An integrated approach to unconventional resource play reservoir characterization, Thistleton-1 case study, NW England

Scott Brindle[1*], David O'Connor[2], Richard Windmill[1], Peter Wellsbury[1], Guy Oliver[3], Graham Spence[3] and Chi V. Ly[3] characterize a UK unconventional reservoir using integrated AM and TOC data to constrain and improve the accuracy of petrophysical modelling.

In the past, the oil and gas industry considered hydrocarbon resources locked in tight, impermeable formations like shale uneconomical to produce. However, advances in well steering, drilling and reservoir stimulation techniques have dramatically changed this perspective.

Unconventional shale reservoirs have low permeability and cannot produce economically without effective placement of horizontal laterals and effective hydraulic stimulation. To achieve this, it is critical to recognize brittle units responsive to hydraulic fracturing and rich in organic matter. Shale mineralogy impacts the effectiveness of stimulation. Heterogeneity in shale reservoirs expressed by mineral composition, richness of organic matter and brittleness significantly influences shale gas production. In these reservoirs, the occurrence of clays is a significant risk to production and it is a major challenge to be able to locate and quantify them. The industry reported $7bn of unnecessary costs due to unconventional wells not reaching their production targets (Welling and Company, 2012). Moreover, 15-20% of all fracture stages are reported as ineffective while 35-40% of perforation clusters do not contribute to production (Hodenfield, 2012) highlighting a need for more low-cost and low-risk data. This data could help to improve completion designs to achieve more consistent production from all stages and increase the overall profitability.

Traditionally, reservoir characterization is carried out using a suite of wireline log data to predict lithology and textural parameters and to identify pay zones while mitigating the time and costs associated with coring and core analysis. Though this approach is widely used it can be prone to errors associated with hole conditions, thus leading to inaccurate reservoir characterization. We propose a new integrated approach using mineralogy, textural and Total Organic Carbon (TOC) data derived from drill cuttings which are almost always available, combined with petrophysical logs to create a more accurate prediction of unconventional reservoir characteristics. Drill cuttings are sampled, washed and mounted in resin blocks and then analysed using a Scanning Electron Microscope (SEM) – Energy Dispersive X-ray Spectrum (EDS)-based Automated Mineralogy (AM) system, pioneered by CGG Robertson in 2006. The outputs of this analysis include mineralogy and textural data such as grain size, sorting, pore size distribution and aspect ratio, which then feed into the petrophysical model, greatly enhancing reservoir characterization. Furthermore, rock mechanical properties are calculated from the wireline logs and integrated into the model. Table 1 quantifies the

Parameter	Max. Difference	Mean Difference	Standard Deviation
Synthesised Shear velocity	28.0%	11.4%	4,0%
Young's Modulus	33.0%	12.0%	7,4%
Water Saturation	90.0%	9.0%	11,5%
Hydrocarbon Residue	30.0%	3.0%	3,0%
Effective Porosity	35.0%	4.5%	4,0%

Table 1 *The table summarises the differences in value of key reservoir-quality parameters between using a traditional petrophysical approach and the integrated workflow used on the Thistleton-1 well.*

[1] *CGG Robertson, Llandudno, UK.*

[2] *CGG Data Management Services, Conwy, UK.*

[3] *CGG GeoConsulting, Houston, USA.*

[*] *Corresponding author, E-mail: Scott.Brindle@cgg.com*

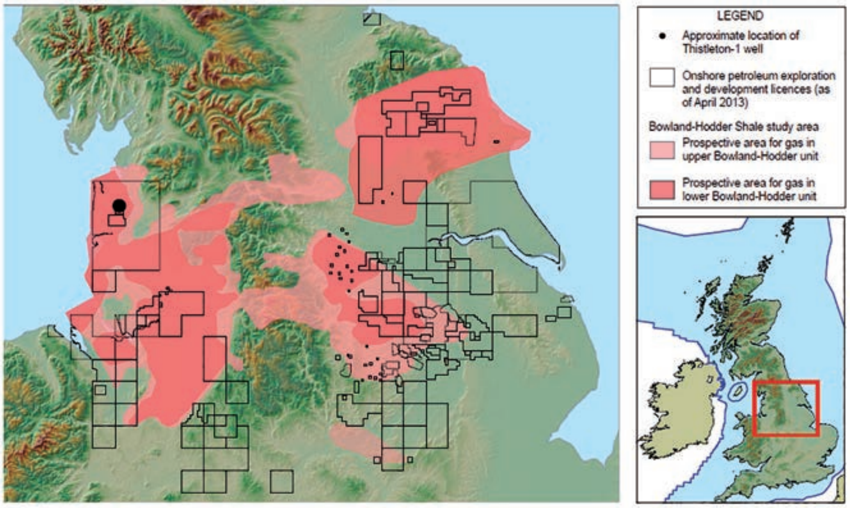


Figure 1 *Bowland shale distribution map showing the approximate location of the Thistleton-1 well. Current UK onshore exploration licences are also shown. Adapted from Andrews, 2013.*

differences between using the outlined integrated approach (including AM information from drill cuttings) and using the traditional petrophysical modelling approach based on well logs only, with reference to some key reservoir quality parameters for this study. To highlight the value of the workflow, a 4.5% difference in effective porosity estimates would have a great impact on the economic viability of the well, while a 12% difference in Young's modulus could impact the suitability of the shale for stimulation or the fracking fluid/proppant strategy.

The combined data set enables far more accurate identification and prediction of so-called 'sweet spots' to help improve stage design for hydraulic fracturing than the typical geometric approach which implies that the reservoir or formation is laterally homogeneous and does not account for facies or mineralogical changes, thus inevitably including uneconomic zones. Employing this integrated approach therefore serves to reduce operating costs while increasing production and well profitability.

In this paper, we present a UK case study and draw on lessons learnt from the American market by using mineralogical and textural data obtained by AM and measured TOC to constrain and improve the accuracy of petrophysical modelling. We characterize a UK unconventional reservoir using integrated AM, TOC and petrophysics to define and quantify favourable and unfavourable zones for further development/production and outline the potential benefits and applications of the workflow.

Study area

The Thistleton-1 well is situated in the Bowland Basin in Lancashire, North West England (Figure 1) and was drilled in 1988 to target overlying Permian and Triassic sands. Gas shows were noted in the low-permeability Carboniferous shale which source the overlying sands but the well was abandoned as uneconomical at the time. The well cuts through the organic-rich Carboniferous Sabden and Bowland Shales (1-3 % TOC). The younger Arnsbergian Sabden unit however is not considered to be sufficiently buried to have reached gas maturity by Andrews (2013) however; the drilling report accompanying the logs indicates gas shows throughout the unit. The Bowland unit has been the subject of focused exploration and is considered to be gas mature. The Bowland Basin, also referred to as the Craven Basin (Hudson, 1933), is a NE-SW trending feature formed by crustal extension during the late Devonian through early Pennsylvanian (Leeder, 1988). The basin is fault-bounded to the NE and SW by the Craven Fault and Pendle Lineament respectively which controlled basin subsidence and allowed for up to 2 km of shales, silts and limestone to be deposited (de Pater and Baisch, 2011). The basin was inverted during the Variscan orogeny with up to 5km uplift (Corfield et al., 1996) and seismicity studies cite the present-day stress regime as strike slip (de Pater and Baisch, 2011).

Data availability and methods

Wireline data such as gamma, resistivity, neutron porosity and compressional sonic were available from the surface down to a Total Measured Depth of 7020 ft. The Arnsbergian Sabden shale between 4250-5162ft and the Pendleian-Brigantian Bowland Shale between 5162-7020ft (stratigraphic units given according to Cuadrilla Resources (de Pater and Baisch, 2011)) are the interval of interest. A Formation description log (FDL) was created from the wireline data detailing key reservoir parameters such as lithology, clay volume estimates, water saturation (Sw) and bulk volume gas (BVG) (Figure 2 shows an example from the interval). The lithology was modelled using a neutron-density cross plot (Figure 3) using the cuttings report from the original composite log. Clay volumes were estimated from the neutron-density cross plot and gamma data while porosity was estimated using neutron-density and compressional sonic where bad hole conditions prevailed. The modified Simandoux equation was used to calculate Sw from which BVG was estimated. Shear wave velocities were not available and had to be generated from the compressional sonic using the Greenberg-Castagna model (Greenberg and Castagna, 1992) for the purposes of estimating rock mechanical properties. Example results from the petrophysical modelling using the well log data is shown in the left-hand track of Figure 2.

Drill cuttings were sampled at 30 ft intervals from 4250 ft to 7020 ft covering the Bowland and Sabden shale intervals. The cuttings were washed, sieved and mounted in 30 mm-diameter polished resin blocks before carbon coating. The blocks were analysed using a QEMSCAN 650F applying a 15 kv electron beam to the surface generating back-scattered electrons and X-rays. The particles are distinguished from the mounting medium by density contrast and a subsequent EDS measurement is taken at each discrete sample point. The resulting EDS and density data are filtered through CGG's extensive proprietary database of mineral responses and the appropriate mineral identity is assigned to the data point. For this study a resolution of 10 μm was applied, meaning that a data point was taken every 10 μm on each sample surface resulting in 810,000 data points per cuttings sample block. The resultant mineralogy and textural data were then extrapolated for the log sampling rate of 6 inches and input into the petrophysical modelling software PowerLog to calibrate and constrain the reservoir characterization model. Example results from the petrophysical modelling, which integrates the AM data, is shown in the right-hand track of Figure 2.

The cuttings were also analysed in the laboratory for TOC with the aim of calibrating log-derived TOC values which were estimated using the ΔlogR technique, the optimal superposition coefficient (Passey et al., 1990) and the CARBOLOG technique (Carpentier et al., 1991).

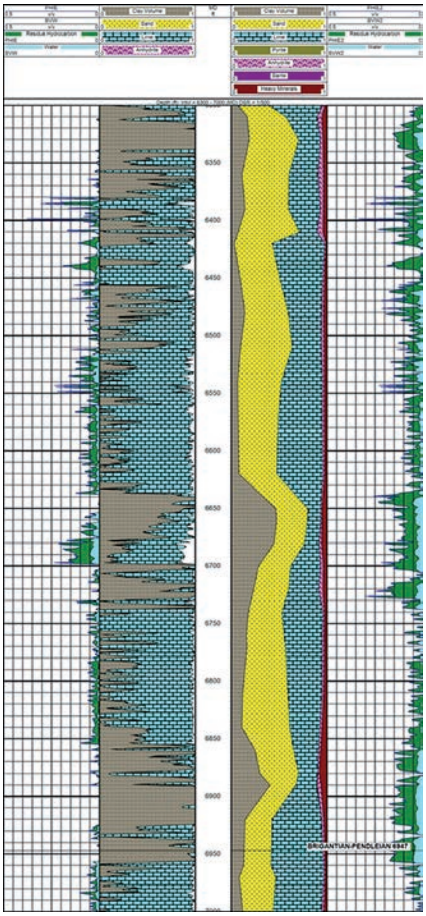


Figure 2 *An example formation description log from the Thistleton-1 well at 6300 ft-7000 ft, in the Bowland Shale unit. Four logs are shown; Sw, effective porosity and BVG derived from analysis of the well logs only (far left), modelled lithology derived from the well logs (middle left), modelled lithology from the integrated approach using AM data (middle right) and integrated Sw, effective porosity and BVG from the integrated approach (far right). A very clear difference can be seen in all values between the integrated and well log-only models.*

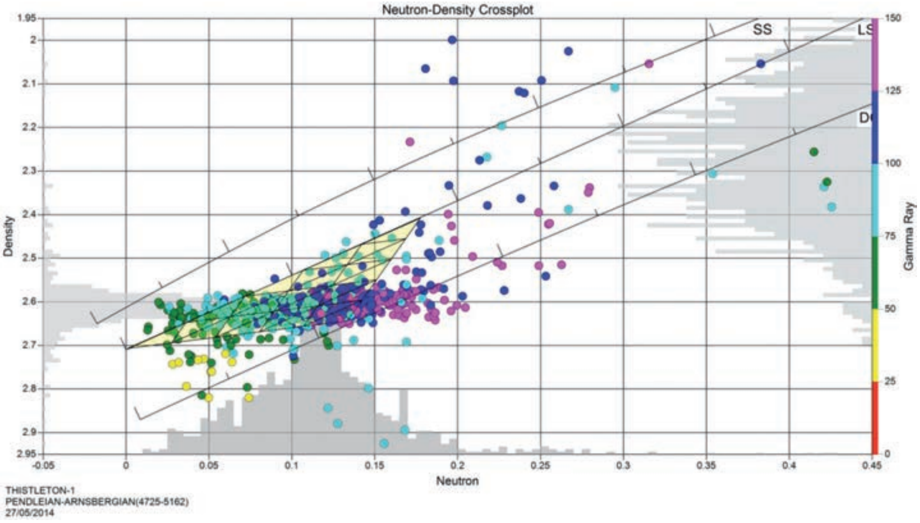


Figure 3 *Sample neutron density cross plot for Thistleton-1 on which the initial lithology interpretation was based. The distribution of the clean matrix along the limestone line is an indication of the nature of the matrix. The outliers can be attributed to poor hole condition affecting the logging tools.*

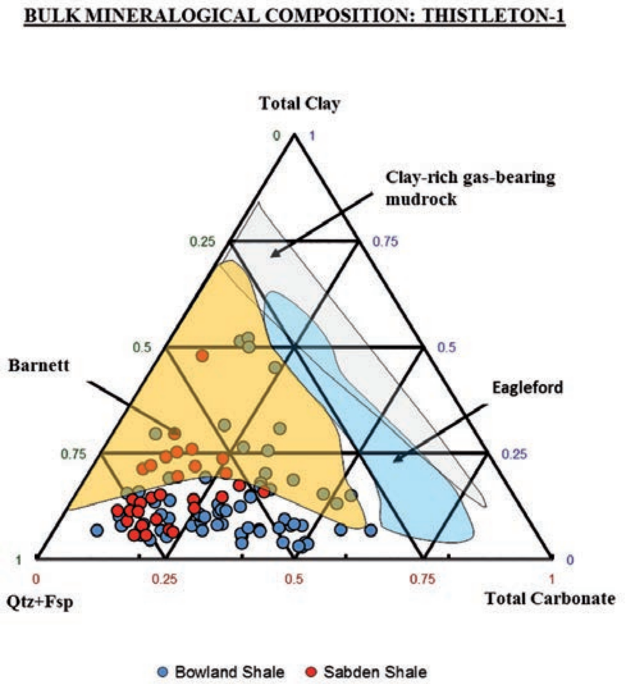


Figure 4 *Mineral ternary plot comparing the Bowland and Sabden shales with American analogues. The majority of samples lie outside of either formation but are more comparable with the Barnett formation than the Eagle Ford.*

Results

The integrated modelling indicates that the Sabden shale is characterized by a slightly higher quartz volume (56% mean), much lower carbonate content (16% mean volume) and a similar clay volume (15% mean) than the underlying Bowland shale which has 50% mean volume quartz, 27.5% mean carbonate content and 12% mean clays. Local increases in clays and carbonates are observed over both formations. Figure 4 shows how the formations compare mineralogically with American analogues such as the Eagle Ford and Barnett Formations. The majority of samples lie outside of either formation but are more closely matched with the Barnett Formation.

Integrated petrophysical modelling (using the AM results) shows mean effective porosities of 7.1% and 8.0% for the Bowland and Sabden shales respectively. Water saturation is slightly higher in the Bowland shale (2.9% mean) compared with 2% for the Sabden. Mean bulk volume gas (BVG) is 5.1% over the whole interval. Differences between the original log-derived model and the integrated model are discussed below.

Mechanically, the formations are strong and rigid and are ideal for hydraulic fracturing. Young's modulus averages 57GPa while Poisson's ratio is 0.18 over the whole interval. RoqFRAC, a relative brittleness indicator based on bulk mineralogy, shows a good match with the log-derived strength parameters (Figure 5). Local increases in strength are concurrent with increases in the amount of carbonate minerals. This increase in strength suggests that dissolution of carbonates has occurred, precipitating carbonate in the pores and fractures and increasing rigidity. This is validated by the mineral maps provided by the AM analysis, highlighting the value of the technique (Figure 6). Young's modulus and Poisson's ratio typically average 63.8GPa and 0.16 respectively in carbonate-rich intervals. In contrast, local decreases in strength are concurrent with increases in clays and typical clay-rich intervals average 49GPa for Young's modulus and 0.19 for Poisson's ratio. An increase in carbonates downwell suggests that the Bowland shale will be mechanically stronger that the overlying Sabden unit. To refine our model further, net pay brittle material was calculated using a cut-off of Poisson's ratio of <0.19 and Young's modulus >37.9GPa in a simplification of the brittle/

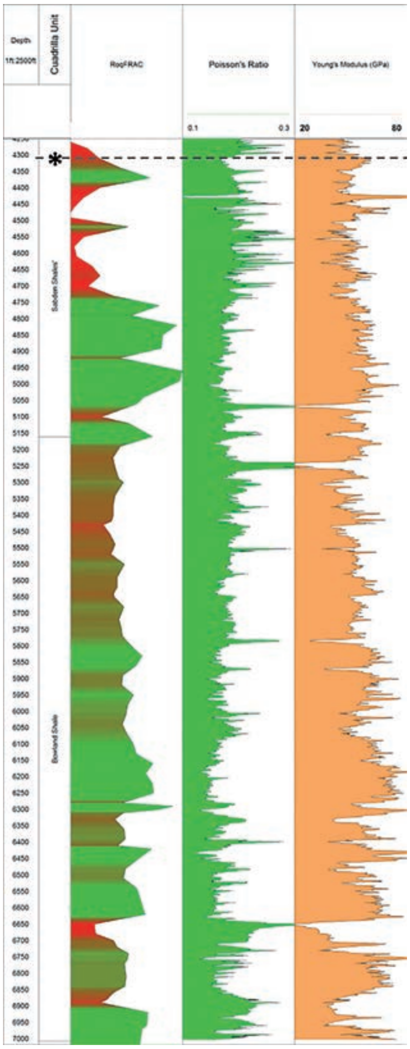


Figure 5 *Mechanical properties; the leftmost log shows the relative brittleness based on bulk mineralogy of the drill cuttings with Poisson's ratio (middle) and Young's modulus (right) derived from well log data. A good match between the log profiles is apparent. *Approximate depth of sample 4310 ft (Figure 6), which represents cuttings collected over a 30 ft interval.*

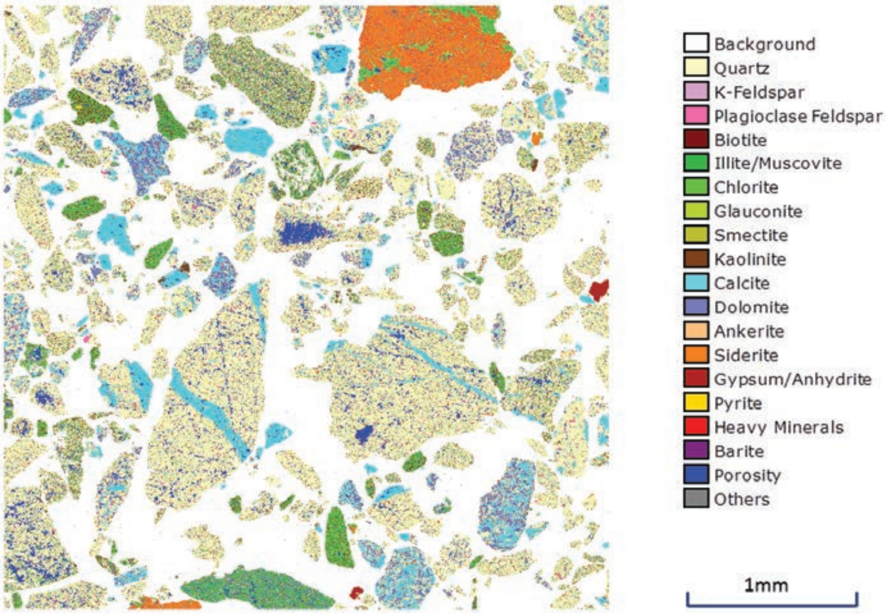


Figure 6 *Example drill cuttings mineral map from 4310 ft in the Thistleton-1 well which provides fully quantitative mineral and textural information. The image also provides key mineral distribution and textural relationships. This example shows carbonate precipitated in fractured lithology which increases the brittleness.*

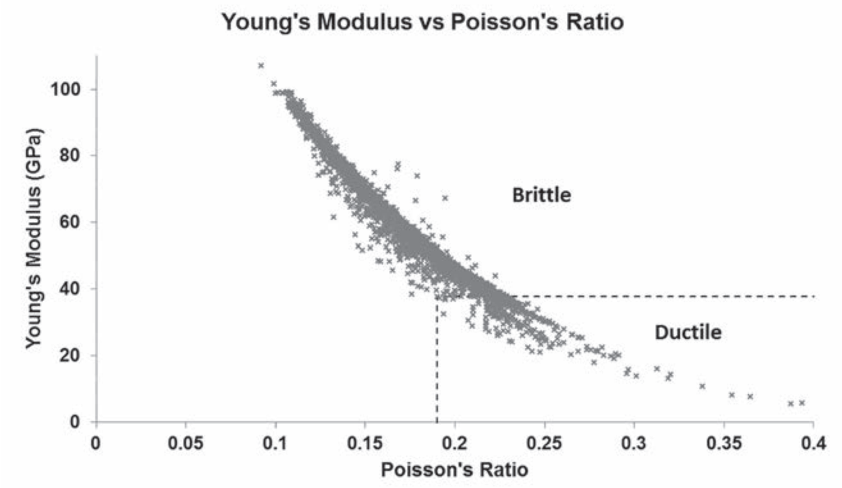


Figure 7 *Young's modulus vs Poisson's ratio cross plot for Thistleton-1. The chart shows the majority of the well is in the brittle zone. A cut-off of 0.19 for PR and 37.9GPa has been used to define the brittle/ductile zones, simplified from Grieser and Bray, (2007).*

ductile chart provided by Grieser and Bray, (2007) (Figure 7). This suggests that a total of 1915.5 ft of 2770 ft (~69%) of the interval lies in the brittle regime.

TOC values determined in the laboratory were between 1-2% and showed very little variation over the measured interval as was the case with the log-derived values (0.4 – 2.4%). The correlation between the two data sets, which form a small cluster of points on the cross-plot, was poor with $R^2=0.23$ (Figure 8), suggesting limitations in extrapolating from the log-derived values. Increases in log-derived TOC values tend to correspond with high caliper readings and are thus unreliable and have been excluded from the analysis

The overall reservoir quality has been summarised throughout the measured interval in a single log to define the more favourable and less favourable units for lateral production (Figure 9). The log combines Young's modulus, water saturation, effective porosity and bulk volume gas data, and suggests three good intervals (marked in green) in the Sabden unit and four in the Bowland unit. Combining all these parameters, the calculated total net pay of favourable material throughout the interval is 1066 ft (38.5%) of the total material.

Discussion

The effectiveness of wireline logging tools can be limited within high pressure-high temperature environments and suffers in bad hole conditions. In addition, full logging suites are rarely collected in lateral wells due to cost and hole conditions. Data from AM analysis of cuttings which are abundantly available can provide important calibration or control on the petrophysical modelling when such conditions prevail. Figure 2 shows a comparison of the initial log-derived

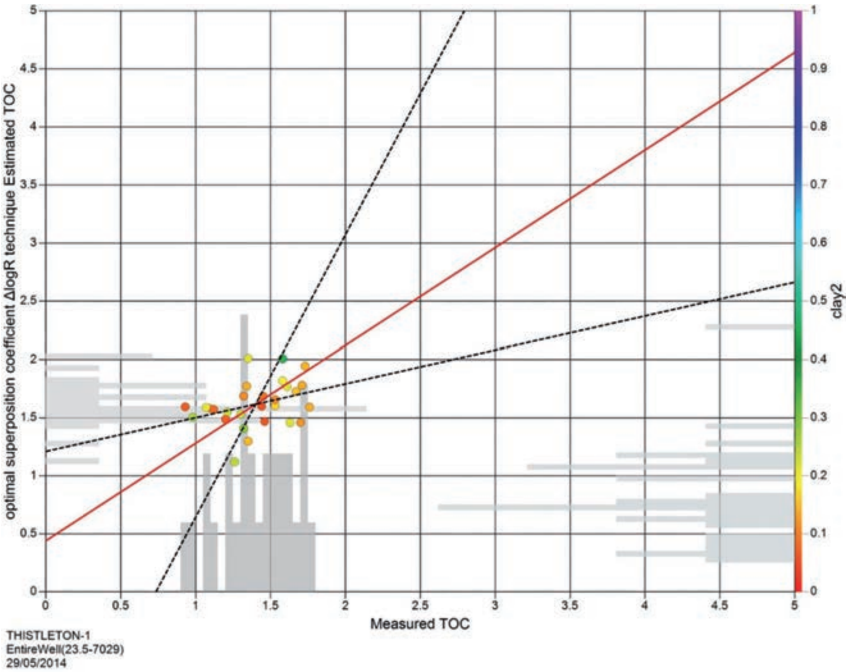


Figure 8 *Measured TOC vs Log-estimated TOC for Thistleton-1. Both methods provide a small range of TOC values (1-2%) and the datasets are weakly correlated (R^2 = 0.23).*

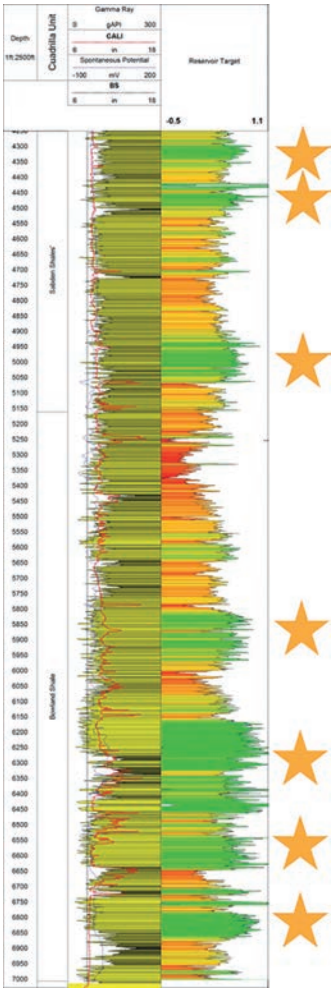


Figure 9 *Reservoir-quality summary log including Sw, Young's modulus, BVG and effective porosity for the measured interval, Thistleton-1. The distribution of sweet spots (green) can be easily picked out from the intermediate (yellow) and low favourability (red). Net pay material = 1066 ft or 38.5%.*

petrophysical interpretation versus the AM-calibrated model for lithology, water saturation, effective porosity and BVG. There is a clear difference in interpreted lithology and mineral volumes where the initial interpretation reports a binary shale-lime system with no quartz or silt component. Average clay volumes in the log-derived model are up to three times higher than the measured cuttings data. Carbonates are also 29% higher by mean volume in the original log-based model. These interpretations have a crucial knock-on effect because accurate determination of clay volume is important in the estimation of water saturation and thus BVG. Similarly, lithology data and clay volume are also used in the computation of effective porosity. The effects are summarised in the histogram (Figure 10) highlighting the value of using an integrated approach in the estimation of key reservoir-quality parameters. Effective porosities are on average 4.1% higher over the interval, water saturation is 1.2% higher on average and BVG is 5.1% higher overall, discounting the Sabden shale which is not considered to be gas mature (Andrews, 2013). These differences would have an impact on risking and volumetric calculations and the overall suitability of the well for further production.

Automated Mineralogy data from cuttings has also proved to be a valuable input for modelling of shear velocities which were required for generating the rock mechanical properties such as Poisson's ratio, shear modulus and Young's modulus. Figure 11 shows a workflow cycle that was used to model the shear velocities using the input mineralogy data. Furthermore, the values generated from the model were validated in a blind test on a nearby well which had data availability. A strong correlation (R^2=0.81)

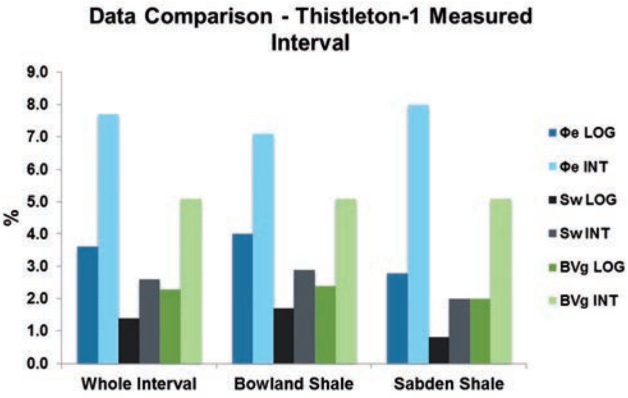


Figure 10 *Comparison of key reservoir-quality parameters for each unit in the measured interval. The integrated approach using AM (INT values) gives values that are more than double the original interpretation using well logs only (LOG values) in most cases.*

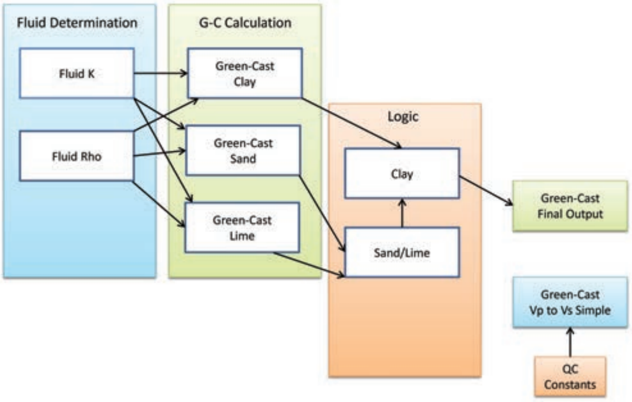
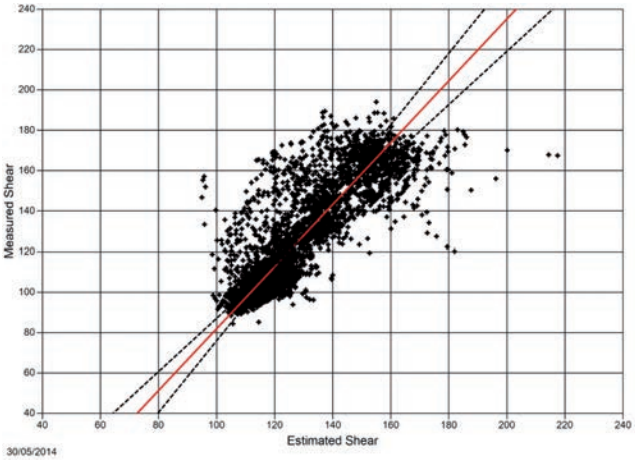


Figure 11 *Greenberg-Castagna shear modelling flow chart with lithology control from AM data. The workflow was used to accurately model shear velocities from measured compressional.*



30/05/2014

Figure 12 *Blind test well, measured shear vs Greenberg-Castagna (1992) modelled shear in nearby well with data availability. A strong correlation R^2 = 0.81 was found between the modelled shear and measured shear validating the model.*

was observed (Figure 12) between the measured velocities and the modelled ones, giving confidence in them and any values derived from them. A mean difference of 11.4% was observed for modelled shear velocities when not using the mineralogy data for control. The effects of this can be seen in the calculation of Poisson's ratio which requires the modelled velocities and Young's modulus (12% mean difference). These changes have key implications for geomechanical parameters whereby parts of the formation that are 12% either side of the brittle/ductile boundary could fall in the opposite category and the deformation behaviour during hydraulic fracturing would be different, perhaps requiring a different fracturing strategy.

Textural data from AM provides further input to the overall model. Pore aspect ratio can have an effect on sonic velocities: a reduction in the sonic velocities of the clay material with respect to sand is attributed to flatter or lower aspect ratio pores in clay minerals (Xu and White, 1995). Larger pore sizes >200μm have been correlated with increases in microseismic events during hydro-fracture treatment (Castillo et al., 2014) although no cause for the effect has been validated. A pore size of >200 μm in shale is larger than expected as shale pores tend to be sub-micron (Nelson, 2009). These could therefore signify microfractures, which, in a favourable orientation with relation to the local stress field (critically stressed), could increase microseismic events as slip along the pre-existing weak planes occurs due to effective stress reduction during stimulation. Further work is required in this area but valuable pore fabric data from AM systems could contribute to the understanding.

Additionally, the inspection of mineral maps for mineral distribution and texture provides important information for relative brittleness calculations. Carbonate minerals can clearly be seen forming cements in some samples, serving to increase the internal friction coefficient of the rock and thus the overall rigidity (Figure 6). Therefore the mineral maps provided by automated mineralogy systems provide valuable information to constrain relative brittleness calculations based on bulk mineralogy (RoqFRAC) which would not be possible with bulk composition-only mineral analysis techniques such as X-ray Diffraction.

Application of the workflow

The workflow described here serves as a good tool for accurate prediction of 'sweet spots' and quantification of net pay material within an analysed well interval, whether vertical or lateral. Running tools on lateral wells can be risky, resulting in limited wireline data under these circumstances; cuttings-based mineralogy (which could be provided at the well site) could be used to provide real-time 'real rock' data to help with drilling decisions. In this study, we set up a relative brittleness indicator calibrated to the log-derived mechanical properties which could be used to determine brittle and ductile zones along the lateral. A correlation between relative brittleness from cuttings and Young's modulus from seismic inversion is noted by Castillo et al. (2014). This calculated relative brittleness can be used to help with completions such as the selection of frac-fluid, proppant type and volume. In addition, the accurate determination of clay species provided by AM provides further useful information for completions, for instance when the presence of a ductile interval composed of swelling clays such as smectite would require the use of a hybrid gel. The vertical mineral profile can be used to determine landing points for horizontal drilling (Ashton et al., 2013), and cuttings data analysed along subsequent lateral wells can be used to monitor heterogeneities and geosteer the well in the target zone (Ashton et al., 2013). Using this workflow to accurately locate the 'sweet spots' by acknowledging and monitoring geological heterogeneities such as lateral facies or mineralogical changes could serve to mitigate non-productive zones instead of applying a geometric completion model which will inevitably target non-productive zones. On a field- and basin-wide scale the data can be integrated with seismic data to upscale the model across the basin, as well as reservoir correlation and mapping where multiple wells are available.

Summary and conclusions

In this paper we have outlined a workflow which integrates automated mineralogy data with wireline data and measured TOC to accurately define and quantify sweet spots in the Thistleton-1 well, Lancashire, NW England. The 'sweet spots' are based on key reservoir parameters such as effective porosity, water saturation, Young's modulus and bulk volume gas. Three 'sweet spots' were identified in the Sabden unit and four in the Bowland. A total net pay favourable material of 1066 ft (38.5%) was defined for the measured interval (assuming gas is present as indicated by the drilling report) with 1915.5 ft (69.2%) of net brittle material. Mineralogical and textural data from automated mineralogy systems was used to constrain a petrophysical model and improve the accuracy of prediction of key reservoir properties such as effective porosity (±4.1%), water saturation (±2.6%), BVG (±5.1%), all of which would have an impact on the economic viability of the well for production. Shear velocities were modelled from compressional velocities using the Greenberg-Castagna method with lithology control from AM. Shear velocities showed a mean difference of ±11.4% while Young's modulus had a mean difference of ±12% when just using a traditional well log-based petrophysical approach. Shear velocity modelling was validated by a blind test of the model on a nearby well. A strong correlation between the measured velocities and model estimated ones was found with an R^2 coefficient of 0.81. Due to the lack of suitable core samples, lab calibration was not possible for the velocities and rock strength parameters in this case, but would add great value to the workflow. Log-derived and lab-measured TOC shows little variation (between 1 and 2.4%) and therefore did not correlate very well on the cross-plot. However, the values from both analyses are within the average range of known values from other samples in the formation given by Andrews (2013). A great deal of applications of the workflow have been discussed; from risking and volumetrics, drilling and completions to integration with seismic data for large-scale reservoir characterization. Overall, the workflow uses real-rock data to calibrate and constrain petrophysical modelling and recognizes geological heterogeneities that may have in the past been overlooked. By using this integrated approach, the number of unsuccessful fracture stages could be reduced while production and profitability could be increased. The study demonstrates the value of integrating disciplines to gain a better understanding of the subsurface and how it may be one of the many key elements needed to improve drilling and completion programmes as we explore a growing number of shale plays which throw up their own individual complexities.

References

Andrews, I.J. [2013] *The Carboniferous Bowland Shale gas study: geology and resource estimation*. British Geological Survey for Department of Energy and Climate Change, London, UK.

Ashton, T., Ly, C.V., Spence, G. and Oliver, G. [2013] *Portable technology puts real-time automated mineralogy on the well site*. SPE 166982.

Carpentier, B, Huc, A.Y. and Bessereau, G. [1991] Wireline logging and source rocks – Estimations of organic carbon content by CARBOLOG method [J]. *Log Anal,* **32** (3), 279–297.

Castillo, G., Voisey, S., Chesser, K., van de Coevering, N., Bouziat, A., Oliver, G., Vinh Ly, C. and Kuo, L. [2014] Integrating surface seismic, microseismic, rock properties and mineralogy in the Haynesville shale play. *First Break,* **32** (2), 71–79.

Corfield, S.M., Gawthorpe, R.L., Gage , M, Fraser, A.J. and Besly, B.M. [1996] Inversion tectonics of the Variscan foreland of the British Isles. *Journal of the Geological Society*, **153**, 17–32.

de Pater, H. and Baisch, S. [2011] *Geomechanical Study of Bowland Shale Seismicity.* Synthesis Report.

Greenberg, M.L. and Castagna, J.P. [1992] Shear-wave velocity estimation in porous rocks theoretical formulation, preliminary verification and applications. *Geophysical Prospecting,* **40**, 195–209.

Grieser, B. and Bray, J. [2007] *Identification of production potential in unconventional reservoirs: SPE Production and Operations Symposium*. SPE 106623.

Hodenfield, K. [2012] Operators Seek Fracture Consistency. *American Oil & Gas Reporter.*

Hudson, R.G.S. [1933] The scenery and geology of North-West Yorkshire. *Proceedings of the Geologists' Association,* **44**, 228–255.

Leeder, M.R. [1988] Recent developments in Carboniferous geology: a critical review with implications for the British Isles and NW Europe. *Proceedings of the Geologists' Association,* **9**, 73–100.

Nelson, P.H. [2009] Pore throat sizes in sandstones, tight sandstones and shales. *AAPG Bulletin*, **93** (3), 329–340.

Passey, O.R., Moretti, F.U. and Stroud, J.D. [1990] A practical model for organic richness from porosity and resistivity logs. *AAPG Bulletin,* **74**, 1777–1794.

Welling and Company [2012] *Pressure Pumping*.