The Lancaster Field: progress in opening the UK’s fractured basement play

A. BELAIDI, D. A. BONTER, C. SLIGHTAM and R. C. TRICE*

Hurricane Energy plc, The Wharf, Abbey Mill Business Park, Lower Eashing, Godalming, Surrey GU7 ZQN, UK

*Correspondence: robert.trice@hurricaneenergy.com

Abstract: To date, fractured crystalline basement reservoirs (basement) on the UK Continental Shelf (UKCS) have largely been underexplored, despite the fact that numerous indications of hydrocarbons have been reported from basement in wells dating back to the 1970s. As production from the UKCS continues to decline, and with the exploration potential of more traditional plays becoming increasingly mature, the potential of the overlooked and underrated basement play warrants further exploration. Over the last 10 years, Hurricane Energy (Hurricane) have deliberately set out to explore the potential of this untapped resource, focusing on the Rona Ridge trend, West of Shetland. The Lancaster Field has been penetrated by four wells and benefits from a full 3D seismic survey, and, as such, represents Hurricane’s most de-risked basement asset. The level of understanding of the Lancaster reservoir is such that Hurricane is now working towards a phased field development. This paper provides a summary of the geology and reservoir characteristics of the Lancaster Discovery, and a description of the technical progress achieved, to date, in de-risking the Lancaster Field.

Drilling history

The Lancaster reservoir is the UK’s first fractured basement field and was granted field status in September 2015. The field is delimited by four wells, each of which has been the subject of drill stem testing resulting in oil to surface. Estimates of the resource potential at Lancaster are provided by an independent Competent Persons Report (CPR), commissioned as part of the process for the admission of Hurricane Energy (Hurricane) to the AIM market in 2014. Consequently, this volumetric assessment has been subject to the 2007 SPE/AAPG/WPC/SPEE Petroleum Resource Management System (PRMS). Volumetric ranges are presented as Table 1: however, it should be noted that the volumetric assessment was written prior to the 205/21a-6 horizontal development well drilled in 2014, the productivity of which transformed Hurricane’s understanding of the Lancaster reservoir productivity potential.

This paper builds on previous publications (Slightam 2012; Trice 2014; Bonter 2015; Belaidi et al. 2016) and provides a summary of the progress Hurricane has made in de-risking Lancaster. The paper is split into five sections covering drilling history, reservoir description, fracture porosity, field simulation and technical de-risking. A concluding section on the future plans for the Lancaster Field is also provided.

Hurricane considered the 205/21-1A test to have been impaired because of reservoir damage induced by overweighted drilling mud and concluded that, with a focused exploration programme, the fractured basement at Lancaster could prove to be a productive reservoir. As a consequence, Hurricane drilled the Lancaster pilot well (205/21a-4) in 2009 on a 100% basis. It was drilled near the crest of the structure in an area of well-defined seismic-scale faults in order to determine the reservoir potential of the faulted and fractured basement. The well encountered four fault zones and a porous/permeable fracture network in the basement that successfully produced light oil (38° API) to the surface on test. Oil shows were also seen in the overlying Lower Cretaceous Victory Sandstone. Over 500 m of vertical thickness of basement was penetrated, with hydrocarbon indicators seen throughout. However, the drill stem tests (DSTs) were compromised by a combination of operational issues and severe formation damage caused by the chosen drilling fluid. The latter, a mixed metal oxide drilling fluid, was selected for its ability to solidify within open fractures to limit losses while drilling, but with the capacity to be broken down and removed by application of a weak citric acid. Unfortunately, operational issues precluded the deployment of acid and, consequently, drill stem testing was severely compromised. Despite the operational issues relating to the testing, the combination of borehole image data and pressure measurements indicated that the reservoir appeared to be of good quality and warranted further appraisal.

In 2010, the pilot well was re-entered and sidetracked (205/21a-4Z), targeting the two shallowest seismically defined fault zones penetrated by 205/21a-4, at a lateral distance of only 40 m away from the original well path. The sidetrack well was also drilled on a 100% basis, and similarly encountered hydrocarbon shows in the Victory Sandstone and in the Lewesian Basement. The Victory Sandstone was cased off and the basement was drilled using a balanced seawater/brine drilling fluid. The first fault zone was penetrated (Fault Zone 1) and DST #1 was performed in this upper section, flowing 38° API oil at rates of 2200 BOPD with no water production. The well was then deepened to the base of the second fault zone (Fault Zone 2) and DST #2 was performed on the combined open hole interval. Stable rates of 2600 BOPD
of 38° API oil and 370 BWPD (barrels of water per day) were achieved. Production logging was carried out on both tests to characterize the flow profile, indicating that productive fractures were present throughout the entire reservoir section (Fig. 2). Comprehensive logging while drilling (LWD) and wireline datasets were acquired in the sidetrack well to help quantify the characteristics of the basement reservoir. Of these, the combination of production logging and borehole image logs confirmed that an effective fracture system was present throughout the penetrated reservoir, and that productivity was not confined by either lithology or depth. Further details describing the 205/21a-4 and 205/21a-4Z drilling and testing operations can be found in Slightam (2012) and Trice (2014).

Well 205/21a-6 (horizontal well) was drilled by Hurricane in 2014 on a 100% basis. The well path penetrate slightly over 1 km horizontally through the reservoir, encountering 10 seismically identified faults within the highly fractured basement. Oil shows were encountered in the Victory Formation overlaying the Lewisian Basement, and also in the fractured basement itself. The Victory Formation was cased off and an open-hole DST was conducted over the entire 8 1/2 inch hole (1003 m). The well was tested both using an electric submersible pump (ESP) and under natural flowing conditions. A stabilized flow rate of 9800 stb/day was achieved using the ESP, which was restricted by surface equipment – primarily the length of the flare booms, which were designed for 10 000 stb/day. A stabilized natural flow rate of 5300 stb/day was achieved, constrained by reaching critical flow conditions in the separator. The oil quality was 38.2° API, with a gas to oil ratio of 363 scf/stb (standard cubic feet per stock tank barrel), and no formation water was produced. Post-well analysis indicated that the reservoir could achieve rates of 20 000 stb/day under a moderate drawdown of 120 psi.

A comprehensive LWD dataset was acquired throughout the basement in the horizontal well to enable full petrophysical interrogation of the fracture network (Belaidi et al. 2016).

### Reservoir description

The Lewisian Basement at Lancaster is a crystalline rock of igneous origin, and in cuttings samples it is dominated by smoky white translucent, occasionally light green translucent, but also commonly variegated, quartz. Petrographical analysis of rotary sidewall cores (RSWCs) primarily classify the basement as a quartz–plagioclase-rich tonalite, which, from comparison to density neutron data, comprises between 80 and 95% of the reservoir gross rock volume (GRV). The tonalite is associated with secondary/authigenic minerals including sericite, epidote, pyrite, hematite, calcite and chlorite. The remaining GRV consists of dolerite and basalt, together with scarce mylonite, cataclasite and breccias. Age dating of the dolerite has revealed a minimum age of 2.3 billion years, which is consistent with published ages for the Lewisian Basement.

The basic conceptual model for the Lancaster reservoir is that it is a Type 1 naturally fractured reservoir (Nelson 2001). Type 1 fractured reservoirs owe their porosity and permeability entirely to the hydrodynamic fracture network, and, as such, the static reservoir description is critical for effective field management. Hurricane’s static reservoir description is based on a deterministic conceptual model derived from Lancaster well data. The geological

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### Table 1. Published resource estimates for the Lancaster Field

<table>
<thead>
<tr>
<th>Resource</th>
<th>STOIP (MMstb)</th>
<th>Recovery factor (%)</th>
<th>Contingent resources* (MMstb)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1C</td>
<td>2C</td>
<td>3C</td>
</tr>
<tr>
<td><strong>Discovered</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>conventional</td>
<td>143</td>
<td>258</td>
<td>411</td>
</tr>
<tr>
<td><strong>Discovered</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>unconventional</td>
<td>328</td>
<td>789</td>
<td>1665</td>
</tr>
<tr>
<td><strong>Total discovered</strong></td>
<td>470</td>
<td>1056</td>
<td>2076</td>
</tr>
</tbody>
</table>

*Contingent resources are based on the assumption that production facilities will operate with an 80% up-time.

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**Fig. 1. Lancaster Field: outline and location of well penetrations.**
elements of the model have been compared to outcrops of Lewisian Basement on the Isle of Lewis, which is considered to be a realistic geological analogue to Lancaster (Slightam 2012).

The conceptual reservoir model comprises three fracture end members, each of which represents a scale-dependent subset of the hydrodynamic network. The three end members are microfractures (non-discrete fractures), joints (discrete fractures) and faults (seismically identified fault planes) (Fig. 3). Available data indicate that these three end members form a continuum and are in communication with one another, and that each end member is associated with commercially producible oil. Key assumptions that are implicit within the conceptual model have been cross-checked by dynamic data, specifically pressure transient analysis (PTA) of well test data and discrete fracture network models matched to the PTA (Fig. 3). History matching of the horizontal well test, using well test analysis software and full-field simulation modelling, supports the static and dynamic assumptions within the conceptual model (Bonter 2015). The dynamic modelling corroborates a reservoir with no barriers, a primary poroperm system dominated by productive joints and faults, and the presence of productive microfractures that are connected to an effective joint network (Fig. 4).

Microfractures is a term used to define non-discrete fractures. Microfractures are identified from core and from borehole image logs, and are associated with fracture trace lengths less than the borehole diameter. The limited trace length of microfractures on image logs means that they are not identified as an individual feature that has specific geometrical properties and, therefore, they are not included in any fracture frequency analysis or image log-based quantitative assessment. Microfractures are considered to be permeable and, therefore, porous. Figure 5 shows an example of microfractures observed in the 205/21a-4Z well. Evidence of porosity and permeability associated with microfractures is provided by thin-section analysis and laboratory-based petrophysical measurements of RSWCs.

Joints are classified as fractures that are reasonably continuous and through-going planar fractures identified from borehole image logs. In outcrop, joints commonly manifest on the scale of centimetres to hundreds of metres in length, along which there has been imperceptible ‘pull-apart’ movement more-or-less perpendicular to the fracture surface. Joints are products of brittle failure, and they form when the tensile strength of stressed rock is exceeded in response to actions such as burial and compaction, heating and expansion, uplift, cooling and contraction, and tectonic loading.

From the perspective of the Lancaster reservoir, joints are discrete fractures: that is, they are fractures that can be identified and picked manually at a workstation as an individual sine wave feature on a given image log (Fig. 6). As such, joints have the properties of depth, dip, azimuth, apparent aperture and joint type. Joints are interpreted as being permeable based on the integration of other data, including the responses of deep resistivity logs, production
logging, modular dynamic testing (MDT) and gas chromatography. Joints are further subdivided into fracture sets (analogues to joint systems) based on their dip and azimuth characteristics, as described below:

- Regional joints: joints with a consistently steep dip angle (more than 60°) and a systematic preferred NE–SW strike orientation. They usually have a regular spacing of one joint per metre.

- Cross joints: subdivided into three subcategories:
  - sets of steeply dipping joints (more than 60°) presenting a dominant east–west strike orientation and a secondary north–south orientation. Their spacing is approximately one joint per metre;
  - sets of randomly orientated joints with a dip angle of between 20° and 60°;
  - a set of low-angle joints (less than 20°) that are randomly orientated.

Fig. 3. The three fracture end members (microfractures, joints and seismically identified faults) that comprise the Lancaster conceptual model. Dynamic data have been used to constrain the modelling assumptions applied to the fracture end members. As an example, the DFN model is a ‘snapshot’ of a modelled pressure response to the fracture and fault network, thus providing additional information on the fracture network properties away from the immediate wellbore environment.

Fig. 4. Lancaster conceptual reservoir model. Microfractures and joints are present throughout the Fractured Basement and Fault Zone facies. The conceptual model is intended to represent a continuum of connected fractures consisting of the three end members: microfractures, joints and faults.
Shear fractures: joints with a clear displacement along the fracture plane.

Large aperture fractures: joints with a large planar or non-planar aperture manually estimated as having an effective aperture in excess of 20 mm. Large aperture fractures are well-recognized features identified by combining a number of different wireline or LWD tool measurements, including an increase in the rate of penetration (ROP), caliper, a sharp increase of the neutron, a sharp decrease of the density and also a decrease of the resistivity log. The image logs show a clear contrast between the resistivity of the rock and the conductive mud filling the fractures. The aperture enhancement is interpreted as the product of either hydrothermal or epithermal activity, which has resulted in the leaching and/or abrasion of pre-existing open fractures. Evidence of such diagenetic processes at Lancaster is supported by the evaluation of thin sections acquired from RSWC data where dissolution has been frequently reported; furthermore, cuttings and their thin-section evaluation indicate the presence of unconsolidated clastic infill within specific faults penetrated in the 205/21a-6 well. Such unconsolidated material within the basement fractures supports the argument for the potential of abrasion as a process of enhancing pre-existing fractures.

Faults are associated with volumes of fault rock, termed ‘Fault Zones’, the identification and properties of which are described in more detail in the subsection on ‘Reservoir facies distribution’.

**Fracture aperture and fracture porosity determination**

Estimating effective fracture aperture from wireline and/or LWD data is a challenge that has faced the industry for many decades. The various methods published by Luthi & Souhaite (1990) and Measo et al. (2014) have some practical application; however, experience at Lancaster indicates that apertures calculated from FMI (Formation MicroImager) data are unreliable, being adversely influenced by mud resistivity and tool effects. Apparent joint apertures in excess of 20 mm are considered to be reliable for manual interpretation and, once identified, are corrected for borehole angle and fracture orientation. The resulting effective fracture aperture distribution is further constrained by fracture apertures measured from thin sections of RSWC material (Fig. 7).
As demonstrated in Figure 7, the potential distribution of apertures within the Lancaster reservoir is from 20 μm to 2 m. This is a significant distribution, as it implies a highly permeable hydrodynamic fracture network and also indicates that irreducible water will not be present: therefore, no fluid transition zone is to be expected (Aguilera 1999). Given the uncertainties present in estimating effective fracture apertures from image log data, aperture-derived fracture porosities are considered to be associated with a too large uncertainty and, as a consequence, fracture porosity is estimated from bulk porosity methods.

Bulk porosity has been calculated from neutron density, nuclear magnetic resonance (NMR) (deep and shallow shell), acoustic and density data. Bulk porosity measurement is a summation of discrete and non-discrete fracture porosities, the assumption being that any measured porosity is effective fracture porosity. Porosity analysis is constrained by porosities and grain densities derived from RSWC data acquired in the 205/21a-4Z well. The preferred porosity method is the technique used by Bateman & Konen (1977), which is demonstrably the most reliable comparison with RSWC data, and, when cross-checked with a PEF-derived lithology curve, proves to be a robust match with the interpreted lithological distributions. The technical best-case effective porosity distribution is based on the LWD data from the horizontal well, which had the greatest number of Fault Zones and Fractured Basement facies (see the following subsection for a discussion of facies) owing to its 1 km penetration of basement, and is the Lancaster well with the lowest recorded formation damage (skin). LWD data have a lower resolution than wireline data, and true porosities are expected to be elevated compared to those summarized in Figure 8. Average bulk porosity values for the reservoir are calculated as 4.3%,

![Figure 7](http://pgc.lyellcollection.org/)

**Fig. 7.** Interpreted ranges of effective fracture apertures. Fractures (TS) represent fracture aperture ranges estimated from thin-section measurements. Joints reflect estimates of joint aperture ranges from manual estimates of borehole image logs corrected for fracture dip and borehole attitude. Veins (TS) represent widths of veins measured from thin section; and vein image logs represent vein widths estimated from FMI images. Note that veins are mineral-filled fractures and therefore do not contribute to reservoir porosity or permeability. The range of estimated fracture apertures is consistent with extremely high fracture permeability ($K_{air}$) and zero immobile water saturation ($S_{w}$) (Aguilera 1999).

![Figure 8](http://pgc.lyellcollection.org/)

**Fig. 8.** Summary of bulk porosity measurements and bulk porosity interpretation from LWD density neutron data recorded in the horizontal well. (a) Batemen–Konen-derived porosity (Bateman & Konen 1977) plotted against bulk density showing the relationship of bulk porosity to ‘litholines’ associated with sidewall core-derived grain densities representative of tonalite and dolerite bulk density ranges. (b) Bulk porosity averages split into Fault Zone facies and Fractured Basement facies. Facies thicknesses and percentage distribution is also noted. (c) Average bulk porosity for individual facies encountered in the horizontal basement section. Yellow bars represent Fault Zone facies; green bars represent Fractured Basement facies.
which compares favourably with the previously reported wireline derived value of 4.7% (Trice 2014).

Reservoir facies distribution

Two reservoir facies are described for the Lancaster reservoir: Fault Zones and Fractured Basement. Both facies are considered to be present throughout the GRV regardless of depth or relative position on the structure. Both facies are associated with microfractures and joints; faults are confined only to Fault Zones (Fig. 4). That stated, there is evidence of shear fracturing within the Fractured Basement facies that indicates that subseismic faults are present within this facies; however, for the purpose of resource modelling, these subseismic features are currently not represented.

Fault Zones are the GRV explicitly associated with seismically defined faults. They are the volume of host rock ‘damaged’ by the kinematics of a specific fault and are considered to be an envelope of host rock surrounding a fault. Determining Fault Zone widths is a challenge, as the apparent width of a given fault cannot be directly measured from seismic data. Before drilling, Hurricane used outcrop data from the Isle of Lewis to constrain seismic-scale fault widths, providing a range of 15–95 m. Subsequent to drilling, wireline and drilling data were used to interpret where the Fault Zones are present in a given borehole, and the calculated width of the Fault Zones from these data compare favourably with the outcrop observations, providing a range of between 15 and 73 m, with an average of 42 m.

Fault Zones are characterized using a combination of seismic, wireline/LWD and mudlogging data based on all, or a subset of, the following criteria:

- A break in the top basement seismic reflector defines a plane around which the Fault Zone is present.
- The fault boundaries can be sharp or gradational and are marked by either the presence of a shear fracture or a cluster of large permeable joints. Shear fractures and joints have an overall strike parallel to fault strike.
- Image log fabrics indicate a formation rock texture showing evidence of damage, with rock breccia associated with the damaged zone. A marked change in image log fabric is seen across the interpreted fault-zone boundary.
- A more frequent occurrence of gas shows, elevated gas percentages, drilling breaks, permeability indicators from gas chromatography and higher bulk porosity are associated with Fault Zones. These characteristics all serve to indicate a better fracture connectivity and associated permeability when compared to the Fractured Basement facies.

An example Fault Zone from the horizontal well is depicted in Figure 9, showing the boundaries of the Fault Zone to be defined by distinct joints. The upper boundary strikes NW–SE and the lower boundary strikes east–west, which is consistent with the interpretation of the strike of the seismically picked fault boundaries. Elevated porosity values are present within the Fault Zones.
(Fig. 8) compared to the Fractured Basement, and indications of improved permeability are inferred from the C1 (methane) gas curve from conventional mudlogging divided by ROP. In addition, when the aromatic/alkane curve (benzene + toluene/C1–C8) is plotted against a hydrocarbon curve (C1/C4–C8), the cross-over of the two curves is indicative of an increased hydrocarbon content and increased permeability.

The Fractured Basement facies comprises the remaining GRV that is not classified as Fault Zone. This Fractured Basement facies is highly fractured and, from the perspective of joint distribution, there is little to distinguish Fractured Basement from Fault Zones (Fig. 10). That stated, the porosity is elevated within Fault Zones compared to Fractured Basement (5.2% bulk average porosity in Fault Zones compared to 3.6% in Fractured Basement – refer to Fig. 8). This elevated porosity and permeability is interpreted as resulting from preferential diagenetic enhancement within the Fault Zones. Preferential enhancement is interpreted as occurring due to fault lengths and enhanced fracture connectivity providing preferential conduits for epithermal and hydrothermal fluids, which have the potential to enhance fracture apertures through dissolution and/or abrasion.

**Dynamic modelling**

The static and dynamic modelling of the Lancaster Field attempts to replicate the conceptual model (Fig. 4) within a geocellular grid, distributing geological properties within that model and simulating fluid flow through it. The model is constructed with Fault Zone and Fractured Basement facies, as described earlier. Dolerite intrusions within the reservoir are not modelled as there is no significant alteration to the fracture network with lithology, and it is this fracture network that comprises the reservoir and is the focus of the modelling work. The full-field geocellular simulation grid is shown in Figure 11.

As Fault Zones are key to accurately representing reservoir behaviour, fault modelling is highly important. The faults are modelled based on seismic interpretation, each cell in the model is assigned a value based on its distance from a fault, and the facies model is created from this ‘distance to fault’ property based on the average width of the Fault Zones. This process is shown in Figure 12. Creating the model in this manner allows for probabilistic variation in the average widths of the Fault Zone, which have a base case of 40 m based on well logs but have been seen to be significantly wider or narrower than this width both from well data and at outcrop locations. Once the facies model is created, reservoir properties can be assigned to both the Fault Zone and Fractured Basement facies accordingly. Using the model as the basis for an Intersect simulation (Bonter 2015), various ‘Oil Down To’ (ODT) and aquifer strength scenarios can be modelled for the Lancaster full-field GRV.
Fig. 12. Workflow for constructing a static reservoir model. (a) Fault planes as interpreted from seismic. (b) Distance to fault property. (c) Fault-zone width property (40 m in this instance).
Permeability thickness ($K_h$) was calculated from the well test analysis of 205/21a-6 at approximately 265 000 mD m. With a horizontal penetration of roughly 1 km, this translates to an average bulk permeability of 265 mD. Although this number appears low, in reality it represents the average permeability of a section that includes open fractures along 4.3% of its length, and tight, impermeable rock in the remaining 95.7% (in the base-case porosity scenario with an effective fracture porosity of 4.3%). Removing the impermeable rock from the calculation creates an effective fracture permeability of many Darcies, but, for the purposes of the simulation model, the bulk values are appropriate for use in the cells that, at 10 × 10 m aerially, are far larger than the fracture scale. It should be noted that, for the method of calculation, should the contributing wellbore length have actually been less than the entire horizontal section during the test, the average reservoir permeability would consequently increase.

Whilst fluid flow into the wellbore, and therefore the $K_h$ interpreted from the well test, is dominated by joints, the effective poroperm system is interpreted as a combination of highly productive joints and supportive microfractures. This interpretation is based on static data, as well on the pressure data, as demonstrated by the contribution of the non-discrete fractures towards the end of the pressure build-up from 205/21a-6 (Fig. 13). Within Fault Zones, the fracture apertures are generally observed to be larger and more significant gas peaks are observed on mudlogging data: therefore, an increased permeability contribution is modelled within the Fault Zone facies in the model compared to the Fractured Basement. The average permeability for the reservoir model is 265 mD, matching the well test analysis.

**Technical de-risking of the basement reservoir**

When Hurricane started its exploration of the Lewisian Basement, there were many technical uncertainties. Of these, the most significant were:

(a) the ability to drill the basement in a cost effective and safe manner with limited formation damage;

(b) determining which fractures were permeable;

(c) the ability to demonstrate commercial flow rates;

(d) the challenge of building an effective and practical full field simulation.

Following on from the pilot well in 2009, Hurricane has been able to address these and other issues through a sequential process of technical de-risking. The key observations arising from this de-risking are summarized in the following paragraphs.

**Drilling**

A major challenge when drilling naturally fractured basement is the ability to drill safely and efficiently whilst acquiring returns (cuttings and mudlogging data) and causing limited formation damage. Analysis of available drill bit and bottom-hole assemblies from analogue fields globally indicated that the mechanical process of drilling was not anticipated to be a challenge, as the use of tri-cone insert bits coupled with high drilling weights provide a practical method of drilling basement. Average rates of penetration of 4.5 m h$^{-1}$ were achieved in the 205/21a-4 and 205/21a-4Z wells, with bit wear proving to be extremely efficient and with the best bit run of 302 m. In the case of the horizontal well, ROPs were, on average, 9 m h$^{-1}$, and bit wear was minimal, with the 1 km horizontal reservoir section being completed with three bit runs.

Despite high drilling efficiency, there are challenges in maintaining hole angle within the basement as there are intervals of fracturing, faulting and lithology changes that can alter hole inclination and azimuth. Substantial doglegs in the wellbore trajectory have a cumulative effect of increasing wellbore friction, particularly with respect to torsion. The horizontal well’s basement section was drilled using a rotary steerable system (RSS) and it was found that vigilance for zones that enabled steering was essential, as these zones could be exploited to correct hole trajectory. While improvements can be made to the RSS set-up, it is likely that there will always be zones within the Lancaster reservoir where steering will be difficult. Details of the deployment of RSS technology within Lancaster can be found in Belaidi et al. (2016).

Given the expectation that the mechanical drilling process would be relatively straightforward, the prime drilling challenge was that of drilling fluid management, recognizing the safety concern of drilling with high losses in fractured basement. For Hurricane’s pilot well, a mixed metal oxide (MMO) drilling fluid was chosen. The MMO mud is a shear splitting fluid that has the property of setting into a solid gel away from the borehole, thus curing drilling fluid losses as they occur. The MMO mud proved to be an excellent product for drilling, and allowed the well to be drilled with virtually no losses and for high ROPs to be achieved. An unfortunate byproduct of the MMO mud was that it blocked surface gas chromatography equipment, thus reducing the effectiveness and frequency of high-resolution gas chromatography.
measurements. Furthermore, an operational issue meant that a coiled tubing acid wash deployment was cancelled and, as a consequence, the MMO mud was not flushed from the open fractures, and was therefore resident in the formation during MDT surveying and well testing. A complication that arose from this situation, only determined post-well operations through laboratory analysis, was that the MMO properties preferentially allowed for water flow in preference to hydrocarbons, and that the drawdowns applied during testing and MDT sampling were too low to remove the MMO solid from open fractures. These factors resulted in an unsatisfactory well test that reached stabilized rates of only 200 BOPD. Third-party analysis reported that, had the MMO mud been removed from the fractures, the 205/21a-4 DST testing should have achieved rates in excess of 10,000 BOPD.

Given this experience, and with a refined knowledge of formation pressure, the subsequent Lancaster wells were drilled with brine. In the case of the 205/21a-4Z well, a sodium chloride brine proved to be an ideal fluid for the acquisition of mudlogging, LWD and wireline data; however, its poor lifting properties contributed to reduced hole-cleaning efficiency and, as a result, the well suffered from a skin of over 200. High drawdowns and a maximum flow rate of 2885 BOPD. Third-party analysis concluded that, with a reduced skin, the well could deliver 8000 bopd.

An improvement to the brine concept was applied in the horizontal well, which utilized a solids-free viscousified calcium chloride brine. Drilling practices also focused on real-time equivalent circulating density (ECD) management and hole-cleaning techniques, which had been improved through experience developed over the Lancaster (205/21a-4 and 205/21a-4Z) and Whirlwind (205/21a-5) drilling operations. Extremely high dynamic losses were periodically experienced during the drilling of the horizontal well. However, these losses were managed and drilling returns, in the form of both gas chromatography and cuttings, were achieved, enabling an effective formation evaluation to be carried out throughout the reservoir section. The key result was that the use of the brine, along with refined operational practices, resulted in the 205/21a-6 well having an extremely low skin and, as a result, well testing was able to achieve an extremely high productivity index (PI), thus proving the potential of the Lancaster reservoir.

Whilst additional improvements in drilling fluid, bottom-hole assemblies and drilling practices will continue to be sought, the de-risking of drilling operations has been such that Hurricane’s first horizontal well. Formation evaluation was therefore confined to LWD logging and imaging, advanced gas detection, and conventional mudlogging, which had been demonstrated to be effective in the previous wells. Of these data, it was clear that azimuthal deep resistivity, azimuthal density and C1/R0P were responding to similar downhole features. The most significant of these were also associated with elevated drilling losses and improved permeability indicators, as seen from the aromatic/alkane ratio recorded as part of the high-resolution gas chromatography data (Fig. 9). The formation evaluation data in 205/21a-6 indicated a reservoir section with no permeability barriers: this observation was subsequently supported by the DST data.

The formation evaluation approach applied to the Lancaster wells indicates that detecting permeable fractures is possible at the well site, and can be further refined with increased data integration during post-operational analysis. The conclusions derived from static LWD and wireline data are supported by dynamic data, including wireline pressure measurements, wireline sampling and PLT. Determining formation fluid distribution is achieved through the combination of high-resolution gas chromatography and PLT. The use of wireline-derived pressure gradients to infer a field representative free water level as a means of establishing fluid distribution is yet to be confirmed: however, a comparison of data from 205/21a-4 and 205/21a-4Z provides encouragement. Consequently, future inclined wells at Lancaster will therefore deploy high-resolution gas chromatography, wireline pressure surveys and production logging runs to establish permeable fracture and fluid distributions.

Identifying permeable fractures

It was intended that the formation evaluation of the pilot well would benefit from electrical and acoustic borehole image logs (UBI), array acoustic (sonic waveform), MDT (dual packer) and production logging (PLT) to determine which fractures were porous and permeable. The range of measurements was intended to ensure that fracture infill by electrically conductive material would not provide erroneous indicators of permeability and that apparently permeable fractures were, in fact, contributing to flow. Unfortunately, a tool failure meant that no acoustic imaging was acquired and a downhole restriction precluded running of the PLT. Despite these restrictions, it was evident from limited MDT data, formation imaging (FMI) and deep resistivity measurements that the Lancaster reservoir was highly fractured and permeable. This observation was supported by well test data that, although significantly compromised by the drilling fluid, indicated a highly permeable formation.

The subsequent 205/21a-4Z well formation evaluation program built on that of the previous well by the inclusion of LWD imaging data (both resistivity and density), UBI, RSWCs and a multi-arm spinner PLT (FSI). The use of LWD and wireline data at the well site allowed for the effective picking of fractured intervals for pressure surveying by a dual-packer MDT. Of the 15 MDT points picked, nine proved to be permeable and associated with good-quality pressure measurements, and this result gave confidence that the combination of deep resistivity, FMI and UBI were the key data sources for determining open and permeable fractures. Once these data had been used to define open fractures, it became apparent that many such features were also associated with increased porosity and increased gas curve activity, associated with conventional mudlogging data and from high-resolution gas sensors, thus adding further confidence that conventional wireline measurements could be utilized to infer permeable fractures. Further corroboration of the approach was provided by the FSI data, which confirmed fracture permeability (Fig. 2) throughout the logged basement interval, with fractures contributing to flow regardless of depth or lithology.

In the case of the horizontal well, no wireline or PLT data were acquired, as it was considered too great a risk to the successful testing (within budget) of Hurricane’s first horizontal well. Formation evaluation was therefore confined to LWD logging and imaging, advanced gas detection, and conventional mudlogging, which had been demonstrated to be effective in the previous wells. Of these data, it was clear that azimuthal deep resistivity, azimuthal density and C1/R0P were responding to similar downhole features. The most significant of these were also associated with elevated drilling losses and improved permeability indicators, as seen from the aromatic/alkane ratio recorded as part of the high-resolution gas chromatography data (Fig. 9). The formation evaluation data in 205/21a-6 indicated a reservoir section with no permeability barriers: this observation was subsequently supported by the DST data.

The formation evaluation approach applied to the Lancaster wells indicates that detecting permeable fractures is possible at the well site, and can be further refined with increased data integration during post-operational analysis. The conclusions derived from static LWD and wireline data are supported by dynamic data, including wireline pressure measurements, wireline sampling and PLT. Determining formation fluid distribution is achieved through the combination of high-resolution gas chromatography and PLT. The use of wireline-derived pressure gradients to infer a field representative free water level as a means of establishing fluid distribution is yet to be confirmed: however, a comparison of data from 205/21a-4 and 205/21a-4Z provides encouragement. Consequently, future inclined wells at Lancaster will therefore deploy high-resolution gas chromatography, wireline pressure surveys and production logging runs to establish permeable fracture and fluid distributions.

Demonstrating commercial flow

Well 205/21a-4 was designed to demonstrate that permeable, oil-bearing fractures were present within the Lewisian Basement. To achieve this aim, the well was deviated at an inclination of 35° and targeted to penetrate two seismicly identified near-vertical faults. The expectation was that the fault zones associated with the seismically identified faults would be preferentially productive and result in attractive flow rates during drill stem testing. This approach was repeated in the subsequent sidetrack 205/21a-4Z.

In both cases, third-party analysis of the DST data indicated a highly permeable reservoir, with no barriers and the potential for flow rates in excess of 10,000 BOPD. In reality, the maximum flow rate achieved was 2200 BOPD in the 205/21a-4 well and 2885 BOPD in 205/21a-4Z. In both cases, the measured flow rates were significantly compromised by formation damage primarily caused by the chosen mud and, in the case of 205/21a-4Z, compounded by the practice of bullheading mud and oil within the
string prior to undertaking a second phase of drilling and subsequent second DST. In the case of 205/21a-4Z, the effects of drilling fluid sumps that could not be lifted through the application of nitrogen were also detrimental to establishing the true formation flowing potential.

It was evident from static and dynamic data that the concept of targeting seismic-scale faults to achieve attractive flow rates was conceptually sound: furthermore, PLT analysis also indicated that the Fractured Basement between Fault Zones would also contribute to hydrocarbon flow and reservoir permeability. To achieve a sustainable and commercial flow rate, it was therefore necessary to establish a method to reduce formation damage. Hurricane recognized that underbalanced drilling (UBD) and managed pressure drilling (MPD) are solutions to reducing formation damage: however, the reality of drilling on the UKCS is that operators are confined to using the available conventional rig stock that did not, and currently does not, include UBD units or rigs fitted to accommodate MPD. Despite strong technical support, there is no approved safety case for MPD in the UKCS, nor are there drilling units with MPD provision or appropriately trained drill crew (at time of writing). As a consequence, Hurricane was, and is, focused on achieving base-ment drilling using conventional drilling units.

Given these constraints, Hurricane designed a horizontal production well (205/21a-6) by building on its operational experience to date. The well was targeted, as in Hurricane’s previous basement wells, to penetrate seismically identified faults, and also to be drilled perpendicular to a regional joint trend identified from the 205/21a-4 and 205/21a-4Z borehole image log data. Whilst the horizontal well benefited from refined drilling practices and drilling fluid that combined to provide optimum hole cleaning and limit formation damage, the well was also tested using an ESP to clean the hole and remove all resident drilling fluid. This process led to a maximum flow rate of 9800 BOPD with only 70 psi drawdown. A subsequent natural flow rate of 5300 BOPD was achieved with 35 psi drawdown. Although these rates were the best so far achieved at Lancaster, they were both constrained by surface equipment, namely flare boom length and separator properties. The combination of revised operating practices whilst drilling and use of the ESP as part of the testing phase resulted in a PI of 160 stb/day per 1 psi. To put Lancaster into context, the Saudi Arabian Ghawar oil field, arguably the most efficient reservoir in the world, has reported average PI of 141 stb/day/psi (Gregcroft: http://www.gregcroft.com/ghawar.ivnu). The Lancaster PI is, therefore, an unequivocal measure of the Lancaster potential to provide commercial flow rates.

The collective experience gained through drilling and testing operations, drilling fluid design, drilling fluid management, and formation evaluation will help to optimize the drilling and data acquisition from future basement exploration wells, and thus reduce the costs and time associated with determining the commercial viability of other basement discoveries. Further improvements will be sought, but the Lancaster experience to date, however, indicates that a practical method of drilling and testing the Lewisian Basement has been achieved.

Simulating

Dynamic evaluation of fractured basement fields can be challenging, and company approaches are often proprietary and not well documented in the public domain. Modelling software is generally focused on reservoirs with intergranular or interparticulate poro-perm, and therefore must be adapted to work well with fractures. Hurricane has used a number of different methods to evaluate the potential dynamic behaviour of Lancaster going forwards, with new technologies and the acquisition of better dynamic datasets enabling a continued development of the dynamic evaluation.

As part of the analysis of ‘Contingent Resources’ summarized in the CPR, well test performance observed from 205/21a-4 and, more particularly, 205/21a-4Z was used to construct decline curve type profiles using Prosper, which were cross-checked against analogue field performance. Building on this work, a sector model using Eclipse was constructed. The maximum model size that was achieved with a reasonable run time was a 4 × 4 km square, which, as shown in Figure 14, is a relatively restricted area of the entire field. Being so restricted meant that edge effects were seen in forecasts, and it was not possible to perform a full-field simulation. However, reasonable matches to the 205/21a-4Z well test were achieved, and certain forecast uncertainties were investigated focusing on the ODT, the presence or absence of a supportive aquifer, and the well profile (inclined v. horizontal). The limited area of the sector model, and imperfect nature of the well test data available to work with from the 205/21a-4 and 205/21a-4Z wells, meant that the Eclipse model sensitivities could not be effectively taken further. However, in 2014, Hurricane investigated the potential of performing a full-field simulation of Lancaster using Intersect, Schlumberger’s new simulation software with greatly

Fig. 14. Sector model consisting of a 4 × 4 km sector model area in relation to the Lancaster Field. The sector model was undertaken in Eclipse to provide initial sensitivities on well orientation (inclined v. horizontal), potential aquifer strength and ‘Oil Down To’ (ODT).
enhanced performance to cope with large models (Bonter 2015). Coupled with the high-quality dataset acquired in the 205/21a-6 horizontal well test, Hurricane could confidently build on this initial work to create a full-field simulation model. A robust history match of the well test data has been achieved in the full-field simulation model, which comprises cells that are $10 \times 10 \times 30$ m – a very fine resolution for a simulation grid, which is required to accurately model the uncertainty of Fault Zone widths. This gives a total number of cells in excess of 75 million, which requires significant parallel computing capability to simulate in a reasonable timeframe. The Intersect software scales up to utilize this parallel hardware much better than Eclipse because it has been designed much more recently with newer computer architecture in mind: therefore, it is a better tool for the job of simulating Lancaster.

Simulation cases run on Lancaster to date have involved a series of uncertainty analysis runs, focusing on the effects of varying the ODT, aquifer strength and contributing wellbore length. Further runs have examined the effects of altering the permeability, both in terms of average values and the vertical to horizontal permeability ($K_v/K_h$) ratio. Variations in average porosity have been compared, and a number of potential scenarios for the early development phase of Lancaster have been run. Hurricane ensures that the simulation model honours all robust property measurements/interpretations, and focuses on those parameters that are most uncertain or have the greatest effect on the forecast production profiles.

One of the advantages of utilizing a full-field geocellular grid to simulate the field is the ability to visually interrogate the simulation results, and observe the modelled reservoir behaviour over time. Figure 15 is an example of a snapshot of pressure drawdown at a horizontal well. The modelled pressure response shows an isotropic distribution. The Intersect software scales up to utilize this parallel hardware much better than Eclipse can because it has been designed much more recently with newer computer architecture in mind: therefore, it is a better tool for the job of simulating Lancaster.

Figure 15. Extract from the Intersect full-field simulation model exhibiting a pressure drawdown snapshot over a particular reservoir depth in relation to the horizontal well. The modelled pressure response shows an isotropic distribution.
the UK’s fractured basement play, but provide a focal point for new West of Shetland developments, thus contributing significantly to maximizing the UK economic recoverable reserves.

References


