Basement exploration, West of Shetlands: progress in opening a new play on the UKCS

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Abstract: Commercial production of hydrocarbon from fractured crystalline basement is well documented, with petroleum basins across the globe hosting fractured basement fields. The UK is an anomaly within this global phenomenon as, despite numerous serendipitous discoveries of basement oil in the North Sea and the West of Shetlands, there is currently no commercial field on the United Kingdom Continental Shelf (UKCS) that is reliant on oil production from fractured basement. Recognizing that this situation presented an exploration niche, Hurricane Energy plc (Hurricane) was formed to focus on UKCS basement exploration and concentrated its efforts in acquiring exploration acreage in the West of Shetlands. In 2009 Hurricane drilled the first well designed to explore the basement play on the UKCS, leading to the Lancaster Discovery with a contingent resource range (1C–3C) of 62–456 million barrels of oil equivalent (MMboe). The Lancaster Discovery is presented to summarize the challenges and processes that have been applied in the exploration and evaluation of the West of Shetlands basement play. Conclusions from this work indicate that basement hydrocarbon resource potential is of such significance that it may represent a strategic resource for the UK, with over 1154 MMboe of 2C and mean unrisked prospective resources so far identified.

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The Lancaster Discovery is located in Quad 205 West of Shetlands (WoS), SE of the Foinaven and Schiehallion fields and NE of the Solan Field (Fig. 1). Lancaster is located on the Rona Ridge, a prominent NE–SW-trending basement high which acts as a structural feature separating the Faroe–Shetland Basin from the West Shetland and the East Solan basins (Figs 1 & 2). The Lancaster Discovery is the result of the first UK exploration well drilled specifically to evaluate basement as an exploration play. While Lancaster is considered to be the first UKCS basement exploration well, it is important to note that it is not the first basement discovery. Many UK wells have been drilled into the basement with a significant number of these being cored and tested, each adding to an important database of serendipitous UK basement discoveries. With the exploration success of Lancaster and the nearby Whirlwind discoveries (Fig. 1), the remaining challenge to proving a UK basement play is to demonstrate proven basement reserves. That stated, the data and story behind the Lancaster Discovery is encouraging, and Hurricane believes that realization of UK basement reserves is simply a function of further investment in appraisal drilling and planning for field development. This perspective is not considered to be optimistic when considered in context with the global experience of basement discoveries, many of which were made accidentally and yet have still led to world-class producing assets. A summary of the rationale, planning and operations that resulted in the Lancaster Discovery is provided as well as insight into some of the key challenges that have been overcome in evaluating one of the UK’s few remaining unproven hydrocarbon plays.

The basement play
Naturally fractured crystalline basement reservoirs (basement reservoirs) are a global phenomenon, as depicted in Figure 3 (see also Aguillera 1995; Nelson 2001; Petford & McCaffrey 2003; Gutmanis et al. 2012). Despite the proven commercial success of basement reservoirs it has long been recognized that basement reservoirs are a globally underexplored play (Eggleston 1948; Hubbert & Willis 1955; Landnes 1959; Landnes et al. 1960; P’an 1982). Support for this perspective arises from the fact that basement reservoir discoveries have historically occurred more by chance rather than as a result of basement-focused exploration programmes. A successful reverse in this trend has however been seen in recent years resulting in numerous basement oil discoveries and increasing numbers of basement field developments. Examples can be found in Yemen and Vietnam, both of which have enjoyed material impacts to reserves as a result of basement field developments (Areshev et al. 1992;
San et al. 1997; Tran et al. 2006; De Urreiztieta et al. 2007; Gutmanis 2009; Cuong & Warren 2011; Gutmanis et al. 2012).

The petroleum system components of basement reservoirs are no different from those of conventional clastic reservoirs. The basement trap is typically a four-way dip closed structure, either a faulted block or buried hill (or combination of the two) or the trap can be formed as the flank of a tilted fault block. Source rock is generally found proximal to the trap juxtaposed as onlapping or capping successions. The reservoir typically comprises lithologies such as granite, granodiorite and gneiss with secondary lithologies including dolerite and basalt. The basement reservoir poro-perm system is provided by fractures ranging in scale from faults detectable from seismic data to those fractures that can be detected and quantified from the evaluation of core. Basement reservoirs tend to have complex geological histories with fracture properties resulting from a combination of tectonic, hydrothermal and epithermal processes.

Analysis of well data in the West of Shetlands led Hurricane to the conclusion that, of the wells with serendipitous basement discoveries, very few had penetrated significant intervals of basement. From the perspective of basement exploration a significant penetration is considered to be 100–300 m as analogue data indicates that any penetration less than this is unlikely to confirm the presence of permeability or mobile hydrocarbon (Agulliera 1996). At the time of study, the majority of basement penetrations in the WoS were typically less than 50 m TVT. One important exception to this trend is the Clair Field discovery well 206/7-1 which, although targeting a sedimentary succession, additionally penetrated a potential oil column of at least 200 m in the Lewisian Basement. An appraisal of fractured Devonian sandstone and the underlying fractured Lewisian was undertaken by a subsequent deviated well, 206/7a-2, which tested the basement through a 530-m-long horizontal section. The basement was characterized as faulted, fractured and weathered. After acidification, production rates from the basement were reported as 2110 barrels of oil per day (bopd) from an interval having five fracture zones.

As part of Hurricane’s data review an analysis of the fracture trends recorded from the 206/7a-2 well and review of the well’s position relative to mapped seismic faults was undertaken. A conclusion of this work was that 206/7a-2 had not been located or oriented optimally to evaluate the basement potential. This observation, coupled with the limited number and limited depth of basement penetrations in the WoS, provided support to Hurricane’s supposition that the basement in the West of Shetlands was a material play requiring a bespoke exploration well.

Fig. 1. Location of the Lancaster and Whirlwind basement discoveries, Quad 205 West of Shetlands.
Fig. 2. Regional cross-section across the Rona Ridge portraying the structural disposition of the Lancaster Prospect and its relationship to the ‘hydrocarbon kitchens’ of the Foula Sub-Basin and East Solan basin.
After completing a narrowing process that involved the evaluation of 2D seismic, offset well data and regional geological analysis, an application was made for a nine-block Frontier Licence in the UK Offshore 23rd Licencing Round. The licence application area included a large basement high, the Lancaster Prospect, that had been previously drilled in 1974 (by well 205/21-1a) to evaluate a Mesozoic clastic succession which onlapped the basement. The 205/21-1a well was a discovery, testing oil to surface and recovering core which supported oil-bearing clastics and oil associated with fractures in the underlying basement. The well was plugged and abandoned with the operator concluding that the clastics were of non-reservoir quality. Hurricane’s preliminary interpretation of composite log and end-of-well reports indicated that not only was there potential for commercial volumes of oil to be present in the basement, but that the oil would most likely be light. A provisional assessment of the Lancaster Prospect resource potential was achieved through a thorough evaluation of producing basement field analogues and WoS well data. Global analogues provided insight into basement reservoir properties, exploration histories and appraisal/development strategies, all of which combined to provide a template of basement reservoir characteristics and a basement exploration strategy (see Wu et al. 2005 for exploration applications of analogues). Analogue information also provided ranges and averages applied in assessing basement resource potential. Core data from the WoS was used as a control on analogue porosity types and porosity ranges. The initial assessment of the Lancaster Prospect resource potential was a P50 of 191 million barrels (MMbbl) of oil recoverable which consisted of a conventional closure model and a combined conventional closure/flank upside model, the latter reflecting the stratigraphic trapping nature of buried hill traps and the potential for extensive hydrocarbon columns and flank accumulations reported in analogue datasets.

Despite Hurricane’s perceived technical low risk of the Lancaster Prospect, the mechanics of making a successful licence application raised the first challenge in exploring the UK basement play: the challenge of funding. Funding was difficult as the concept of basement was untried in the UK, Hurricane as a company had no track record and the company had no licence. Hurricane was faced with the classic ‘Catch 22’ conundrum of no licence no funds, no funds no licence. Ultimately sufficient funds were raised to accommodate the proposed licence work programme and therefore secure the licence, but not without overcoming challenges raised by geological advisors to the finance community. Many advisors, professional geoscientists, doubted the validity of a UKCS basement play. Furthermore they considered the West of Shetlands to be a heavy oil province which would add significant risk to the basement play concept. Many potential investors heeded their geological advisors and decided that the Hurricane story was not for them; however, a core group of investors bought into the story and, thanks to their vision and support, Hurricane has now achieved two significant basement discoveries.

Having overcome the financial hurdle, the remaining pre-drill challenges distilled to three
key points: (1) identifying a robust drilling target that would effectively evaluate the basement reservoir and its hydrocarbon bearing potential; (2) establishing the source of the 205/21-1a basement oil; and (3) establishing a safe and optimum method of drilling the basement. Before describing how these technical challenges were overcome it is prudent to review the petroleum system in which the Lancaster prospect resides.

**Lancaster petroleum system**

The petroleum system elements that are relevant to the WoS basement play are associated with the Rona Ridge, a major tectonic feature depicted in Figure 2. The Rona Ridge is composed of a NE–SW-trending basement structure stratigraphically classified as the Lewisian Basement (see inset, Fig. 2). The Lewisian Basement is a remnant of Pre-Cambrian crust. Recovered core and cuttings from offset wells indicate the Rona Ridge to be composed of gneiss and granite with subordinate basic rock (dolerite and diorite). The basic rock is either the result of segregation in the early melt or post-cooling intrusions. Local deformation to cataclasite and tachylite is also noted proximal to fault/shear zones.

The trap at Lancaster is a buried hill with a four-way dip closed crest, formed as a result of the rifting and opening of the NE Atlantic during Jurassic–Cretaceous time and subsequent uplifting during phases of Tertiary compression. Specifically, the Lancaster buried hill trap results from the Cretaceous drowning of the Rona Ridge that had previously existed as an uplifted region from at least Devonian–Carboniferous time to Jurassic time. Top and lateral seal is provided by Upper Cretaceous mudstones. The source for Lancaster is provided by the Kimmeridge Clay formation which onlaps on the Rona Ridge. The Kimmeridge Clay Formation has been at sufficient depth for hydrocarbon to be generated on both sides of the Rona Ridge, specifically within the Foula Sub-Basin to the north, in the main Faroe Shetland Basin and also in the East Solan Basin to the south (Fig. 2).

The Lancaster reservoir is the Lewisian Basement and is considered a Type 1 fractured reservoir (Nelson 2001). Type 1 fractured reservoirs owe their productivity and storativity to a hydrodynamic fracture network which is a subset of the natural fracture network, consisting of fractures that are spatially connected and collectively capable of transmitting fluid. Fluid flow in the hydrodynamic network is controlled by: (a) fracture connectivity; (b) the relative magnitude of fluid pressure and lithostatic pressure; and (c) the magnitude and orientation of the mean stress across the fracture network (Jolly & Cosgrove 2003).

Although fractures have traditionally been considered by geoscientists and reservoir engineers as a series of smooth-sided parallel plates (Reiss 1980), the reality is far more complex as fluid flow within the hydrodynamic network is a function of channelling. Fracture fluid flow cannot therefore be assumed to be related to aperture at a specific location. Channelling within a fracture is controlled by a critical path of connected void space (Pyrak-Nolte et al. 1987; Tsang & Tsang 1989); consequently, fracture network flow properties are more like those of fluvial systems.

The Lewisian Basement comprises a number of specific fractures identified from subsurface and outcrop analogue data, each of which has the potential to contribute to the hydrodynamic fracture network: (a) faults; (b) regional joints; (c) shear fractures; and (d) sheet fractures. From the prospective basement, exploration faults are partitioned as seismic- and subseismic-scale features. Seismic-scale faults represent specific mappable features that are considered as potential drilling targets and can be readily interpreted at the basement level from the analysis of 3D seismic data. Subseismic faults are detectable from image logs and core and consequently do not represent potential drilling targets. Faults are associated with a fault damage zone (fault zone) which includes a variety of fractures and a range of rock fabrics associated with fault rock. Specific rock fabrics of exploration interest include fault breccia, which can be associated with pervasive fracturing at the scale of core measurement. Faults within the basement that are most likely to act as super-conduits for fluid flow are those that have been heavily reactivated by several phases of brittle deformation (Holdsworth et al. 2007). Regional joints, detectable from image log data, are fractures having no detectable shear movement and that have a specific orientation that is persistent across a given structure or geological/geographical region. Regional joints are considered to include cross joints and regional longitudinal fractures as described by Cloos (1922). Regional joints are not treated as a specific drilling target but are given consideration in the planning of exploration and appraisal well paths. Shear fractures have a detectable shear displacement and are often associated with fault rock. The identification of shear fractures is important as an aid in defining fault zones and subseismic faults. Sheet fractures are a phenomenon associated with the unloading of basement during uplift. Sheet fractures do not form an explicit exploration target although it is recognized that, as in the case of regional joints, sheet fractures have the potential to improve the connectivity of the hydrodynamic fracture network and thereby increase the drainage potential of the Lewisian Basement.
The identification of the prospective fracture types present in the Lewisian basement is a key step in developing a conceptual exploration model; however, it is also important to evaluate the potential for epithermal and hydrothermal processes to have contributed to the properties of the hydrodynamic fracture network, as the analysis of global analogues indicate that such processes are important geological components in producing basement fields (Dimitriyevskiy et al. 1993; Petford & McCaffey 2003; Li et al. 2004; C&C Reservoirs 2005; Geoscience 2007). The Lewisian Basement has a long geological history of subaerial exposure and orogenic activity; there is therefore significant potential to enhance fracture network drainage through epithermal and hydrothermal processes. Minerals associated with epithermal processes have been recorded from basement cores recovered from the Rona Ridge and include feldspar and calcite dissolution (porosity enhancing), kaolinite and pervasive haematite cements (porosity reduction). Weathering of basement reservoirs can represent preferential exploration targets (Areshev et al. 1992), but while the process of subaerial exposure can result in enhanced porosity and permeability, it can also generate porosity and permeability inhibiting clays which reduce reservoir potential. Offset and analogue data indicated that at Lancaster such processes are expected to be concentrated within the longer and better-connected fault planes as well as any joint systems hydraulically connected to unconformity surfaces. Evidence of hydrothermal alteration of the Rona Ridge basement is explicitly noted in offset well 208/27-2 by the presence of minerals such as epidote, iron pyrite and chlorite. These minerals are commonly associated as vein fill from Rona Ridge basement core. Hydrothermal products including epidote, opaque magnetite or goethite and sericite/talc are also recorded from sidewall cores recovered from the Lancaster Discovery. It is also worth noting that hydrocarbon-stained calcite vein fill is ubiquitous in Rona Ridge basement cores and is also described in basement cuttings and sidewall cores recovered from Lancaster. Dissolution of vein calcite is also recorded from Lancaster sidewall cores and from the offset well 204/23-1, which has whole core measurements describing 2–3 cm vugs in calcite vein fill with up to 20% porosity as inter-crystalline void space.

While it is considered important to understand the potential fracture types and processes that could enhance fracture channelling, it was also considered essential to evaluate offset data to evaluate where the best poro-perm systems are likely to be located within the Rona Ridge and, explicitly, within the Lancaster prospect. After comparing offset composite logs, basement cored intervals, basement well tests and seismic sections from the Rona Ridge it became evident that seismic-scale faults will likely have the greatest potential to exhibit enhanced permeability in the basement. Such an observation is consistent with analogue data which document the importance of faulting in basement rock, as it is the fault zones and fault zone intersections that are associated with the best-developed fracture networks (Younes et al. 1998; C&C Reservoirs 2005). Consequently, defining a robust drillable fault zone became the first step in planning a basement exploration well.

**Planning the basement exploration well**

Given that seismic-scale fault zones were considered to be the primary exploration target, the mapping of seismic-scale faults became an essential element in the exploration work flow. It was apparent from the most rudimentary seismic interpretation of the Lancaster prospect that the basement was highly faulted, so the challenge was to find a seismic fault that would deliver an exploration success. This first step in the process of identifying a drilling target was to develop a conceptual fault target, that is, what combined fault properties are considered optimum to make a discovery? The five key criteria for a drillable seismic fault at Lancaster were considered to be: (a) robust seismic feature; (b) fault is within proven oil-bearing rock volume; (c) fault forms part of a connected fault network; (d) age of the fault is consistent with a history of reactivation; and (e) fault preferentially oriented to the current-day stress field. A robust seismic feature was considered to be a fault trace associated with an obvious offset at the basement reflector and that was also clearly mappable as an extensive lateral feature. The interpreted fault could be identified by both manual and automatic methods (Slightam 2012). The Lancaster structure benefited from the earlier exploration well 205/21-1a drilled in 1974 (Fig. 4). The 205/21-1a well encountered hydrocarbon in the basement and overlying clastic succession. Oil bleeding from fractures was described in the end-of-well report and these data were used to define an oil-down-to contour (Fig. 4) and therefore an associated gross-volume (GRV) in which to locate a suitable fault drilling target. Defining a well-connected fault was achieved by detailed seismic mapping of the fault network, integrating manual and coherency picked faults (Slightam 2012). This approach resulted in a map of the fault network which was then subjected to specialist software designed to provide a numeric connectivity analysis. The results of the connectivity analysis allowed for specific well-connected faults to be highlighted from which
potential drilling targets could then be chosen. An important element in the connectivity analysis was high-grade long faults, as such faults had the greatest potential for extension into the basement and were therefore more likely to be subjected to hydrothermal processes. Fault age is an important consideration as older faults have the greatest potential to be reactivated, and reactivated basement faults are documented as being associated with enhanced permeability (Holdsworth et al. 2007). A further consideration was that older faults are more likely to have undergone more extensive periods of hydrothermal/epithermal enhancement given that the Lewisian Basement has a long history of orogenic activity and subaerial exposure.

It is well documented that there is a significant relationship between the maximum horizontal stress and fracture fluid flow (Heffer & Lean 1993; Ameen 2003; Rogers 2003; Henriksen & Brathen 2006). Stress impacts on fault fluid flow have also been documented (e.g. Barton et al. 1995; Canchani et al. 2003). However, it can be considered that in situ stress has a more limited effect upon the permeability of faults and fault zones in crystalline rocks as the rock mass within the fault zone can accommodate rock stresses in ways other than through the mechanical reduction of fracture aperture. An additional consideration is that channelling enhanced by dissolution/abrasion is less likely to respond to effective aperture reduction through stress-related processes than fracture apertures generated through purely mechanical processes. If seismic-scale faults are being pursued as the most productive targets, considerations of the current in situ stress field may therefore be of secondary importance to the structural history and the possibility of a history of fault reactivation. Predicting the stress magnitude and orientation of the basement’s stress field at a specific proposed well location is a challenge, due to the paucity of bespoke stress measurements available for the Lancaster prospect. Recognizing the difficulty in assessing the current-day stress field, a variety of stress evaluation methods were employed and the results compared with the objective of establishing end-members for the most likely direction of maximum horizontal stress.

Evaluation of the seismic fault map using the five key criteria for a drillable fault target led to a specific well location that accommodated the drilling of two seismic-scale faults (Fig. 4). The faults were interpreted as being vertical based on
inferences from outcrop analogues; this interpretation was subsequently supported by the Lancaster well result. Given the uncertainty of the stress conditions acting on the reservoir, and indeed the degree by which stress would affect fluid flow, it was decided that drilling across faults with different strike orientations (Fig. 4) would provide an improved chance of encountering permeable fault zones and thereby achieving oil to surface. This interpretation was further supported by coherency analysis and connectivity analysis that indicated the target faults to be well connected within the identified fault network. Furthermore, Fault 2 was interpreted as being connected directly to a kitchen area to the NW of Lancaster and was consequently considered to be a potential conduit for migrating hydrocarbons from the kitchen to the crest of the Lancaster structure (Fig. 4).

The various geological observations were combined and used to develop two conceptual models: one of the fracture network (Fig. 5) and one of the reservoir within structural closure (Fig. 6). The conceptual models of the fracture network utilize data from producing basement field analogues, seismic mapping of the Lancaster structure and outcrop observations from the Isle of Lewis (Slightam 2012) combined with the previously described observations of: (a) fracture type; (b) potential for hydrodynamic and epithermal enhancement; (c) structural disposition most likely to favour enhanced poro-perm systems. A further key assumption portrayed in Figure 5 is that maximum horizontal stress would be oriented NW–SE, thus preferentially enhancing the fluid flow potential of NW–SE-striking faults and similarly striking fractures within the fracture network. The conceptual fracture network model also indicates that orthogonal fracture sets and faults could contribute to background flow through providing additional connectivity. The ‘background’ fracture network is anticipated to support reasonable fluid flow through the provision of frequent and local high connectivity. Implicit in the Conceptual Fracture Network Model is the assumption that should the actual maximum horizontal stress differ from that modelled, then there would be corresponding effects on the conceptualized fracture behaviour to fluid flow such that preferential fluid flow would be noted within fractures and faults with strike directions aligned to within 45° of $S_{\text{Hmax}}$ (Fig. 5).

The conceptual model of the ‘basement reservoir within structural closure’ was derived from observations gained from reviewing field analogue data and offset well data. It was used primarily to convey understanding of fluid distribution and the concept of a threefold facies scheme, which was
used as a template for pre-drill volumetric analysis, and to act as a reference for well planning. The facies, which are based on the faults identified from seismic data, include Pseudomatrix, Inner Fault Zone and Outer Fault Zone (Fig. 6).

The conceptual model considers seismic-scale faults to be linear bodies and associated with volumes of faulted and fractured rock distributed within a fault zone. Fault zones are characterized as two facies: Inner Fault Zone and Outer Fault Zone (Fig. 6).

The Inner Fault Zone is effectively the volume of rock associated within the immediate vicinity of the fault plane and is associated with the greatest degree of fracturing. Such fracturing is considered to be at a range of scales with fracture lengths ranging from the core scale (pervasively fractured rock) up to decametre fracture lengths. Small-scale fractures are anticipated to have highly variable fracture strike azimuths whereas longer fractures are anticipated to have fracture strike azimuths parallel to the seismically mapped fault trace. The fracture network within the Inner Fault Zone was anticipated to be highly connected with relatively enhanced apertures. The Inner Fault Zone aperture enhancement and connectivity are physical properties related to preferential fluid flow associated with hydrothermal and epithermal processes. The Inner Fault Zone would also include volume(s) of fault core which was anticipated to be cataclasite and consequently a local seal or low permeability volume.

The Outer Fault Zone is the GRV volume located between the Inner Fault Zone and the Pseudomatrix. Fracture frequency was anticipated to diminish as a function of distance away from the Inner Fault Zone.

The Pseudomatrix is the facies term applied to the remaining GRV and comprises fractures and subseismic-scale faults. Fracture orientations within the Pseudomatrix were anticipated to be dominated by regional fracture strike trends but also to be
influenced by local seismic-scale and subseismic-scale faults (Fig. 5). The Pseudomatrix was considered to be associated with a wider range of fracture strike azimuths than Fault Zones resulting in a fracture network with local volumes of high connectivity, which could contribute to fluid flow (Fig. 5). However, it was anticipated that the Pseudomatrix would have a significantly less-well-connected hydrodynamic network than the Fault Zones and this would be reflected by significantly smaller effective apertures and lower fracture frequencies.

The nature of the fracture network, described by the conceptual model, would result in significant permeability anisotropy and heterogeneity which in turn would lead to specific volumes of the GRV having relatively poor fracture connectivity. Such regions could be bypassed during phases of hydrocarbon fill, resulting in volumes of perched water. This phenomenon would be exacerbated closer to any aquifer with the fractures within the Pseudomatrix retaining significant volumes of connate water. In contrast, the Inner Fault Zones would be associated with the highest oil saturations with residual water confined to the fracture population having the smallest aperture fractures and, of this water volume, a significant proportion would be considered immobile. Local alteration of the facies reservoir properties was anticipated to occur where the basement surface had been modified by subaerial exposure resulting in a weathered interval as depicted in Figures 5 and 6.

In summary it was anticipated that porosity permeability and oil saturation would increase significantly towards seismic-scale faults with the Inner Fault Zone representing the best-quality reservoir rock. This in turn would result in a variable ‘oil down to’ across the Lancaster prospect (Fig. 7) with an anticipated deeper oil-down-to associated with the structural flank proximal to the Foula Sub-Basin kitchen area (Fig. 9). Such a distribution of oil would in turn lead to the potential of oil being found outside the structural closure. Extensive hydrocarbon column heights are anticipated to be preferentially located proximal to the Faroe Shetland Basin (Foula Sub-Basin) along the NW flank of the Lancaster structure. Hurricane considered that a significant charge, or multiple charges, would be required to generate the necessary oil volumes for oil to accumulate outside of Lancaster’s structural closure. A significant charge was considered unlikely to be provided solely by the East Solan Basin, which meant that the best

![Conceptual model of the Lancaster reservoir across the main crestal area depicting fluid distribution as a function of the reservoir facies Fault Zone and Pseudomatrix.](http://sp.lyellcollection.org/)

Fig. 7. Conceptual model of the Lancaster reservoir across the main crestal area depicting fluid distribution as a function of the reservoir facies Fault Zone and Pseudomatrix.
chance for Lancaster to work as a prospect filled beyond structural spill would be for it to be charged from the Faroe–Shetland Basin.

The second exploration challenge was therefore to establish the source of the 205/21-1a oil. Consequently a geochemical analysis of the oil samples recovered from 205/21-1a core was undertaken. This work was aided by an understanding of the regional basin development (Dean et al. 1999) and a burial history analysis of the Lancaster structure and the local kitchen area proximal to the Lancaster NW structural flank. The conclusions from the oil sample analysis were that the 205/21-1a oil was typical of oils sourced for the Faroe–Shetland Basin and distinct from oil sourced from the East Solan Basin. Hydrocarbon expulsion and timing was modelled using offset well data and pseudo-wells (PW1 and PW2, Fig. 9) located proximal to Lancaster in the Foula Sub-Basin of the Faroe–Shetland Basin (Farrimond 2007).

The results from this work were also correlated to burial history analysis (inset Fig. 9) and indicated that Lancaster had undergone at least two periods of charge with the latest charge occurring during a period of significant uplift post-Neogene time (Figs 9 & 10). An additional observation was that, prior to uplift, Lancaster had been buried to a sufficient depth that it crossed the 80 °C biodegradation threshold and had effectively become ‘pasteurized,’ killing any bacteria within the reservoir. Subsequent charge of the uplifted structure would therefore be unaffected by biodegradation and so the resultant accumulated oil would include a remnant of earlier biodegraded component, but be predominantly a light oil charge. The burial/expulsion history model and the predicted oil type fitted well with the oil density of 0.839 g mL$^{-1}$ recorded from the testing of well 205/21-1a and published data describing regional fluid pulses (Parnell et al. 1999). These and other data were compared as a summary table (Fig. 10) to describe charge and tectonic history of the Lancaster prospect which indicated the favourable combination of coeval uplift and charge.

The combination of seismic mapping and geochemical analysis meant that a provisional well location and well path could be delineated. The exploration objective was to drill and test a 300 m

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**Fig. 8.** Schematic NW–SE cross-section across the Lancaster Prospect portraying hydrocarbon associated with conventional four-way dip closure and oil trapped outside of conventional structural closure described as unconventional upside. Insert table is a summary of pre-drill prospective resource estimates for Lancaster Prospect.
measured depth (MD) section which would cross two subvertical seismic-scale faults. The proposed deviated well path would penetrate the first fault (Fault 1) within the oil-down-to GRV and the second fault (Fault 2) would be penetrated at a depth outside of the structural closure, thus allowing for the testing for oil outside of the structural closure (Figs 4, 8 & 11).

The remaining technical challenge was to determine whether a 300 m basement section could be drilled effectively. Acceptable rate of penetration (ROP), vibration and mud loss management would be required in order to drill the well safely and cost-effectively and to provide quality logging while drilling/measurement while drilling (LWD/MWD) data. Offset and analogue data were used to evaluate bit technology and preferred bottom hole assemblages (SPD 2007, see also Nooraini et al. 2009). Techniques employed for controlling mud loss were reviewed from published examples from the Cuu Long Basin, Vietnam and correlated to drilling fluids performance. One of the challenges of drilling basement is to reduce drilling fluid ingress into open fractures. This is for two reasons: firstly, any solids associated with drilling fluid can reduce fracture permeability; and secondly, fluids can enter the fractured formation and require extensive ‘clean up’ during production testing. This not only adds time to an operation but provides ambiguity in distinguishing formation water from drilling fluids. While there are solutions to fluid loss, such as underbalanced drilling and managed pressure drilling, deployment of such engineering solutions is impractical when an operator is faced with a very limited rig market. Accepting that basement drilling could be a challenge and that losses were to be expected, a review of drilling fluids was undertaken and the optimum solution was determined to be use of a mixed metal oxide mud (MMO), which is a shear thinning fluid and as such has excellent solid suspension when being circulated by mud pumps. When an MMO penetrates a fracture, the fluid is out of the path of the circulating drilling fluid column and is consequently removed from shear processes. It subsequently solidifies into a highly viscous ‘gel’. This solidifying effectively stops mud loss into the fractures. Post-drilling, the MMO can be removed from the fractures by deploying, through coiled tubing, weak acid which breaks down the MMO gel on contact.

Fig. 9. Modelled hydrocarbon expulsion and timing from the Foula Sub-Basin to the Lancaster Prospect. Actual and modelled wells (PW-1 and PW-2) are marked. Inset graph depicts the temperature history, biodegradation threshold and timing of two phases of oil expulsion for the Lancaster prospect.
Part of Hurricane’s operational planning was to have company staff present offshore. This approach arises from the author having the old-fashioned view that a geoscientist should take responsibility for his/her data, and that responsibility starts with data acquisition. While data acquisition includes wireline, testing and vertical seismic profile (VSP) witnessing, the broader context is to ensure that communication between the various disciplines for drilling, mud logging and LWD was optimized. Such an effort is considered paramount for fractured reservoir operations, as early integration of operational data is an essential step in decision making at the well site and in providing supporting information during post-operational data analysis.

With all technical and operational preparations in place, Hurricane was ready to drill what was, to our knowledge, the first well ever planned with the explicit intention of exploring the UK basement play.

**Lancaster operations**

The operational plan was to drill the basement section to the planned total depth (TD) equating to the base of the fault zone associated with Fault 2 and, if there was sufficiently encouraging signs of hydrocarbon presence, to extend the well to a depth recommended by the offshore team. The TD decision would be aided by high-resolution gas chromatography augmented by traditional mud logging techniques. On reaching TD, the well would be cleaned using acid deployed through coiled tubing and tested via a single open hole drillstem test (DST). During testing a production logging tool (PLT) would be run and down-hole fluid samples taken. Prior to testing, the reservoir section would be evaluated through an offset VSP and wireline logging, the latter to include image logs, conventional porosity and resistivity logs and wireline conveyed pressure testing. The latter technique was targeted at measuring pressure within individual fractures.

The operational plan started well with drilling through the basement proceeding better than expected. Clear signs of fractures were detected through drilling breaks and LWD and, despite these positive signs of fracture permeability, mud losses were kept at manageable levels. Additional support for formation permeability was provided by gas peaks, oil-stained cuttings and gas ratios typical of mobile oil. On reaching the planned TD

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**Fig. 10.** Summary of local and regional tectonic events in relations to fluid pulses and local hydrocarbon charge to the Lancaster.
the mud logging/gas chromatography data were supportive of hydrocarbon presence. The well was therefore extended by an additional 248 m, over which a further two faults were crossed (Fig. 11). During operations ROP and vibration while drilling were better than anticipated and, on inspection, the drill bit was seen to have very little wear. This was later determined to be a function of the Lewesian Basement being significantly less abrasive than the granites reported from the Cuu Long Basin, which Hurricane had referred to as one of the most recent analogues for drill bit selection.

At the final extended TD, everything looked extremely positive and wireline operations proceeded with the anticipation of detecting a highly fractured basement succession. The first wireline run included the FMI (Formation Microimager, electrical imaging log) and wellsite interpretation of this data supported the presence of numerous permeable fractures based on the integration of the FMI, gas chromatography, drilling breaks and LWD data. The presence of permeable fractures was later confirmed by running a wireline tester (Schlumberger Modular Dynamic Tester in dual packer mode) and drill stem testing.

Despite the very positive indicators of a highly permeable reservoir, the realization of a significant discovery was diluted by a testing programme fraught with operational difficulties. The first issue arose while running coiled tubing with the inability to deploy the tubing into the open hole due to a blockage within the test string. Despite significant effort, the blockage could not be overcome and testing proceeded without the benefit of cleaning the fractures of the drilling fluid.

After a short flow period to clean up the well, the test produced oil to surface (measured at 38° American Petroleum Institute); however, no stability in the produced fluid was achieved with oil rates significantly lower than water rates. In addition to oil and water production, the well flowed drilling fluid indicating that the well was cleaning up. It was also noted that the produced oil had mixed with the drilling fluid to create an emulsion, the flowing properties of which were unknown. Figure 12 presents representative operational photographs of how the MMO drilling fluid interacted with oil. Added to this unexpected turn of events, the weather was turning for the worst and it was clear that the well would need to be unlatched. In an attempt to reduce the water cut it was decided to cement the open hole to the base of Fault 2 (a depth consistent with very good indicators of a hydrocarbon column) and then unlatch the well.
with the intention of undertaking a second DST. The second DST would hopefully not be associated with a blockage, and coiled tubing could therefore be deployed to clean the fractures of drilling fluid. The second DST would be confined to the interval of the original drilling targets Fault 1 and Fault 2.

On laying out the DST string on deck and later inspection under laboratory conditions it was determined that the SenTree component of the DST string was packed with rubber and the ball valve would only partially open. DST 1 had therefore been undertaken through highly restricted tubing which compromised the ability to achieve an optimum flow. Analysis of the rubber and inspection of the blowout preventer (BOP) confirmed that the rubber was sourced from the BOP due to an earlier stripping operation.

DST 2 was also undertaken without the benefit of running coiled tubing. In this instance the coiled tubing was not run due to time constraints imposed by anticipated bad weather. The DST 2 results showed no material improvement despite a short period of 100% oil flow. Analysis of BS&W (bottom sediment and water) indicated that produced fluids were being impacted by drilling fluid and that the drilling fluid was reacting with the oil to create an emulsion, as in DST 1. The produced fluids from DST 2 can be summarized as 200 bopd, (15% of total flow) v. 1200 barrels of water per day (bwpd), 85% of total flow. Given the compromised nature of the DSTs, the decision was made to suspend the well with the intention of returning to Lancaster to undertake a side-track. In summary, the key conclusions from testing the Lancaster well were:

1. a light 38° oil was produced;
2. no H₂S or CO₂ were produced;
3. no depletion was evident;
4. the reservoir was highly permeable;
5. flow rates were limited by a tubing restriction;
6. the well was not cleaned up partly due to limited drawdown due to the rubber debris within the test string and partly due to the return permeability properties of the drilling fluid (which was a significant inhibitor to oil flow and likely to have been a major factor in the poor production performance of the test); and
7. formation water was produced.

Given the 205/21a-4 results the Lancaster side-track (205/21a-4z) was planned with the primary objective of undertaking a test that would significantly reduce the ambiguity of reservoir producibility and fluid distribution. The side-track was drilled in the following year (2010) with the aim of evaluating both Fault 1 and Fault 2, which were penetrated in the original well. The side-track was designed to drill and test Fault 1 and then drill to the base of Fault 2 and then test Fault 1 and Fault 2 as a combined test (Fig. 13). A key part of the rationale behind this plan was to check for mobile water within the Pseudomatrix and each fault zone as the mud logging data acquired during the original well indicated that mobile water could be associated with Fault 1 but was less likely within Fault 2. During both DSTs production logging and fluid sampling was to be undertaken. Seabed pressure gauges were also deployed as it was anticipated that reservoir pressures would be affected by semi-diurnal and diurnal tides; with the provision of accurate seabed data, the reservoir pressures could be corrected for tidal effects. In addition to the testing programme, an extensive wireline programme was planned, expanding on that already procured in 205/21a-4 with the addition of sidewall cores, acoustic imaging and nuclear magnetic resonance.

The side-track logging and testing proceeded as planned with no material incident and procurement of excellent quality static and dynamic data. Wireline data, including wireline pressure

Fig. 12. (a) Characteristics of mixed metal oxide drilling mud during testing aerated foam; (b) fluid sample after gravity segregation demonstrating emulsion and separated water; and (c) foaming oil emulsion at the test separator.
measurements, supported the presence of numerous permeable fractures and the well test results over the comimilled interval (geological equivalent to the original well DST 2) providing encouraging results with oil flow rates significantly in excess of that achieved in the original well and water rates reduced to 8% of flow being confined to a single fracture associated with Fault 2. A comparison of the DSTs over the Fault 1 and Fault 2 interval from the original and the side-track are provided in Figure 14. Analysis of the side-track well test data supports the assumption that the majority of the reservoir is fractured and productive. The well was also associated with significant skin attributed to cuttings ingress and the effects of bull-heading; despite this, a maximum flow rate of 2500 bopd was achieved (the original well achieved a maximum oil flow rate of 200 bopd). Post-well analysis indicates that should well damage and the associated skin be overcome, the reservoir should be able to achieve sustainable rates in excess of 10 000 bopd.

DST 2 is also associated with water production with water from a single fracture being produced on a 48/64″ choke; however, this fracture does not represent an oil-down-to as dry oil was produced from this fracture on a 16/64″ choke and from fractures located deeper in the well (Fig. 15). The origin of the water is yet to be confirmed and it is postulated that the water originates from a depth below the side-track TD, with the water mobility encouraged by preferential ‘injection’ of bull-headed fluid through the wide aperture fracture (aperture estimate accounting for hole deviation and fracture angle is 0.6 m) prior to testing. This thesis is supported by the change in water chemistry during DST 2, which showed a gradation in salinity from that specific to the drilling fluid to that of formation water recorded during testing of the original well.

The key outcome from evaluating the original and side-track data is that the reservoir is highly permeable and far more fractured than predicted in the conceptual model, particularly within the reservoir volume assigned as Pseudomatrix. Permeable and productive fractures have been established by the integration of image logs, PLT and wireline tester data and are found to comprise fractures associated with seismic-scale fault zones and also

Fig. 13. Representation of the Lancaster crestal area portraying the original 205/21a-4 (yellow) and side-track, 205/21a4z, (green) wells and their relative position to Fault 1 and Fault 2.
regional joints sets that are distributed throughout the penetrated intervals. Figure 16 provides examples of representative image log responses for the Lancaster reservoir. Each interval portrayed in Figure 16 is associated with fluid flow as determined from the PLT (refer to Fig. 14). Further details on Lancaster fracture characteristics can be found in Slightam (2012).

Fig. 14. Comparison of (a) original and (b) side-track drill stem test measurements over the interval of Fault 1 and Fault 2. Y-axis: oil water rate (bpd), scale 0–2000 for original and 0–5000 (bpd) for side-track. The marked improvement in the side-track DST is attributed to a test string devoid of blockage and use of brine as a drilling fluid.
Further to analysis of both the original and side-track well data, a surprising and key observation is that the Fault Zone/Pseudomatrix transition cannot be defined by fracture frequency and that no distinction between an Inner and Outer Fault Zone can be made. This conclusion reflects the very high intensity of fractures throughout the logged intervals rather than poor-quality or ambiguous data. This observation is further supported by post-side-track fieldwork undertaken on the Isle of Lewis. As a result, a new approach to interpreting fault zone rock emphasizing the role of highly fractured fault rock is proposed. This approach is illustrated in Figure 15, which compares cumulative and zonal flow from PLTs recorded in the side-track (205/21a4z) over Fault 1 and Fault 1 comingled with Fault 2. DST 1 represents flow from top basement to the base of Fault Zone 1 and DST 2 represents flow from top basement to the base of Fault Zone 2. Refer to Figure 13 for relative position of Fault 1 and Fault 2 to the side-track well path.

Fig. 15. Comparison of cumulative and zonal flow from PLTs recorded in the side-track (205/21a4z) over Fault 1 and Fault 1 comingled with Fault 2. DST 1 represents flow from top basement to the base of Fault Zone 1 and DST 2 represents flow from top basement to the base of Fault Zone 2. Refer to Figure 13 for relative position of Fault 1 and Fault 2 to the side-track well path.

Fig. 16. Representative image logs responses of the Lancaster reservoir. Images are dynamically enhanced over the presented image interval and presented depth increments are 2 ft. Dark colouration is electrically conductive formation; light colour is electrically resistive formation. (a) Relatively wide aperture fracture associated with oil and water production; (b) formation within a Fault Zone close to the Fault Zone/Pseudomatrix boundary; and (c) an example of a relatively wide aperture fracture and an image log fabric interpreted as representing fault rock. Image (b) and (c) are associated with oil inflow identified from the PLT.
result of these well- and field-based observations, a new conceptual model was generated in which the GRV volume is split into Pseudomatrix and Fault Zone (Fig. 17). This bimodal facies split correlates well with wireline facies split correlates well with wireline mudlogging and fracture aperture data and replaces the tripartite split of the original predrill conceptual model as depicted in Figure 6. The bimodal split is also refined by the presence of a pervasive NE–SW regional joint set which is present within Pseudomatrix and Fault Zone intervals. A further refinement of the original conceptual model is that the effects of weathering have been removed from the conceptual model as neither the side-track nor the original well show any significant rock mass weathering effects despite acquisition of sidewall cores, natural gamma and chemical logging data. It is accepted that weathering of the rock mass may be present elsewhere on the Lancaster structure, however it is also acknowledged that granites having a low biotite mica content are more resistant to weathering and may form hills or mountains with abundant rock outcrop and thin, sandy, easily eroded soils. Other refinements to the conceptual model include lithology, with the original conceptual model based only on tonalite (a quartz-rich granite) being refined to include dolerite. The dolerite is distributed with a well-defined North–South strike orientation. Dating of a dolerite sample from the side-track well provides a minimum age of 2.3 billion years, indicating that the dolerite is interpreted as being part of the initial melt rather than a post-cooling intrusion. Image log data indicate dolerite intervals to be highly fractured and the PLT data indicate that fractured dolerite contributes to hydrocarbon flow.

Establishing the Lancaster Discovery resource potential

Fracture reservoirs are a challenge to evaluate from the perspective of establishing hydrocarbon resource volumes. Currently there is no
Acknowledged industry standard for evaluating fractured reservoirs; those companies with fractured reservoir assets develop their own methodology for assessing resource volumes. Type 1 fractured reservoirs bring their own specific challenges and Hurricane has worked closely with third-party specialists to develop a robust methodology for establishing fractured basement resource volumes. The details of this approach remain proprietary; however, the method applied provides a mechanism for evaluating and risking hydrocarbon within structural closure and hydrocarbon outside of structural closure. This bilateral split provides a very practical method of accommodating Hurricane’s exploration and appraisal strategy, as well as focusing on the specific resource volume that could be fast tracked to field development. The basic steps to estimating resource volumes are summarized in Figure 18. Figure 18a depicts the faults across the Lancaster structure and is derived from manual fault picks and coherency analysis (Slightam 2012).

Faults are treated as vertical features based on the practicality of modelling software and the interpretation of seismic fault attitude inferred from the evaluation of image log, VSP and outcrop data and the interpretation of intra-basement reflectors. Any disparity between modelled fault geometries and reality is considered to have an insignificant error on calculated in-place volumes. While it is accepted that fault and fracture geometry plays a significant role in the connectivity of the fracture network and consequently the ultimate recoverable volume, the geometry of the fracture network has not explicitly been applied in establishing an effective recovery factor at the time of writing.

A subset of the faults is extracted and transferred to a static 3D model (Fig. 18b). This subset is used to model the two facies component of Fault Zone and Pseudomatrix, each of which has distinct input parameters. This subset is also used to define a dynamic sector model, which is used to predict well rates as well as act as a corroboration of the static model. The modelled GRV is confined by a top surface which is provided by the top basement reflector (Fig. 18c) and a bottom surface represented by an ODT. The ODT is variable to allow for the modelling of oil within structural closure and without structural closure. A depiction of a single realization of a model based on a deep oil contact is seen by reference to Figure 19.

Input parameters for the facies are chosen to reflect the conceptual model and are constrained by static and dynamic data recorded from the sidetrack and original wells. Net to gross is assumed to be 100%. This reflects the conceptual model of a Type 1 fractured reservoir and is consistent with PLT and image log data which indicate that permeable fractures are pervasively distributed throughout the drilled sections and, by inference, throughout the Lancaster structure. Effective fracture porosity (porosity) is considered to be entirely associated with a hydrodynamic fracture network with no material contribution from the matrix. It was therefore considered that bulk porosity derived from a combination of neutron/density and nuclear magnetic resonance would provide end-member values from which to estimate porosity ranges. The established porosity ranges are consistent with reported analogue data (C&C Reservoirs 2005). Based on the established wireline-derived porosity ranges the average porosity for the gross structure is calculated to be 4.7%. This average porosity value is consistent with porosity estimates derived from history matching of the Lancaster well data and estimates of average fracture porosity derived from image log fracture apertures calibrated to PLT data.

For the purposes of volumetric modelling, bulk porosity measurements are used to populate the facies input parameters. Water saturation ($S_w$) cannot be readily measured in a Type 1 fractured reservoir as the relevant wireline tools run to infer $S_w$ will be affected by near wellbore invasion of saline drilling fluids (Tuan et al. 1995; Ngoc et al. 2007). This fact, coupled with disparities in the measured volume for formation between resistivity tools and porosity tools, further compounds the problem, also exacerbated by the heterogeneous and commonly anisotropic poro-perm systems present in Type 1 fractured reservoirs. While it can be inferred that the irreducible water saturation within a fracture measured at the core plug scale is of order 0–20% (Aguilera 1999; Ngoc et al. 2007), the effective porosity system at Lancaster is not, and cannot be, represented by core or core plug-scale measurements as the flowing fractures as detected by image log and PLT comparison cross-cut the borehole as discrete planes. Such fractures are commonly associated with apertures of sufficient magnitude to cause discernible responses on conventional and high-resolution wireline logs; with apertures estimated to be commonly in excess of 2 cm, such fractures are anticipated to be associated with zero irreducible water (Aguilera 1999).

Despite the inability to measure $S_w$ it is used in the volumetric analysis; however, it is applied primarily to provide an estimate of perched water distribution. Perched water has not been confirmed with the available well data; however, perched water is predicted to be present by the conceptual model and therefore requires inclusion. The thickness of the Fault Zone is determined from a combination of well and outcrop data while the upper and lower boundaries of the Fault Zone within the model are terminated by either basement top
surface or the modelled ODT. Tables 1 and 2 provide summaries of the input parameters applied in the evaluation of the Lancaster GRV within and outside of structural closure. For GRV outside of structural closure, the input parameters are varied to reflect geological uncertainty and the concept that oil distribution will have increased irregularity as a function of the connected fracture pathways, relative proximity to any aquifer and the relative position on the structure with flank locations anticipated to be associated with more extensive oil columns (Table 2).

Once constructed the model was populated with input parameter ranges and various volumetric
modelling estimates were run using a combination of Monte Carlo and static-model-based realizations. Third-party volumetric evaluation, as part of a formal competent persons report, estimate that Lancaster has a contingent (1C-3C) resource range of 62–456 MMboe. The next step towards further de-risking of the Lancaster resource potential is to undertake an appraisal drilling program.

Appraisal wells will be placed and designed so that they can, in the case of success, be readily converted to producing wells. Appraisal well drilling will be targeted to reduce uncertainty on the 1C-2C volumes by further evaluating the ODT and to drill to a sufficient depth that will allow for any aquifer to be evaluated. In addition, appraisal drilling will investigate the potential of achieving improved productivity through a horizontal well.

The first horizontal well will be planned to evaluate the 1C volume, specifically the productivity, fracture network characteristics and potential for perched water within structural closure. If both of these wells prove to be successful it is anticipated that Lancaster will be progressed to a first phase of field development. This first phase will concentrate on accessing the estimated 60 million barrels of recoverable oil within structural closure and in the recognition that excessive ‘high or aggressive’ flow rates will shorten the productive life for the reservoir and result in a lower ultimate recovery. An additional consideration for the successful management of the Lancaster Discovery is that reservoir performance will depend on the drive mechanism. It is therefore critical to gain an understanding of the hydraulic fracture network and

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**Table 1. Input parameters applied to resource evaluation within structural closure**

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<tr>
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<td></td>
<td></td>
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<tr>
<td>Proportion FZ (%)</td>
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<tr>
<td>Porosity FZ (%)</td>
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<tr>
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<td>10</td>
<td>20</td>
</tr>
<tr>
<td>$S_W$ FZ (%)</td>
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<td>5</td>
<td>10</td>
</tr>
<tr>
<td>$B_0$ (rb/stb)</td>
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<td>1.2</td>
</tr>
</tbody>
</table>

$B_0$, oil formation volume factor; PM, Pseudomatrix; FZ, Fault Zone; rb, barrel(s) of oil at reservoir conditions; stb, stock tank barrel.

**Table 2. Input parameters applied to resource evaluation within GRV outside of structural closure**

<table>
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<td>Proportion FZ (%)</td>
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<td></td>
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<tr>
<td>$B_0$ (rb/stb)</td>
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</table>

PM, Pseudomatrix; FZ, Fault Zone.
the drive mechanism ahead of a field development plan. This will require:

(a) the ability to map drillable targets from the available seismic data;
(b) acquisition of sufficient static and dynamic data to effectively quantify the properties of the fracture network; and
(c) acquisition of sufficient static and dynamic data to quantify the properties of an aquifer or gas cap.

Conclusions

The exploration concept that fractured Lewisian basement has the potential to be a productive and material play has been evaluated by two wells on the Lancaster prospect. The exploration program successfully tested the concept that basement would be associated with preferentially permeable seismic-scale fault zones and that oil columns would extend outside of structural closure. The well results also confirmed geochemical modelling that indicated light oil would be present within the basement reservoir. The strategy of spending time in acquiring high-quality and wide-ranging data and the investment in ensuring that company staff have a visible offshore presence has paid off, resulting in a robust estimate of Lancaster’s resource potential. Furthermore, the testing of a pre-drill conceptual model has resulted in a refined geological model from which future operations can be planned with increased confidence. Correlation of well data with seismic data indicates that seismically mapped faults can be identified from wireline data and that such faults are associated with preferential reservoir properties. Comparison of subsurface data with outcrop analogues has proven invaluable in developing conceptual and numerical reservoir models. The observation that the basement play may represent a material resource for the UK is given further encouragement by Hurricane’s second basement discovery, Whirlwind, which was drilled back to back with the Lancaster side-track in 2010. The Whirlwind discovery located some 12km north of Lancaster has very similar reservoir properties to Lancaster and is associated with either volatile light oil or a gas condensate. Contingent resource volumes for Whirlwind are of a similar magnitude to Lancaster ranging from 98 to 373 million stock tank barrels (MMstb) of oil and 236–1017 billion standard cubic feet (Bscf) of gas for the volatile oil case and 236–1017 billion standard cubic feet (Bscf) of gas for the gas condensate case. The current evaluation of two basement discoveries, Lancaster and Whirlwind, and two basement prospects, Lincoln and Typhoon, indicates that basement has the potential to deliver on Hurricane’s acreage 710 MMboe 2C contingent resource estimate and 444 MMboe of un-risked mean prospective resource. In considering such estimates it is important to recognize that the two prospects are associated with oil on structure as confirmed by previous operators’ exploration activities.

In evaluating the basement, Hurricane has attempted new and experimental techniques and has been rewarded by some valuable lessons and insight into a reservoir that has the potential to be a strategic resource for the UK. Lancaster would not have been possible without the philosophy promoted by DTI/DECC to the PESGB in January 2002 in which the clear message was that ‘we want to get licenses in the hands of those who are hungry and innovative’. It was this message that encouraged Hurricane to explore the basement of the Atlantic Margin and it is continued application of this philosophy that will be required to take the UK Basement Play to the next stage and progress Lancaster to reserves and field development.

I would like to thank the reviewers of this manuscript for their comments and suggestions which have helped improve this paper and bring clarity to key issues.

References


