An investigation of the relationship between reservoir quality and heterogeneity in a North Sea, clastic reservoir: the effect of measurement resolution

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Abstract

Standard petrophysical analysis combines a variety of well log and core measurements to generate estimates of the key rock properties used in calculating STOIIP. However, each measurement type investigates a different volume of rock, at different vertical resolutions, and so may be responding to different types and scales of heterogeneity within a reservoir. Reservoir quality in clastic reservoirs is influenced by many different factors including depositional environment, diagenesis, burial history, and depositional architecture, and is commonly the result of a complex combination of different factors. An understanding of how geological heterogeneities in a reservoir can influence the variability of the well log responses, and consequently the derived estimates of reservoir quality, has a significant impact on data integration and the reliability the estimated rock properties.

This paper investigates and quantifies the relationship between reservoir quality and heterogeneity in a siliclastic reservoir. A detailed petrophysical analysis has been completed using all available well log and core data. Using derived formulas and published techniques, the petrophysical analysis was performed starting with estimating volume of shale, determining porosity, determining permeability and determining water saturation, while seeking to understand the relation between numerical heterogeneity and reservoir quality and relating it to resolution and measurement volumes of logging involved

Integration of the various petrophysical properties for wireline estimates, core, and NMR helped to identify appropriate model to be used on the reservoir. The use of hydraulic flow unit (Amaefule et al. 1993) was essential for separating the reservoir into various layers and gives us an idea of reservoir quality at different depths while comparing the above to Lorenz coefficient gives us and idea on how heterogeneity might affect reservoir quality. The typical Lorenz curve used in reservoir property modeling is a plot of cumulative flow capacity against cumulative thickness (Lake & Jensen 1991).
1. INTRODUCTION

The in-depth understanding of variability and that of various petrophysical properties such as porosity and water saturation together with locating hydrocarbon zones throughout the reservoir is of very great importance. Reservoir heterogeneity plays an important role in reservoir performance. Hence, an understanding of how geological heterogeneities in a reservoir can influence the variability of the well log responses, and consequently the derived estimates of reservoir quality, has a significant impact on data integration and the reliability the estimated rock properties. Heterogeneity measures, such as Lorenz Coefficient, quantify the numerical variation (heterogeneity) in a dataset producing a single output value that allows comparison between measurement, reservoir and their sub-units (Fitch et al. 2013).

Initial investigations suggest that existing Heterogeneity Measures, such as the Lorenz Coefficient, have great potential to be adapted and enhanced to gain a more comprehensive understanding of this numerical variability. This project will use a dataset provided by the London Petrophysical Society to investigate how different scales and types of petrophysical data can capture the same underlying geologic variability – is the same level of heterogeneity captured at all measurement resolutions, and how does this relate to the physics of the measurement tool? An understanding of numerical heterogeneity captured, will be integrated with detailed petrophysical analysis to explore the relationship between heterogeneity and reservoir quality in a North Sea reservoir.

The implementation of the Lorenz coefficient in this project will be focused on the porosity and permeability of datasets provided as well as on detailed derived petrophysical analysis of core, NMR and wireline data. The results from this petrophysical analysis will be integrated with one another to see how they compare so that subsequently we can make use of the most adapted results for our project. The results obtained are then used to discuss on the relationship between reservoir quality of the above mentioned parameters and furthermore relating the better understanding of the varying petrophysical property data to reservoir quality indicators. In the case of reservoir quality, we shall apply the hydraulic flow unit (Amaefule et al. 1993) to have our reservoir subdivided into smaller flow units each characteristic to specific reservoir qualities whereas in the case of heterogeneity we are going to apply the Lorenz coefficient (Schmalz and Rahme, 1950) to obtain variation in single numerical values ranging from 0-1 indicating different levels of heterogeneity.

1.1 Geological Background

1.2 Geological setting

Analogue reservoir. The data provided by the London Petrophysical Society (LPS) is from an unspecified North Sea field. However, the geology of the field is suggested to be analogous to the Buzzard Field (Dore and Robbins 2005 and Ray et al. 2010).

The Buzzard Field. The Buzzard field is among the greatest field to have been discovered on the United Kingdom continental Shelf in the last 25 years; it has a current reserve estimate of about 400×10^6 BBL. (Dore and Robbins, 2005). It lies 50 km northeast of the Scottish mainland and 20km west of the Ettrick Field in a water depth of 300ft (Dore and Robbins 2005).

The Buzzard Field was discovered in May 2001 by well 20/6-3 (Dore and Robbins, 2005). This well encountered high quality 32° API oil trapped within a latest Oxfordian to Early Volgian age reservoir locally referred to as Buzzard Sandstone Member. The field was subject to an appraisal programme in 2001 and early 2002, with eight wells and side-tracks drilled to define it extent (Dore and Robbins 2005).

The trapping mechanism for the field involves a complex stratigraphic pithchout of reservoir sands within shales of Kimmeridge Clay Formation. The Buzzard Sandstone Member comprises base of slope, submarine gravity flow sands with excellent porosity and permeability characteristics. Reservoir pressure is maintained by an active water flood programme using produced water supplemented by treated sea water when necessary. The upper Jurassic Buzzard field comprises sandstone units of up to 60ft thickness interbedded with in-situ and remobilised mudstones along with cemented and injected sandstones. Sandstone units can be correlated basin wide whilst maintaining their thickness and with very little evidence of amalgamation surfaces. Thick Buzzard sandstone units are interpreted as single depositional events of non-erosive high-density, accumulative turbidity currents confined only by the basin margins triggered by catastrophic mass failure events. Fine material, which was not in high concentration in the initial flow, has been transported beyond the Buzzard basin and deposited in a more distal location (Mark and Ben, 2011).
2. METHODS

2.1 Methodology

Data. The data available for this research were provided by the London Petrophysical Society and these are complete triple combo, plus NMR data, digital log plots, core and pressure data. This project focuses on the integration of various petrophysical parameters.

The basic analysis procedure we used involves the following steps, each of which will be described in the following sections.

1) Acquire data from The London Petrophysical Society and acquire high accuracy digitization of paper log prints;
2) Calculation of shale volume from Gamma ray, neutron and density logs;
3) Compute total porosity and shale corrected porosity from density, neutron and sonic logs;
4) Compute water saturation using, Simandoux, Indonesia and Archie model.
5) Compute permeability from core data, nmr data and wire-line log data using various permeability correlations;
6) Compute RQI and PHIE(Z) of various data to obtain a value for FZI;
7) Compute various values for Lorenz coefficient and compare quality with heterogeneity;

The plot below gives a representation of the available raw wireline log data and reflects how they vary with one another against depth.

![Plot of wireline log data](image)

Fig 1: Figure displaying reservoir separated into different zones prior to analysis. Zonation was performed by observing changes in characteristic patterns for the different logs which is very important for quantitative analysis. Caliper log display good borehole conditions as there are very few shifts hence suggesting availability of good data.

Looking at zone C in figure 1, the gamma log reading shows numerous variations in spike which is representative of presence of shale as presence in shale will respond positively with variations on the gamma ray log. Different zones were also picked...
based on the identification of a shift of 10% in gamma ray log readings prior to a stable signal and comparing the signal response of the varying zones with other log response to be able to identify the lithology present at those particular zones. Parameters used in the petrophysical analyses and calculations were provided by the London Petrophysical Society (LPS) and are represented in table 1 below. A standard quality check of the logs was also performed focusing mainly on identifying any flushed or invaded zone or any variation on the caliper log. For this study part of all the petrophysical analysis and calculation was done by use of Microsoft excel to have a better understanding of the underlying petrophysical concepts and techniques.

### FLUID AND WELL INFORMATION

<table>
<thead>
<tr>
<th>Fluid/Well Information</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil</td>
<td>32 api</td>
</tr>
<tr>
<td>Gas oil ratio (GOR)</td>
<td>270 scf/stb</td>
</tr>
<tr>
<td>Viscosity</td>
<td>1.46cp</td>
</tr>
<tr>
<td>Temperature</td>
<td>195 deg.F</td>
</tr>
<tr>
<td>Oil density</td>
<td>0.77g/cc</td>
</tr>
<tr>
<td>Water resistivity (Rw)</td>
<td>0.135ohm</td>
</tr>
<tr>
<td>Mud filtrate resistivity (Rmf)</td>
<td>0.045ohm</td>
</tr>
<tr>
<td>MW</td>
<td>11.45ppg</td>
</tr>
<tr>
<td>Water Salinity</td>
<td>40,000ppm</td>
</tr>
</tbody>
</table>

**Tab 1: Parameters and informations used for petrophysical analysis and provided by the London petrophysical society**

It’s not uncommon that petrophysical data used is uncalibrated and poorly quality checked. To avoid these, a general checklist of quality check represented in table 2 below was created and followed.

### LOG QUALITY CHECK CONTROL CHECKLIST

<table>
<thead>
<tr>
<th>Check</th>
<th>YES</th>
<th>NO</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rm, Rmf, and corresponding temperature measured reported</td>
<td>YES</td>
<td>NO</td>
</tr>
<tr>
<td>Proper logging scales chosen and reported for all logs</td>
<td>YES</td>
<td>NO</td>
</tr>
<tr>
<td>Calibration checks</td>
<td>YES</td>
<td>NO</td>
</tr>
<tr>
<td>Caliper log stable</td>
<td>YES</td>
<td>NO</td>
</tr>
<tr>
<td>Resistivity curves do not read less than zero</td>
<td>YES</td>
<td>NO</td>
</tr>
</tbody>
</table>

**Tab 2: Quality checklist for petrophysical analysis in order to avoid working with erroneous data**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Matrix density ($\rho_{ma}$)</td>
<td>2.65</td>
</tr>
<tr>
<td>Density of shale ($\rho_{sh}$)</td>
<td>2.7</td>
</tr>
<tr>
<td>Density of filtrate ($\rho_{f}$)</td>
<td>1.1</td>
</tr>
<tr>
<td>Shale Porosity ($\Omega_{sh}$)</td>
<td>0.38</td>
</tr>
<tr>
<td>Porosity of filtrate ($\Omega_{f}$)</td>
<td>1.2</td>
</tr>
<tr>
<td>Sonic matrix transition time (DTm)</td>
<td>52.9</td>
</tr>
<tr>
<td>Sonic shale transition time (DTsh)</td>
<td>90</td>
</tr>
<tr>
<td>Sonic fluid transition time (DTf)</td>
<td>180</td>
</tr>
</tbody>
</table>

**Tab 3: Table of values used for computing different petrophysical parameters such as volume of shale, porosity and water saturation**
2.2 Shale Volume

The first set of petrophysical analysis for this project was that to obtain values for shale volume ($V_{shale}$). $V_{shale}$ estimator are mathematical relationships that help to have an estimate of the shale fraction of the reservoir rock. The estimator should yield a value of zero in clean sandstone and one in shale. The common estimation of shale-volume is by use of SP, natural gamma ray and potassium curve from the spectral gamma ray. For this project, the first estimator for this project using available data is the gamma ray method as $V_{shale}$ is directly proportional to the gamma ray log value whereas, $V_{shale}$ values estimated by the second method was calculated by use of derived neutron-density porosity values. Both methods were applied by use of linear equations represented:

In the case of gamma ray, the equation used was that proposed by (Dresser, 1982)

$$V_{shale} = \frac{(GR_{log} - GR_{clean})}{(GR_{clay} - GR_{clean})} \tag{1}$$

Where $GR_{log}$ is gamma ray value obtained from logs, $GR_{sand}$ is the gamma ray value obtained from sand and is also usually referred to as gamma ray minimum because of the low value of gamma ray in sand. $GR_{clay}$ on the other hand is the value of gamma ray obtained from clay and is usually high due to the large quantity of radioactive material found in clay. $GR_{clay}$ is often referred to as $GR_{max}$ is taken as the highest reading value of the log on the gamma log. The values used for clean gamma ray and gamma ray clay were 45 and 75 GAPI respectively.

In the case of neutron-density, Volume of shale ($V_{shale}$) calculation was performed using the linear equation proposed by (Shlumberger, 1989)

$$V_{shale} = \frac{(\Omega_N - \Omega_p)}{(\Omega_{NSH} - \Omega_{SH})} \tag{2}$$

Where $\Omega_n$ and $\Omega_p$ are porosity values of the log readings in the zone of interest for neutron and density logs respectively (fractional), whereas $\Omega_{NSH}$ and $\Omega_{SH}$ are the log readings in the near-by shale whose clay mineral mix resembles that of the zone of interest $\Omega_p = \Omega_{TOTAL}$.

The neutron porosity and density porosity values used in this calculation were estimated with the help of available core data and available density and neutron data. After obtaining results both reflecting $V_{shale}$ values from the two different methods, they both were calibrated against each other versus depth, focusing on the depths reflecting the zone of interest. This plot found on figure 8 was to view how $V_{shale}$ calculations from both methods compare to each other.

2.3 Porosity Calculation

For our porosity calculation, core porosity and NMR porosity data were made available and used to calibrate with our estimated log porosity values. Estimates of porosity values from logs were derived with the help of provided well log data. In this project, porosity values were derived from the density, neutron and sonic logs. This set of porosity values were obtained using theoretical relationships relevant to each of the above mentioned log listed. The following relationships between porosity and respectively bulk density, sonic and neutron logs are evaluated below (Rider, 1986).

a. Bulk density log

The relation used between bulk density and porosity is related to the following equation:

$$\Omega_p = \frac{(\rho_{ma} - \rho_b)}{\rho_{ma} - \rho_f} \tag{3}$$

Where $\Omega_p$ = porosity

$\rho_b$ = tool measured

$\rho_{ma}$ = matrix (or grain) density

$\rho_f$ = fluid density

In this project analysis is performed on a sandstone reservoir and hence the density matrix value for sandstone which is 2.65 gm/cc was used for the purpose of our calculations. The fluid density value was obtained from a relation obtained by doing a cross plot of log bulk density vs. core porosity as shown on figure 2 below.

b. Sonic log

Porosity value calculated from sonic log is by using the WyllieTime-Average equation:

$$\Omega_{sonic} = \frac{(t_{log} - t_{ma})}{(t_f - t_{ma})} \tag{4}$$
Where
\[
\phi_{\text{sonic}} = \text{porosity}
\]
\[
\tau_{\text{log}} = \text{tool measured interval transit time}
\]
\[
\tau_{\text{ma}} = \text{transit time of matrix material (55.5 \mu \text{sec/ft})}
\]
\[
\tau_f = \text{transit time if interstitial fluid}
\]
\[
\tau_{\text{log}} = \text{tool measured interval transit time}
\]
\[
\tau_{\text{ma}} = \text{transit time of matrix material (55.5 \mu \text{sec/ft})}
\]
\[
\tau_f = \text{transit time if interstitial fluid (200 \mu \text{sec/ft})}
\]

In general, porosities derived from the sonic log are inferior to neutron or density log calculated porosities (Rider, 1986). The value of transit time of the matrix used is characteristic of sandstone.

c. Neutron log

For the purpose of this project, the following relation was used to obtain porosity value from neutron log. An average of the porosity values obtained from neutron log and density log was done to obtain neutron-density porosity values.

\[
\phi_{\text{neutron}} = \frac{\phi_N - \phi_{\text{MA}}}{\rho_W - \rho_{\text{MA}}} (5)
\]

Where
\[
\phi_N = \text{is neutron reading from the log}
\]
\[
\phi_{\text{MA}} = \text{matrix neutron}
\]

![Fig 2: Determination of fluid density by plotting log bulk density against core porosity.](image)

\[
y = -0.0093x + 2.5097
\]
relationship between reservoir quality and heterogeneity in a North Sea, clastic reservoir

**Fig 3:** Crossplot of different estimated porosities with core porosity and NMR porosity. This plot proposes that there is a good trend between the available core and NMR porosity data and the wireline estimated porosity.

Core porosity was plotted on the same scale against the various estimated porosities and as seen on figure 4 which is an extract of figure 8, the porosity values from the average of neutron and density was seen to follow that from core obtained porosities best.

**Fig 4:** Calibration of core porosity to neutron-density porosity. The neutron-density porosity was obtained from an average of neutron and density estimated porosity values.
### 2.4 Water Saturation

Water saturation is a parameter that can either be predicted from core data, well logs, or even seismic attributes directly (Life Science Journal 2013). Water saturation values for this project were made available from Special Core Analysis provided by the LPS and those for wireline logs were estimated using three different models namely, the Archie Model (1942), the Simandoux Model (1963) and the Indonesia Model (1971). Archie’s law postulate the rock matrix is non-conductive. For sandstone with clay material, this assumption is no longer true in general, due to the clays structure and cation exchange capacity. Simandoux (1963) came up with his model based on resistivity, density and neutron logs data. The “Indonesian formula” proposed by Poupon and Leveaux (1971), was developed based on the typical characteristics of fresh formation waters and above average degrees of shaliness that are present in many oil reservoirs in Indonesia. In the Indonesia model the conductivity relationship between $R_t$ and $S_w$ is as a result of conductivities of the clays, formation water and conductivity from their interaction if our formation is all clean sand, the different water saturation models will provide the same value, but if there is presence of shale, the values derived from Simandoux and Indonesia are expected to be different from each other. The various models are represented by sets of linear equations relating different factors.

In the case of Archie the linear equation used is:

$$S_w = \left( \frac{\alpha}{\phi^m} \frac{R_w}{R_t} \right)^{\frac{1}{n}} \tag{6}$$

Where $S_w$ is the water saturation, $\phi$ is derived from log, $R_w$ is the formation water resistivity with a value of 0.135 ohm m provided by the LPS, $\alpha$ is a constant with a value of 1, $m$ (cementation exponent) = 1.8 and $n$ (saturation exponent) = 2 are provided from estimates of the core data.

In the case of the Simandoux model, the linear equation used to calculate water saturation is as follows:

$$S_w = \left[ R_w \phi^{-m} \left( \frac{1}{R_t} - \frac{V_{sh} S_w}{R_{sh}} \right) \right]^{\frac{1}{n}} \tag{7}$$

Where: $R_t$ = log reading in the borehole corrected for bed thickness and invasion.

$R_w$ = Resistivity of the clay with a value of 1

$V_{sh}$ = Clay fraction

$R_{sh}$ = Resistivity of water with a value of 0.135 ohm

$m$ = cementation exponent with a value of 1.8

$n$ = saturation exponent with a value of 2

$$S_w = \left\{ \left( \frac{R_{sh} V_{sh}}{R_{sh}} \right)^{\frac{2}{n}} + \left( \frac{\phi^m}{R_w} \right)^{\frac{1}{n}} \right\}^{\frac{1}{2}} R_t^{-\frac{1}{n}} \tag{8}$$

Where:

$R_c$ = resistivity of uninvaded zone

$V_c$ = volume of clay

$\phi$ = effective porosity

$R_{cl}$ = resistivity of clay (0.98 ohm m)

$R_w$ = resistivity of formation water

$m$ = cementation factor

$n$ = saturation exponent

### 2.5 Permeability Estimation

Next in our petrophysical analysis is permeability estimation. Permeability (a measure of fluid conductivity in porous medium) is a critical parameter in models for reservoir characterization, reservoir estimation and production forecast.
The relationship between reservoir quality and heterogeneity in a North Sea, clastic reservoir (Adeboye et al. 2012). Many empirical models have been proposed for correlations between permeability, porosity, and permeability estimations from porosity. Permeability estimation in this project was estimated by deriving a relationship based on core data and also by calculating irreducible water saturation values and using them in various derived model equations to obtain permeability values; this is because a good correlation exist between irreducible water saturation and permeability (Lawal and Adeguna, 2010). The first step in determining permeability was to do a cross-plot of available core helium core porosity data with available core air permeability. Base on the later, a relationship for obtaining permeability from core porosity and permeability was obtained. Secondly the previous step was repeated but this time with available NMR data to see how they relate. The different permeability estimates include those from cores and NMR were plotted against the same depth to see how they compare to each other as seen on figure of figure 8. (Wyllie and Rose 1950), proposed the following equation for estimation of permeability:

\[ K^{1/2} = C \cdot \frac{\phi^x}{(S_{wi})^y} \]  

(9)

Based on equation (9), various equations listed below were proposed to derive permeability with the help of porosity and irreducible water saturation.

**Tixier 1949** Tixier established a relationship for determining permeability from resistivity gradients but following the work of Wyllie and Rose, Tixier developed a simpler model that is now used more often;

\[ K^{1/2} = 250 \frac{\phi^3}{S_{wi}} \]  

(10)

**Timur 1968** Timur proposed a generalized equation which is widely used to estimate permeability written below as;

\[ K = 0.136 \frac{\phi^{4.4}}{S_{wi}^2} \]  

(11)

**Coates 1981** Coates proposed the following formula for permeability determination

\[ K^{1/2} = 100 \frac{\phi^2 (1 - S_{wi})}{S_{wi}} \]  

(12)

Where \( K \) represents the permeability in millidarcies (mD), \( \phi \) is the porosity, \( S_{wi} \) is irreducible water saturation.

The relationships quoted above are all based on intergranular porosity data and so are generally applied to sandstone reservoirs hence suitable for this project.

The value of irreducible water saturation substituted in the above equations was also derived using the following equation proposed by (Timur 1968):

\[ S_{wi} = 3.5 \frac{\phi^{1.26}}{K^{0.35}} - 1 \]  

(13)

Fig 5: A crossplot of air permeability data and helium porosity. From the figure above it is noticed that and increase in porosity leads to and increase in permeability which is usually characteristic of sandstone reservoirs as in our case.
2.6 Flow Zone Indicators (FZI)

Flow Zone Indicator is a useful value to quantify the flow character of a reservoir and one that offers a relationship between petrophysical properties at small-scale, such as core plugs and large scales such as well bore level, (Chandra, 2008). In the paper, (Amaefule et al., 1993), hydraulic flow unit method is used to investigate reservoir quality. Three derived values were used during this project to come up with Hydraulic Flow Units values namely reservoir quality index (RQI), pore volume-to-grain volume ratio (Øe, PHIZ), and the flow zone indicator (FZI). In equation 14 written below the constant 0.0314 is used to convert permeability from millidarcies to μm² as per Kozeny Carmen, (Amaefule et al., 1993).

\[ RQI = 0.0314 \times \frac{K}{\phi_e^2} \] (14)

\[ \bar{\phi}_z = \left( \frac{\phi_e}{1 - \phi_e} \right) \] (15)

\[ FZI = \frac{RQI}{\phi_z} \] (16)

The above equations are dependent on permeability and porosity hence it is important that the derived values of permeability and porosity be very adequate and calibrated to core. Different FZI calculations were performed for the various data available NMR, cores and wireline log. A plot of RQI vs. PHIZ shown on fig 6 can be used in estimating reservoir quality.

![Fig 6. Schematic illustration of the Amaefule et al. (1993) Hydraulic Flow Unit Plot. In this plot Reservoir quality index (RQI) is plotted against normalized porosity (PHIZ) and it is noticed that reservoir quality increases with higher RQI at lower porosities, as does flow zone indicator value. (Fitch et al., 2013)](image)

2.7 Lorenz Coefficient

In 1950, Schmalz and Rahme proposed a single term for characterizing the permeability distribution within a pay section. The Lorenz coefficient is a plot of cumulative flow capacity F_m versus cumulative thickness (Lake & Jensen, 1991). These cumulative properties are sorted from low to high values. If the formation is purely homogenous, the cumulative properties will have a constant value represented by a diagonal line known as the “line of perfect equality” (Sadras & Bongiovanni, 2004). Whereas normally an increase in the heterogeneity of the property will react in a way that will move the Lorenz coefficient line away from the line of perfect equality (Fitch et al., 2013). For the purpose of our study the cumulative properties used to obtain our Lorenz coefficient were values of porosity and permeability. Here we used one of the two methods developed by (Fitch et al., 2013) using porosity and permeability directly. Referring to figure 7, Lorenz coefficient of heterogeneity is twice the area between the Lorenz Curve and the line of perfect equality. Typical values of Lorenz coefficient of reservoirs are in the range 0.3-0.6 (Lake & Jensen, 1991).
relationship between reservoir quality and heterogeneity in a North Sea, clastic reservoir

Fig 7. Schematic illustration of a Lorenz Plot: cumulative of a property (e.g., permeability or porosity,) sorted from higher to lower value, is plotted on the y-axis, and a second cumulative property (depth increment or storage capacity) is plotted on the x-axis. Grey diagonal line – “line of perfect equality”, Lc =0 and the black lines represent Lorenz Curves for increasing Lc values. (Fitch et al. 2013.)

3. RESULTS

After carefully going through the different methods for our petrophysical analysis, we have obtained a series of results as represented on figure 8 and figure 9 below. These results were calibrated against NMR and core data to have the most suitable parameters in each case selected. In the case of figure 8, the analysis is displayed taking into account all parameters, correlations and models for the various petrophysical parameters such as volume of clay, water saturation, porosity and permeability. Zonation was performed by observing changes in characteristic patterns for the different logs which is very important for quantitative analysis. Also the variation is spikes of Vclay were an additional feature in separating this reservoir into various subunits.

This division of the reservoir into various sub-units plus the selection of the most suitable parameters for the petrophysical analysis is displayed in figure 9. In the case of volume of clay, we made use of the volume of clay estimate from neutron-density. This is because as represented by figure 1 above, the caliper show a stable borehole and volume of clay from neutron-density does not usually require corrections for matrix radioactivity or Vshale over-estimation adjustments. (Geoloil, 2013). This is therefore trusted for a better estimation of volume of clay as compare to that from gamma ray and could be a reason for their different estimation.

In the case of porosity, the average values for porosity obtained from density and neutron was used based on the fact that the latter takes into account both the neutron and density and since the caliper shows a stable borehole the chances of density readings to be severely affected are low. It is worth noting that the parameters give a good representation of geology for example we have a good porosity variation and in the case of water saturation, the estimations from Simandoux, Indonesia and Archie produced close trends though differences in areas with high shale concentration can be observed. This is expected as Simandoux and Indonesia model were adjusted for shaly reservoir and hence when dealing with a clean sand reservoir the later is expected to show similar interpretations. For the purpose of this project, water saturation from Archie was picked since it is a model used in sandstone reservoir. Lastly in the case of permeability, the correlation proposed by (coates, 1981) was selected though they all slightly varied with from one another which could be a sign that the equations used were not totally reflective of our reservoir. Values of irreducible water saturation were adjusted to improve log estimates for permeability of the different models.

The porosity in zone A, zone B and zone D vary from 0.15 to about 0.20 and the porosity values in zone C have a broader range that extends from 0.15 to about 0.30. The permeability in zone A, zone B and zone C vary between 100mD to 1000mD but is slightly higher in zone C as in the case of porosity in that same zone, this is indicative of a highly permeable zone.
Fig 8: The figure is a representation of the various initial petrophysical analyses made. This graph is composed of all initial petrophysical analysis performed and comparing them to the NMR and core data across the same depth.

Fig 9: Similarly to figure 8, figure 9 is a representation of the petrophysical analysis performed but with a difference in the fact that, only the final correlation for the different petrophysical analysis were represented here and the reservoir has been split into sub units.
For a better comparison and understanding on how the available core data, nmr data and estimated wireline parameter relate to each other and too view from a greater picture how the relation between reservoir quality and heterogeneity are affected by them, various crossplots, hydraulic zone indicators and Lorenz coefficients plots of the various parameters were examined.

Fig 10: Hydraulic unit plot of all available data (core, NMR, and derived wireline data) at depths between the interval of 9150ft - 9450ft. The diagram is a representation of the entire reservoir zone.

Fig 11: Hydraulic unit plot for the reservoir units of estimated wireline, Nmr and Core at various depths. Contrary to figure 10, figure 11 displays the plot of RQI versus PHI(z) for the different zones separately in order to give a better insight of the variation of reservoir quality downhole at different depths. Table 4 below describes the depths to which a particular zone corresponds.

<table>
<thead>
<tr>
<th>Zone</th>
<th>Depths (ft.)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>9150-9250</td>
</tr>
<tr>
<td>B</td>
<td>9250-9300</td>
</tr>
<tr>
<td>C</td>
<td>9300-9350</td>
</tr>
<tr>
<td>D</td>
<td>9350-9400</td>
</tr>
</tbody>
</table>

Table 4: representing depths as zones
The highly heterogeneous nature of NMR is well illustrated on the cross-plot of RQI versus PHz (Fig 10: green symbols) as the data is seen to spread across the cross plot from low to high values. The reservoir quality (FZI) is also noticed to be high in zone C form (figure 11). Wireline and core data are seen to be less heterogeneous though they are seen to overlap at some point together with the NMR data. Reservoir quality of NMR is seen to increase downhole while that of wireline is seen to decrease downhole. There is no clear trend in the reservoir quality between core units. Nevertheless, zone C as portrayed on (figure 11) appears to have the highest level of heterogeneity.

![Fig 12: Lorenz coefficient plots and values for the three available log data. The results are in order of decreasing heterogeneity and follow the same trend proposed by the hydraulic unit plot in figure 7 with NMR data reflecting the highest level of heterogeneity and core data reflecting the lowest level of heterogeneity.](image)

![Fig 13: Lc for zone 1 of different parameters (Wireline, Core, NMR) ![Fig 14: Lc for zone 2 of different parameters (Wireline, Core, NMR)]](image)
relationship between reservoir quality and heterogeneity in a North Sea, clastic reservoir

Figure 12 is a representation of cumulative properties of permeability plotted against cumulative properties of porosities to obtain value for Lorenz coefficient. In the case of (figure 12), and average value of different properties (core, NMR and wireline data) are plotted and (figure 12) suggests that NMR has the highest level of heterogeneity, followed by wireline and then core data. On the other hand (Figures 13, 14, 15 and 16) on the other hand present at this values independently by focusing on the different sub-units. As suggested by (figure 11), zone c displaying the highest level of data spreading has the highest level of heterogeneity which suggest that in the case of our reservoir, and increase in reservoir quality could well lead to and increase in heterogeneity. This is because the largest individual value of Lorenz coefficient is found at this particular zone. An increase in heterogeneity of both porosity and permeability for the different properties is seen to generally lead to an increase in reservoir quality. Also zone D and zone A as suggested by (figure 11, 13 and 16), reflect quite a low level of heterogeneity.

<table>
<thead>
<tr>
<th>Zone</th>
<th>Depths (ft.)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Zone A</td>
<td>9150-9250</td>
</tr>
<tr>
<td>Zone B</td>
<td>9250-9300</td>
</tr>
<tr>
<td>Zone C</td>
<td>9300-9350</td>
</tr>
<tr>
<td>Zone D</td>
<td>9350-9400</td>
</tr>
</tbody>
</table>

Table 5: representing depths as zones
DISCUSSION

It has long been recognized that permeability/porosity relationships can be obtained once conventional core data are grouped according to their rock types (Guo et al. 2007). Diagenesis exerts a strong control on the quality and heterogeneity of most clastic reservoirs. Variations in the distribution of diagenetic alterations usually accentuate the variations in depositional porosity and permeability (Morad et al., 2010). Reservoir-quality predictive models will be a useful element of risk analysis until remote-sensing tools are invented that accurately measure effective porosity and permeability ahead of the bit (Joanna and Robert 2010). With knowledge of this, investigating how heterogeneity in sandstone might affect reservoir quality is of prime importance. For typical siliciclastic reservoirs we often associate the well-sorted nature of “homogenous” reservoir rocks, for example the Rotliegendes sandstones, with extremely high reservoir quality and production levels (Rogers & Head, 1961; Glennie et al. 1978). Our approach to investigating the relation between reservoir heterogeneity and quality by primarily having a petrophysical analysis of our reservoir and integrating the results obtained with various properties such as available core and NMR data to see how they compare allows for a better comprehension of the different properties of sandstone reservoir rock and how they influence the behavior of the reservoir. Great understanding of this could lead to enhancing production method. Sample heterogeneity will be influenced by the size of the sample (Lake & Jensen, 1991; Dutilleul, 1993).

Unprocessed log and core data itself, aid our understanding of the intrinsic heterogeneities within a system and how they interact across the different length-scales and measurement volumes (Fitch et al. 2013). In the case of our reservoir this could be seen by high variability on figure 11 and high values of Lorenz coefficient on figure 15 which both represent zone C on (figure 9). Zone C is suspected to be rich in mudstone. Comparison of the different hydraulic flow unit on figure 10 suggest that high resolution data such as those in the case of NMR will have a better reservoir quality as compared to data of low resolution such as in the case of available core data. Futhermore figures 12-16 suggest a direct relationship in the variation of increasing porosity heterogeneity and increasing permeability heterogeneity in the sense that and increase in porosity heterogeneity will lead to an increase in permeability heterogeneity which could be characteristic of a clastic reservoir.

The Lorenz coefficient is also important as it can be used to compare data from a variety of tool and scale of measurement. As heterogeneity can only vary between zero and one, different datasets can be easily compared regardless of the scale of original measurements (Fitch et al. 2013). Though stated that typical values of Lorenz coefficient of reservoirs are in the range 0.3-0.6 (Lake & Jensen, 1991), we came up with Lorenz coefficient value as high as 0.76 in the case of zone c hence suggesting a very high level of heterogeneity. (Amaefule et al.1993), hydraulic flow unit method used to investigate reservoir quality is appropriate for dividing the reservoir into various sub-units and each sub-unit show a characteristic behavior of its properties when compare to log results at the same depth. A plot of Lorenz coefficient versus flow zone index in figure 17 was plotted to integrate reservoir heterogeneity and reservoir quality and understand how theyrelate. A trend of increasing heterogeneity with reservoir quality is seen.

The porosity and permeability distributions are controlled by the heterogeneities within the reservoir formation, such as
The relationship between reservoir quality and heterogeneity in a North Sea, clastic reservoir stratigraphic layering, facies, diagenetic processes, and fracturing. Porosity is enhanced by extensive fracturing and grain dissolution creating intergranular, intragranular and moldic porosity. In addition, permeability is also increased by fractures connecting separated the buildups, that affect directly the reservoir quality (Amani et al. 2010).

The wireline data gave a nice indication of the various lithologies present in the different zones in this project. In figure 9, zone A despite having similar average porosity values as zone D shows a much lower water saturation suggesting that zone D should be our water zone. Porosity values from the logs, nmr and cores show some differences which would be as a result of overestimation or underestimation of the results from the logs or laboratory measurement. Nevertheless they show the same trend as they all show an increase in porosity in zone C and they all give the lowest value of porosity in zone A. As in the case of porosity, the permeability values from NMR cores and logs also show differences but in this case, though they follow similar increasing and reducing trends, the permeability is seen to be quite different in zone D and very similar in the other zones, also the NMR data with a higher resolution give a greater variation in permeability than the core and log data.

6. CONCLUSION

- The main objective of this project was to understand how reservoir quality could vary with variation in heterogeneity. This was investigated by going through a series of integrated petrophysical analysis, determination of hydraulic flow units and obtaining single numerical values for Lorenz coefficient.
- When carrying investigations on reservoir behaviours such as reservoir quality, diagenesis or heterogeneity it is very important to understand the geological background of this reservoir and understand how various petrophysical parameters such as porosity and permeability do affect the nature of this reservoir.
- In order to have a good understanding of how these petrophysical parameters affect the reservoir it is important to carry out a set of detailed petrophysical analysis and make sure appropriate models are used like in the case of water saturation and should be representative of the reservoir (e.g. for clean sandstone use Archie).
- Integration of the results obtained from the point above with available data such as cores and NMR data help in a choice of more concise and specific parameters hence limiting error in your results. Also a good integration of the different parameters especially with core data is very important when estimating permeability in the absence of other methods such as well test and in case the permeability models might not be typical of a clastic reservoir.
- The Lorenz coefficient applied to petrophysics has proven to be a very reliable tool and also efficient tool in the measurement of heterogeneity in the dataset. More importantly, the Lorenz coefficient can be used to compare data from different tools, scale of measurements and reservoir types.
- A plot of RQI vs PHI is a good representation of reservoir quality and is even seen to respond by spread of data when plotted for regions were possible mudstones could be found like in the case of zone C.
- This work has given and insight into basic petrophysics, it has also covered the integration of NMR and core data with log data and finally suggest that an increase in reservoir quality could be as a result of increasing heterogeneity.
- Data with high resolution such as NMR are seen to portray better reservoir quality than data with low resolution such as core hence different level of heterogeneity are captured at different resolutions.

7. RECOMMENDATION AND FURTHER WORK

- The methodology described in this project is to be followed to obtain and calculate various parameters from other clastic reservoirs and see how result obtains vary with the ones. Normally if dealing with the same type of reservoir I would expect result to be somehow showing the same trend.
- Well testing should be carried to have and estimate of permeability from it since it operates at a higher investigation interval than cores, in this case we will have a more accurate value of permeability and hence produce more reliable results and conclusions.
- The same investigation should be carried on reservoir with different lithology to see what the result might be, this will help us know is result obtained are general or specific to our clastic reservoir and hence could then be used as a reference in the case it is.
8) REFERENCES


Mark McKinnon and Ben Kneller “Depositional Processes and Correlation of Structurally Confined Deepwater Sandstones from the Upper Jurassic Buzzard Field” Annual Convention and Exhibition, April 10-13, 2011, Houston, Texas


**Nomenclature**

**Notation**

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>NMR</td>
<td>Nuclear magnetic resonance</td>
</tr>
<tr>
<td>RQI</td>
<td>Reservoir quality index</td>
</tr>
<tr>
<td>FZI</td>
<td>Flow zone indicator</td>
</tr>
<tr>
<td>$V_{sh}$</td>
<td>Volume of shale</td>
</tr>
<tr>
<td>$S_w$</td>
<td>Water saturation</td>
</tr>
<tr>
<td>HU</td>
<td>Hydraulic unit</td>
</tr>
<tr>
<td>$K$</td>
<td>Permeability</td>
</tr>
<tr>
<td>$\varnothing$</td>
<td>Porosity</td>
</tr>
<tr>
<td>$R_w$</td>
<td>Formation water resistivity</td>
</tr>
<tr>
<td>$m$</td>
<td>Emplacement exponent</td>
</tr>
<tr>
<td>$n$</td>
<td>Saturation exponent</td>
</tr>
<tr>
<td>$t_{\text{log}}$</td>
<td>Log measured interval transit time</td>
</tr>
<tr>
<td>$t_{\text{ma}}$</td>
<td>Matrix transit time of matrix material</td>
</tr>
<tr>
<td>$t_f$</td>
<td>Transit time of interstitial fluid</td>
</tr>
<tr>
<td>$t_{\text{mat}}$</td>
<td>Matrix transit time of matrix material</td>
</tr>
<tr>
<td>$t_{\text{f}}$</td>
<td>Transit time of interstitial fluid</td>
</tr>
</tbody>
</table>
A Review of Heterogeneity Measures Used in Reservoir Characterization

Author: Lake, L.W., U. of Texas; Jensen, J.L., Heriot-Watt University

Contribution: This paper reviews the means by which heterogeneity is assessed. The measures fall into two categories: static and dynamic. Static measures do not account for fluid flow directly; they are exemplified by the Dykstra-Parsons and Lorenz coefficient. Dynamic measures include dispersivity and channelling factors which directly relate to the efficiency of a miscible displacement.

Methodology: Discuss individually various methods for Permeability estimation

Conclusions:
1. States that whatever the reservoir properties involved, heterogeneity measures can be classified into different three groups
2. States that the heterogeneity in a reservoir could either be static or dynamic

Comments: Provides good literature background for different correlations relating to permeability estimation. The accurate information presented in this paper could be of very great importance in estimating permeability.
FIRST BREAK VOL 10, NO 3, MARCH 1992/89

Estimating the mean permeability: how many measurements do you need?

Author: Corbett P.W.M, and Jensen, J.L, 1992,

Contribution: From knowledge of variability in a wide range of sediments, we can begin to determine $N_o$ for a range of reservoir rock

Methodology: Three formations have been used to examine the variation of the $N_o$ value. The formations were selected on the basis of their having comprehensive data sets and varying degrees of heterogeneity. In each case, probe permeameter measurements have been used. Intervals from the Rannoch, Etive and Rotliegendes formations were chosen with $C_v$ values of 0.48 (homogeneous), 0.95(heterogeneous) and 3.1 (very heterogeneous), respectively.

Conclusions: The coefficient of variation ($C_v$) value, and hence required number of data ($N_o$), can be predicted roughly from prior knowledge of analogue or comparable lamina, bed or formation types. Both statistics will tend to increase as sediment sorting decreases or the mixing of sediment types increases.

Comments: Helped in the understanding of permeability from a very geological point of view.
**SPE (1996) 26436-MS**

Enhanced Reservoir Description: Using Core and Log Data to Identify Hydraulic (Flow) Units and Predict Permeability in Uncored Intervals/Wells

**Author:** Amaefule et al 1996

**Contribution:** Helps in grasping the concept behind hydraulic flow unit, flow zone index and reservoir quality index

**Methodology:** The paper gave a nice background and analyses of flow zone indicator, (FZI) it also went forward to introduce reservoir quality index and compare permeability-porosity relationship to determine permeability with other permeability methods

**Conclusions:**

1) Improved prediction of permeability and permeability distributions from wireline logs in partially cored/uncored intervals and adjacent wells

2) Forecasts reservoir rock quality (and formation damage potential) in partially cored/uncored wells for improved completions and enhanced recovery decisions

3) Improved well-to-well rock properties correlations for refinement of petrophysical model

4) Provides a unique parameter, the Flow Zone Indicator (FZI) for delineating the number of layers (hydraulic units) required for assignment of geological and petrophysical parameters in numerical simulators

**Comments:** Gave a good explanation of flow zone indicator, made great application of core and Log data to identify hydraulic flow units.
The Buzzard Field

Author: Dore, G. and Robbins

Contribution: Provided adequate geology of the Buzzard Field, its location, current reserve estimate and early discovery history

Methodology: Went from the detailed location of the field, to the date it was discovered and provided an estimate of the actual reserve

Conclusions: The Buzzard Field is one of the largest fields to be discovered on the United Kingdom Continental Shelf in the last 25 years; it has a current reserves estimate of over $400 \times 10^6$ BBL. It lies some 50 km northeast of the Scottish mainland and 20 km west of the Ettrick Field in a water depth of 300 ft.

Comments: Very good description of the Buzzard field touching every aspect from the lithology, to the location and the actual
**Journal of Applied Sciences, 9: 1801-1816, 2009**

The Hydraulic (Flow) Unit Determination and Permeability Prediction: A Case Study of Block Shen-95, Liaohe Oilfield, North-East China

**Authors:** O.D. Orodu, Z. Tang and Q. Fei

**Contribution:** This study analyses three prediction approaches of the Bayesian method for predicting Hydraulic Unit (HU) and consequently predicts permeability for Block Shen-95.

**Methodology:** This is done by first constructing a probability database through the integration of established HU and well log responses at cored wells. HU is then inferred from the database using well log responses. By comparison, estimated permeability from predicted HU gave an overall improved permeability match to that of traditional statistical methods. More so, mutually exclusive multiple well logs proved more favourable

**Conclusions:**

1. Permeability estimation may be considered satisfactory by hydraulic unit with respect to high reservoir heterogeneity, number of cored wells available and poor well log responses correlation to permeability and flow zone indicator

2. Hydraulic unit prediction in uncored wells with the aid of well logs is to a larger extent an art based on finding the optimal well log responses discretization for hydraulic unit inference and the number of hydraulic unit categories with its corresponding core sample point distribution

**Comments:**

The paper showed that significant relationship exists by integrating reservoir performance with HU distribution indicating that reasonable prediction was obtained
The American Association of Petroleum Geologists, 2010

The impact of diagenesis on the heterogeneity of sandstone reservoirs: A review of the role of depositional facies and sequence stratigraphy

**Author:** S. Morad, Khalid Al-Ramadan, J. M. Ketzer and L. F. De Ros

**Contribution:** Investigates the impact of depositional facies on diagenesis and reservoir heterogeneity, links the impact of diagenetic alterations on reservoir heterogeneity to sequence stratigraphy

**Methodology:** Characterised connectivity and diagenesis in sandstone, reservoir heterogeneity and effective permeability

**Conclusions:** Variations in the distribution of diagenetic alterations in sandstone successions may accentuate reservoir heterogeneity. However, linking diagenesis to depositional facies and key sequence-stratigraphic surfaces and systems tracts provides a powerful tool to predict the distribution of diagenetic alterations within sandstone succession, particularly in paralic and shallow-marine sandstones

**Comments:** Very little information discussed on sandstone reservoir instead much of the emphasis was laid on carbonate reservoir. This is probably due to the fact that they have more complex heterogeneity variation than sandstone reservoir
PERMEABILITY ESTIMATION AND HYDRAULIC ZONE PORE STRUCTURES IDENTIFICATION USING CORE AND WELL LOGS DATA

Authors: Y.B. Adeboye, C.E. Ubani, K.K. Farayola

Contribution: presented and improved methodology to accurately estimate permeability from well log devices, with commonly available core log data is

Methodology: Core permeability and porosity data were used to identify three different hydraulic zones namely: micro, meso and macro pores respectively with unique pore structures. Selected logging tools showed different responses for each hydraulic zone. Multi-dimensional data base that relate four logging values to core permeability in order to provide relationship for permeability predictions from log where core is not available was constructed.

Conclusions:

1. A method has been found to link core plug permeability to well log measurements in relational databases. Core plugs of approximately 20ml volume have a permeability value which can be uniquely linked to log measurements

2. If the entire range of permeability from all hydraulic zones is included in a core - log database, it is possible to predict permeability accurately enough to represent changes in permeability across a reservoir. Databases constructed at “key” wells can be used to predict permeability at offset wells.

3. Permeability predictions are good in sandstone reservoirs if permeability is predicted by Kriging with a multi-dimensional database calibrated for each hydraulic zone. Permeability predictions from porosity-permeability transforms were of little value case study presented

Comments: The method presented in determining permeability was simple and straight forward and provided accurate results.
The petrophysical Link between Reservoir Quality and Heterogeneity: Application of the Lorenz Coefficient

**Authors:** Fitch et al.

**Contribution:** Studied the effect of heterogeneity in carbonate reservoirs and showed how the Lorenz coefficient can be used as a measure of heterogeneity in petrophysical measurements. Investigated the attribution of heterogeneity to factors such as lithology, sedimentary facies mineralogy and pore types.

**Methodology:** Used data from three carbonate reservoirs, compare their heterogeneity by application of Lorenz coefficient and Hydraulic flow units. Integrated all available data to core data for calibration.

**Conclusions:**

1. The Lorenz coefficient can be used as a measure of heterogeneity in dataset, to obtain a single value of numerical variation where zero is homogeneous and one is maximum heterogeneity. The Lorenz coefficient can be used to compare data from different tools, scale of measurement and porosity types.

2. The permeability heterogeneity is significantly greater than porosity heterogeneity, regardless of the type of carbonate reservoir under investigation. This is because permeability value exist over a large range of magnitudes than their porosity counterparts.

**Comments:** The paper gave a good insight into the Lorenz plot and hydraulic unit for determining heterogeneity; it assumes that permeability values in carbonate reservoir exist over a larger range of value than porosity, which is appropriate.
# Appendix B – Milestones Table

## Table B1 - Milestones for the investigation of the relationship between reservoir quality and heterogeneity in a North Sea, clastic reservoir: the effect of measurement resolution

<table>
<thead>
<tr>
<th>Paper No.</th>
<th>Year of Publication</th>
<th>Title</th>
<th>Authors</th>
<th>Contribution</th>
</tr>
</thead>
<tbody>
<tr>
<td>20156 -MS</td>
<td>1989</td>
<td>“A Review of Heterogeneity Measures Used in Reservoir Characterization”</td>
<td>Lake, L.W., U. of Texas; Jensen, J.L.,</td>
<td>Measure of heterogeneity, and assesses heterogeneity as either static or dynamic. Static measures do not account for flow directly whereas dynamic measures include dispersivity.</td>
</tr>
<tr>
<td>FIRST BREAKVOL 10, NO 3,</td>
<td>1992/89</td>
<td>“Estimating the mean permeability: how many measurements do you need?”</td>
<td>Corbett P.W.M, and Jensen, J.L</td>
<td>This study describes a pragmatic approach to the selection of samples for relative permeability measurement, which has been found to provide focus in this case study.</td>
</tr>
<tr>
<td>26436</td>
<td>1996</td>
<td>“Enhanced Reservoir Description: Using Core and Log Data to Identify Hydraulic (Flow) Units and Predict Permeability in Uncored Intervals/Wells”</td>
<td>Amaefule et al</td>
<td>Helps in grasping the concept behind hydraulic flow unit, flow zone index and reservoir quality index. Also introduces some heterogeneity measure methods.</td>
</tr>
<tr>
<td>Petroleum Geology Conference series</td>
<td>2005</td>
<td>“The Buzzard Field”</td>
<td>Dore, G. and Robbins</td>
<td>The Buzzard field is suspected to be the field around which this project is focused on. Dore and Robbins gave a good geological background of the field and discussed its location.</td>
</tr>
<tr>
<td>Journal of Applied Sciences, 9: 1801-1816,</td>
<td>2009</td>
<td>“The Hydraulic (Flow) Unit Determination and Permeability Prediction: A Case Study of Block Shen-95, Liaohe Oilfield, North-East China”</td>
<td>O.D. Orodu, Z. Tang and Q. Fei</td>
<td>This study analyses three prediction approaches of the Bayesian method for predicting Hydraulic Unit (HU) and consequently predicts permeability for Block Shen-95.</td>
</tr>
</tbody>
</table>
relationship between reservoir quality and heterogeneity in a North Sea, clastic reservoir

<table>
<thead>
<tr>
<th>Journal</th>
<th>Year</th>
<th>Title</th>
<th>Authors</th>
<th>Abstract</th>
</tr>
</thead>
<tbody>
<tr>
<td>Petroleum &amp; Coal</td>
<td>2012</td>
<td>Permeability estimation and hydraulic zone pore structures identification using core and well log data</td>
<td>Y.B. Adeboye, C.E. Ubani, K.K. Farayola</td>
<td>Presented and improved methodology to accurately estimate permeability from well log devices, with commonly available core log data is</td>
</tr>
<tr>
<td>SPWLA 54th Annual Logging Symposium</td>
<td>2013</td>
<td>The petrophysical Link between Reservoir Quality and Heterogeneity: Application of the Lorenz Coefficient</td>
<td></td>
<td>Studied the effect of heterogeneity in carbonate reservoirs and showed how the Lorenz coefficient can be used as a measure of heterogeneity in petrophysical measurements. Investigated the attribution of heterogeneity to factors such lithology, sedimentary facies mineralogy and pore types</td>
</tr>
</tbody>
</table>

![Crossplot of core permeability and log permeability to calibrate and see how they compare](image)

Fig 18: Crossplot of core permeability and log permeability to calibrate and see how they compare
**Fig 19**: Crossplot of ROI versus PHlz of various parameters Wireline, Core, and NMr at different depths to show how they vary individually. This just strengthens the fact that NMR data has a wider spread of data and higher resolutions than the others. This plot is done at different depth intervals.
The relationship between reservoir quality and heterogeneity in a North Sea, clastic reservoir can be described by the equation:

\[ y = 13178\ln(x) + 21907 \]

with a determination coefficient \( R^2 = 0.6324 \).

**Fig 20**: A cross plot of permeability and helium porosity.

**Fig 21**: Illustration of suspected field “Buzzard” used for the project. Diagram not included above as LPS did not provide the exact name of the field so even if the lithology suspects it is the exact field we are not entirely sure.