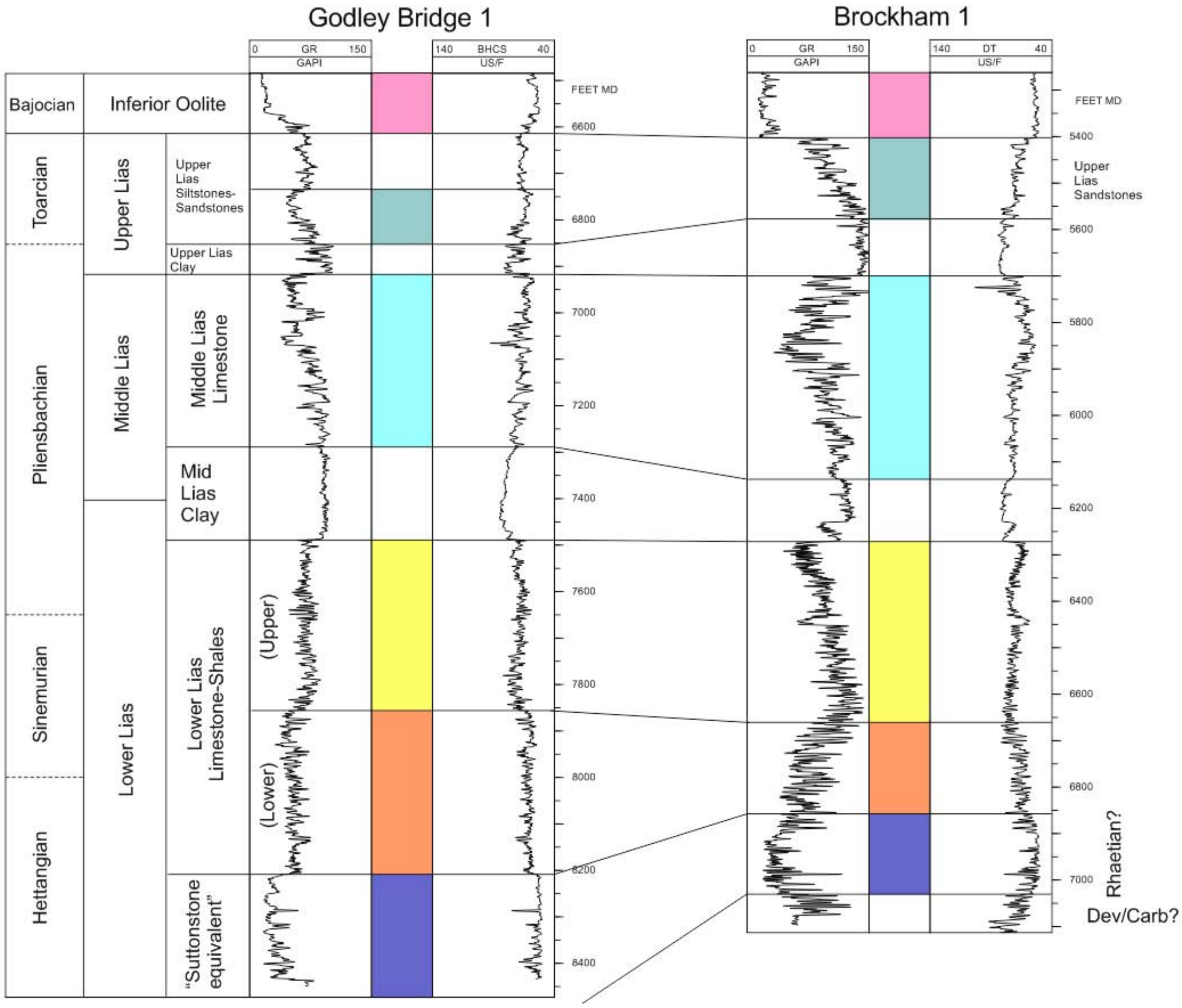

Figure 23. The Lias subdivisions in Godley Bridge 1 and Brockham 1.

3.6.2.3 Middle Lias Limestone

The Middle Lias Limestone (equivalent to and often termed the Marlstone Rock Bed and/or Junction Bed[2]) is a distinct marker and, although typically thin, when combined with the underlying interbedded limestones and shales, can approach 400 ft (120 m) in thickness (e.g. Holtye 1). Limestone interbeds within the shales increase in thickness and persistence upwards, producing a spiky log response until the uppermost, thickest limestones are reached (Figure 23).

This unit may be a target in a hybrid Bakken-type shale oil play, with shale units above and below. This play is recognised in the Paris Basin, where the Banc de Roc is sandwiched between organic-rich shales (Chatellier & Urban 2010).

[2] The Marlstone Rock Bed/Member is the term applied on the East Midlands Shelf and in the Worcester Basin. The term Beacon Limestone Formation was introduced in the Wessex Basin for up to 15 ft (5 m) of ferruginous-ooidal limestone (Cox *et al.* 1999).

3.6.2.4 Upper Lias Clay

Above the Middle Lias Limestone, argillaceous lithologies again dominate in the Upper Lias Clay which is present in the eastern Weald Basin as well as in the western part of the study area (Figures 22 & 23). In these wells, shales and siltstones form the lower half of a further liming-upwards or coarsening-upwards log motif, but elsewhere they are replaced entirely by siltstones and sandstones. Where the Upper Lias Clay forms a distinct shale bed in the Wealden depocentre, it is typically 50-220 ft thick (15-70 m), but reaches a thickness of 290 ft (90 m) further west at Furzedown 1.

This unit comprises 15-28% organic-rich shales in the 'core mature area' (see Section 3.7.2).

The Upper Lias Clay is of early Toarcian age and correlates with the Schistes Carton ("paper shales") of the Paris Basin and the Posidonia Shale of the Lower Saxony Basin. These are both proven oil source rocks in their respective basins. In the Paris Basin, the amount of organic material in the shales increases towards the centre of the basin, where average TOC values reach 5.5-6% (Espitalie *et al*. 1987, Bessereau *et al.* 1994, 1995) and maximum values of up to 12% have been recorded (Katz 1995, Horsfield *et al*. 2010). TOCs of up to 20% have been recorded in immature Posidonia Shale in Germany.

3.6.2.5 Upper Lias Sandstones

The local incoming of sandstones (equivalent to the Bridport Sandstones) marks the top of the Upper Lias in the west of the study area; siltstones are found in the central and southern Weald Basin. Further west, these sandstones form a reservoir in the Wytch Farm oilfield. Elsewhere in the Weald Basin, the uppermost Lias typically contains an increasing amount of carbonate, with an upward decreasing gamma-log response.

3.6.3 Inferior and Great Oolite Groups

Between the base of the Inferior Oolite Group and the top of the Cornbrash (Great Oolite Group), limestone is the dominant lithology (Figure 22). The term 'Fuller's Earth' is used in this study for a more argillaceous subdivision between the Inferior Oolite and Great Oolite in the subsurface, as this can be broadly correlated with the montmorillonite-rich Fuller's Earth Formation at outcrop.

There are facies changes across the area, with the Frome Clay replacing the Great Oolite in the west (e.g. Hurn 1). The Great Oolite reaches its maximum thickness in a belt running NW-SE then W-E centred on Stockbridge 1, where the deposits of stacked oolitic shoals reach a maximum thickness of 285 ft (85 m) (Sellwood *et al.* 1985, 1989). Here the unit forms the reservoir of several major oil fields (see Section 3.2, Figure 4, Table 4). Further north-east the unit thins into the Weald Basin depocentre.

The top of the Cornbrash is a well-marked geophysical log break, marking the top of this limestone-dominated unit. This forms the datum for the correlation panels in Appendix F.

3.6.4 Oxford Clay Formation

Above the Cornbrash, the Kellaways Clay marks the incoming of shales at the start of the Callovian, although this trend was briefly interrupted by the deposition of a thin sandstone (Kellaways Sand) before the thick Oxford Clay was deposited (Figures 22 & 24). During Oxfordian times, tectonic activity was characterised by regional flexural subsidence, with little or no syndepositional faulting (except in the uppermost Corallian [Sequence 4] in Dorset, Newell 2000).

The Oxford Clay reaches a maximum thickness of 590 ft (180 m) in Shrewton 1 in the extreme west of the study area. Elsewhere, it is commonly 200-500 ft (60-150 m) thick in the central part of the Weald, thinning towards the London Platform to the north and also towards the east, south and south-west.

The lithologies and hence the geophysical log responses of the Oxford Clay vary across the Weald. In the extreme east of the study area, the gamma-log response is uniform. Elsewhere, there is a tripartite division, with a lower-gamma, carbonate-rich unit between two shales (Figure 24). The lowermost unit, 50-100 ft thick (15-30 m), is the most organic-rich part of the formation (see geochemistry section 3.7.6), and is best developed in the western half of the study area.

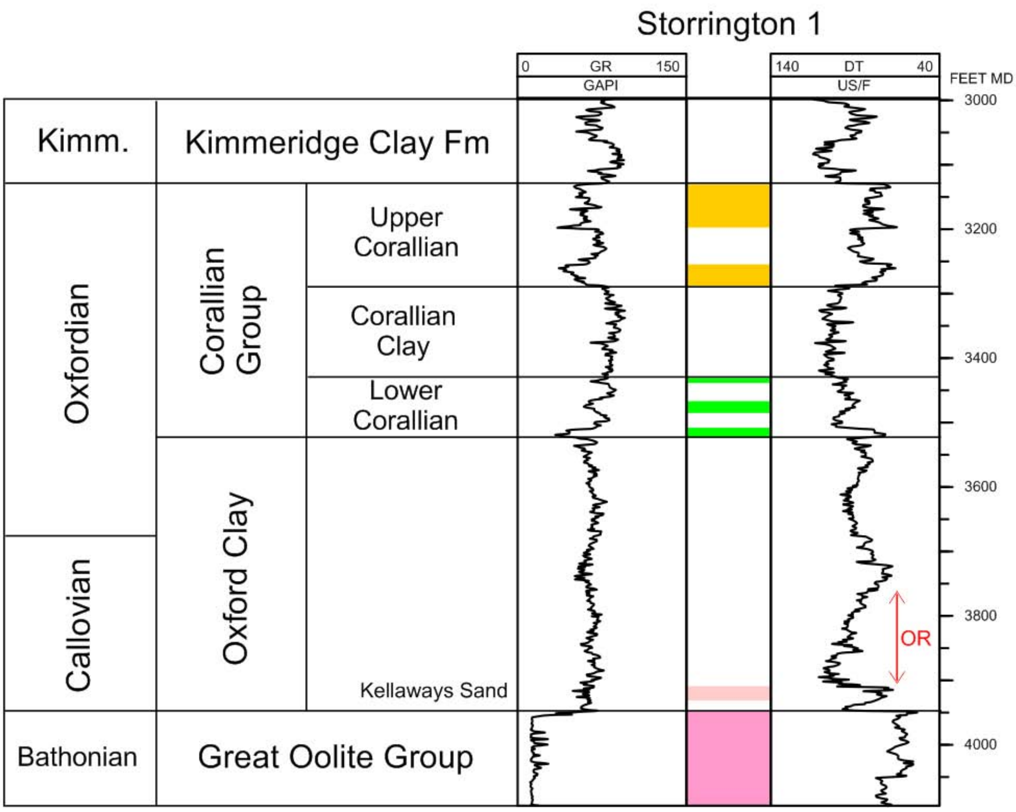

Figure 24. Stratigraphy of the Oxford Clay and Corallian Group in Storrington 1. OR = the organic-rich lower Oxford Clay unit.

3.6.5 Corallian Group

The presence of sandstones and limestones differentiates the Corallian Group from the Oxford Clay, but the intervening shales, which are frequently thick, are most similar to those of the overlying Kimmeridge Clay. Typically, the Corallian Clay[3] has a higher gamma-log response than the Oxford Clay (Appendix F), alluding to the fact that it may be more organic-rich. In the west, the term Ampthill Clay is often used on composite logs for this unit.

The Corallian Clay reaches a maximum thickness of 263 ft (80 m) in Rogate 1 and thins in all directions away from this depocentre. Across most of the Weald Basin, thicknesses of 50-250 ft (15-75 m) are commonplace.

The dating of the uppermost 'Corallian' in the Weald Basin as early Kimmeridgian has led some authors to include these youngest strata within the Kimmeridge Clay Formation (Taylor *et al.* 2001). That convention is not followed in this study.

In the Weald Basin, the Corallian Group contains coral-dominated patch reefs and oolitic shoals, developed locally along the northern basin margins (Sun & Wright 1989, Sun *et al.* 1992) and storm-dominated offshore sandstones (Sun 1992), separated by mudstones deposited on an offshore shelf. These limestones and sandstones form the reservoirs of several conventional oil and gas fields in the Weald Basin (see Section 3.2, Figure 4, Table 4).

3.6.6 Kimmeridge Clay Formation

The return of widespread offshore mud deposition after the Corallian Group marks the start of the Kimmeridge Clay Formation. Argillaceous rocks are dominant, with some being organic-rich, although there is a paucity of 'hot shales' with high gamma-log peaks in the Weald area. This difference is highlighted by comparison with the well-studied Swanworth Quarry and Metherhills boreholes in Dorset (Tyson *et al*. 2004) and the absence of the Kimmeridge oil shale or Blackstone Bed in the Weald Basin.

The thickness of the Kimmeridge Clay follows the pattern of the underlying Corallian Clay, with over 1,800 ft (550 m) deposited in the centre of the basin, thinning radially. The thickest well penetration is 1,864 ft (568 m) in Balcombe 1 (Figure 25).

Several coccolith micrite beds are present within the Kimmeridge Clay, notably in the eastern Weald (Figures 22 & 25), where they are known as the mid-Kimmeridge micrites. The lower "J-Micrite" reaches a maximum thickness of c.125 ft (38 m), whereas the upper "I-Micrite" is up to 150 ft (45 m) thick. A thinner "K-micrite" has a more restricted distribution. The micrite beds thicken towards the basin centre and pinch out towards the basin margins. These low porosity and low permeability micrites may be targets in a hybrid Bakken-type shale play, with shale units above and below. The oil in the micrite in the Balcombe 1 well has been compared to the hybrid Bakken play, but see the footnote on page 60.

[3] The term Corallian Clay is an informal name used for this mid-Corallian shale unit; where differentiated, this unit has also been referred to on composite logs as the Corallian Argillaceous Unit. It equates with 'Corallian Unit 2' of Sun (1992) and Ahmadi (1997).

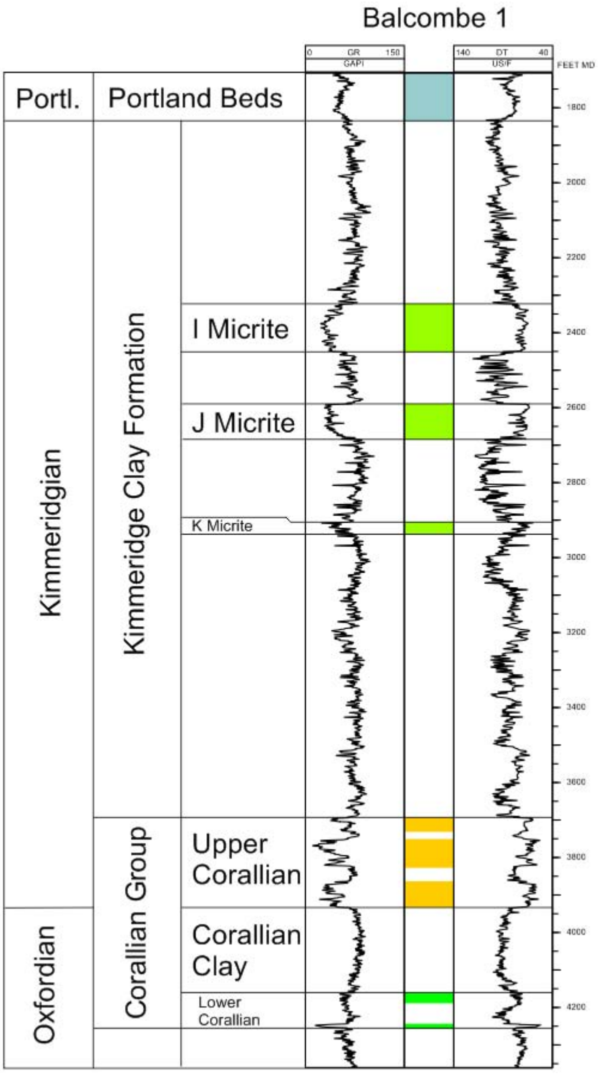

Figure 25. The Kimmeridge Clay and associated micrites in Balcombe 1. Note the maximum gamma-log response of only 100 API.

Sandstones occur in the Kimmeridge Clay Formation in the eastern Weald Basin, e.g. in Fairlight 1.

Clay contents of the Kimmeridge Clay are generally greater than 20%, and can reach 65% (Cox & Gallois 1981, Morgan-Bell *et al*. 2001) (Table 6). In this study, all the Kimmeridge Clay samples had a TOC of 0.6-12% and a total clay content of 6-59% (Appendices B & C). Organic-rich shales (TOC of 2-12%) had a clay content of 33-53%.

Lithology	**Kerogen (%)**	**Total clay content (%)**
Bituminous mudstone	2-10	30-50
Oil shale	10-45	20-40
Dark grey mudstone	<2	45-65
Medium grey mudstone	<1	35-55
Pale grey mudstone	<1	25-45
Cementstone	<1	10-20
All (Morgan-Bell *et al*. 2001)		20-65

Table 6. Clay content of the Kimmeridge Clay, Dorset (Cox & Gallois 1981 and others).

3.6.7 Portland and Purbeck groups

This uppermost Jurassic unit is marked by the incoming of sandstones (Portland Sandstone) followed by limestones, shales and anhydrites of the Purbeck Group (Figure 22). The sandstones are thickest in the basin centre (maximum of over 250 ft, 75 m). Shales are most prominent at the top of the unit (in the Lulworth Formation, upper Purbeck Group).

3.7 Geochemistry

3.7.1 Introduction

The following section presents a review of all available geochemical data for the Jurassic in the Weald study area[4] (and also published data from the Wessex area). It summarises the present-day total organic carbon (TOC_{pd}) contents and present-day vitrinite reflectance (R_{opd}) (or equivalent from T_{max}) data obtained from geochemical analyses. Where Rock-Eval analyses are available, S1, S2, HI (Hydrogen Index) and OI (Oxygen Index) data were also collated.

The results of new Rock-Eval analyses of 103 samples are presented in Appendix B, together with a more detailed breakdown of the published data.

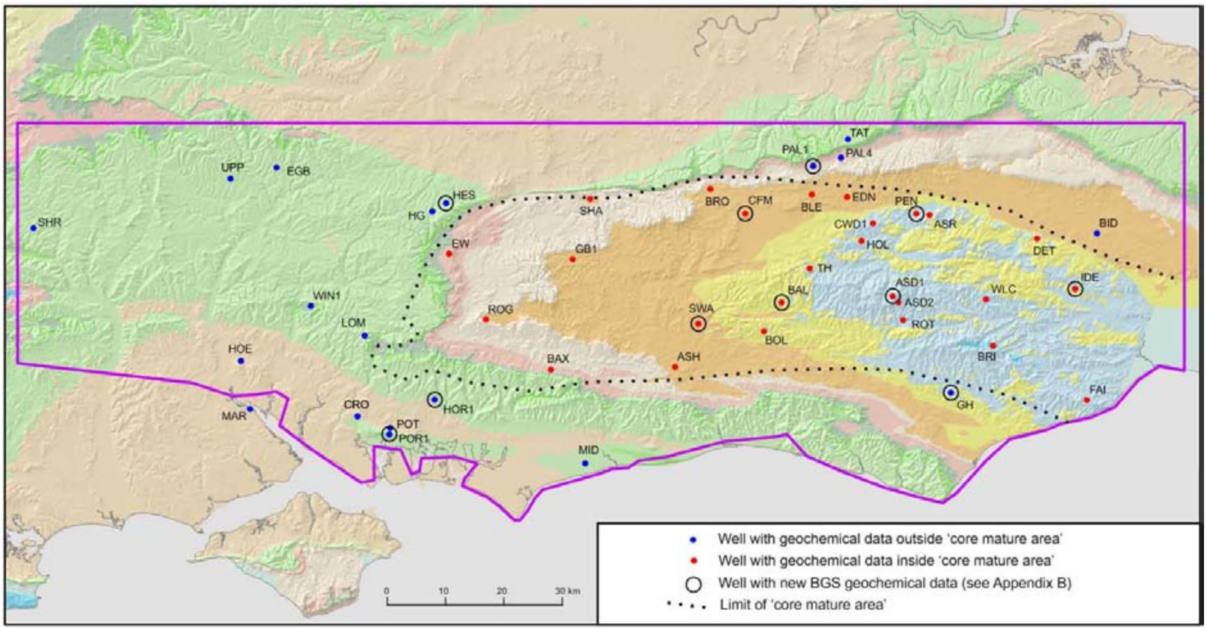

Figure 26. Location of wells for which geochemical data are available. See Appendix E for the key to well name abbreviations.

Calculated TOC values have also been generated using the Δlog R (Passey) method on downhole logs (Passey *et al.* 1990). This method uses sonic, density, neutron and resistivity logs to calculate a continuous log-derived TOC curve down the well, which can be calibrated with sampled intervals.

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[4] The geochemical database used in this study was compiled from released well reports, publications and additionally supplied data (see Acknowledgements on page iii). Wherever possible, only analyses of fine-grained sediments were incorporated, but this was not possible in cases where lithological information was lacking.

This method indicates that the calculated TOCs from logs are not significantly different than the core samples and add many more data points to the analysis. See Appendix D.

Notes:

(1) In the absence of cored shales, many analyses have been carried out on cuttings. There is an inherent problem in cuttings with sampling, caving and general mixing of lithologies. This is exacerbated by the fine interbedding of organic-rich shale and organic-poor limestone typical of the Lias.

(2) The evaporative loss of S1 from the samples over time may have been considerable, especially if more volatile oils are present. See Section 3.7.9 and Appendix B. A small reduction of TOC can also occur through oxidation over time.

(3) Obtaining valid R_o data is not straightforward, especially when extracting data from analyses carried out in the 1980s. Measured R_o values can be lower (suppressed) or higher (enhanced) than expected for a given depth of burial. Above all, these R_o values are subject to the interpretation of the analysts. In the past, the selection of primary vitrinite on which to carry out the analysis may have been less standardised that it is now. Vitrinite may be scarce or absent, and many samples have elevated R_o that may result from the erroneous selection of other organic macerals. Recycled vitrinite may present the most significant issue. Butler & Pullan (1990) stated that the use of vitrinite reflectance as a maturity indicator for the Weald Basin seems to give low estimates. Scotchman (1991) commented that variations in kerogen facies (in particular the amount of reworked Type III) may be responsible for “often spurious and scattered maturation measurements which conflict with the geological model”. T_{max} is also indicative of the level of maturity, and a conversion formula is widely used (although this relationship was derived specifically for the Barnett Shale). T_{max} becomes less reliable when TOC is low or when S2 < 0.5; it also suffers if there has been severe recycling of organic macerals. Bray *et al.* (1998) also commented on lower-than-expected R_o values, ‘geochemical suppression’ and a large scatter of data, in the Wessex Basin.

3.7.2 Summary

Five major Jurassic shale units are represented in the Weald Basin; another, the Lower Lias, is considered too lean to have any significant prospectivity in the study area.

One point to note is the fact that nearly all the Jurassic shales have a gamma-log response less than 120 API, with especially high gamma-log spikes being totally absent in the Weald Basin. This contrasts with the Carboniferous Upper Bowland-Hodder Unit of northern Britain, where high-gamma zones are widespread (Andrews 2013). A cut-off of 150 API is often used to identify prospective shales worldwide (Table 7), but it has been pointed out that this is not an absolute value and can be lower if the organic carbon content is demonstrably high (D. Gautier, USGS, pers. comm.). It can also be lower in hybrid plays.

	Total number of samples analysed	% of samples with TOC>= 2% (= '% net pay') from geochemical analyses	% of points with TOC>= 2% (= '% net pay') from geophysical logs (Appendix D)	Net pay values in 'core mature area' used in Monte Carlo analysis (Appendix A)	Average TOC based on all samples in study area (%)	Average log-derived TOC in net shale (%) (Appendix D)	Average TOC in 'core mature area' * only (%)
Lower Lias (Weald wells)	237	8	17	0 (no effective pay)	1.1	1.4	0.9
Mid Lias Clay (Weald wells)	94	9	37	9 – 20 – 37	1.2	1.9	1.1
Upper Lias Clay (Weald wells)	127	28	22	15 – 22 – 28	1.6	1.5	1.45
Oxford Clay (Weald wells)	156	22	39	22 – 30 – 39	1.7	2.7	1.1
Corallian Clay (Weald wells)	91	9	67	20 – 27 – 35 (for whole Corallian)	1.1	3.3	1.0
Kimmeridge Clay (Weald wells)	406	52	63	52 – 63 – 70	3.2	3.8	3.3
Lias clays (published data from Dorset outcrops)	109	52.3			2.5		
Kimmeridge Clay (Dorset well study, Tyson 2004)	2771	62.2			3.8		
Bowland-Hodder unit, northern England (Andrews 2013)	815	58.2			2.4		

*Table 7. Summary of all available TOC data and net pay (TOC>=2%) thicknesses for the Jurassic of the Weald Basin, compared with data from the Dorset outcrops and the Bowland-Hodder Unit of the Carboniferous of northern Britain. * the 'core mature area' is shown on Figure 26.*

3.7.3 Lower Lias

	S2 (kg/t)	TOC (%)	HI
Lower Lias (Burwood *et al*. 1991, [average] southern England)	6.0	1.8	325
Blue Lias (Akande 2012, Lyme Regis, Dorset)	46.3	8.1	569
Lower Lias (Burwood *et al*. 1991, maximum southern England)	38.0	6.0	630
Lower Lias (Ferguson 2002, maximum Chickerell 1, Weymouth, Dorset)	27.5	5.7	480
Lower Lias (Ferguson 2002, average Chickerell 1, Weymouth, Dorset)	9.0	2.7	334
Lower Lias (average for all Weald wells, this study)	1.7	0.9	196
Lower Lias (average for wells in 'core mature area', this study)	1.5	0.9	170
Lower Lias (maximum for all Weald wells, this study)	15.5	2.0	773
Lower Lias (maximum for wells in 'core mature area', this study)	6.8	1.2	550

Table 8. Comparison of geochemical data (S2, TOC and HI) for the Lower Lias of the Wessex and Weald basins.

Although considered as an important source rock in the Weald area by many authors (e.g. Burwood *et al*. 1991), the predominance of limestones in the study area compared with Dorset downgrades its significance in the Weald Basin. The fact that this optimism in other studies is based on data from the Wessex rather than the Weald Basin is substantiated by a comparison of the geochemical data (Table 8, Figure 27).

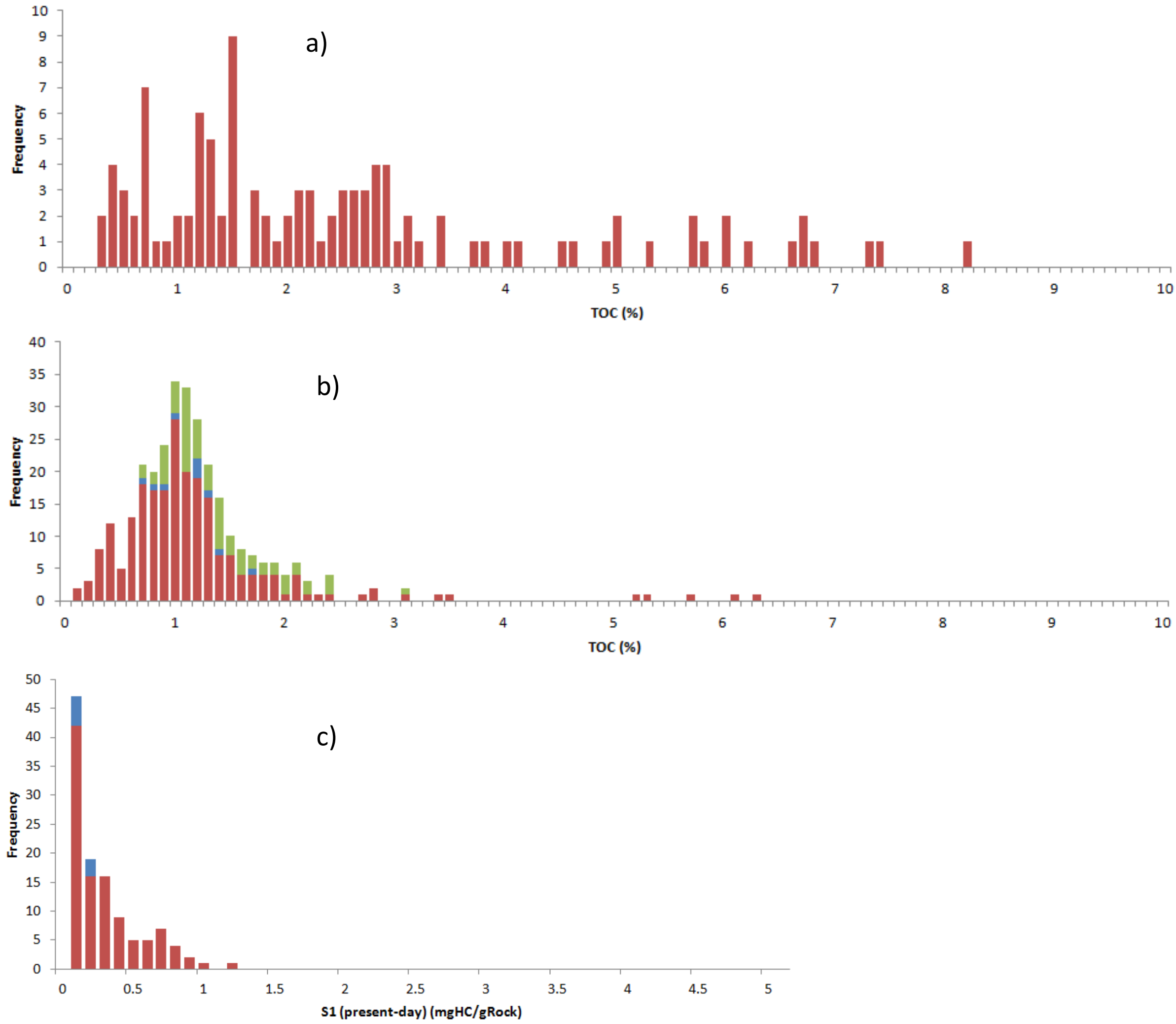

Figure 27. (a) Total organic carbon (TOC) from the Lower Lias in the Wessex Basin (from Ebukanson & Kinghorn 1985, Kiriakoulakis et al. 2000, Scotchman 2001, Ferguson 2002, Salem 2003, El-Mahdi 2004, Eltera 2004, Akande 2012, P. Farrimond (unpubl.), (b) total organic carbon (TOC) and (c) present-day S1 values from the Lower Lias in the Weald Basin, based on all available data. Red = legacy data; blue = new BGS data (see Appendix B); green = pyrolysis-derived TOCs, courtesy of Celtique Energie.

The average TOC for the Lower Lias samples in the study area is 1.1%, with only 18 of the 237 analyses recording TOC >=2%. The highest recorded values are 6.02% in Shrewton 1 and 6.24% in Upper Enham 1. These wells are both in the west of the study area, reflecting the increase in Lower Lias source rock potential to the west and into Dorset. These organic-rich samples are probably from shale interbeds between the predominant limestone lithologies, as in the Dorset coastal outcrops. Lower Lias strata thicken dramatically south of the Portland-Isle of Wight fault zone, with mature, organic-rich Lower Lias shales forming the main source rock for the Wytch Farm oil field (Ebukanson & Kinghorn 1986b, Burwood *et al*. 1991).

The low concentration of organic matter in the Lower Lias in the Weald Basin suggested by limited Rock-Eval data is confirmed by log-derived TOC, with 0.7-2.0% (average 1.4%) in wells across the study area (Appendix B) and an average of 1.4% in 78 pyrolysis-derived TOCs (Figure 27).

Within the area predicted in this study to be within the oil window (Figure 26), the average measured TOC in the Lower Lias is only 0.9% (maximum 2.1%), and S1 values average just 0.28 mgHC/gRock. These values confirm that organic carbon contents are insufficient for it to be considered a source rock in the study area.

The Lower Lias is elsewhere reported to be mature for oil generation across much the Weald Basin (Lamb 1983, McLimans & Videtich 1987, 1989), with some burial history studies indicating that the Lower Lias could have even entered the gas window in the deepest part of the Weald Basin (Butler & Pullan 1990) and purportedly reaching R_o=1.2% in the basin centre (Ebukanson & Kinghorn 1986b, Smith *et al.* 2010).

In this study, the Lower Lias is considered to be mature for oil generation in the 'core mature area', and, being the deepest Jurassic shale-bearing unit, is the most likely to have reached the gas window (R_o > 1.1%). However, note the lack of evidence for substantial organic-rich shales at this level in the Weald.

3.7.4 Mid Lias Clay

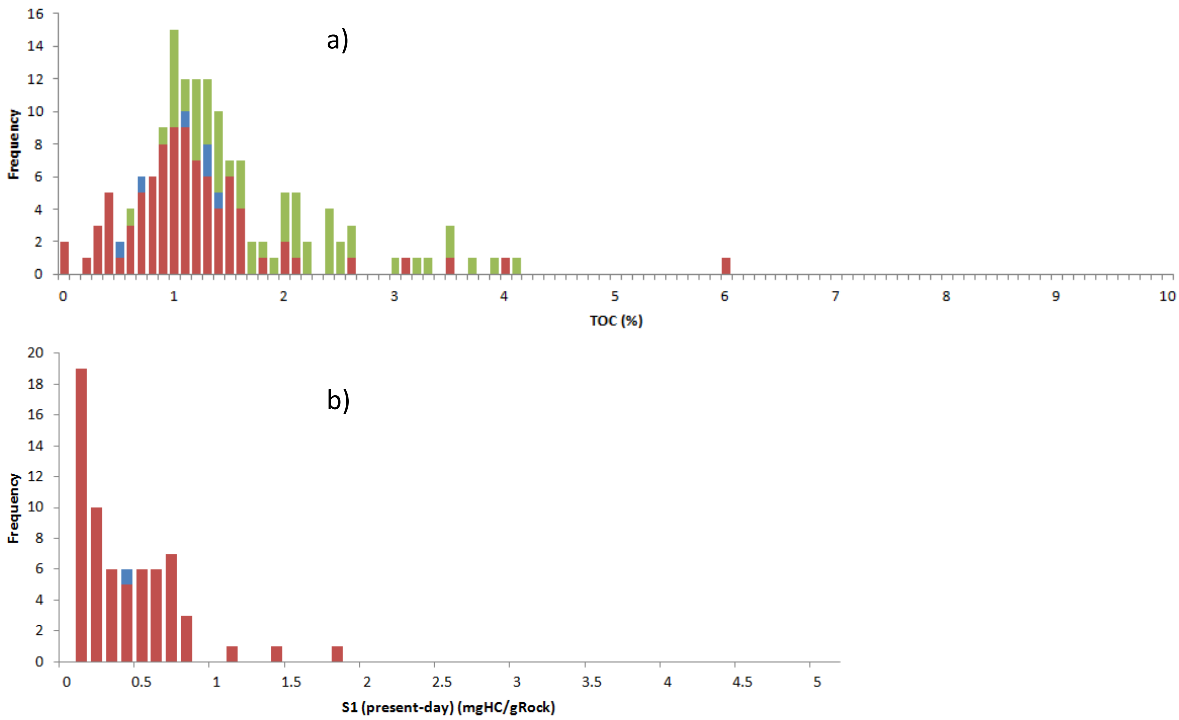

Figure 28. (a) Total organic carbon (TOC) and (b) present-day S1 values from the Mid Lias Shale in the Weald Basin, based on all available data. Red = legacy data; blue = new BGS data (see Appendix B); green = pyrolysis-derived TOCs, courtesy of Celtique Energie.

The Mid Lias Clay consists of a 125-300 ft (38-90 m) thick mudstone. Based on all available geochemical data, the average TOC for the Mid Lias Clay samples is 1.2%, with 8 of the 94 analyses recording TOC >=2% (Figure 28). In the 'core mature area', the average TOC is 1.1% and average S1 is 0.88 mgHC/gRock. The highest TOC values are 3.95% in Shrewton 1 and 5.94% in Marchwood 1. These wells are both in the west of the study area, where the unit is immature.

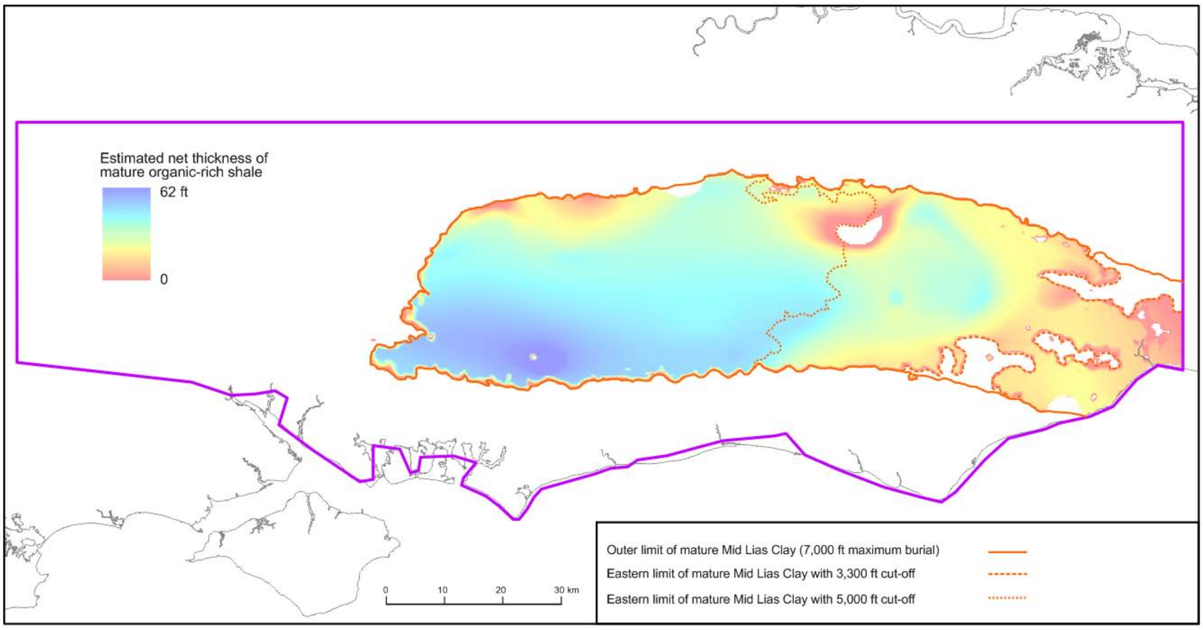

Figure 29. Potential thickness and distribution of organic-rich shales of the Mid Lias Clay that are within the oil window (using a maximum burial depth of 7,000 ft/2,130 m) and at a depth below ground level greater than 3,300 ft (1,000 m). The eastern limit of the area deeper than 5,000 ft (1,500 m) is indicated by the dotted line.

Two samples have an oil saturation index greater than 100 after applying an evaporative correction of 2.42 (the P10 case in Appendix A); both are in East Worldham 1.

In this study, the Mid Lias Clay is mature for oil generation in the 'core mature area', with a maximum net mature organic-rich shale thickness of 62 ft (19 m) (Figure 29). Nowhere has the Mid Lias Clay been buried sufficiently deeply to have entered the gas window as modelled in this study.

3.7.5 Upper Lias Clay

The Upper Lias contains a 50-220 ft (15-67 m) thick mudstone. Based on all available geochemical data, the average TOC for the Upper Lias samples is 1.6%, with 6 of the 28 analyses recording TOC >=2% (Figure 30). There are four recorded TOCs greater than 5% in Shrewton 1 and two in East Wordham 1 (maximum 6.0%). The average log-derived TOC based on Passey *et al.* (1990) is 1.4% (Appendix D).

Two samples have an oil saturation index greater than 100 after applying an evaporative correction of 2.42 (the P10 case in Appendix A); both are in East Worldham 1.

In the basin centre, where the unit lies within the oil window (Figure 31), the average TOC is 1.45% and the average S1 is 1.07 mgHC/gRock. In this 'core mature area', the net thickness of mature organic-rich shale reaches 112 ft (34 m) (Figure 31). Nowhere has the Upper Lias been buried sufficiently deeply to have entered the gas window as modelled in this study.

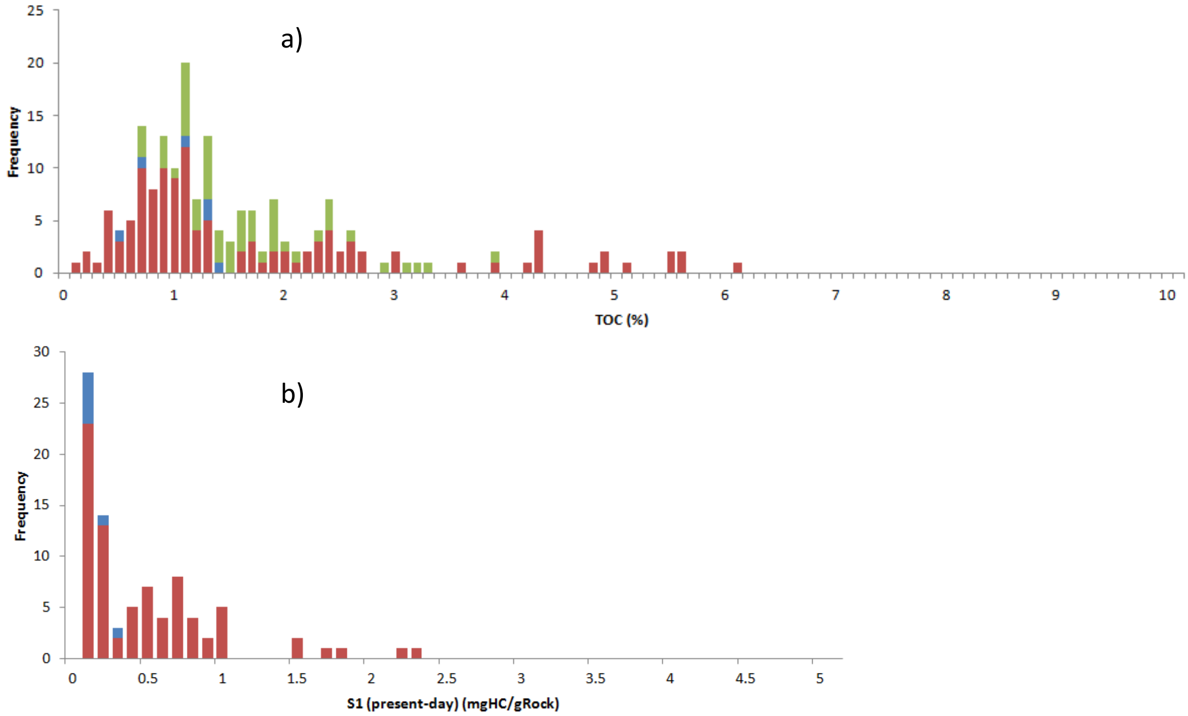

Figure 30. (a) Total organic carbon (TOC) and (b) present-day S1 values from the Upper Lias in the Weald Basin, based on all available data. Red = legacy data; blue = new BGS data (see Appendix B); green = pyrolysis-derived TOCs, courtesy of Celtique Energie.

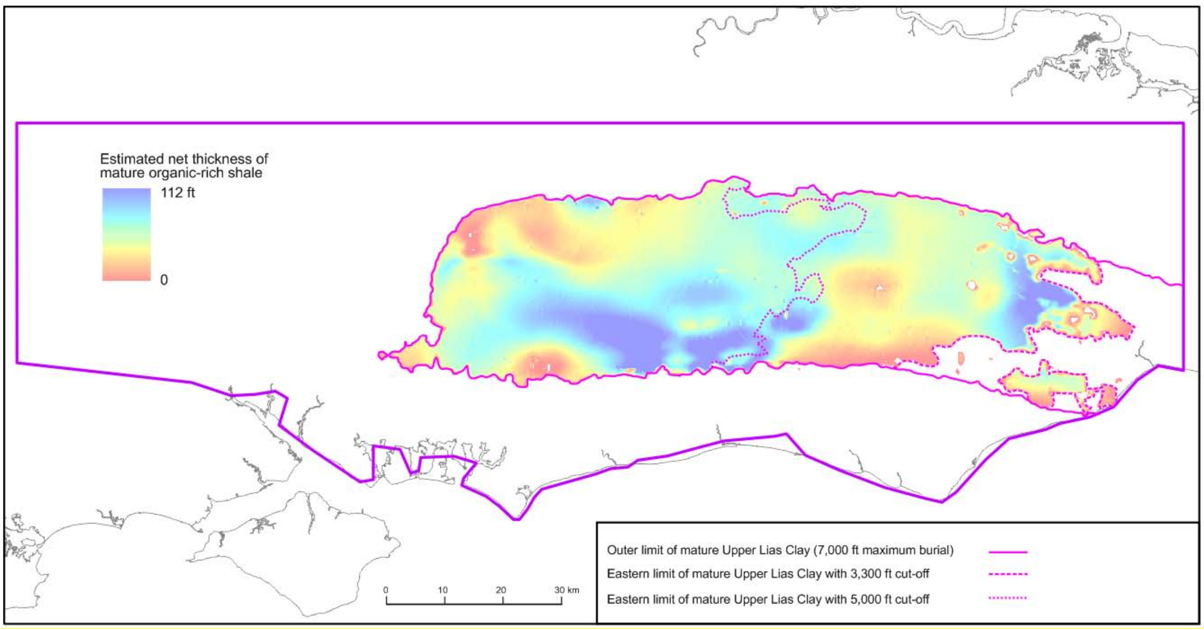

Figure 31. Potential thickness and distribution of organic-rich shales of the Upper Lias Clay that are within the oil window (using a maximum burial depth of 7,000 ft/2,130 m) and at a depth below ground level of greater than 3,300 ft (1,000 m). The eastern limit of the area deeper than 5,000 ft (1,500 m) is indicated by the dotted line.

3.7.6 Oxford Clay

The Oxford Clay samples have a relatively low average TOC (1.4%), but an increased number of samples have TOC >= 2% (Figure 32). Of the 156 samples of Oxford Clay analysed, 34 recorded TOC >=2%.

The higher TOC samples all originate from the poorly-sampled, lower 50-100 ft (15-30 m) of the unit, which has a distinctive low-velocity (high interval transit time), but only slightly elevated gamma-log response (Figure 24). The remainder of the Oxford Clay is organically lean. The average log-derived TOC for the whole Oxford Clay is 2.8% (Appendix D). This method also confirms that the lower Oxford Clay is an organic-rich unit, with a maximum TOC of 7.8%. This lower unit deserves further investigation as a potential 'sweet-spot' for shale exploration.

Rock-Eval S1 data for the formation reach 2.6 mgHC/gRock in the organic-rich lower unit in East Worldham 1, but is generally less than half this figure (Figure 32b). Even in this very limited dataset, it is significant that applying an evaporative correction of 2.42 (the P10 case in Appendix A) to these three S1 values and dividing by their respective TOC (2.7-6%), gives an oil saturation index of 101, 109 & 126 (above the 100 required for producible oil *sensu* Jarvie 2012b).

Type II kerogen predominates in the lower Oxford Clay, with mainly Type III kerogen in the upper part (Penn *et al.* 1987, England 2010).

Several publications state that the Oxford Clay is within the oil window in at least part of the Weald Basin (Lamb 1983, Ebukanson & Kinghorn 1986a, Penn *et al.* 1987, McLimans & Videtich 1989, Butler & Pullan 1990).

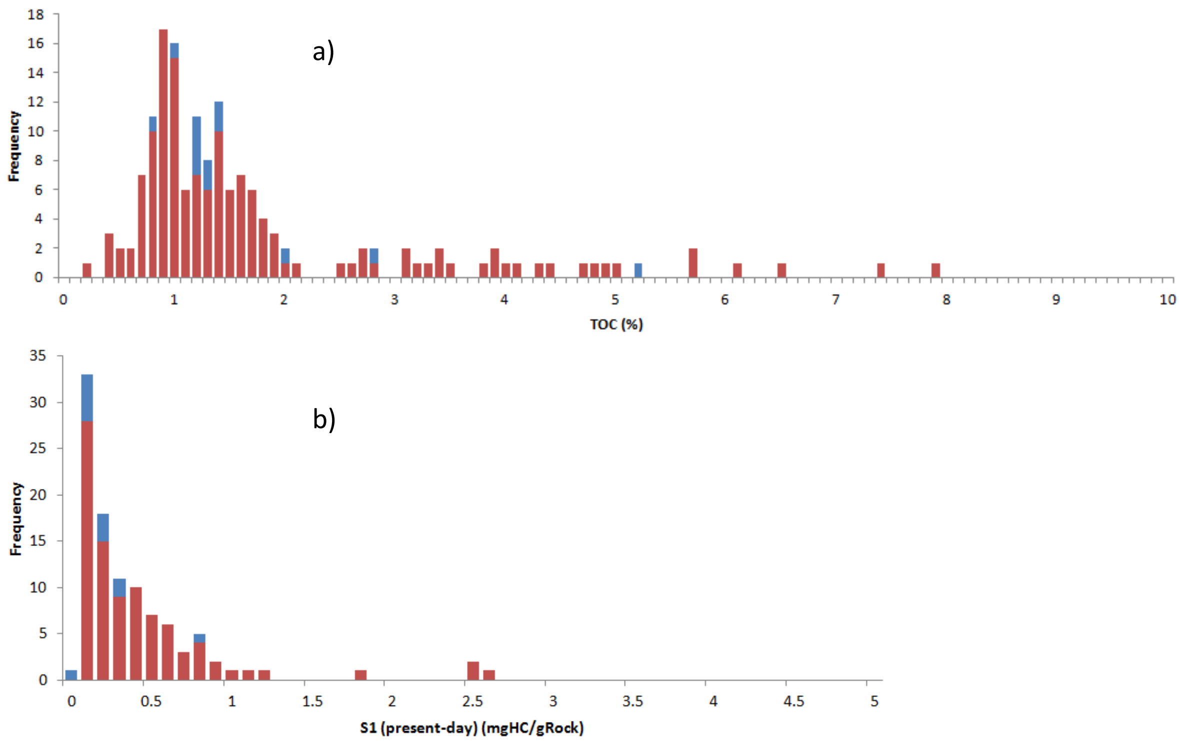

Figure 32. (a) Total organic carbon (TOC) and (b) present-day S1 values from the Oxford Clay in the Weald Basin, based on all available data. Red = legacy data; blue = new BGS data (see Appendix B).

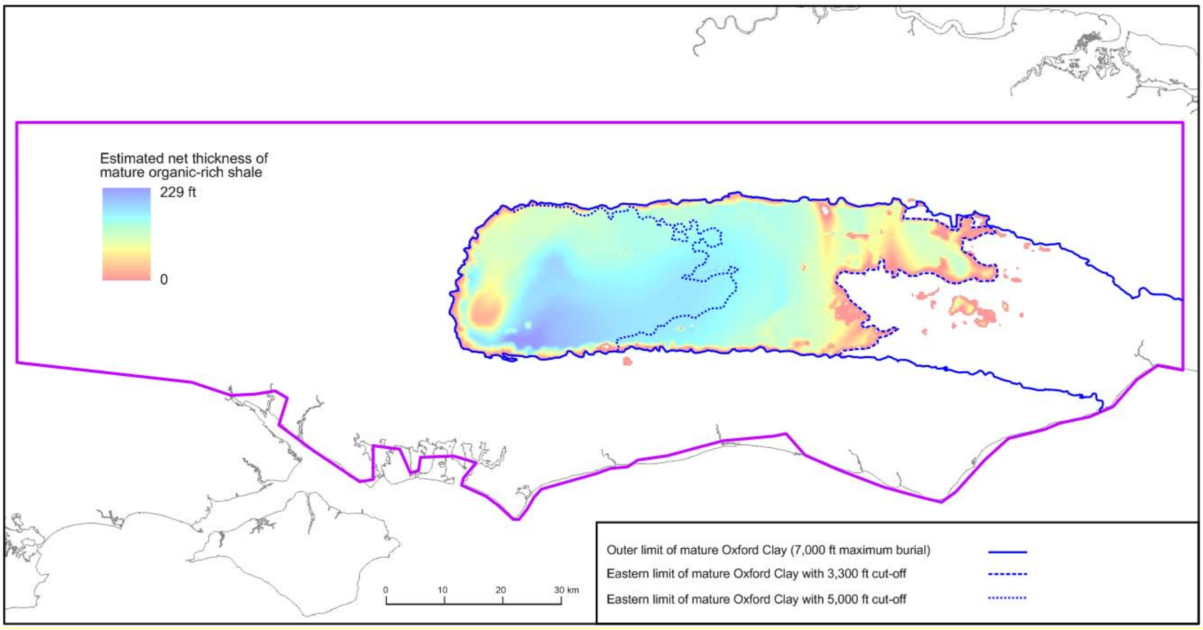

Figure 33. Potential thickness and distribution of organic-rich shales of the Oxford Clay that are within the oil window (using a maximum burial depth of 7,000 ft/2,130 m) and at a depth below ground level greater than 3,300 ft (1,000 m). The eastern limit of the area deeper than 5,000 ft (1,500 m) is indicated by the dotted line.

Using a maximum burial depth of 7,000 ft (2,130 m) prior to uplift, this report maps an area across which at least the base of the Oxford Clay is mature (R_o > 0.6%) (Figure 33).

3.7.7 Corallian Clay

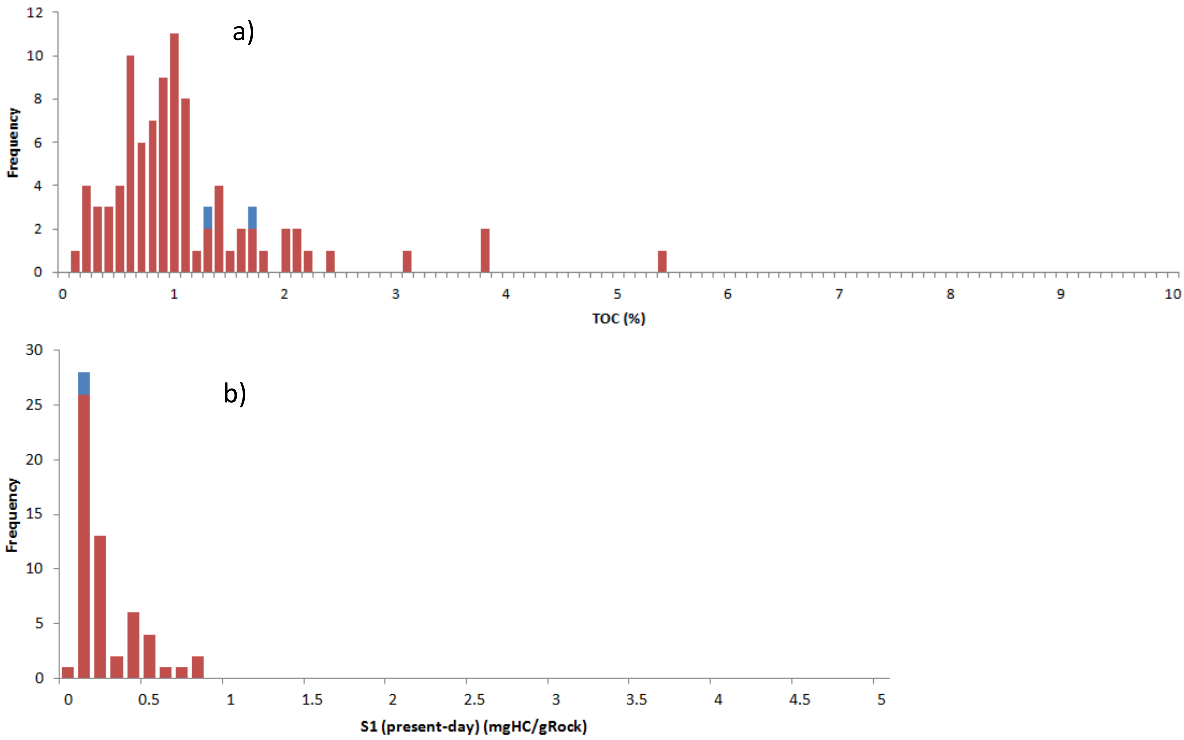

Figure 34. (a) Total organic carbon (TOC) and (b) present-day S1 values from the Corallian Clay in the Weald Basin, based on all available data. Red = legacy data; blue = new BGS data (see Appendix B).

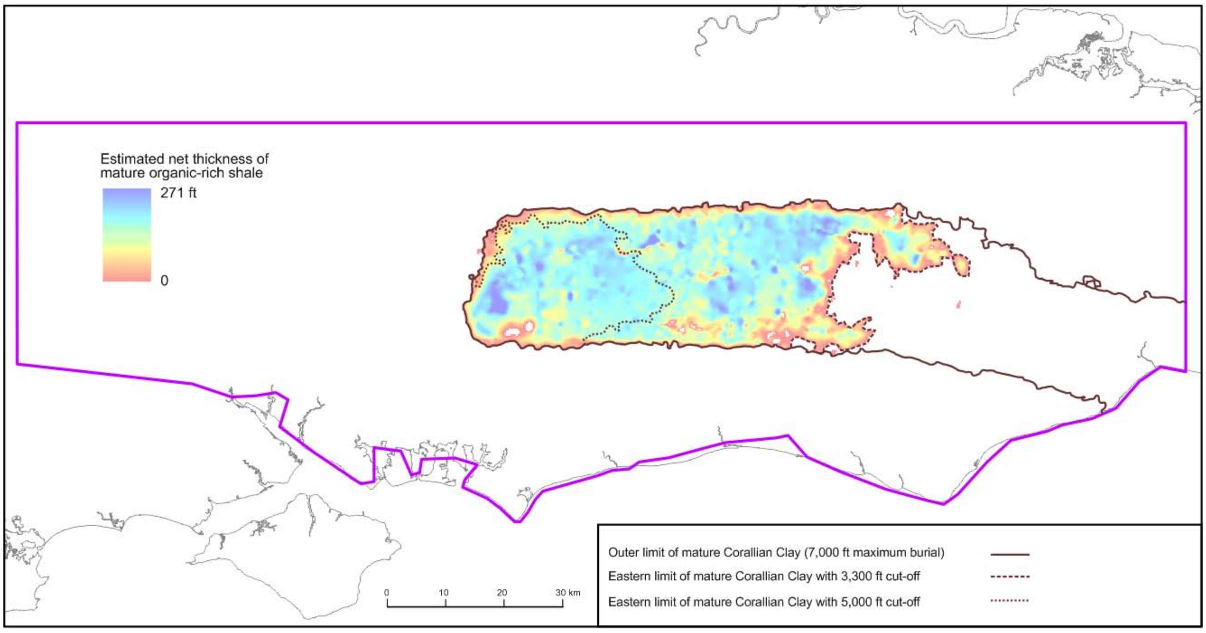

Figure 35. Potential thickness and distribution of organic-rich shales of the Corallian Clay that are within the oil window (using a maximum burial depth of 7,000 ft/2,130 m) and at a depth below ground level greater than 3,300 ft (1,000 m). The eastern limit of the area deeper than 5,000 ft (1,500 m) is indicated by the dotted line.

Although not one of the traditionally recognised source rocks in the Weald, high TOCs have also been recorded in the shales of the Corallian Group. The average TOC from all available Corallian analyses is 1.1%, with 8 of the 91 analyses recording TOC >=2% (Figure 34). The highest value is 5.4% in Egbury 1. The Passey TOC average is 3.8%, with a maximum of 5.4% (Appendix D). This higher average value may reflect the poor sampling rate of the 91 geochemical analyses.

Figure 35 shows the area where the Corallian Clay is within the oil window.

3.7.8 Kimmeridge Clay

The Kimmeridge Clay samples from the Weald Basin wells again show lower TOC values (average TOC = 2.8%) than equivalent strata in Dorset (average TOC = 3.8%), but there remains a large proportion of the samples with TOC> 2% (Figure 36). The log-derived average TOC for the Weald Basin is 3.8%, with a maximum of 21.3% (Appendix D). These TOC values derived from geophysical logs show that the middle Kimmeridge Clay, between and immediately below the mid-Kimmeridgian micrites, is more organic-rich than the lower and uppermost parts (Appendix D). This part of the succession deserves further investigation as a potential ‘sweet-spot’ for shale exploration and as part of a hybrid play in association with the adjacent micrites.

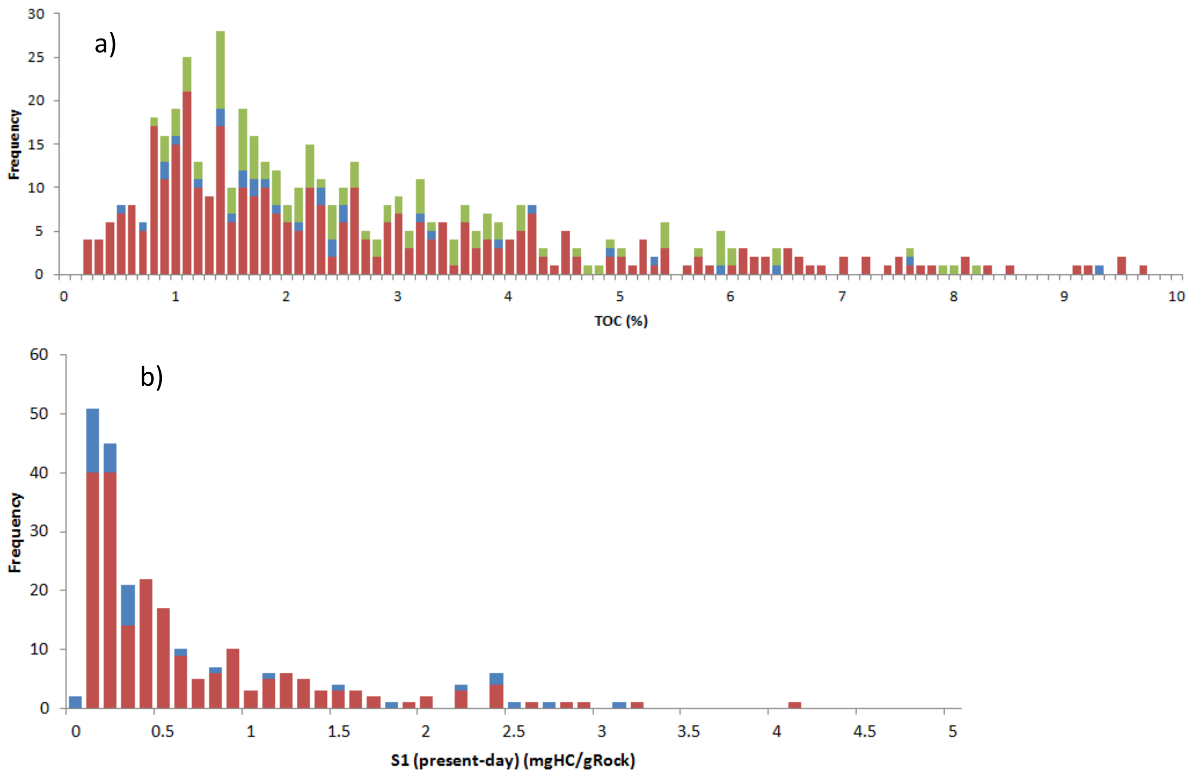

Figure 36. (a) Total organic carbon (TOC) and (b) present-day S1 values from the Kimmeridge Clay in the Weald Basin, based on all available data. Note: 19 samples have TOC>10% and two samples have S1 >5 mgHC/gRock. Red = legacy data; blue = new BGS data (see Appendix B); green = pyrolysis-derived TOCs, courtesy of Celtique Energie.

The highest TOCs recorded in the Kimmeridge Clay of the Weald area are 21.3% in Penshurst 1 and 20.9% in Ashour 1. In Dorset, samples from thin oil shale beds have yielded up to 60% TOC (e.g. Farrimond *et al.* 1984).

Rock-Eval S1 data for the formation reach 7.9 mgHC/gRock in Bolney 1, but is generally considerably less than this figure (Figure 36b). Applying an evaporative correction of 2.42 (the P10 case in Appendix A) to the S1 values and dividing by their respective TOC, gives a wide range of oil saturation index values from 5 to 358; five sample have a OSI above the 100 required for producible oil *sensu* Jarvie (2012b).

Type II kerogen predominates in the basin-centre Kimmeridge Clay, with varying amounts of terrestrially derived Type III also present, but especially closer to the basin margins (Scotchman 1991). Over shelf areas, mixed Type II-Type III kerogens are prevalent. Van Krevelen plots of OI vs. HI indicate that significant amounts of algal Type I kerogen are also present (Figure 37).

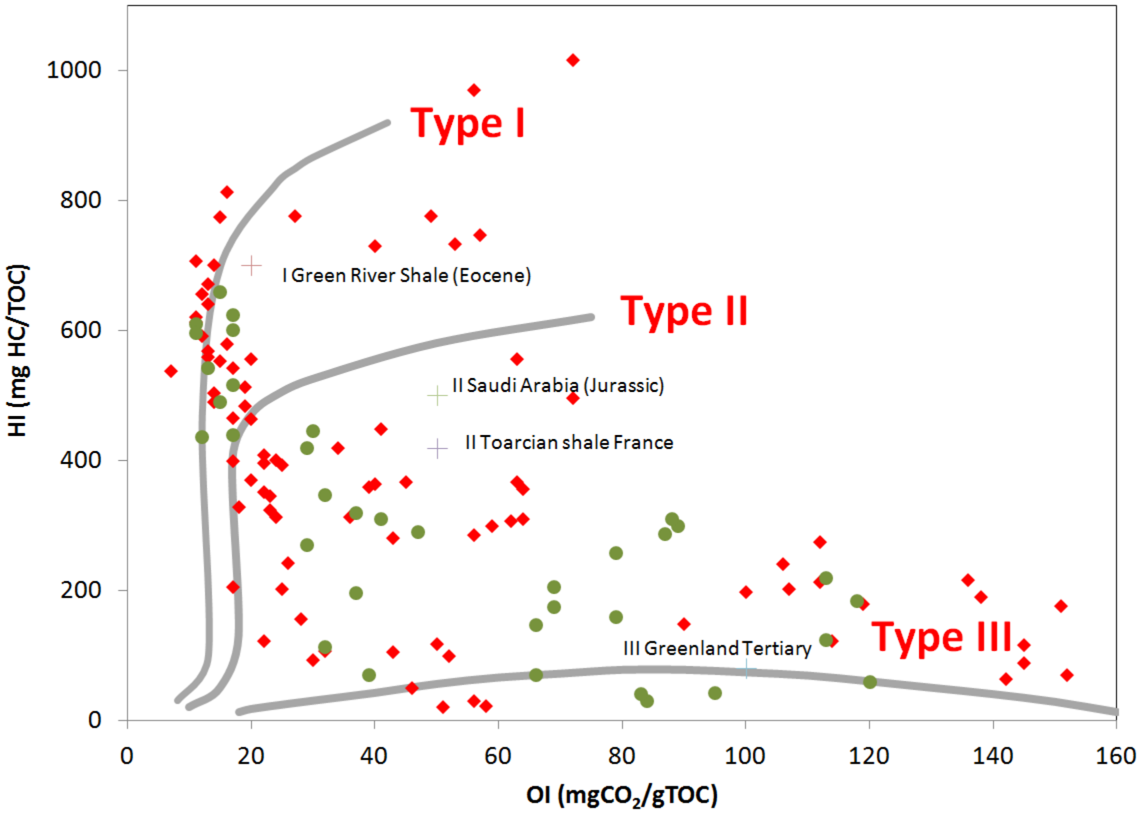

Figure 37. Van Krevelen plot using all available Rock-Eval data for the Kimmeridge Clay. New BGS data are shown in green; red dots indicate all other available data.

Most published maturity studies for the Kimmeridge Clay suggest that the unit is immature on the basin margins and only mature for oil generation in a small area in the basin centre (Gallois 1979, Lamb 1983, Ebukanson & Kinghorn 1986a, Penn *et al.* 1987, McLimans & Videtich 1989, Butler & Pullan 1990, Burwood *et al*. 1991). However, some workers report that it is immature across all of both the Weald and Wessex basins (Hawkes *et al.* 1998), whilst others suggest significant maturity levels (R_o=1.0) are reached in the centre of the Weald Basin (Williams 1986). This wide range of opinions can be explained by the poor correlation of vitrinite reflectance to maturity.

The presence of oil within the mid-Kimmeridge I-micrite in Balcombe 1 is significant in that it may provide evidence for both maturity and the capacity of the Kimmeridge Clay to generate oil, at least locally. Burwood *et al*. (1991) stated that the oil reservoired in the micrite “could be ascribed an *in-situ* origin from the isotopically lightest (and immediately juxtaposed) Kimmeridge Clay shales”. Applying the maturity model proposed in this report, the Kimmeridge Clay close to the micrites in this well is likely to have a maturity of R_o = 0.57-0.67%.

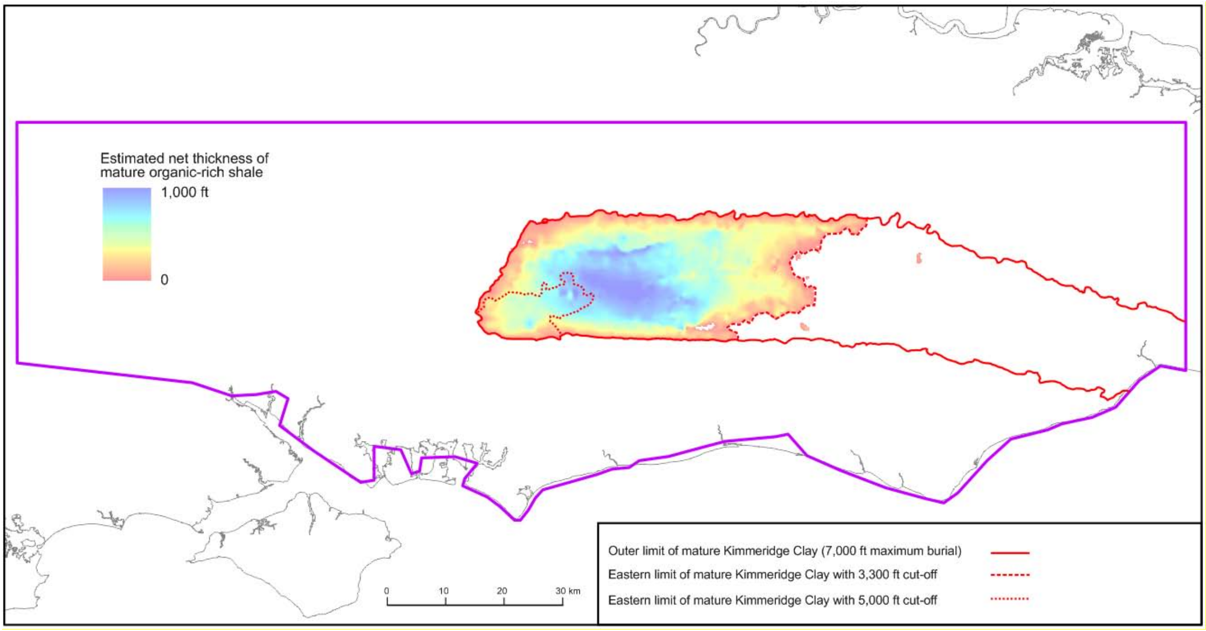

Figure 38. Potential thickness and distribution of organic-rich shales of the Kimmeridge Clay that are within the oil window (using a maximum burial depth of 7,000 ft/2,130 m) and at a depth below ground level greater than 3,300 ft (1,000 m). The eastern limit of the area deeper than 5,000 ft (1,500 m) is indicated by the dotted line.

This report suggests that at least the base of the Kimmeridge Clay is mature across the central part of the Weald Basin (Figure 38). The upper part, which is more organic-rich, has a smaller prospective area due to a combination of shallower maximum burial depth and shallower current-day depth after uplift; the latter factor is particularly important in the eastern part of the area.

3.7.9 Input criteria for resource calculations - potential oil yields from S1 data

The methodology used in this report to calculate the in-place shale oil resource of the five Jurassic shale units (see Appendix A) requires an estimation of the *in situ* free oil content of each shale unit.

One of the outputs from the standard Rock-Eval pyrolysis analyzer is S1. This is a measurement of the amount of free hydrocarbons already generated in the source rock and present in the sample as both 'free oil' in microscopic pore spaces and 'sorbed oil' in the kerogen. It is the free oil component that can potentially be extracted after fracture stimulation.

Rock-Eval analyses from wells within the 'core mature area' provide present-day S1 values for organic-rich shales (TOC > 2%) in the area under review (Table 9). These averages are used as the P50 values in the Monte-Carlo simulation (Appendix A).

Source rock unit	**Average present-day S1 in all samples in study area (mgHC/gRock)**	**Average present-day S1 in organic-rich shales in the 'core mature area' (mgHC/gRock)**	**Estimated average original S1 * (mgHC/gRock)**	**Average oil yield using Jarvie *et al.* (2007) (bbl/acre-ft)**	**Average oil yield using Michael *et al.* (2013) (bbl/acre-ft)**	**Average oil yield using Michael *et al.* (2013) (bbl/m3)**
Kimmeridge Clay	1.40	1.21	2.42	53.0	62.6	0.051
Corallian Clay	0.90	0.60	1.20	26.3	31.0	0.025
Oxford Clay	1.10	1.16	2.32	50.8	60.0	0.049
Upper Lias Clay	1.00	1.07	2.14	46.8	55.4	0.045
Mid Lias Clay	0.90	0.88	1.76	38.5	45.5	0.037
Lower Lias[1]	1.00	0.28	0.56	12.3	14.5	0.012

*Table 9. Estimates of average oil yields for the main source rock units within the Weald Basin using S1 Rock-Eval data. * assuming evaporative loss of 50%. [1]The Lower Lias is included for comparison only; it is not considered to have resource potential.*

The oil saturation index (OSI) is a measure of the free oil from Rock-Eval-measured S1 in relation to TOC:

The oil saturation index (OSI) = (S1 x 100)/TOC, giving results in mgHC/gTOC

When the oil saturation index exceeds the sorption potential of oil in kerogen, potentially producible oil is likely to be present in the pore space. Experimentation suggests that the sorption potential for oil in kerogen is c. 100 mg oil/g kerogen, so OSI values above 100 are taken to indicate the presence of potentially producible oil (Jarvie & Baker 1984, Sandvik *et al*. 1992, Jarvie 2012b).

However, in the study area the strong relationship between TOC and S1 (Figure 39) and the low ratio of 'free oil' relative to TOC (the 'oil saturation index', see above) could also point to the fact that most of the 'free oil' is bound within the kerogen and is not likely to be producible (see further discussion in Appendix A). This scenario represents the minimum case for the Monte Carlo, i.e. the free oil component of S1 is zero.

For the Jurassic of the Weald Basin, the average oil saturation index is 28 mgHC/gTOC, with a maximum at one point of 148 mgHC/gTOC, from a single Kimmeridge Clay sample (Figure 39a).

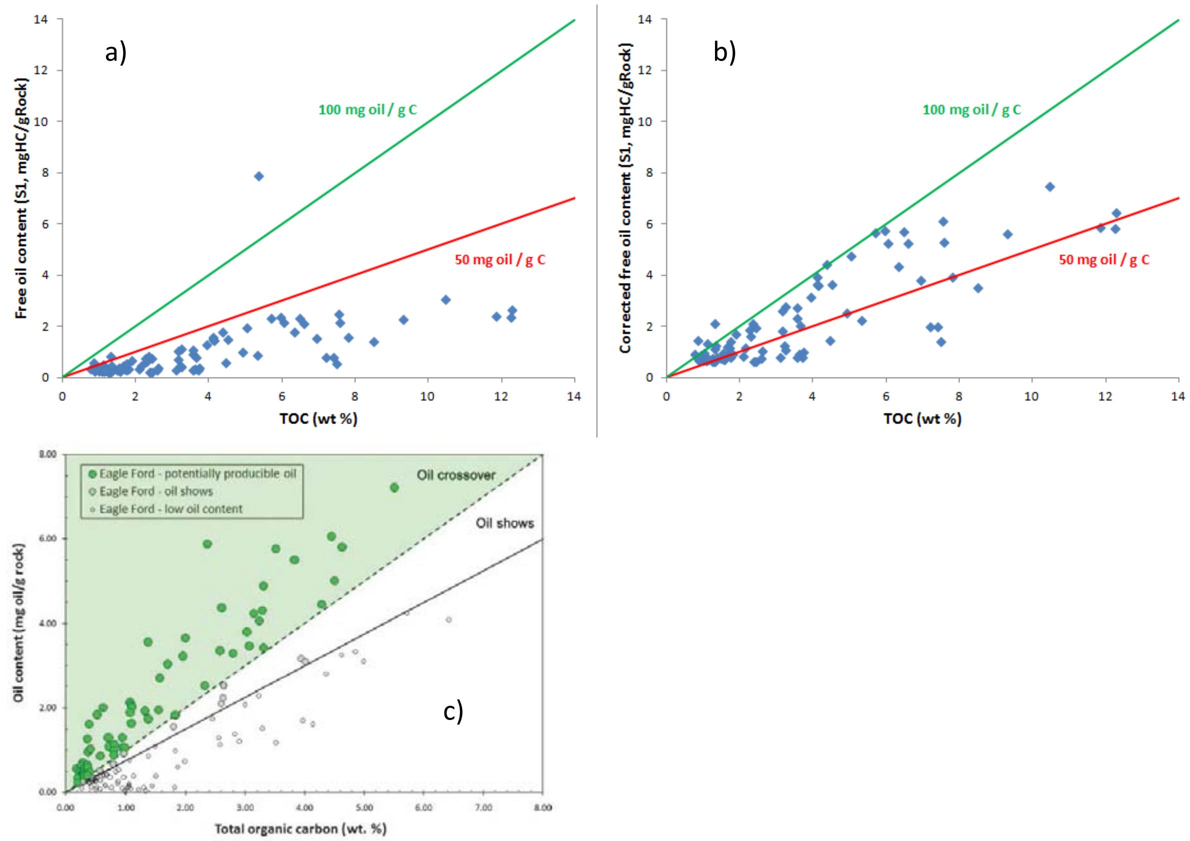

Figure 39. (a) Plot of TOC vs. S1 for all Jurassic shales in the Weald Basin. Data with T_{max} < 425 (i.e. immature) and S1 < 0.25 mgHC/gRock (i.e. lean) are excluded. The one extraneous data point is from a sample of Kimmeridge Clay. (b) Plot of TOC vs. corrected S1, as above, but with an evaporative correction of 2.42 applied. (c) Comparative plot with data from the Eagle Ford Shale (Upper Cretaceous) in Texas (Jarvie et al. 2012b).

The correction of S1 for 'evaporative loss' is an important factor in converting the present-day S1 figures into data that are likely to pertain to the shales under reservoir conditions at depth. The loss of light oil from samples between down-hole collection and its analysis (often decades later) is often estimated to be 35% (a correction factor of 1.33), but it is highly dependent on organic richness, lithofacies, oil type, sample type and method of preservation (see Jarvie 2012b). Jarvie *et al*. (2012) warned that correction factors of over 5.0 may be necessary and Michael *et al*. (2013) showed that oil gravity has a major control on evaporative loss (see Appendix A).

Even if the S1 values are corrected with an evaporative factor of 2.42 (the P10 case used in Appendix A), the average oil saturation index is well below the 'producible oil' value. This remains the case even in extremely organic-rich shales (TOC >10%). A small number of samples within each unit may have producible oil (Figure 39b; see also Section 3.7) and reflect potential sweet-spots within the shales that warrant further investigation.

Even corrected potential oil yields are generally poor when compared to the shale oil plays of the USA (Figures 39b & c, Table 10). It should be noted that yields comparable to those proposed for the Weald Basin, even for the averaged Kimmeridge Clay, might be considered non-commercial in the USA.

Unit/area	**Oil yield (bbl/acre-ft)**	**Source/description**	**Reference**
Miocene Monterey Shale, California	80 (maximum)	Free oil yield (S1)	Jarvie (2012b)
Miocene Antelope Shale, California	c.90	Free oil yield (S1)	Jarvie (2012b)
Bakken Formation, Williston Basin	58 (average) for Middle Bakken; 11 (average) for Scallion	Absolute oil content	Jarvie (2012b)
Barnett Shale, Fort Worth Basin	120 (average)	Retained oil	Jarvie (2012b)
Eagle Ford, Texas	400 to 1,200 (maximum)	Oil yield	Grabowski (1995) quoted in Jarvie (2012b)
A "liquid-rich shale play"	c.100 (average based on $S1_{pd}$) or 224 (average based on $S1_{corr}$)	In-place oil	Michael *et al.* (2013)
Bakken (commercial well)	c.250 (average), c.550 (maximum)	Producible oil index (POI)	Jarvie *et al.* (2012)
Bakken (non-commercial well)	c.50 (average), c.150 (maximum)	Producible oil index (POI)	Jarvie *et al.* (2012)
Scallion (non-commercial)	c.50 (average)	Producible oil index (POI)	Jarvie *et al.* (2012)
Jurassic Weald Basin	14.5 (Lower Lias Limestone-Shales) to 62.6 (Kimmeridge Clay)	Using corrected S1	This report (Table 9)

Table 10. Example oil yields from commercial and non-commercial shale oil plays in the USA. The Producible Oil Index (POI) is the difference between the total oil and adsorption index.

3.7.10 Source for conventional hydrocarbons

3.7.10.1 Oil

Lamb (1983) concluded that with only sparse data available "the oil has probably been generated from the Lias and/or the Lower Oxford Clay of the Weald. Reliable evidence does not yet exist that higher horizons have done so."

Ebukanson & Kinghorn (1986b) established a link between mature Lower Lias source rocks and the Dorset oils at Kimmeridge Bay and the Wytch Farm oil field. Butler & Pullan (1990) suggested the closest isotopic match was for a Lower Lias source for the Weald Basin oils also, but with some degree of mixing likely.

Burwood *et al*. (1991) confirmed that the oil in the Wessex Basin fields (e.g. Wytch Farm oil field) originated from the Lower Lias, and added that the Great Oolite reservoirs of the western Weald were sourced from a mixed Lower and Upper Lias source, with those in the east relying on Upper Lias sourcing. Balcombe 1 was the only Kimmeridge-sourced oil analysed.

Given the poor source rock quality of the Lower Lias away from Dorset, this study suggests that the Mid and Upper Lias Clays are more likely to be the source for much of the hydrocarbons found in the various reservoirs in the Weald Basin, although a contribution from the younger Oxford, Corallian and Kimmeridge Clays, and possibly older, pre-Jurassic strata cannot be discounted. See also Appendix B.

3.7.10.2 Gas

This study concludes that there is no significant Jurassic shale gas potential in the Weald Basin. Even the deepest Lias shales are unlikely to have attained sufficient maturity to allow for significant gas generation. However, gas is encountered in many wells in the basin and there are several significant gas fields (Table 4), some not associated with oil (e.g. the Albury and Bletchingley gas fields). Biogenic gas may occur at shallow depths, but is unlikely to source the deeper fields.

Three hypotheses for the origin of the gas in the Weald Basin have been proposed previously.

Firstly, it is possible that this gas was generated coevally with oil in the oil window (Figure 40) and was subsequently exsolved from pore water (and possibly oil) at relatively shallow depths as a result of uplift (Conoco 1986, Butler & Pullan 1990, Hawkes *et al*. 1998). The high percentage of methane in some gas samples could be explained by the exsolution of gas from water.

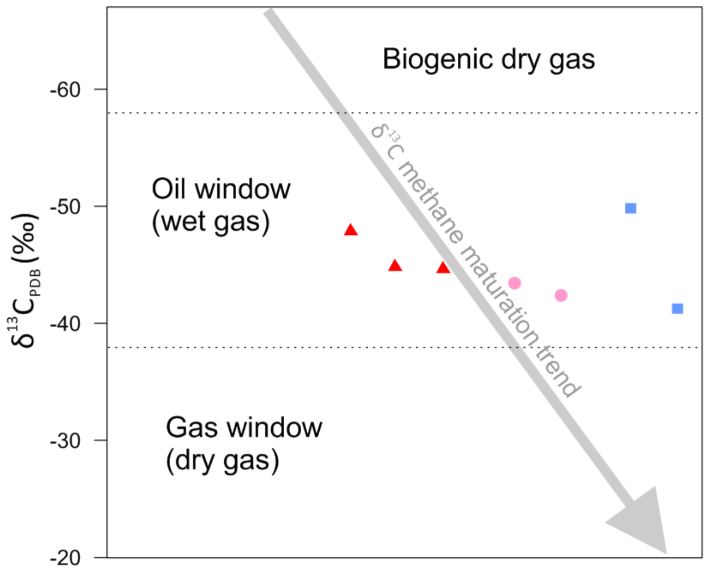

Figure 40. Maturation trend of δ^{13}C methane through the oil and gas windows (Stahl 1977) and δ^{13}C methane of the Weald Basin gas samples (from Conoco 1986).

Alternatively, the gas may have originated in deeper reservoirs and have preferentially migrated to higher levels than the oil as a result of its greater mobility (Butler & Pullan 1990).

Thirdly, the possibility of an older, pre-Jurassic (most likely Carboniferous) gas source cannot be excluded (see Taylor 1986, Kettel 1989, Smith 1993). High concentrations of nitrogen (a feature of some of the Weald gas samples, see Section 3.2.5) are often associated with the thermal breakdown of organic matter during high grade maturation.

The mixing of gases produced during different phases of hydrocarbon generation is also possible.

3.8 Thermal maturity and uplift

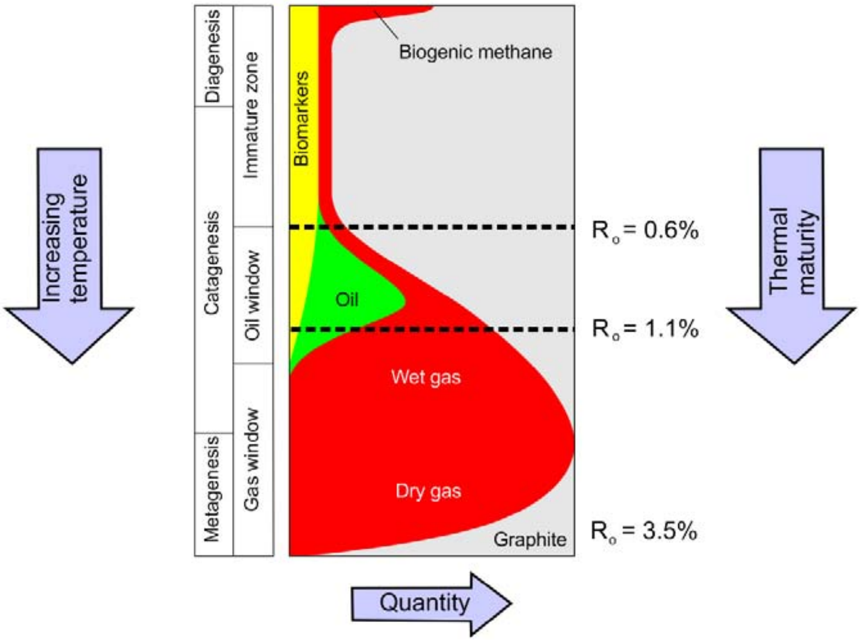

Figure 41. Relationship between temperature, vitrinite reflectance of organic material and phases of hydrocarbon generation (modified from Tissot et al. 1974 and McCarthy et al. 2011).

Estimating the present-day depth at which organic-rich shales become sufficiently mature for oil (R_o = 0.6%) and gas (R_o = 1.1%) to be generated relies on many factors. Firstly, the R_o measurements in the Weald area show a wide variation (see Section 3.7.1 and the scatter of points on Figure 42b). Secondly, rocks reached their peak maturity during the Late Cretaceous (e.g. Hawkes *et al*. 1998) or immediately prior to the Miocene (e.g. Ebukansen & Kinghorn 1986a) and have subsequently been uplifted by significant amounts (see Section 3.5.4). Thirdly, any threshold (i.e. R_o = 0.6 as used in this study, Figure 41) is based on a basin's thermal history and the composition of any kerogen; oil can in some cases be generated at lower maturity, R_o of 0.4-0.5%, and is usually recognised to reach peak generation at R_o = c.0.9% (Figure 41).

From all the available well data, using R_o calculated from T_{max} (Figure 42c) in preference to measured R_o (Figure 42b), an estimation of the depth for the onset of oil generation (R_o = 0.6%) used in this report occurs at a maximum burial depth of 7,000 to 8,000 ft (2,130-2,440 m) (Figure 42c). A wider depth range, resulting from the variability in the maturity data, is also possible (i.e. R_o values of 0.55-0.65 have been recorded at depths between 2,600 ft (790 m) and 11,700 ft (3,570 m) maximum burial depth).

The available data do not allow for an accurate estimation of the onset of the gas window (R_o = 1.1%). From the data presented in Figure 42c, there is little evidence to suggest that it occurs at maximum burial depths above 12,000 ft (3,660 m) and even the deepest Lias source rock is unlikely to have ever reached this burial depth (see Figure 46).

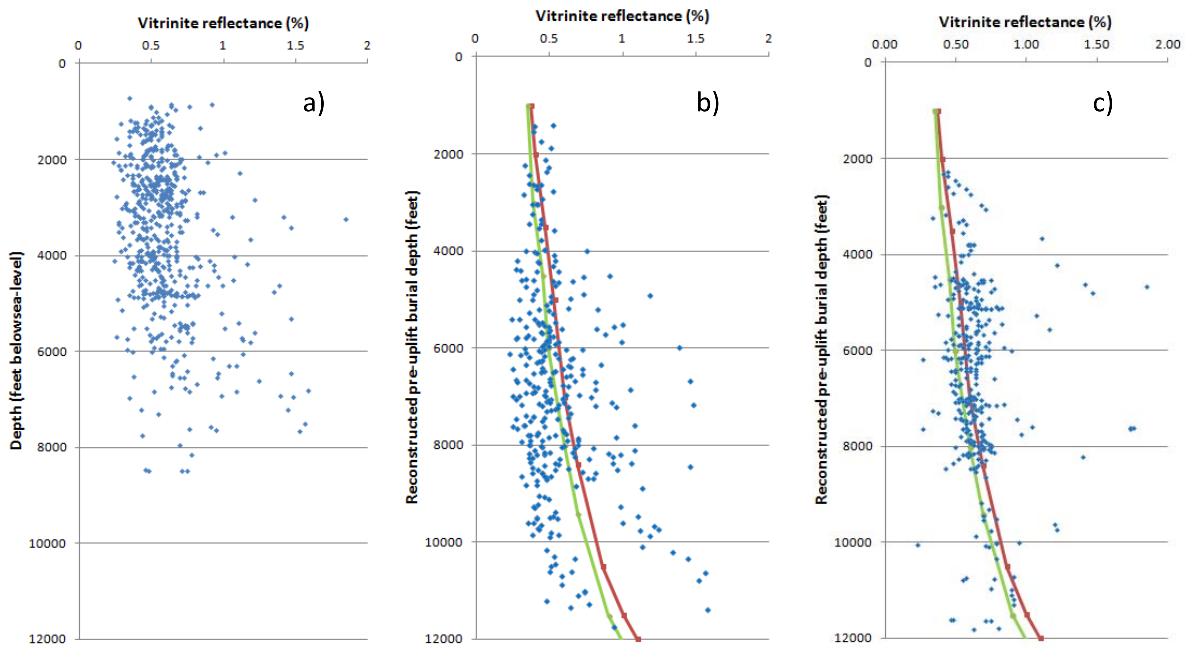

Figure 42. Plots of (a) all vitrinite reflectance data against present-day depth, (b) microscope-derived vitrinite reflectance values against reconstructed maximum pre-uplift burial depth, and (c) T_{max}-derived vitrinite reflectance data against reconstructed maximum pre-uplift burial depth. Two potential trend lines are displayed; green line has R_o =0.6% at 8,000 ft (2,440 m) and R_o = 1.1% at 13,000 ft (3,960 m); red line has R_o = 0.6% at 7,000 ft (2,130 m) and R_o = 1.1% at 12,000 ft (3,660 m). Other trends lines are possible. See text for a discussion on the wide scatter of data points in (b).

3.9 Mineralogy

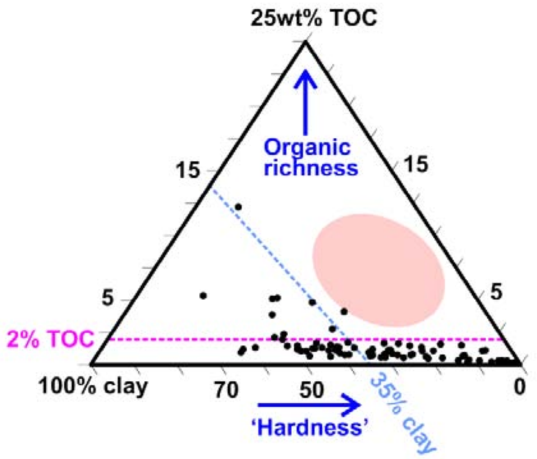

Figure 43. Ternary plot of TOC and total clay content for Jurassic samples in the Weald area. The area with TOC=2-10% and clay 5-35% (shown as a pink oval) represents the optimal lithology for a potential shale play in North America.

Mineralogical analyses carried out on 49 fine-grained sedimentary rock samples from boreholes in the study area are detailed in Appendix C. Whole-rock and clay mineral X-ray diffraction (XRD) techniques were used, and the results integrated with the geochemical analyses of the same samples (Appendix B).

Only a limited number of samples have been analysed for both TOC and mineralogy, and only a few of these are relevant, organic-rich shales. However, it should be noted that the 10 Weald samples with TOC>2% all have clay contents of 33-63%. Based on this restricted dataset, prospectivity would appear to be limited (Figure 43), but until further organic-rich shales, which form a high percentage of some units, are targeted for detailed analysis, no conclusion can be offered.

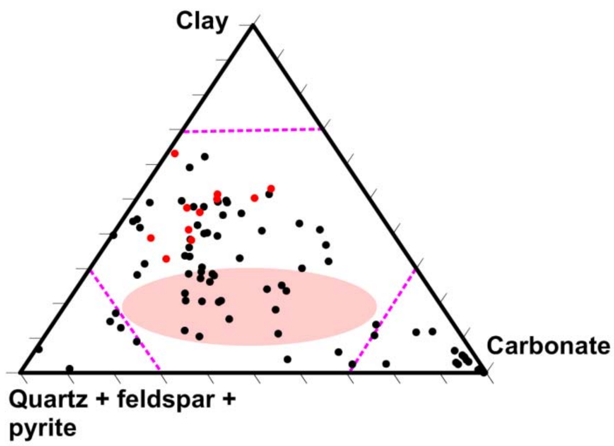

Figure 44. Ternary plot showing the mineralogy of all available Jurassic samples from the Weald area. Red dot = TOC >=2%. Note that some samples are essentially sandstones and limestones, and many samples have a clay content >35%. The pink oval shows the shale lithologies most suited to fracture stimulation.

Mineralogically, the samples analysed by XRD cover a range of lithologies, including some that are carbonate-rich and quartz-rich (Appendix C, Figure 44). Irrespective of TOC, this has a bearing on their suitability for fracture stimulation. Further samples of organic-rich shales are required.

The mineralogy of clays transforms as soft mud is converted to lithified shale, and the level of smectite-to-illite recystalisation can be used as a broad indication of thermal maturity (Appendix C). The clay mineralogy of the Weald samples suggests that the majority have reached a maximum burial depth sufficient to reach the 'light oil' maturity zone. Several shallow samples are immature for oil generation, whilst the deep samples from Balcombe 1 and Shalford 1 indicate burial into the 'wet gas' zone. The Shalford 1 samples are of Silurian age, whilst those in Balcombe 1 are from the Lias.

3.10 Calculating oil-mature shale volumes

The work flow used to estimate the in-place oil resource in this study is shown in Figure 45. 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 range of uncertainty of the shale volume, and a greater uncertainty in the range of oil yields used to calculate the total in-place oil volume.

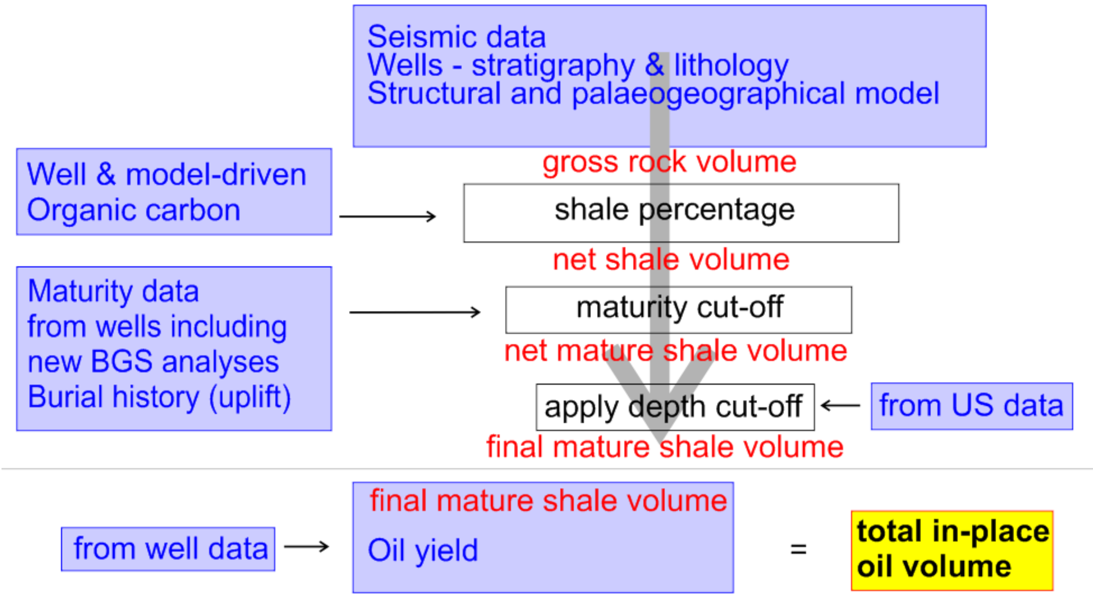

Figure 45. Workflow used in this study to estimate the in-place shale oil resource.

The calculation of the net oil-mature shale volume in the study area used basic screening criteria adapted from Andrews (2013):

- Identification of potentially prospective shale oil units from well information
- Mapping the top and base of units to enter into a 3D model
- Mapping the organic-rich shale component as a proportion of the seismically mapped unit
- Minimum cut-off where $R_o < 0.6\%$ (7,000 – 8,000 ft (2,130-2,440 m) maximum burial depth)
- Minimum depth cut-offs of 3,300 ft and 5,000 ft (1,000 m and 1,500 m) below land surface (see below for the rationale behind these cut-offs)

The volume of shale in each shale unit was calculated using the following formula:

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

[1] below the depth where $R_o = 0.6\%$ or 3,300/5,000 ft, whichever is the deeper.

The thermal maturity surface was integrated with the depth structure mapping and net organic-rich shale proportions (Table 7) to calculate the net volume of each shale unit within the oil window. Areas where the shales are less than 3,300 ft (1,000 m) below the land surface were removed from the potentially prospective volume following the protocol used by USEIA (2013). USEIA (2013) proposed that “areas shallower than 1,000 m [3,300 ft] have lower reservoir pressure and thus lower driving forces for oil and gas recovery. In addition, shallow shale formations have risks of higher water content in their natural fracture systems”. An alternative cut-off of 5,000 ft (>1,500 m) was proposed by Charpentier & Cook (2011). This is a basin-wide assessment; any depth constraint for a specific area would require integration of local data including pressures, hydrogeology and geomechanics.

The location of the five shale units relative to the top of the proposed oil and gas windows and to the 3,300 ft depth cut-off is shown in a series of cross-sections across the study area in Figure 46.

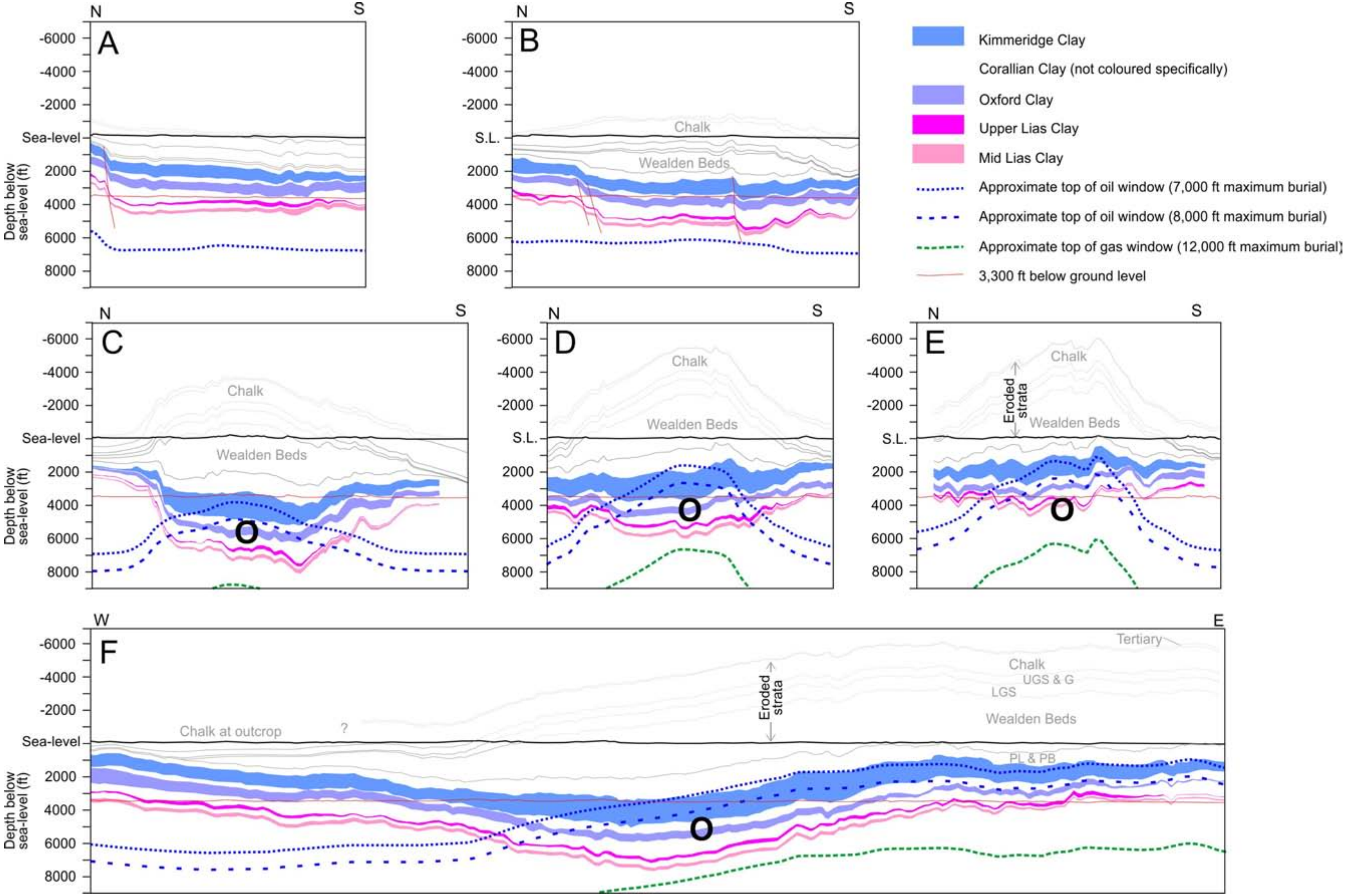

Figure 46. Schematic geological cross-sections indicating where the main Jurassic shales of the Weald Basin might be considered a shale oil target (labelled 'O'). Alternative depths for the top of the oil window are indicated (blue dotted and dashed). Thicknesses of eroded strata (grey dashed) are based on regional isopachs. Faults have been excluded for clarity. For the location of the sections, see Figure 47.

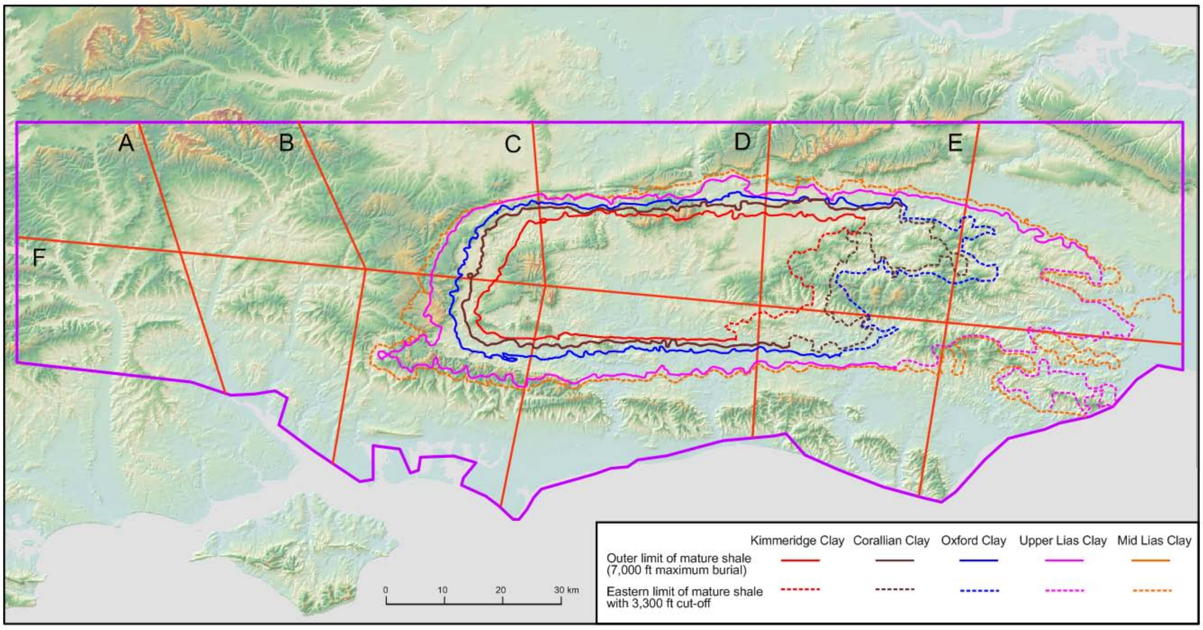

Figure 47. Map showing the location of schematic cross-sections A-F (Figure 46).

4 Resource estimation

DECC has not previously addressed in-place shale gas and/or oil resources in southern Britain and no shale oil or shale gas drilling has yet been carried out in this area[5]. Following detailed work undertaken by BGS in 2013-14, the first oil-in-place resource estimation can be made for the various shale units beneath the Weald area. The details of this study's calculation and its results are presented in Appendix A.

Estimates of in-place gas resources in the Weald area are few. DECC (2010a) suggested that there might be 200 bcf of recoverable shale gas in the Weald Basin if it were analogous to the Antrim Shale in Michigan. However, this latter play contains biogenic gas, and is unlikely to be analogous to the Weald Basin. In 2010, based on their 3D geological model, Celtique Energie estimated that the recoverable shale gas potential of their acreage for the Lias could be as high as 14 tcf, and that recoverable shale oil on their acreage was estimated at 125 million bbl. USEIA (2013) published a figure of 8 tcf for risked gas in place and risked recoverable resources of 0.6 tcf for the Weald Basin. Their oil estimates for the Weald are risked OIIP of 17.1 billion bbl and risked recoverable resources of 0.68 billion bbls.

This current study concludes that significant volumes of shale gas are unlikely to occur in the Jurassic of the Weald area, due to insufficient depth of burial and hence maturity. This does not preclude the potential presence of gas generated at an early stage of maturity in association with oil, or the presence of biogenic gas occurring at shallower depths or the presence of gas within deeply-buried

[5] The oil discovered in Balcombe 1 and appraised by Cuadrilla with Balcombe 2 in 2013 is likely to constitute a conventional oil accumulation (probably in a structural closure or combination trap), albeit in a low-porosity limestone. In the #2 well, it was reported that the micrite was naturally fractured and would not require fracking (www.cuadrillaresources.com).

pre-Jurassic shales that cannot be imaged or modelled using current geological and geophysical data.

The following table summarises the potential for each Jurassic shale unit:

Unit	**Shale oil potential**	**Shale gas potential** *
Kimmeridge Clay	Good potential where mature (R_o > 0.6%) and where free oil exists (perhaps limited to sweet-spots).	No potential (immature)
Corallian Clay	Some potential where mature (R_o > 0.6%) and where free oil exists (perhaps limited to sweet-spots).	No potential (immature)
Oxford Clay	Some potential where mature (R_o > 0.6%), especially in lower part and where free oil exists (perhaps limited to sweet-spots).	No potential (immature)
Upper Lias Clay	Limited potential where TOC > 2% and mature (R_o > 0.6%). But lack of evidence for free oil in available samples and TOC rarely exceeds 2%.	No potential (immature)
Mid Lias Clay	Limited potential where TOC > 2% and mature (R_o > 0.6%). But lack of evidence for free oil in available samples and TOC rarely exceeds 2%.	No potential (immature)
Lower Lias Limestone-Shale	Limited potential (lean, but little data from depocentre)	No potential (presumed lean & immature); due to its burial this unit has the highest maturity of the Jurassic units.

Table 11. Potential for shale oil and shale gas resources in the Jurassic shales of the Weald Basin based on the 3D geological model produced in this study. (thermogenic gas potential only; potential volumes of biogenic and associated gas have not been assessed)*

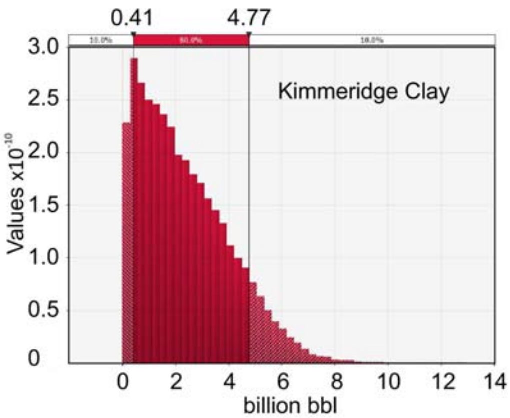

Figure 48. Probabilistic distribution and cumulative probability curve representing the result of a Monte Carlo analysis for the in-place resource estimation of shale oil in the Kimmeridge Clay. Distributions for other units are included in Appendix A.

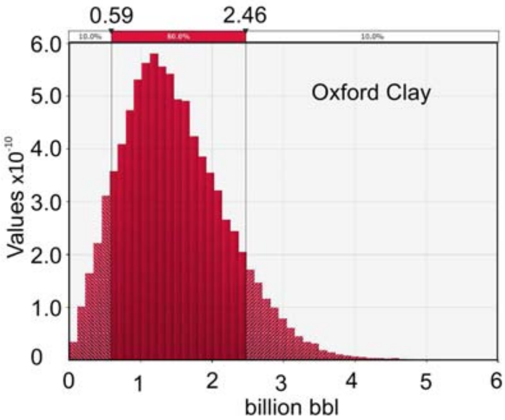

Figure 49. Probabilistic distribution and cumulative probability curve representing the result of a Monte Carlo analysis for the in-place resource estimation of shale oil in the Oxford Clay. Distributions for other units are included in Appendix A.

	Total oil in-place estimates (billion bbl)		**Total oil in-place estimates (million tonnes)**	
	With top of oil window at 7,000 ft (2,130 m) maximum burial depth	With top of oil window at 8,000 ft (2,440 m) maximum burial depth	With top of oil window at 7,000 ft (2,130 m) maximum burial depth	With top of oil window at 8,000 ft (2,440 m) maximum burial depth
Kimmeridge Clay	0.41 – 2.03 – 4.77	0.11 – 0.61 – 1.44	55 – 270 – 636	15 – 81 – 192
Corallian Clay	0.20 – 0.52 – 1.04	0.11 – 0.30 – 0.61	27 – 69 – 139	15 – 40 – 81
Oxford Clay	0.59 – 1.39 – 2.46	0.41 – 0.96 – 1.70	79 – 185 – 328	55 – 128 – 227
Upper Lias Clay	0.28 – 0.63 – 1.05	0.22 – 0.52 – 0.85	37 – 84 – 140	29 – 69 – 113
Mid Lias Clay	0.33 – 0.79 – 1.43	0.27 – 0.64 – 1.15	44 – 105 – 191	36 – 85 – 153
All Jurassic clays	**2.2 – 4.4 – 8.6**		**293 – 591 – 1,143**	

Table 12. Estimates of the total potential in-place shale oil resource in the Jurassic, Weald study area. P90, P50 and P10 values are given for each unit.

In order of significance, the Kimmeridge Clay contributes the largest in-place resource in this model, followed by the Oxford Clay, Mid Lias Clay, Upper Lias Clay and finally the Corallian Clay. However, as rock volumes at shallower levels are excluded by using a more cautious maturation gradient or a shallower accessibility/viability cut-off, the Kimmeridge Clay falls to second or even third place.

This range of figures is an estimate of total oil in-place, because a reliable estimate of recoverable shale oil cannot be made at this time (see Section 2.3). Only with shale oil exploration drilling and testing over an extended period, and optimization of the extraction process, will it be possible to determine whether this identified shale oil prospectivity can be exploited commercially.

5 Conclusions

The Weald Basin has had a long history of conventional oil and gas exploration with 13 currently producing fields in the basin. These oil and gas fields, other discoveries and natural seeps attest to the presence of an active petroleum system and this study concludes that it is possible that oil and associated gas could have been generated from any or all of the five main Jurassic shales which are the subject of this study.

The Jurassic of the Weald Basin was deposited in shallow seas with alternations of mudstones, calcareous mudstones, interbedded micritic limestones and some oolitic limestone and sandstone shoals. Subsidence continued through the Jurassic and Cretaceous and as the basin filled, maximum burial was reached during the Late Cretaceous. During the Tertiary, compressive forces on a plate-tectonic scale, and linked to the formation of the Alps, resulted in the progressive uplift of what had previously been the Weald Basin. The entire basin was inverted, forming a gentle regional feature and unroofing the core as it emerged, with some reactivation and reversal of pre-existing faults. The Jurassic stratigraphic horizons studied can be followed across the entire basin, on seismic data and in wells where they are only offset by relatively small faults.

This study has identified the potential for a significant volume of oil-mature shale to be present at several horizons in the Jurassic in the centre of the basin, but shales further west and on the northern and southern flanks are not considered mature for oil generation (Figure 50). The estimated oil-in-place range for the combined five mature shale intervals is 2.2 – 4.4 – 8.6 billion bbl of oil (0.29 – 0.59 – 1.14 billion tonnes) (P90 – P50 – P10) (Table 12). Weald Basin shale oil has the potential to add to the country's resource base, but with only limited well control and no flow testing from the basin's shales, it is not yet possible to make an estimate of the amount of shale oil that might ultimately be produced from the basin.

This study concludes that there is no significant Jurassic shale gas potential in the Weald Basin. Even the deepest Lias shales are unlikely to have attained sufficient maturity to allow for significant gas generation.

Most of this identified shale oil potential falls on extant licences, so shale oil drilling and testing does not rely on the award of new licences (Figure 50). Figure 51 shows the groundwater source protection zones in relation to the areas of mature shale. Some of the most prospective plays are in environmentally sensitive areas, in National Parks, Areas of Outstanding Natural Beauty or under towns and villages (Figure 52). Shale oil exploration and potential development should progress cautiously to ensure the activity is safe and the environment is properly protected.

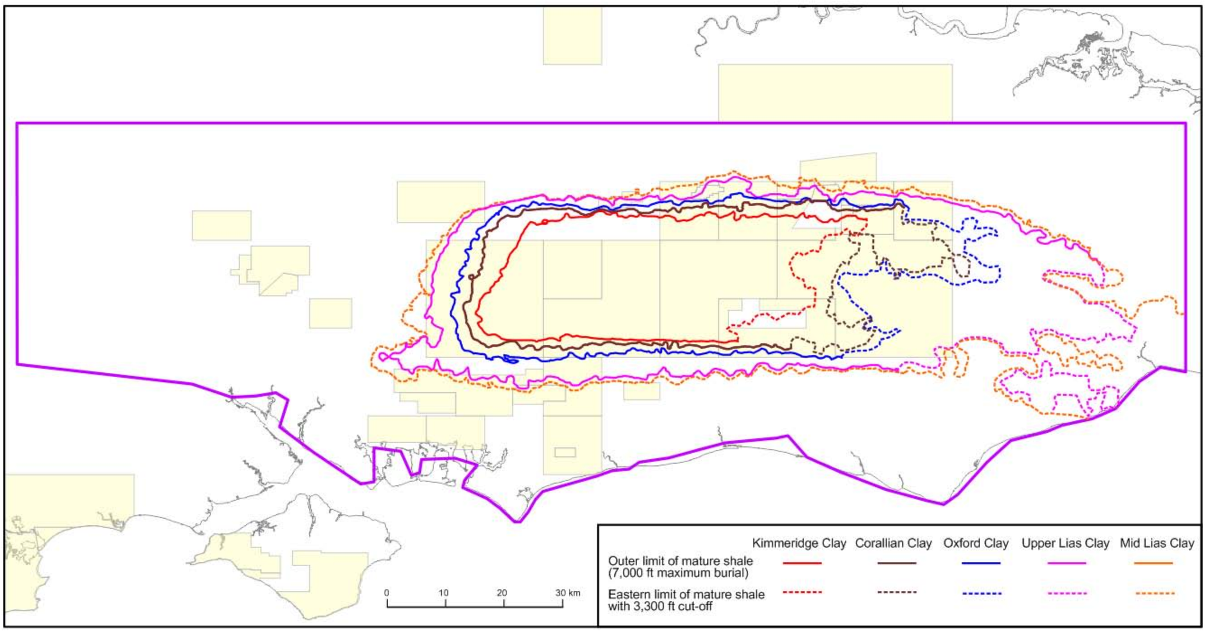

Figure 50. Summary of areas considered prospective for oil in the Jurassic shale units in southern Britain with licensed acreage (as of April 2014) also shown.

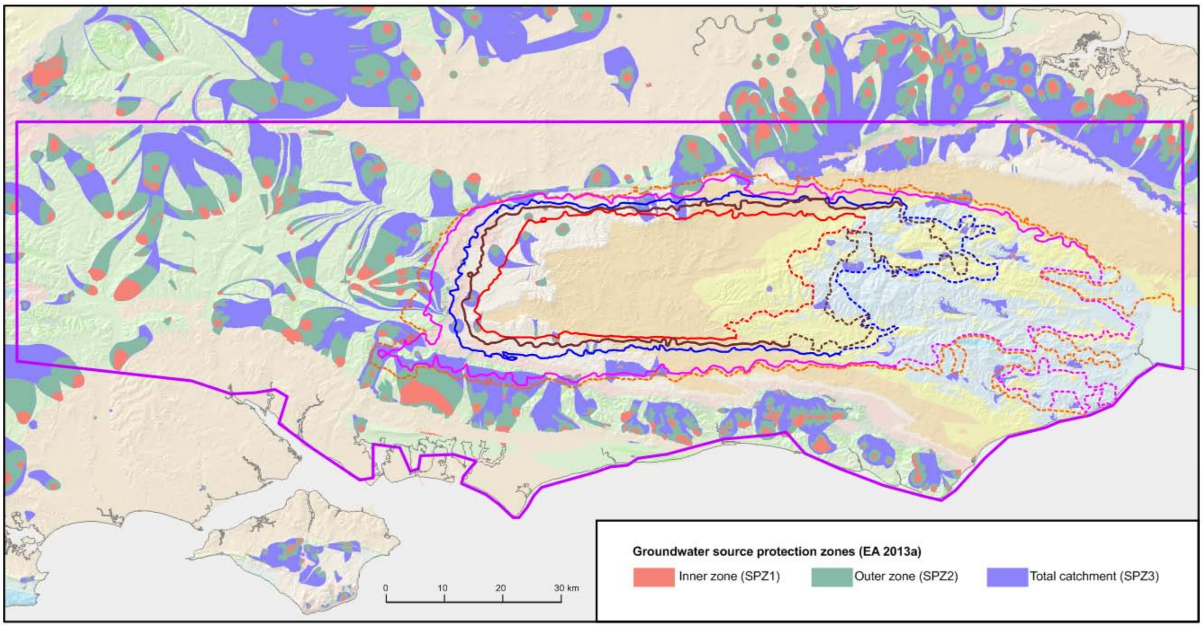

Figure 51. Summary of areas considered potentially prospective for oil in the Jurassic shale units in southern Britain (see Figure 52 for key) with the EA's groundwater source protection zones (EA 2013a) also shown.

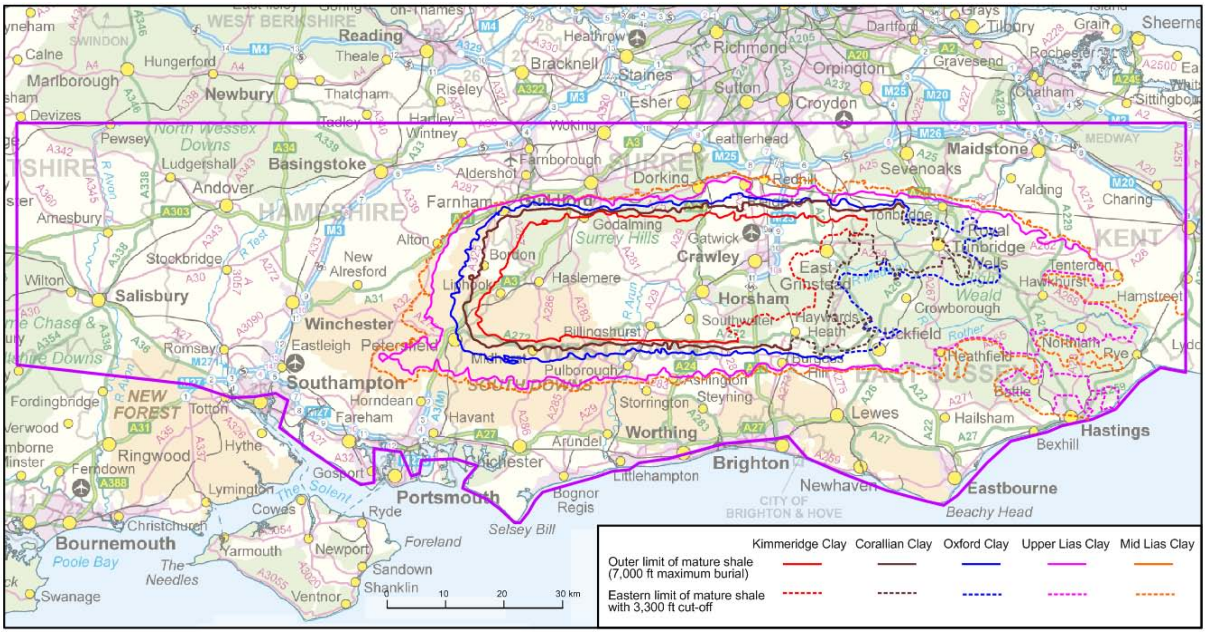

Figure 52. Summary of areas considered prospective for oil in the Jurassic shale units in relation to the urban areas of southern Britain. Contains Ordnance Survey data © Crown copyright and database right 2014. The South Downs and New Forest National Parks are indicated in pale orange; Areas of Outstanding Natural Beauty are shown in pale green.

6 Glossary

Unit/abbreviation	Full name
API	standard (American Petroleum Institute) measure of natural gamma radiation typically in a borehole, or of oil gravity
bbl	barrel (of oil)
bcf	billion (10^9) cubic feet
ft	foot/feet
ft^3 or scf	(standard) cubic foot/feet
GIIP	gas initially in place
HI	hydrogen index = [S2*100]/TOC. It is a measure of the ratio of H to C.
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
$mile^2m$	a volume occupying an area of 1 square mile with a thickness of 1 metre (1 $mile^2m$ = 2,589,988 m^3)
mmbo	million (10^6) barrels of oil
mmcf	million (10^6) cubic feet of gas
OI	oxygen index = [S3*100]/TOC. It is a measure of the ratio of O to C.
OIIP	oil initially in place
R_o	vitrinite reflectance (in oil) (%)
S1	the amount of hydrocarbons volatalised during the first stage of Rock-Eval pyrolysis (in milligrams of hydrocarbon per gram of rock, mgHC/gRock)
S2	the amount of hydrocarbons generated through thermal cracking of non-volatile organic matter during Rock-Eval pyrolysis (mgHC/gRock)
ss	sub-sea level
STOIIP	stock-tank oil initially in place (at surface temperature and pressure)
tcf	trillion (10^{12}) cubic feet
tcm	trillion (10^{12}) cubic metres
T_{max}	the temperature (°C) at which the maximum release of hydrocarbons from cracking of kerogen occurs during Rock-Eval pyrolysis (top of S2 peak). It is a measure of maturity.
TOC	total weight percent of organic carbon (% or wt%)
$\delta^{13}C$	an isotopic signature; a measure of the ratio of carbon stable isotopes ^{13}C : ^{12}C

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