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Technically Recoverable Shale Oil and Shale Gas Resources:

United Kingdom

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Introduction

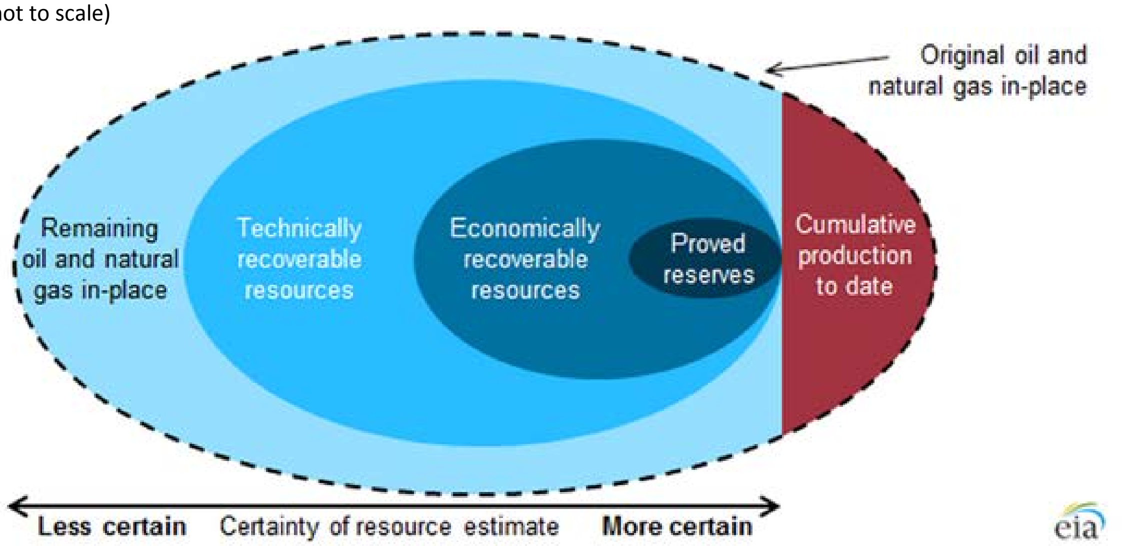
Although the shale resource estimates presented in this report will likely change over time as additional information becomes available, it is evident that shale resources that were until recently not included in technically recoverable resources constitute a substantial share of overall global technically recoverable oil and natural gas resources. This chapter is from the 2013 EIA world shale report Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States.

Resource categories

When considering the market implications of abundant shale resources, it is important to distinguish between a technically recoverable resource, which is the focus of this supplement as in the 2013 report, and an economically recoverable resource. Technically recoverable resources represent the volumes of oil and natural gas that could be produced with current technology, regardless of oil and natural gas prices and production costs. Economically recoverable resources are resources that can be profitably produced under current market conditions. The economic recoverability of oil and gas resources depends on three factors: the costs of drilling and completing wells, the amount of oil or natural gas produced from an average well over its lifetime, and the prices received for oil and gas production. Recent experience with shale gas and tight oil in the United States and other countries suggests that economic recoverability can be significantly influenced by above-the-ground factors as well as by geology. Key positive above-the-ground advantages in the United States and Canada that may not apply in other locations include private ownership of subsurface rights that provide a strong incentive for development; availability of many independent operators and supporting contractors with critical expertise and suitable drilling rigs and, preexisting gathering and pipeline infrastructure; and the availability of water resources for use in hydraulic fracturing. See Figure 1.

Figure 1. Stylized representation of oil and natural gas resource categorizations

(not to scale)



Source: U.S. Energy Information Administration
Note: Resource categories are not drawn to scale relative to the actual size of each resource category. The graphic shown above is applicable only to oil and natural gas resources.

Crude oil and natural gas resources are the estimated oil and natural gas volumes that might be produced at some time in the future. The volumes of oil and natural gas that ultimately will be produced cannot be known ahead of time. Resource estimates change as extraction technologies improve, as markets evolve, and as oil and natural gas are produced. Consequently, the oil and gas industry, researchers, and government agencies spend considerable time and effort defining and quantifying oil and natural gas resources.

For many purposes, oil and natural gas resources are usefully classified into four categories:

- Remaining oil and gas in-place (original oil and gas in-place minus cumulative production at a specific date)
- Technically recoverable resources
- Economically recoverable resources
- Proved reserves

The oil and natural gas volumes reported for each resource category are estimates based on a combination of facts and assumptions regarding the geophysical characteristics of the rocks, the fluids trapped within those rocks, the capability of extraction technologies, and the prices received and costs paid to produce oil and natural gas. The uncertainty in estimated volumes declines across the resource categories (see figure above) based on the relative mix of facts and assumptions used to create these resource estimates. Oil and gas in-place estimates are based on fewer facts and more assumptions, while proved reserves are based mostly on facts and fewer assumptions.

Remaining oil and natural gas in-place (original oil and gas in-place minus cumulative production). The volume of oil and natural gas within a formation before the start of production is the original oil and gas in-place. As oil and natural gas are produced, the volumes that remain trapped within the rocks are the remaining oil and gas in-place, which has the largest volume and is the most uncertain of the four resource categories.

Technically recoverable resources. The next largest volume resource category is technically recoverable resources, which includes all the oil and gas that can be produced based on current technology, industry practice, and geologic knowledge. As technology develops, as industry practices improve, and as the understanding of the geology increases, the estimated volumes of technically recoverable resources also expand.

The geophysical characteristics of the rock (e.g., resistance to fluid flow) and the physical properties of the hydrocarbons (e.g., viscosity) prevent oil and gas extraction technology from producing 100% of the original oil and gas in-place.

Economically recoverable resources. The portion of technically recoverable resources that can be profitably produced is called economically recoverable oil and gas resources. The volume of economically recoverable resources is determined by both oil and natural gas prices and by the capital and operating costs that would be incurred during production. As oil and gas prices increase or decrease, the volume of the economically recoverable resources increases or decreases, respectively. Similarly, increasing or decreasing capital and operating costs result in economically recoverable resource volumes shrinking or growing.

U.S. government agencies, including EIA, report estimates of technically recoverable resources (rather than economically recoverable resources) because any particular estimate of economically recoverable resources is tied to a specific set of prices and costs. This makes it difficult to compare estimates made by other parties using different price and cost assumptions. Also, because prices and costs can change over relatively short periods, an estimate of economically recoverable resources that is based on the prevailing prices and costs at a particular time can quickly become obsolete.

Proved reserves. The most certain oil and gas resource category, but with the smallest volume, is proved oil and gas reserves. Proved reserves are volumes of oil and natural gas that geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved reserves generally increase when new production wells are drilled and decrease when existing wells are produced. Like economically recoverable resources, proved reserves shrink or grow as prices and costs change. The U.S. Securities and Exchange Commission regulates the reporting of company financial assets, including those proved oil and gas reserve assets reported by public oil and gas companies.

Each year EIA updates its report of proved U.S. oil and natural gas reserves and its estimates of unproved technically recoverable resources for shale gas, tight gas, and tight oil resources. These reserve and resource estimates are used in developing EIA's Annual Energy Outlook projections for oil and natural gas production.

- Proved oil and gas reserves are reported in EIA's U.S. Crude Oil and Natural Gas Proved Reserves.
- Unproved technically recoverable oil and gas resource estimates are reported in EIA's Assumptions report of the Annual Energy Outlook. Unproved technically recoverable oil and gas resources equal total technically recoverable resources minus the proved oil and gas reserves.

Over time, oil and natural gas resource volumes are reclassified, going from one resource category into another category, as production technology develops and markets evolve.

Additional information regarding oil and natural gas resource categorization is available from the Society of Petroleum Engineers and the United Nations.

Methodology

The shale formations assessed in this supplement as in the previous report were selected for a combination of factors that included the availability of data, country-level natural gas import dependence, observed large shale formations, and observations of activities by companies and governments directed at shale resource development. Shale formations were excluded from the analysis if one of the following conditions is true: (1) the geophysical characteristics of the shale formation are unknown; (2) the average total carbon content is less than 2 percent; (3) the vertical depth is less than 1,000 meters (3,300 feet) or greater than 5,000 meters (16,500 feet), or (4) relatively large undeveloped oil or natural gas resources.

The consultant relied on publicly available data from technical literature and studies on each of the selected international shale gas formations to first provide an estimate of the "risked oil and natural gas in-place," and then to estimate the unproved technically recoverable oil and natural gas resource for that shale formation. This methodology is intended to make the best use of sometimes scant data in order to perform initial assessments of this type.

The risked oil and natural gas in-place estimates are derived by first estimating the volume of in-place resources for a prospective formation within a basin, and then factoring in the formation's success factor and recovery factor. The success factor represents the probability that a portion of the formation is expected to have attractive oil and natural gas flow rates. The recovery factor takes into consideration the capability of current technology to produce oil and natural gas from formations with similar geophysical characteristics. Foreign shale oil recovery rates are developed by matching a shale formation's geophysical characteristics to U.S. shale oil analogs. The resulting estimate is referred to as both the risked oil and natural gas in-place and the technically recoverable resource. The specific tasks carried out to implement the assessment include:

1. Conduct a preliminary review of the basin and select the shale formations to be assessed.

2. Determine the areal extent of the shale formations within the basin and estimate its overall thickness, in addition to other parameters.
3. Determine the prospective area deemed likely to be suitable for development based on depth, rock quality, and application of expert judgment.
4. Estimate the natural gas in-place as a combination of *free gas*[1] and *adsorbed gas*[2] that is contained within the prospective area. Estimate the oil in-place based on pore space oil volumes.
5. Establish and apply a composite success factor made up of two parts. The first part is a formation success probability factor that takes into account the results from current shale oil and shale gas activity as an indicator of how much is known or unknown about the shale formation. The second part is a prospective area success factor that takes into account a set of factors (e.g., geologic complexity and lack of access) that could limit portions of the prospective area from development.
6. For shale oil, identify those U.S. shales that best match the geophysical characteristics of the foreign shale oil formation to estimate the oil in-place recovery factor.[3] For shale gas, determine the recovery factor based on geologic complexity, pore size, formation pressure, and clay content, the latter of which determines a formation's ability to be hydraulically fractured. The gas phase of each formation includes dry natural gas, associated natural gas, or wet natural gas. Therefore, estimates of shale gas resources in this report implicitly include the light wet hydrocarbons that are typically coproduced with natural gas.
7. Technically recoverable resources[4] represent the volumes of oil and natural gas that could be produced with current technology, regardless of oil and natural gas prices and production costs. Technically recoverable resources are determined by multiplying the risked in-place oil or natural gas by a recovery factor.

Based on U.S. shale production experience, the recovery factors used in this supplement as in the previous report for shale gas generally ranged from 20 percent to 30 percent, with values as low as 15 percent and as high as 35 percent being applied in exceptional cases. Because of oil's viscosity and capillary forces, oil does not flow through rock fractures as easily as natural gas. Consequently, the recovery factors for shale oil are typically lower than they are for shale gas, ranging from 3 percent to 7 percent of the oil in-place with exceptional cases being as high as 10 percent or as low as 1 percent. The consultant selected the recovery factor based on U.S. shale production recovery rates, given a range of factors including mineralogy, geologic complexity, and a number of other factors that affect the response of the geologic formation to the application of best practice shale gas recovery technology. Because most shale oil and shale gas wells are only a few years old, there is still considerable uncertainty as to the expected life of U.S. shale wells and their ultimate recovery. The recovery rates used in this analysis are based on an extrapolation of shale well production over 30 years. Because a shale's geophysical characteristics vary significantly throughout the formation and analog matching is never exact, a shale formation's resource potential cannot be fully determined until extensive well production tests are conducted across the formation.

Key exclusions

In addition to the key distinction between technically recoverable resources and economically recoverable resources that has been already discussed at some length, there are a number of additional factors outside of the scope of this report that must be considered in using its findings as a basis for projections of future

[1] Free gas is natural gas that is trapped in the pore spaces of the shale. Free gas can be the dominant source of natural gas for the deeper shales.

[2] Adsorbed gas is natural gas that adheres to the surface of the shale, primarily the organic matter of the shale, due to the forces of the chemical bonds in both the substrate and the natural gas that cause them to attract. Adsorbed gas can be the dominant source of natural gas for the shallower and higher organically rich shales.

[3] The recovery factor pertains to percent of the original oil or natural gas in-place that is produced over the life of a production well.

[4] Referred to as risked recoverable resources in the consultant report.

production. In addition, several other exclusions were made for this supplement as in the previous report to simplify how the assessments were made and to keep the work to a level consistent with the available funding.

Some of the key exclusions for this supplement as in the previous report include:

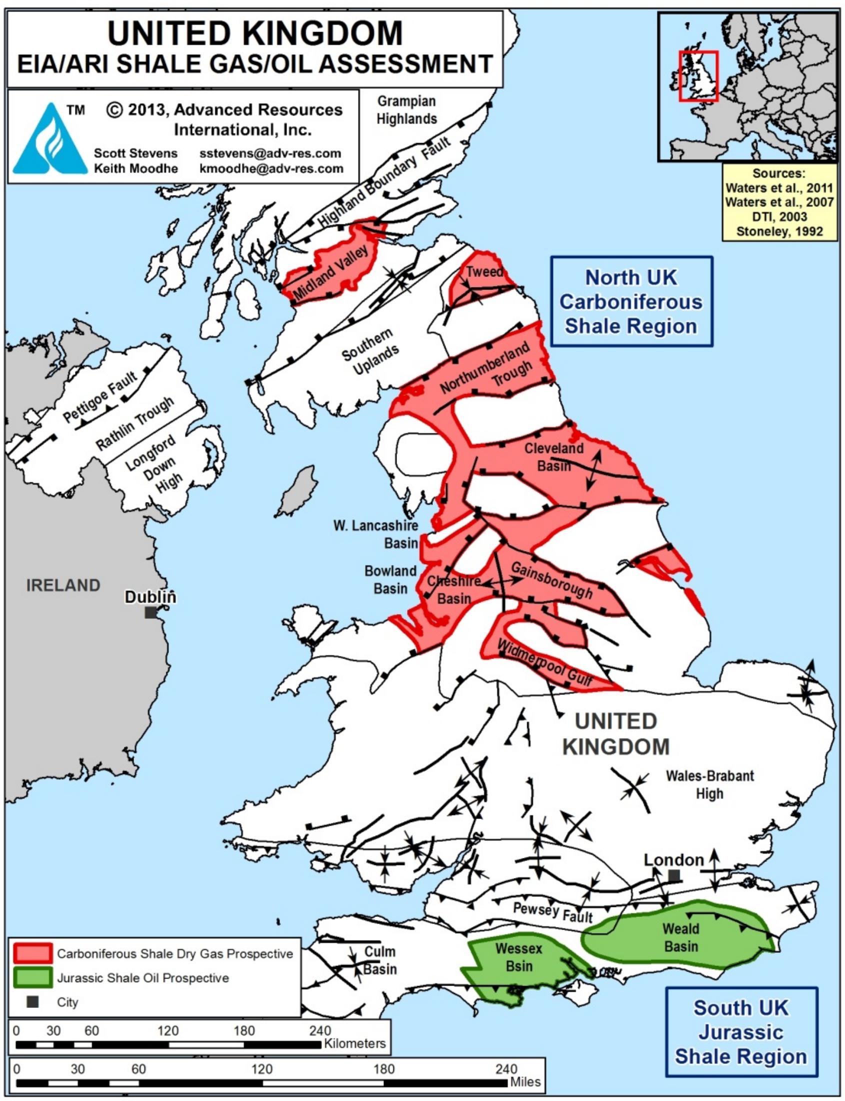
1. **Tight oil produced from low permeability sandstone and carbonate formations** that can often be found adjacent to shale oil formations. Assessing those formations was beyond the scope of this supplement as in the previous report.
2. **Coalbed methane and tight natural gas** and other natural gas resources that may exist within these countries were also excluded from the assessment.
3. **Assessed formations without a resource estimate**, which resulted when data were judged to be inadequate to provide a useful estimate. Including additional shale formations would likely increase the estimated resource.
4. **Countries outside the scope of the report**, the inclusion of which would likely add to estimated resources in shale formations. It is acknowledged that potentially productive shales exist in most of the countries in the Middle East and the Caspian region, including those holding substantial non-shale oil and natural gas resources.
5. **Offshore portions of assessed shale oil** and shale gas formations were excluded, as were shale oil and shale gas formations situated entirely offshore.

XI. UNITED KINGDOM

SUMMARY

The United Kingdom has substantial volumes of prospective shale gas and shale oil resources within Carboniferous- and Jurassic-age shale formations distributed broadly in the northern, central and southern portions of the country.

Figure XI-1 : Shale Basins in the United Kingdom



Source: ARI 2013.

The risked, technically recoverable shale resources of the U.K. are estimated at 26 Tcf of shale gas and 0.7 billion barrels of shale oil and condensate in two assessed regions, Tables XI-1 and XI-2. This is based on the much larger unrisked estimates of 623 Tcf of shale gas in-place (134 Tcf, risked) and 54 Bbbl of shale oil in-place (17 billion barrels, risked). These estimates reflect only the higher-TOC portions of the Carboniferous and Jurassic shale intervals.

Table XI-1. Shale Gas Reservoir Properties and Resources of the United Kingdom

			North UK Carboniferous Shale Region	South UK Jurassic Shale Region
Basic Data	Basin/Gross Area		(10,200 mi^2)	(3,470 mi^2)
	Shale Formation		Carboniferous Shale	Lias Shale
	Geologic Age		Carboniferous	L. Jurassic
	Depositional Environment		Marine	Marine
Physical Extent	Prospective Area (mi^2)		5,100	1,735
	Thickness (ft)	Organically Rich	820	165
		Net	410	149
	Depth (ft)	Interval	5,000 - 13,000	4,000 - 6,000
		Average	8,500	5,000
Reservoir Properties	Reservoir Pressure		Normal	Normal
	Average TOC (wt. %)		3.0%	3.0%
	Thermal Maturity (% Ro)		1.30%	0.85%
	Clay Content		Medium	Medium
Resource	Gas Phase		Dry Gas	Assoc. Gas
	GIP Concentration (Bcf/mi^2)		117.3	14.5
	Risked GIP (Tcf)		125.6	8.0
	Risked Recoverable (Tcf)		25.1	0.6

Source: ARI, 2013

Table XI-2. Shale Oil Reservoir Properties and Resources of the United Kingdom

			South UK Jurassic Shale Region
Basic Data	Basin/Gross Area		(3,470 mi^2)
	Shale Formation		Lias Shale
	Geologic Age		L. Jurassic
	Depositional Environment		Marine
Physical Extent	Prospective Area (mi^2)		1,735
	Thickness (ft)	Organically Rich	165
		Net	149
	Depth (ft)	Interval	4,000 - 6,000
		Average	5,000
Reservoir Properties	Reservoir Pressure		Normal
	Average TOC (wt. %)		3.0%
	Thermal Maturity (% Ro)		0.85%
	Clay Content		Medium
Resource	Oil Phase		Oil
	OIP Concentration (MMbbl/mi^2)		30.9
	Risked OIP (B bbl)		17.1
	Risked Recoverable (B bbl)		0.69

Source: ARI, 2013

Initial exploration drilling has confirmed the presence of thick, gas-bearing shale deposits in the Bowland Sub-basin in the west portion of the Pennine Basin of northwest England. However, production testing has not yet occurred and the other shale regions remain undrilled. EIA/ARI's current estimate of the UK's shale gas resources is about 10% higher than our initial 2011 assessment, while new shale oil potential has been added.

Compared with North America, the shale geology of the UK is considerably more complex, while drilling and completion costs for shale wells are substantially higher. The Pennine Basin, one of the country's most prospective areas, has been tested with five vertical wells which cored the Carboniferous Bowland Shale. Other prospective areas include the rest of the North UK Carboniferous Shale region and the liquids-rich Jurassic Shale region of southern England in the Wessex and Weald basins, Figure XI-1.

Shale testing is still at an early phase in the UK – flow testing and horizontal shale drilling have not even been attempted. In a temporary setback, the first shale well to be hydraulically stimulated triggered a series of minor earthquakes related to a nearby fault. Following an 18-month moratorium, the government concluded that the environmental risks of shale exploration are small and manageable. Shale drilling was allowed to resume in December 2012, albeit with stricter monitoring controls. Current shale operators include Cuadrilla Resources, IGAS, Dart Energy, and others.

INTRODUCTION

Within Europe, the United Kingdom stands next after Poland in pursuing its shale gas and shale oil potential. However, with a small existing onshore conventional oil and gas industry, the UK has limited domestic service sector capability for shale exploration. Natural gas prices are high (~$9/MMBtu) in the UK compared with North America, but geologic conditions are much more complex. Faults are numerous, geologic data control is weak, and shale wells are more costly to drill. While the UK's shale resource base appears substantial, commercial levels of shale production are yet to be established.

Political opposition to shale development is greater in the UK than in Poland but less than in France or Germany. Hydraulic fracturing got off to an abysmal start. The UK's first shale production test well triggered small local earthquakes during fracture stimulation and the vertical wellbore was deformed. This is perhaps unsurprising given the highly faulted nature of shale deposits in the UK (and generally in Europe). The government banned onshore hydraulic fracturing for a period of eighteen months to better evaluate the risks.

In January 2012 the British Geological Survey noted that the risks of shale development to groundwater and earthquakes had been exaggerated. Minor earthquakes caused by the Preese Hall-1 well were "comparable in size to the frequent minor quakes caused by coal mining. What's more, they originate much deeper in the crust so have all but dissipated by the time they reach the surface."[1] In December 2012 the UK government finally granted conditional approval for shale exploration, albeit with strict monitoring conditions. Cuadrilla recently delayed its plan to resume fracture stimulation until 2014 at the earliest.

Companies which have been granted a Petroleum Exploration and Development license (PEDL) by the UK government are permitted to explore and develop shale gas, as well as other types of petroleum resources (conventional, coalbed methane, tight gas, etc.). Field development is subject to necessary national and local consent and planning permission. Currently there are about 334 onshore PEDLs, of which several dozen have recognized shale potential. Proprietary shale data typically are kept confidential for a four-year period from the date of well completion.

At least six oil and gas companies are targeting shale gas exploration in the UK but only two have actually drilled shale wells. All wells have been vertical. UK-based Cuadrilla Resources, partly (43%) owned by Australian drilling company AJ Lucas, is the most active, drilling and coring four shale exploration wells in the West Bowland Sub-basin that confirmed the presence of up to 2-km of gas-bearing organic-rich shale. However, at least one well encountered active faults and high-stress conditions. IGAS Energy has drilled a shale well nearby, coring the 1,600-ft thick Bowland Shale. Horizontal shale wells have not yet been attempted in the UK, nor have flow tests been reported. Coastal Oil and Gas Ltd., Celtique Energie, Dart Energy, and Eden Energy also are evaluating their UK shale resource potential but haven't yet drilled.

GEOLOGIC OVERVIEW

As early as the late 1980s researchers at Imperial College, London had identified the main stratigraphic targets for shale gas exploration in the UK, the marine-deposited black shales of Carboniferous and Jurassic age.[2,3] More recently in 2003, a study conducted by the British Geological Survey (BGS) and published by the UK Department of Trade and Industry (DTI) presented an integrated review of the geology of Britain's onshore conventional oil and gas fields and source rock shales, although it was not asked to consider shale as a productive reservoir.[4] In 2010 BGS published a compilation of shale-specific geologic data collected from outcrops and conventional petroleum wells.[5]

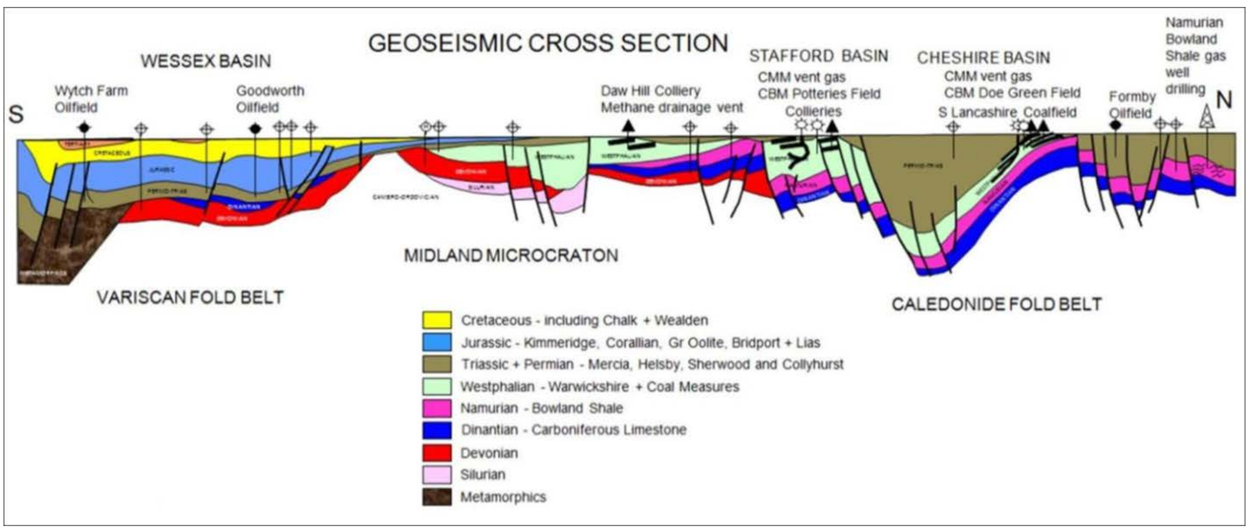
BGS published its preliminary evaluation of UK shale gas resources later in 2010, conducted on behalf of the Department of Energy and Climate Change (DECC).[6] BGS' initial estimate was 5.3 Tcf (150 Bcm) of recoverable shale gas resources. BGS, in association with DECC, plans to release an updated evaluation of shale gas potential of northwest England later in 2013, followed eventually by a more complete national estimate.[7]

The main onshore sedimentary basins in the UK that produce oil and gas or have conventional or shale exploration potential are shown in Figure XI-1. The current EIA/ARI resource assessment groups these numerous, typically fault-bounded basins into two main shale exploration regions:

- **North UK Carboniferous Shale Region.** A complex assemblage of isolated structural basins and troughs is present across northern England and southern Scotland. These contain prospective organic-rich shales of Carboniferous age, including notably the Bowland Shale. Within the greater Pennine Basin, individual sub-basins include the Bowland, Cleveland, Cheshire, West Lancashire, Northumberland, East Midlands, Gainsborough, Midland Valley, as well as others. The Bowland Sub-basin is the only area to undergo shale exploration drilling to date.
- **South UK Jurassic Shale Region.** In southern England the Wessex and Weald basins extend offshore into the English Channel. They contain Jurassic-age shales that are oil-prone. While no shale drilling has occurred here yet, the region includes Britain's largest onshore oil field and appears highly prospective for shale oil development.

It is important to note that the UK shale basins generally are not simple continuous structures, such as found in many North America shale regions, but rather typically comprise a series of small fault-bounded sub-basins. Figure XI-2 shows a regional cross-section from the Wessex Basin in the south to the Bowland Sub-basin in the north, highlighting the Carboniferous-Namurian and Jurassic shale targets. Even the interior of the sub-basins may be significantly faulted, to an extent generally not displayed on schematic cross-sections. The structural complexity, coupled with the relatively small data base of onshore petroleum wells in the UK (particularly in the troughs), makes resource assessment more difficult. It also could slow the pace of shale exploration, de-risking, and commercial development in the UK.

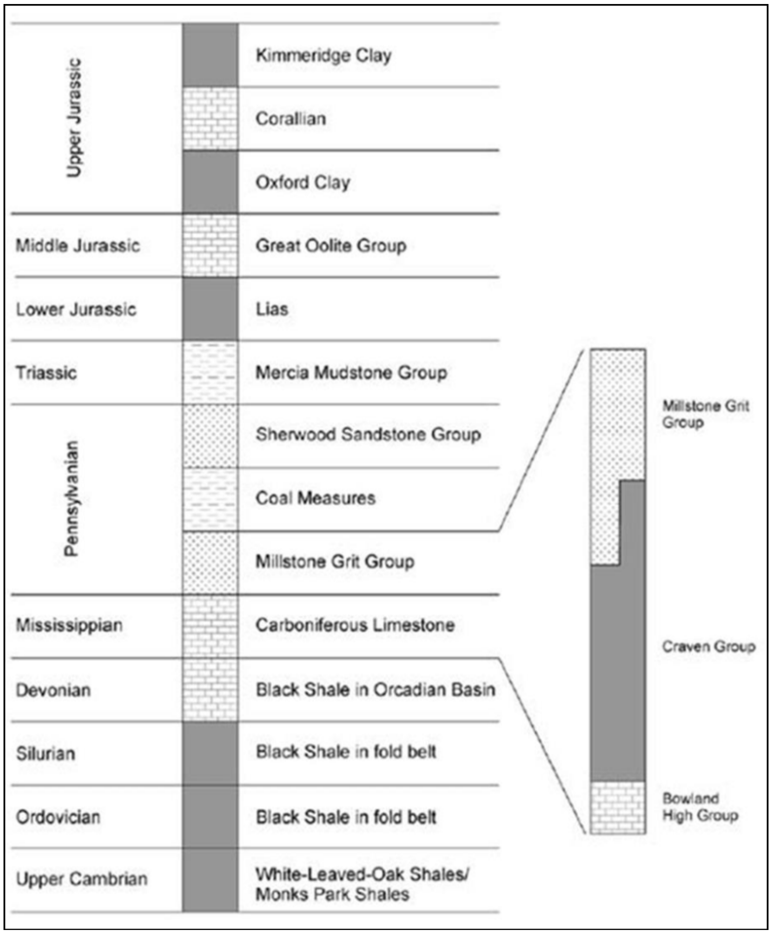
Figure XI-2 : Regional Cross-Section from Wessex Basin Through Bowland Sub-basin Highlighting Carboniferous-Namurian and Jurassic Shale Targets



Source: British Geological Survey, 2012

The main stratigraphic targets for shale exploration in the UK are the Carboniferous Mississippian (Lower Namurian)[8] and the Lower Jurassic Lias formations, both of which contain organic-rich, marine-deposited shales, Figure XI-3. Other potential shale targets include the U. Cambrian and the U. Jurassic Oxford and Kimmeridge Clays, but these were excluded from our study due to their low thermal maturity, lower organic content, and/or extreme structural complexity. In particular, organic-rich shales found within the Carboniferous Coal Measures were excluded because these non-marine shales are coaly, high in clay, and unlikely to be sufficiently brittle. However, further data collection and mapping may reveal these or other shale formations to be prospective in places.

Figure XI-3: Stratigraphic Column Showing UK Formations That Contain Organic-Rich Shales. The Lower Jurassic Lias And Carboniferous Shales Appear Most Prospective.



Source: Smith et al., 2010

The BGS has cited the Middle Cambrian Conasauga Shale in Alabama as the closest North American geologic analog for Cambrian shale deposits in the UK, given their similar age and degree of structural complexity. However, shale gas development in the Conasauga Shale has not been successful to date. The Cambrian-age shale deposits in the UK were not assessed in the EIA/ARI study due to their structural complexity and lack of geologic data.

SEISMIC HAZARDS

The UK shale industry experienced a serious setback in 2011, when the first hydraulic fracturing operation of a shale well unexpectedly generated a series of very small earthquakes. However, it is noteworthy that none of the approximately 50,000 horizontal shale wells drilled in North America during the past decade have generated significant earthquakes, although a few suspected seismic events are under review.

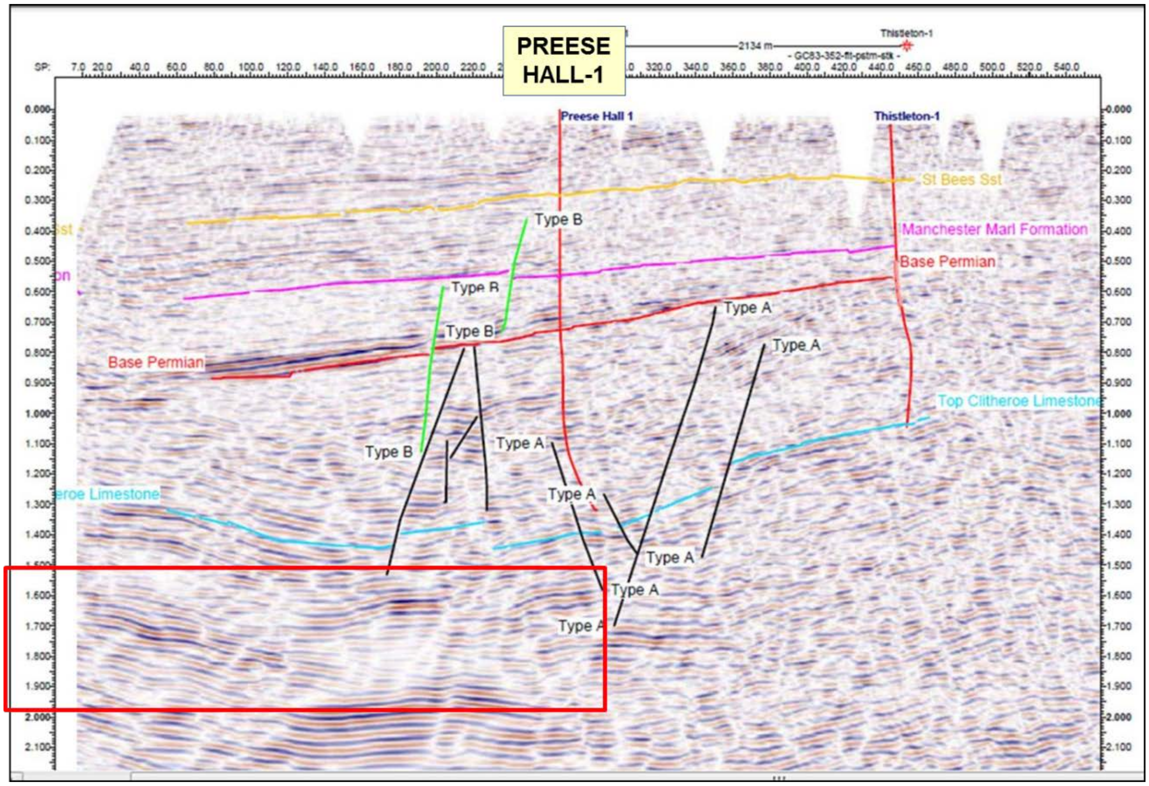
In August 2010 Cuadrilla drilled the UK's first shale gas exploration well, spudding the **Preese Hall-1** vertical well in the Bowland Sub-basin near Blackpool, Lancashire. The well was fracture stimulated during early 2011, inducing several dozen small earthquakes close to the downhole injection zone. The timing of the earthquakes corresponded with fluid injection and continued for several hours after injection ceased. Fortunately, the largest earthquakes were relatively small, measuring magnitudes of 2.3 and 1.5 on the Richter scale. No surface damage was reported. However, the UK government shut down shale testing in the country for 18 months to determine the cause of the seismic events and to develop mitigation rules.

An evaluation of seismicity from these earthquakes generated by the Preese Hall-1 well and the fault geometry of the basin indicated that movement was strike-slip along a sub-vertical fault plane. The suspected fault was located on the well's image log as well as on detailed seismic, Figure XI-4.[9] Separately, bedding plane slip -- already noted in core cut prior to running casing in the well -- induced wellbore damage, with oval deformation noted across several hundred feet of the 5.5-inch casing.

The maximum horizontal stress gradient, based on mini-frac and borehole breakout data, was determined to be relatively high at 1.25 psi/ft. The stress differential within the Bowland Shale -- about 4,000 psi -- was found to be an order of magnitude higher than in North American shale plays, which typically have stress differentials of only several hundred psi. It is unclear whether the high stress differential is local or widely prevalent across the UK.

Cuadrilla's consultants concluded that excess fluid pressure exerted on the fault during the hydraulic stimulation overcame the rock friction containing this stress, which enabled the fault to slip and generate small earthquakes. Simultaneously, bedding plane slip up the hole caused the well's casing string to deform. Based on fault size and geometry, the maximum earthquake in the Bowland Sub-basin was estimated to be approximately magnitude 3.0, still considered too small to cause significant damage to surface structures in this region.

Figure XI-4: Seismic Reflection Line Showing Suspected Active Faults Near The Preese Hall-1 Well In The Bowland Sub-basin



Source: de Pater and Baisch, 2011

The consultants also inferred that the injected frac fluid remained contained within the induced fracture system and did not leak into the shallow freshwater aquifer system, because of the thick and impermeable Bowland Shale and overlying Permian anhydrites. A subsequent report recommended monitoring during hydraulic fracturing operations to help mitigate induced seismicity.[10]

As a result of the earthquakes the government halted shale operations in the UK from May 2011 until December 2012. The Royal Society and Royal Academy of Engineering conducted a review of the risks, recommending the following three primary steps for ensuring health and safety during shale development:[11]

- ***Groundwater Monitoring***. The BGS should conduct regional baseline surveys of groundwater ahead of shale development, while operators conduct site-specific surveys to identify possible natural methane concentrations in groundwater. Abandoned wells should be monitored and remediated to prevent fracture fluids from entering freshwater aquifers.

- ***Well Integrity***. Well design, construction, and integrity testing should ensure that multiple layers of steel and cement are present to preclude leakage of fluids into freshwater aquifers.
- ***Mitigating Seismicity.*** The BGS should survey the regional distribution of faults, stresses, and seismic hazards ahead of shale development, while operators conduct site-specific surveys. Seismicity should be monitored before, during, and after hydraulic stimulation, which should be shut down if seismic risks become unacceptable.

After considering these and other views, DECC put in place a new regulatory regime for shale development starting December 2012. The regime requires operators to evaluate potential seismic hazards posed by hydraulic fracturing, implement seismic monitoring of each individual well site area, and propose mitigation steps to minimize the chance of future earthquakes due to hydraulic fracturing. A real-time trigger is to be installed to cut off injection should significant earthquake risks arise. These rules are expected to add significant cost and time to drill shale wells in the UK. Cuadrilla's Anna's Road-1 well is the first to be spud under the new shale rules. Hydraulic stimulation of this well -- which Cuadrilla recently announced would be delayed until 2014 at the soonest -- would require further specific approvals.

1. NORTH UK CARBONIFEROUS SHALE REGION

1.1 Introduction and Geologic Setting

Northern England and southern Scotland are characterized by a complex assemblage of isolated basins and troughs which contain thick, organic-rich Carboniferous shales, Figure XI-1. These shale-prospective lows are separated by structural highs where Carboniferous was not deposited or has been eroded. Based on mapping of Carboniferous basins conducted by the BGS, these troughs cover a total area of approximately 10,000 mi^2.

The Bowland Sub-basin of Lancashire, where shale drilling has been concentrated thus far, is one such trough, representing the onshore margin of the petroliferous East Irish Sea Basin. Further to the east the Cleveland Basin is considered the onshore extension of the Southern North Sea gas basin. In between lay the Cheshire, West Lancashire, Northumberland, East Midlands, Pennine, Gainsborough, Midland Valley, and other basins and troughs containing Carboniferous-age shales. Our study grouped these isolated basins into a single region for shale resource assessment.

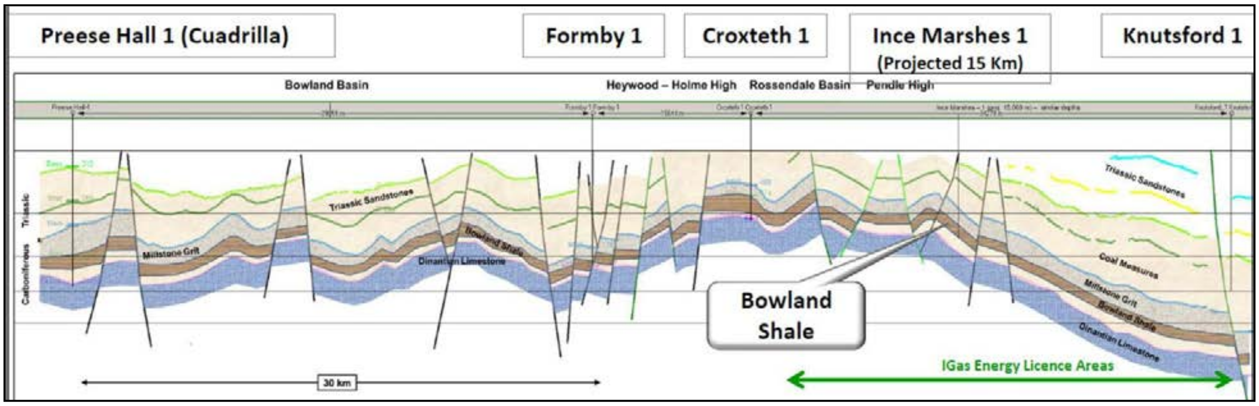
The western portion of the Bowland Sub-basin has been the site of all UK shale exploration drilling to date. The Carboniferous Bowland Shale is the main target, ranging from about 2.0 to 2.5 km deep across the moderately faulted Bowland Sub-basin, Figures XI-5 and XI-6. Cuadrilla's Preese Hall-1 well encountered the top of the target Lower Carboniferous Bowland Shale at a measured depth of 6,854 ft and penetrated a total 2,411 ft of organic-rich shale, Figure XI-**7**. The BGS has mapped the thickness of the Upper Bowland Shale Formation, as well as its organic-rich (high-gamma) section, across northern England, Figure XI-8. The organic-rich shale ranges up to 120 m thick but more typically is recorded as 20 to 40 m thick. Note, however, that petroleum wells are preferentially drilled on structural highs, where shale tends to be thinner than in the troughs.

The eastern Bowland Shale play extension in the Gainsborough Basin has less geologic control than the west. Here the shale ranges up to 300 m thick in the Dinantian half-graben basins, Figure XI-9. Dart Energy reported that the most organic-rich portion defined by high-gamma shales ranges up to 110 m thick. In the Cheshire Basin the Carboniferous (Namurian) Bowland and Holywell shales with TOC up to 5% occur at depths of 1 to 5 km, Figure XI-10.

Elsewhere in the region, the Namurian Holywell Shale, source rock for conventional oil fields in the southern East Irish Sea as well as the Formby oil field, is reported to have an overall average TOC of 2.1% (range 0.7% to 5%) and averages 3.0% TOC in its lower, more organic-rich portion. Clay content is uncertain, although public data indicate that Carboniferous mudstones in the UK generally average around 25% Al_2O_3 (range 12-38%), mostly from clay.

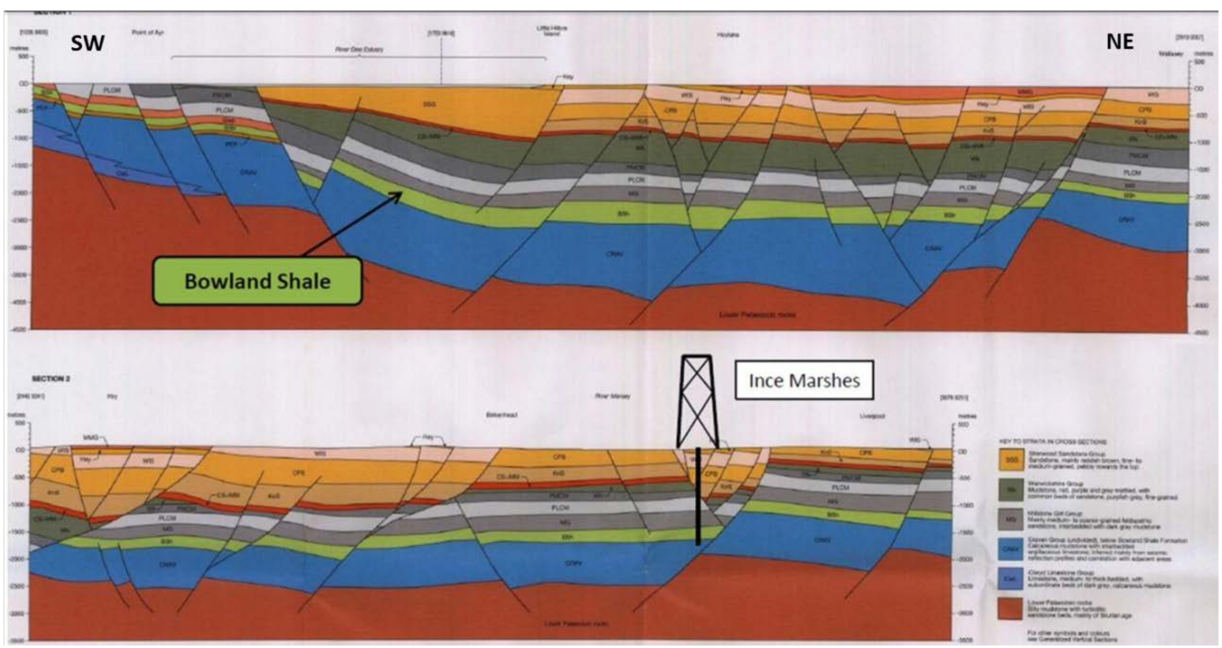
The Pennine Basin has relatively good geologic control from past petroleum exploration. The Craven Group (Mississippian) ranges from about 1.5 km thick in the Craven sub-basin to over 5 km thick in the Widmerpool Gulf. These mudstones were deposited in distal slope turbidite and hemipelagic environments in relatively narrow, deep depocenters. The early Namurian shale units (local names Bowland, Edale, Holywell shales, top part of Craven Group) of the Pennine Basin have high TOC and are known to have sourced hydrocarbons. These Namurian marine shales generally have rich TOC in excess of 4%.

Figure XI-5: Structural Cross-Section in the Bowland Sub-basin Region, Northwest UK Showing Numerous Faults Across the Cuadrilla and IGas Energy Licenses.



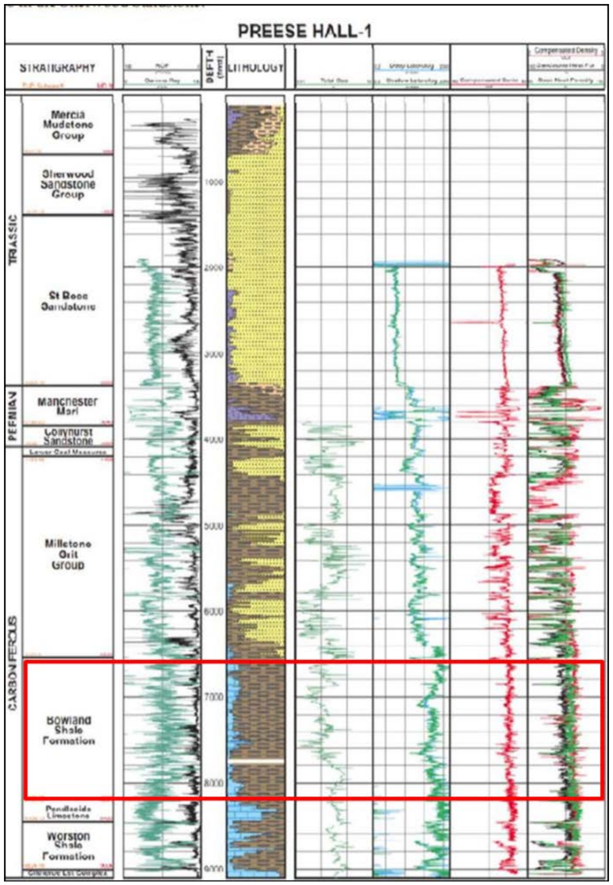
Source: Source: IGAS Energy, 2012

Figure XI-6: Structural Cross-Section In The Bowland Sub-basin Region Showing The Highly Faulted Bowland Shale At 2 To 3 Km Depth. Additional Faults Penetrated By The Ince Marshes Well Suggest That Many Additional Faults Are Present But Unrecognized.



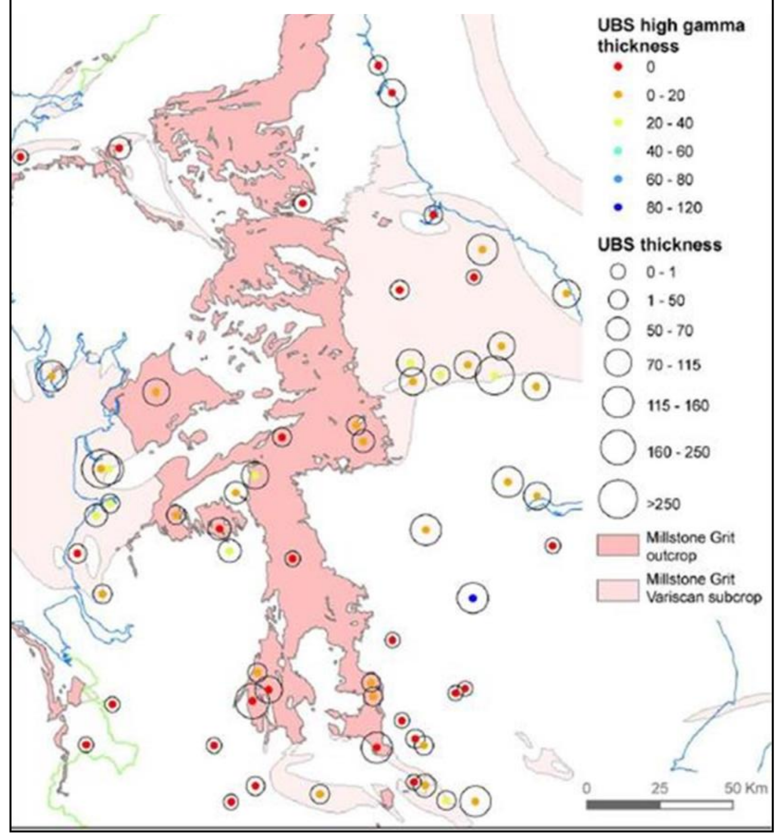
Source: IGAS Energy, 2012; modified from BGS Map 96_Liverpool

Figure XI-7: Stratigraphic Column and Composite Log for the Cuadrilla Preese Hall-1 well in the Bowland Sub-Basin



Source: de Pater and Baisch, 2011

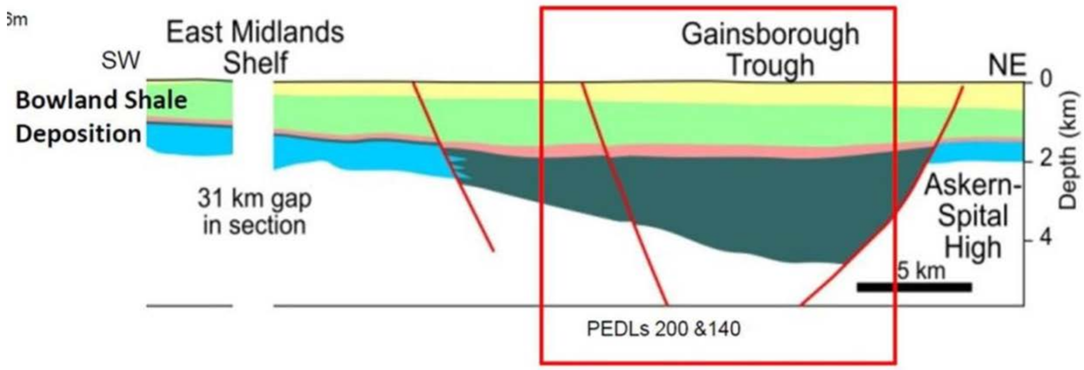
Figure XI-8: Thickness of the Upper Bowland Shale Formation in Northern England, as Well as the High-Gamma Thickness. Note That Petroleum Wells Tend to be Drilled on Structural Highs Where the Shale May be Thinner Than in the Troughs.



Source: Smith et al., 2010

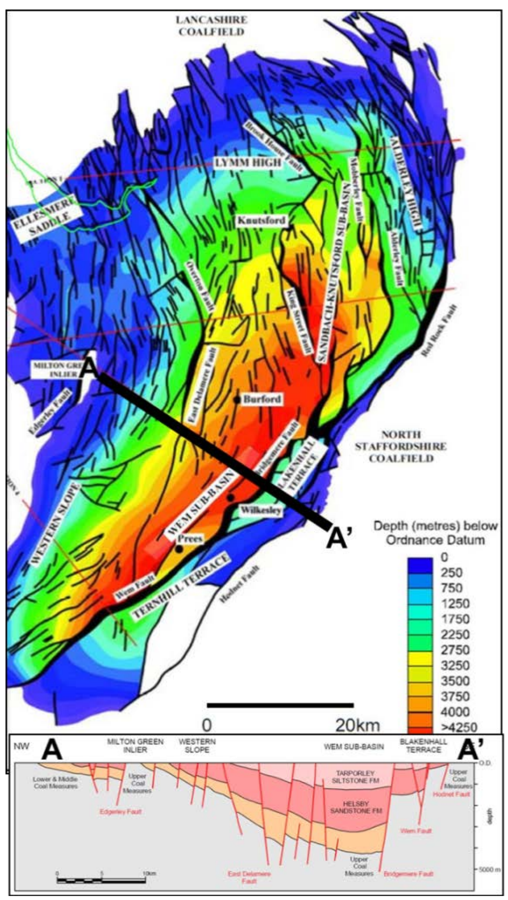
Advanced Resources International, Inc.

Figure XI-9: Schematic Cross-Section Across The Gainsborough Trough Showing Thick Bowland Shale. Additional Faults Are Likely To Be Present But Not Shown.



Source: Dart Energy, 2013

Figure XI-10: Geologic Map and Generalized Structural Cross-Section of the Cheshire Basin. Carboniferous (Namurian) Bowland and Holywell Shales with TOC Up to 5% Occur at Depths of 1 to 5 km.



Source: DECC, 2012

Advanced Resources International, Inc.

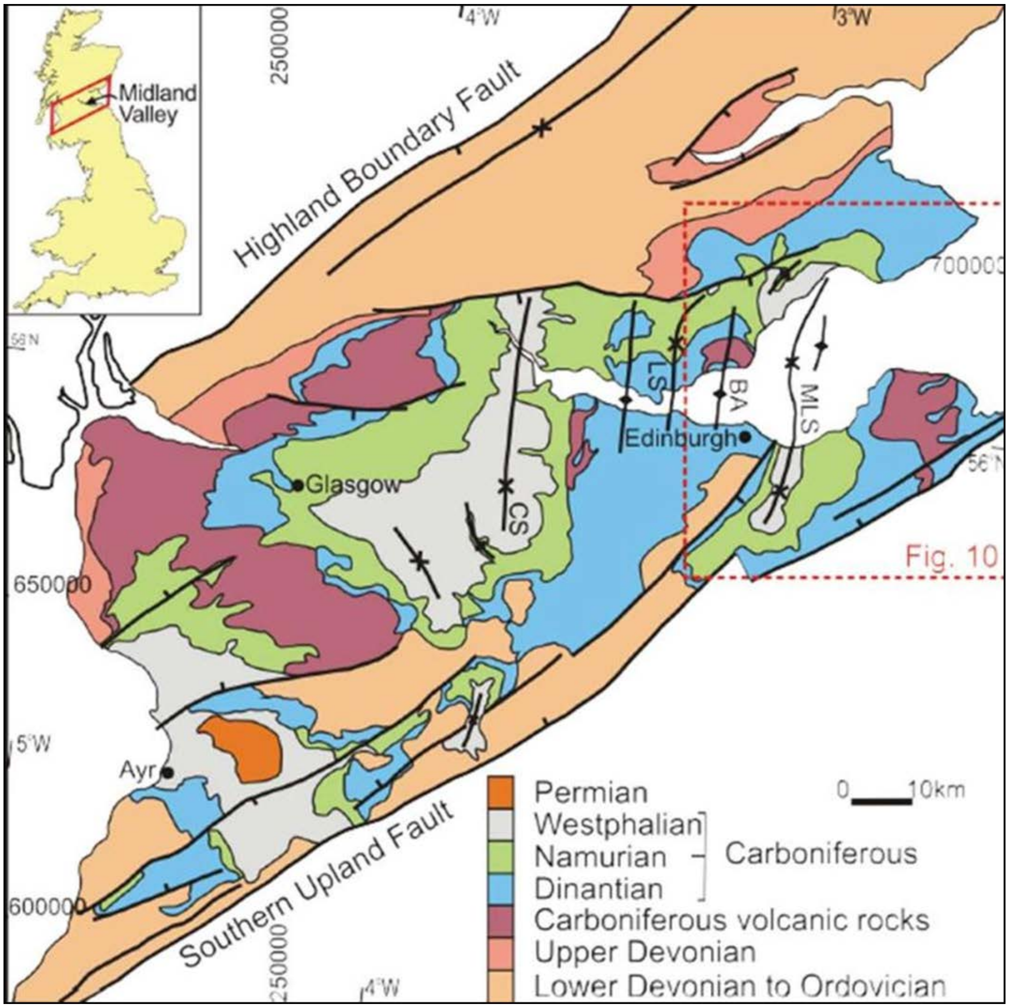
The North UK Carboniferous Shale region is mainly in the dry gas window. For example, the Normanby-1 and Grove-3 conventional petroleum wells reportedly recorded high-gamma sections within the Bowland Shale, while the Scaftworth-B2 well measured 2.07% to 3.63% TOC with 1.26% R_o at a depth of 2,246 m.[12] In addition, most of the Cleveland Basin is known to be within the dry gas window. Oil and wet gas thermal maturity windows may be present locally but could not be defined with the limited data available.

No porosity data are available for Namurian shales in the Pennine Basin. Based on boreholes drilled by the BGS in the southern Midlands, relatively shallow (900 m deep) Upper Paleozoic shales retained high porosities (5-10%). However, porosity is likely to be considerably lower (perhaps 3-5%) at typical target shale depth of 2-4 km.

The Midland Valley Basin (MVB), a large east-northeast trending graben complex that stretches across southern Scotland, is bounded by the Highland Boundary Fault to the northwest and the Southern Upland Fault to the southeast. The MVB comprises a complex series of small faulted sub-basins, such as the Kinkardine Basin where Dart Energy is evaluating shale gas resources. This structural complexity was over-printed by extensive igneous intrusion during late Carboniferous to early Permian time.

The MVB contains a relatively complete sequence of Carboniferous deposits up to 6 km thick, Figure XI-11.[13] Namurian strata range from 450 m to 1,400 m thick at outcrop. The depositional sequence reflects mixed marine shelf carbonate and deltaic successions, comprising upward-coarsening cycles of marine limestone, mudstone, siltstone and sandstone.[14] Lower Carboniferous (Dinantian) oil-shale source rocks, such as the Mid-Lothian Oil shale, buried deeply in the Midlothian-Leven Syncline generated waxy crude oil that sourced clastic reservoirs of similar age in the adjacent anticlines.

Figure XI-11: Geologic Map of the Midland Valley Basin. Carboniferous (Namurian) Shales Crop Out at the Surface but May Reach Prospective Depth.



Source: Underhill et al., 2009

1.2 Reservoir Properties (Prospective Area)

The total mapped deep Carboniferous area in the North UK Carboniferous Shale region is approximately 10,200 mi^2. Because of structural complexity and poor depth control was poor, only half of the total area was assumed to be in the prospective depth window and relatively unfaulted (4,635 mi^2). The target lower organic-rich portion of the Bowland and Holywell shales (and local equivalents) averages about 300 ft thick and 8,000 ft deep in the Bowland Sub-basin region, with 3.0% average TOC. Porosity is estimated to be about 4% at target depths of 3 km, much lower than the 5-10% measured at shallow <1 km depth. Thermal maturity is mainly in the dry gas window (R_o 1.3%), although less mature pockets in the wet gas window may exist.

1.3 Resource Assessment

Risked, technically recoverable shale gas resources in the North UK Carboniferous Shale region are estimated to be 25 Tcf, out of a risked shale gas in-place of 126 Tcf, Table XI-1. The play has a favorable net resource concentration of about 117 Bcf/mi^2, reflecting the significant thickness of organic-rich shale.

For comparison, in September 2011 Cuadrilla Resources estimated the total shale gas in-place within its Bowland Sub-basin licenses to be approximately 200 Tcf, based on logs and core from two shale and three conventional petroleum wells.[15] The company has estimated the total shale gas resource-in-place concentration at its Preese Hall-1 well to be 539 Bcf/mi^2. Cuadrilla's estimate is that 10% or about 20 Tcf may be recoverable. It appears that Cuadrilla's estimate is based on the entire shale section, whereas EIA/ARI considers only the lower, most organic-rich section as the prospective interval.

Separately, IGAS Energy's independent consultant identified a 1,195-km^2 prospective area within an average 250-m thick organic-rich interval, constrained by geophysical logs from eight conventional petroleum wells that penetrated the Bowland Shale. After drilling its first shale appraisal well last year, IGAS estimated the shale gas in-place (GIP) resources within its licenses to be about 9.2 Tcf.

Dart Energy's third-party consultant NSAI has estimated that Dart's licenses have some 32.46 Tcf of GIP in unspecified shale formations in the Gainsborough Trough of East Midlands, as well as 30.55 Tcf of shale gas GIP in the Cheshire Basin (gross, Best Estimate). No recovery estimate was reported.[16] Finally, in Scotland's Midland Valley Basin, Dart Energy reported that the company's PEDL 133 license has an estimated 2.5 Tcf of shale gas GIP based on a third-party consultant report. Recoverable prospective shale gas resources were estimated at 115 Bcf in the Carboniferous Black Metal Shale and 255 Bcf in the Lothian-Broxburn Shale (Best Estimates; net to Dart).

1.4 Recent Activity

The Bowland Sub-basin, the only active shale drilling region in the UK, has had five shale exploration wells drilled to date. The main operators are Cuadrilla Resources (4 licenses totaling 1185 km^2; 4 wells), IGAS Resources (14 licenses; 1363 km^2; 1 well), and Dart Energy (11 licenses; 1041 km^2).

In August 2010 Cuadrilla drilled the first shale gas exploration well in the UK, spudding the **Preese Hall-1** vertical well in the Bowland Sub-basin near Blackpool, Lancashire. The top of the target Lower Carboniferous Bowland Shale was encountered at a measured depth of 6,854 ft. The well penetrated a total 2,411 ft of organic-rich shale. Naturally fractured, the Bowland is within the dry gas thermal maturity window.

After drilling was completed on the Preese Hall-1, Cuadrilla completed and fracture stimulated the well in early 2011. This operation represented the UK's first and only concerted attempt to produce shale gas. As previously discussed, small earthquakes were induced near the well by the hydraulic fracture stimulation. Operations at the well were halted in May 2011 with no gas production reported.

In completing the well, Cuadrilla perforated shale formations within the Bowland Shale, Worston Shale, and Hodder Mudstone at depths ranging from 7,670 to 8,949 ft. Five shale zones, out of 12 originally planned, were individually stimulated with a sand/water slurry, separated by bridge plugs. The total stimulation size, over 50,000 bbl of water and 400 t of sand proppant, was relatively large for a vertical shale well but still considerably smaller than the typical stimulation of a horizontal shale well in North America (about half the water volume and 10% of the sand volume).

Cuadrilla drilled and cored two other vertical wells in the Bowland Basin. During 2H 2010 the nearby **Grange Hill-1** vertical well logged over 2 km of Carboniferous shale across the depth interval of 1,200 m to 3,300 m, the total depth of the well. In 2011 the **Becconshall-1** well logged shale from depths of 2,450 m to 3,100 m, the total depth of the well.

Cuadrilla's most recent shale well in the Bowland Sub-basin, the **Anna's Road-1**, was abandoned at a depth of 2,000 ft due to drilling problems. The well was expected to be re-spud in January 2013 and completed in about four weeks, with the top Bowland Shale predicted at a depth of about 3100 m.

IGAS Energy Plc, 24.5% owned by Nexen and the UK's largest onshore operator of oil and gas fields, is evaluating the shale gas potential of its blocks. IGAS had acquired Nexen's portfolio of UK coalbed methane licenses in March 2011. The company reported that at its Point of Ayr acreage has shale extending over the entire block with an expected average thickness of more than 800 ft. IGAS Energy noted that a significant proportion of its acreage in the northwest England—from Ellesmere Port in the west in PEDL 190 to the Trafford Centre in the east within PEDL 193—is considered to have shale potential.

In 2011-12 IGAS drilled the **Ince Marshes-1** well to a total depth of 5,714 ft in the Bowland Sub-basin. Originally intended as a shallow coalbed methane test, the well was deepened and encountered the upper two-thirds of the Bowland Shale at depths of 4,200 to 5,200 ft. The Bowland Shale, estimated at 1,600-ft total thickness, had gas shows and TOC ranging from 1.2% to 6.9% (average 2.7%). Thermal maturity appeared to be in the wet gas window (R_o 1.0-1.1%).[17]

Dart Energy, based in Australia and Singapore, holds a significant shale position in the UK, including the western Pennine Basin, but has not yet drilled for shale there or elsewhere in the country. Dart's 14 PEDL's with shale potential, part of its acquisitions of coalbed methane operators Composite and Greenpark Energy, total about 3,700 km^2 in gross area. Third-party consultant NSAI has estimated these blocks hold approximately 65 Tcf of total shale GIP, of which approximately 30.5 Tcf is located in the western Pennine Basin (gross, Best Estimate).

No shale drilling has occurred yet on the eastern side of the Bowland Shale Region. Dart Energy holds the largest land position, a total of 13 licenses covering about 1,235 km^2. NSAI has estimated that Dart's blocks hold about 47.6 Tcf of shale GIP (gross, Best Estimate). Houston-based eCORP International, LLC has committed to drilling and coring a horizontal well by 2014 to farm into one of Dart's blocks. Separately, IGAS estimates it holds 388 km^2 of shale-prospective area in 9 licenses in this region.

Dart Energy, the only active shale operator in the Midland Valley Basin, has not announced firm plans for shale drilling. BG Group remains a joint-venture partner on Dart's Lothian Shale interval in this region.

Much further to the south, Australia-based **Eden Energy** and UK-based **Coastal Oil and Gas Ltd.** jointly control 2100 km^2 of shale gas and coalbed methane potential in South Wales, Bristol, and Kent. Prospective recoverable shale gas resources were estimated by Eden's third-party consultant to be 18.3 Tcf out of a total 49.8 Tcf of GIP (gross; Best Estimate). This includes 806 km^2 within 7 PEDLs in South Wales with potential in the Namurian Measures. However, this region was not assessed by EIA/ARI because of limited publicly available data.

2. SOUTH UK JURASSIC SHALE REGION

2.1 Introduction and Geologic Setting

The Wessex and Weald basins region of southern England is the UK's principal onshore oil-producing area. Both basins produce oil and some natural gas from conventional Jurassic and Triassic clastic and carbonate reservoirs which were sourced by Jurassic marine shales. The Wessex Basin hosts the 500 million bbl Wytch Farm oil field, by far the country's largest onshore field, whereas the Weald Basin has several much smaller oil fields.

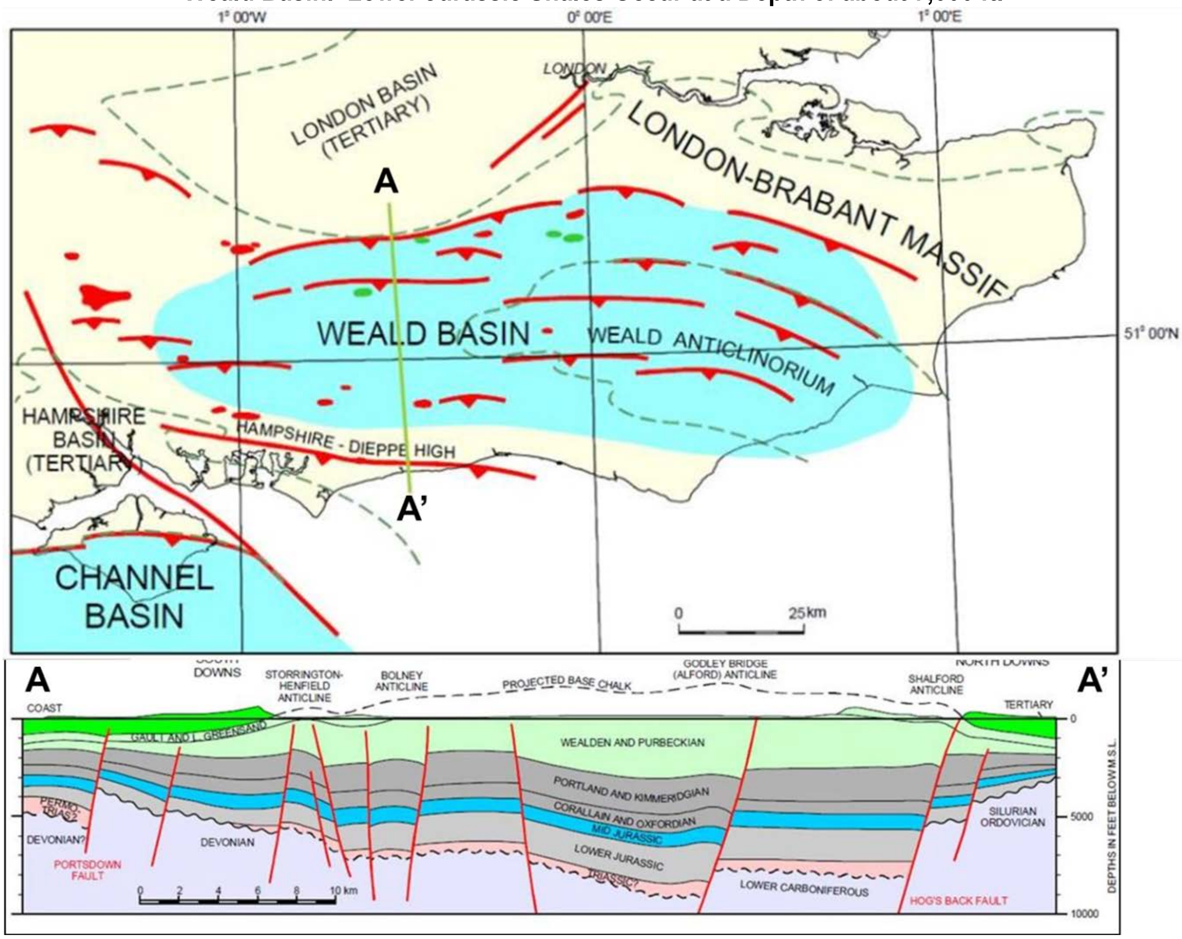
The Wessex Basin comprises a series of post-Variscan extensional sedimentary troughs and intra-basinal highs, located mainly in Hampshire and Dorset and extending into adjacent offshore areas. The Weald Basin is a better defined and structurally simpler syncline located in Sussex, Surrey, and Kent. The basins are separated by the Hampshire-Dieppe High, but the boundary is indistinct and the two basins were intermittently connected during Mesozoic deposition. They contain repeating cycles of Jurassic shallow-water marine mudrocks, sandstones, and limestones which are overlain by largely non-marine sediments of the Lower Cretaceous Wealden Group.

For the purpose of this study, the Wessex and Weald basins are considered a single Jurassic oil-prone shale resource region. Additional Jurassic shale areas with affinity to the Wessex Basin may exist further to the west (e.g., Bristol Channel Basin), but these were not assessed.[18]

The structural geology of the Wessex and Weald basins is somewhat simpler than most other UK shale regions, although still more complex and faulted than North American shale plays. While not intensively deformed, these basins comprise a series of individual sub-basins separated by normal faults. For example, the Wessex Basin comprises four smaller half-grabens (Pewsey, Mere-Portsdown, Dorset and Channel).

Figure XI-12 shows that roughly 10,000-ft thick of Lower Carboniferous to Tertiary sedimentary rocks is present in the Weald Basin. Lower Jurassic organic-rich shales reach depths of about 7,000 ft or more along the basin axis. Interior faults appear to be relatively few, spaced about 5 to 10 km apart, and seemingly allow ample room for shale development. The strata dip quite gently, only a few degrees.

Figure XI-12: Geologic Map and Generalized Structural Cross-Section of the Weald Basin. Lower Jurassic Shales Occur at a Depth of about 7,000 ft.

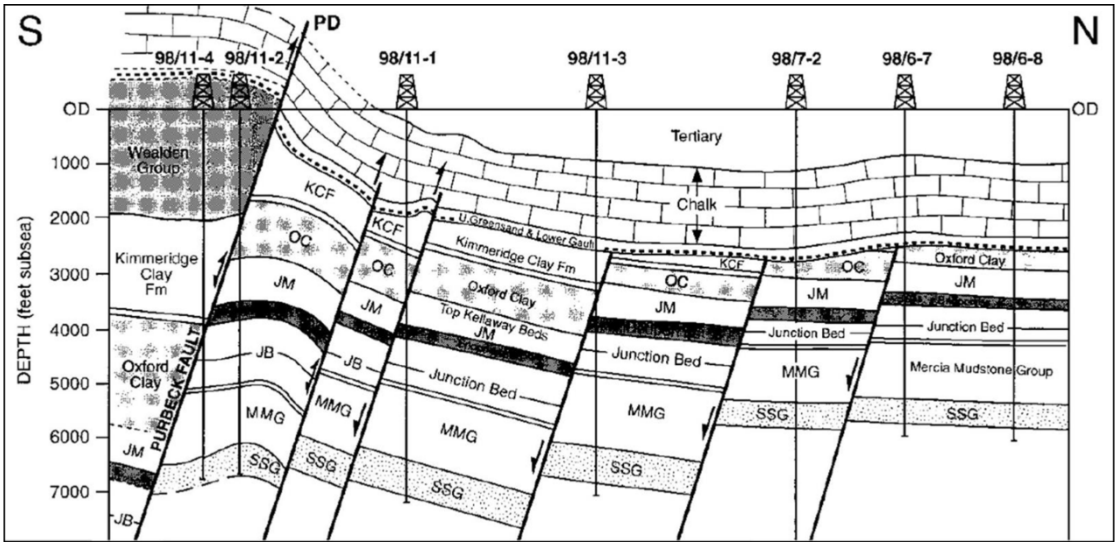


Source: DTI, 2003

However, close-spaced drilling often reveals the presence of additional faults. Indeed, a detailed cross-section of the southern portion of the Wessex Basin, constrained by multiple wells, shows a series of closely spaced faults, Figure XI-13. The depth to the Lias (JB) in this offshore setting south of Wytch oil field ranges from 4,000 to 5,000 ft. Note how each well is located in a separate fault block. Further drilling is likely to discover additional faults.

The Jurassic section comprises an alternating sequence of organic-rich mudstones and carbonates with subordinate sandstones. The main source rocks and potential shale targets in this region are several Jurassic-age shale formations, which are mainly oil-prone in deeper settings (immature elsewhere), in contrast with the mostly dry-gas prone Carboniferous shales of northern England and Scotland.

Figure XI-13: Structural Cross-Section of a 9-Mile Long Portion of the Wessex Basin, Located Offshore Just South of Wytch Oil Field, Showing Depth to the Lias (JB) Ranging from 4,000 to 5,000 ft. Note How Each Well is Located in a Separate Fault Block and Further Drilling is Likely to Discover Additional Faults.



Source: Underhill and Paterson, 1998

The Lias, Kimmeridge, and Oxford clays contain Types II (algal sapropelic), III (terrestrial plant), and II/III (mixed or degraded) kerogen sources. Thermal maturity is highly variable, dependent upon the complex structural evolution of the basins. In general, thermal maturity increases towards the centers of the Wessex and Weald basins, where it reaches adequate rank for shale oil exploration.

The Lower Lias Clays (L. Jurassic), the most important source rock in the region as well as the main shale target, consists of interbedded shales, mudstones, marls and micritic limestones. Lower Lias shales contain 0.5% to 2.1% TOC, reaching as high as 7%. The isotopic character of conventional oils in the Weald Basin (35-42° API gravity) matches with that of the Lower Liassic, indicating close source rock genesis. Organic matter is predominantly sapropelic oil-prone kerogen derived from marine plankton.[19] While vertical TOC variation is considerable, the eastern Weald Basin appears to have lower TOC.

The Arreton 2 well, a key data point located south of the Isle of Wight monocline, recorded oil-prone thermal maturity of 0.8% to 0.9% R_o in the Lias. Similar oil-prone maturity was noted at Penshurst in the central Weald Basin. Thermal maturity modeling indicates that the Lias is within the oil window across much of the Wessex-Channel Basin, perhaps becoming marginally gas-prone in the Pewsey Sub-Basin.

Secondary potential exists in the Oxford (up to 12% TOC) and Kimmeridge clays (up to 20% TOC) in the Upper Jurassic. The Upper Jurassic Kimmeridge Clay consists of alternating shales (including oil shales), calcareous mudstones, interbedded micritic limestones, and thin sandstones and siltstones. The TOC of some thin black shales frequently reaches 10%, occasionally even 20%. Britain's first natural gas well, drilled in 1895 at Heathfield in Sussex, produced 1,000 ft^3/d from an unstimulated Kimmeridge Clay section. However, the Kimmeridge Clay is considered thermally immature in the Wessex-Weald region, apart possibly from the northernmost axial part of the Wessex-Channel Basin. The Upper Jurassic Oxford Clay is organic-rich, reaching 10% TOC, but likewise is thermally immature. Consequently, the Kimmeridge and Oxford clays were excluded from our evaluation.

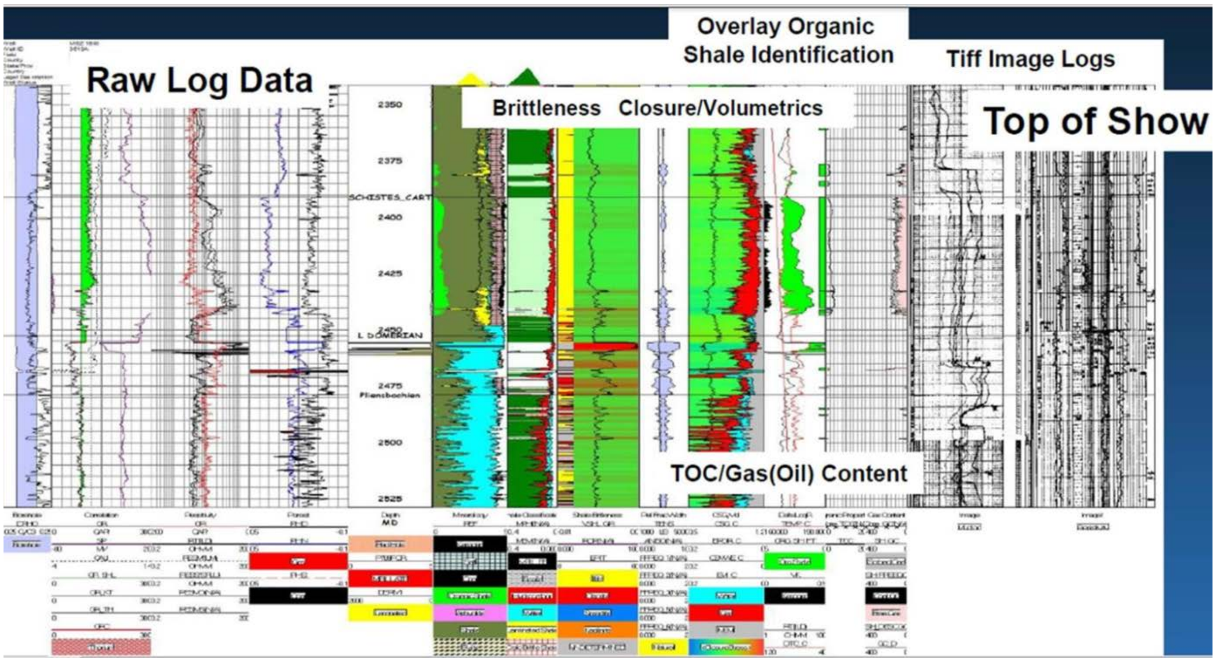
Porosity and permeability of the Jurassic shales are likely to be higher than in the Carboniferous because they have not been subject to as much compaction. Jurassic mudstones encountered in shallow (<30 m) engineering boreholes have porosities in the range 30-40%. However, Jurassic shales buried at depths of 1-5 km are likely to have much lower porosity, perhaps 7%.

2.2 Reservoir Properties (Prospective Area)

The Lias shales average about 600 thick (gross) in the Wessex and Weald basins. Organic-rich thickness of the most oil-saturated and brittle zones, based on analysis of the Lias in the Paris Basin,[20] is estimated at approximately 165 ft, Figure XI-14. Depth to the Lias reaches 6,000 ft in the Weald Basin, averaging about 5,000 ft deep. TOC of the prospective zone is estimated to average 3% but could be considerably higher. Porosity, estimated at 7%, is likely to be higher than older Carboniferous shales, but lower than the 30-40% porosity measured at shallow locations near outcrop.[21] The current average geothermal gradient is 33°C/km.

Although not assessed, the Jurassic Kimmeridge Clay, another potential source rock in the Wessex and Weald basins, is notable for containing thin limestone stringers. These include coccolithic carbonates which are somewhat similar to the lithology of the carbonate-rich Mid-Bakken Shale in North Dakota.

Figure XI-14: Log Suite Showing the Jurassic Lias In the Paris Basin, as a Proxy for the Wessex-Weald Shale Region in the UK



Source: M. Mullen, Realm Energy, 2011

2.3 Resource Assessment

The Wessex and Weald basins extend over an onshore area of approximately 3,500 mi^2. The prospective area was estimated to be half of total area (1,740 mi^2), with the remaining area excluded due to potential faulting, shallow depth, erosion of the Lias, and surface access issues. Out of a risked shale oil in-place of 17 Bbbl and risked shale gas in-place of 8 Tcf, the risked, technically recoverable resources are estimated to be 0.7 billion barrels of shale oil and 0.6 Tcf of associated shale gas, Tables XI-1 and XI-2.

Celtique Energie has reported that the Liassic Shale at their Weald Basin licenses ranges from 9,000 to 13,000 ft deep within a 467-km^2 prospective area. The company estimated that the Liassic could have mean recoverable shale oil and shale gas resources of 125 million barrels of oil and 10 Tcf of shale gas.

2.4 Recent Activity

Privately held **Celtique Energie** holds licenses in three areas of the UK: the Cheshire Basin, East Midlands, and the Weald Basin. In the Weald Basin, Celtique has a 50% share in licenses covering 1,000 sq km. The company claims to have unconventional oil and gas potential in the Jurassic Liassic shales, as well as conventional potential in the Triassic. No shale drilling has been reported.

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