A Review of the Reservoir Quality of Upper Jurassic Fulmar Sandstones by Integrating Sedimentology, Petrography, Petrophysics, and Core analysis using Well 16/21A-13 Blair Oil Field, North Sea.

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Abstract

Understanding the reservoir quality (porosity and permeability) in sandstone reservoirs poses a significant problem in petroleum industries due to their influences on STOOIP, well deliverability in petroleum industries, and reservoir heterogeneity. Core sedimentology, wireline log analysis, core analysis data, and thin section petrography were used to determine the reservoir quality of Upper Jurassic Fulmar sandstones from the Blair oil field. The Upper Jurassic Fulmar sandstones of the central part of the North Sea display variations in grain sizes, bioturbation intensity, and sedimentary structures, indicating differing depositional environments. These Upper Jurassic Fulmar sandstones were deposited in various sedimentary environments with high porosity and permeability. These sandstones also demonstrated variations in cement types, with quartz overgrowth being the dominant cement. Many common controls guide the preservation of high reservoir quality in the Fulmar Formation, some of which are attributed to the localized presence of grain-coating materials and hydrocarbon emplacement, which may have inhibited quartz cement and early detection overpressure development, which may have inhibited porosity loss by compaction. The analysis of this paper can be used to further the understanding of reservoir quality in Jurassic sandstones in the North Sea and can be compared with different Formations (Fm) in other sedimentary basins.

Keywords: Porosity, Permeability, Sedimentary Structures, Reservoir Quality.

1. Introduction

Reservoir quality largely depends on the reservoir's porosity and permeability (Ningliang et al., (2022)). Determining the porosity and permeability of any oil and gas field is vital for a reservoir's entire "life cycle" (Ramm & Bjørlykke (1994)). The porosity and permeability are determined mainly by the depositional setting and the hydrodynamic conditions, portrayed by the mineralogy, grain shape, grain size, and sorting (Saïag et al., (2016)). Field data and core analysis can contribute additional data regarding sand-body geometry and facies distribution (Bjørlykke, 2014).

Reservoir quality can be predicted by combing sediment petrological and diagenetic analysis (Bjørlykke, 2014; Porten et al., (2016)). In the North Sea, cementation is known to be the main reason for the reduction in reservoir quality of Jurassic sandstones at depths > 3000 m (Bowen et al. (2018)). Cementation is an attribute of diagenesis and is influenced by temperature and kinetics (Schmid et al. (2004)). However, high porosity and permeability in deeply buried sandstone reservoirs can be attributed to factors limiting cementation and burial compaction (Stricker et al., (2016)). The porosity of a reservoir influences the volume of gas or oil in place, and permeability influences the rate at which hydrocarbon flow from the reservoir to the wellbore (Worden et al. (2018a)).

The integration of sedimentology, petrography, wireline (petrophysical), and core analysis is used to understand the depositional environment and reservoir quality of the Upper Jurassic Fulmar formation in the Blair oil field. Sedimentological studies are focused on determining the various processes that led to the formation of sedimentary rocks in both continental and marine environments (Mannie et al., (2014)). The petrophysical analysis focuses on determining the lithology, porosity, permeability, and fluid saturation in order to achieve reservoir characterization (Kumar et al., (2018)). Petrography analysis focuses on the use of thin sections to understand the diagenetic processes influencing the reservoir quality (Maast et al., (2011)).

The Upper Jurassic sandstones of the North Sea have exceptional high porosity and permeability for deeply buried sandstones, some of which are the Ula, Piper, Brae, and Emerald Formation (Stewart & Faulkner (2008)). However, this paper is concerned with the Upper Jurassic Fulmar sandstones located in Blair oil field at the central part of the North Sea in well 16/21a-13. The main objective of this paper is to characterize the cored intervals of well 16/21a-13 by providing a sedimentological understanding of the reservoir quality and ascertaining the causes of high porosity and permeability in the Upper Jurassic Fulmar sandstones reservoir from Blair oil field.

2. Geological Settings

The Blair field is located in the Central Graben of the North Sea and is known to be a prolific hydrocarbon province containing more than 20 billion barrels of discovered hydrocarbons (Stricker et al. (2016)). Well 16/21a-13 was drilled in 1984 as an appraisal well to test the extent of the Jurassic sandstone in the Glamis structure. It was discovered that the Upper Jurassic sandstone was found water wet. However, Paleocene oil accumulation was confirmed through a positive test with rates up to 3500 BOPD (Niazi, 2011), Khan Niazi et al. (2019)). The North Sea rift system is classified as a global super basin (figure 2.1), which straddles the United Kingdom, Norway, Germany, and Denmark (John and Nick, (2018)).

The rift basin consists of the Viking Graben, Central Graben, Moray Firth, and their neighboring platform areas. The superposition of these basins in various combinations in the different areas controls the hydrocarbon potential of these basins' respective sectors of the North Sea (Ziegler, 1975). The stages that describe the tectonic evolution of the North Sea are the Caledonian geosynclinal stage (Cambrian-Silurian), Variscan geosynclinal stage (Devonian – Carboniferous), Permo – Triassic intracratonic stage, Taphrogenic rifting stage (Jurassic – Cretaceous) and Post – rifting intracratonic stage (Tertiary) (Ziegler, 1975). The Central Graben (figure 2.1) trends in NW-SE direction and consists of two troughs towards east and west of intra-basinal Forties-Montrose and Josephine Ridge horst blocks, and is more symmetrical compared to the Moray Firth Basin and Viking Graben (Niazi 2011). The Central Graben is 70 to 130 km wide with an approximate length of 550 km (Stricker et al. 2016).

The shallow marine (shelf or shoreface) and turbidite sandstones of the Upper Jurassic age (Oxfordian-Kimmeridgian) have been referred to as the Fulmar Formation (Johnson and Stewart, (1985). The Kimmeridge Clay Formation lies over the Fulmar Formation (figure 2.2) and is dominated by an argillaceous succession encasing a subordinate deeper water sandstone body Shales of the Kimmeridge Clay Formation and the Upper Cretaceous chalk form the cap rocks (Johnson et al., (1986)). The Upper Jurassic sandstones are predominantly fine and medium-grained, moderately well sorted, relatively homogeneous, and variably argillaceous, and were deposited in offshore marine-shelf settings (Brown et al., (1992); Rothwell et al., (1993)).

The tectonic history of the Central Graben created numerous hydrocarbon traps, which were filled with hydrocarbons upon maturation of the Upper Jurassic Kimmeridge Clay and its equivalent later (Niazi 2011). The Upper Jurassic Fulmar Formation is a High-Pressure High Target (HP-HT) gas-condensate reservoir and is located in the North Sea rift system (John and Nick, 2018).

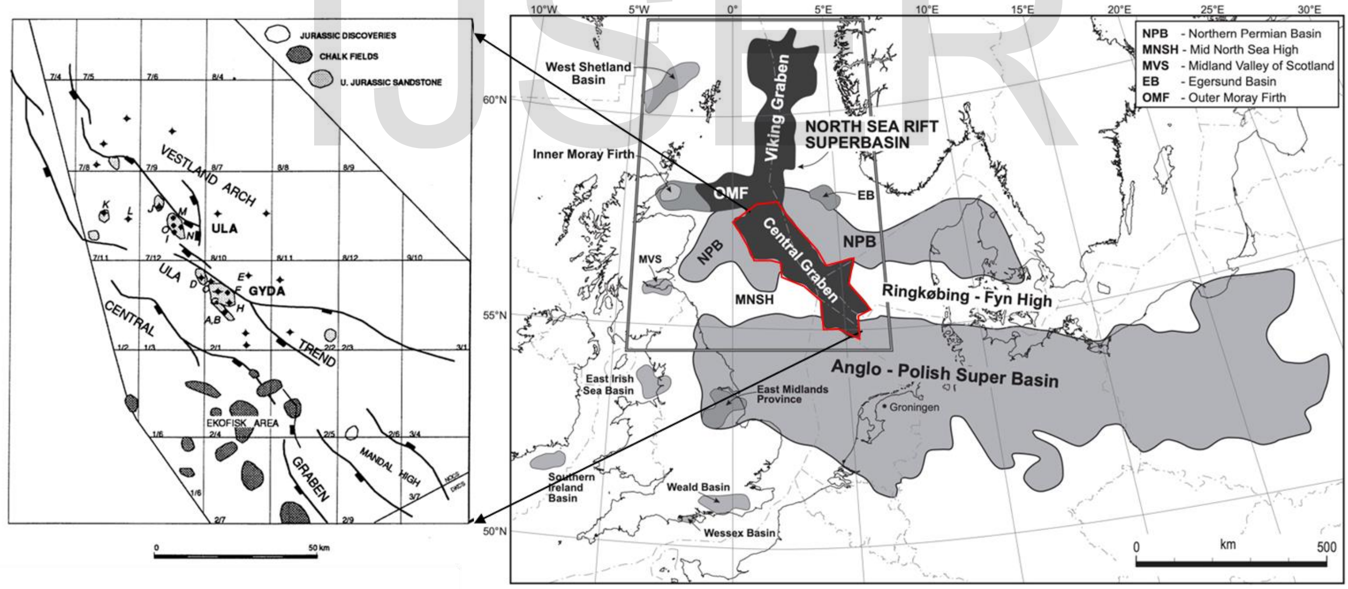

Figure** Error! No text of specified style in document.**.1: Map of the North Sea Rift super basin and the Central Graben area with main structural elements and major discoveries (after John and Nick, 2018; Brown et al., 1992)

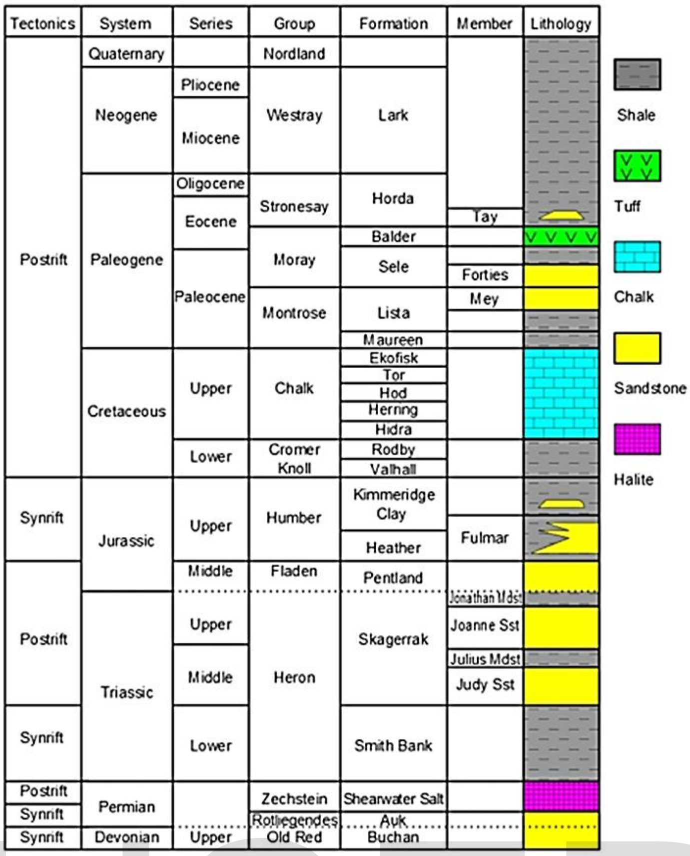

Figure** Error! No text of specified style in document..2: Stratigraphic column of the Central Graben of the North Sea after Knox & Cordey*** (1992)

3. Materials and Methods

The drilled cores of the Upper Jurassic Fulmar Sandstones from well 16/21a-13 are in a depth range of 9984-10281 ft. The methods applied to study and make adequate observations of the data sets of this well will be divided into three categories: petrophysical, core, petrographic and sedimentological analysis.

I. Petrophysical and core analysis

The dataset contained resistivity logs, caliper logs, gamma-ray (GR) logs, sonic logs, and density logs. The petrophysical data were loaded into excel, including the core analysis data for well 16/21a-13 at their respective depth.

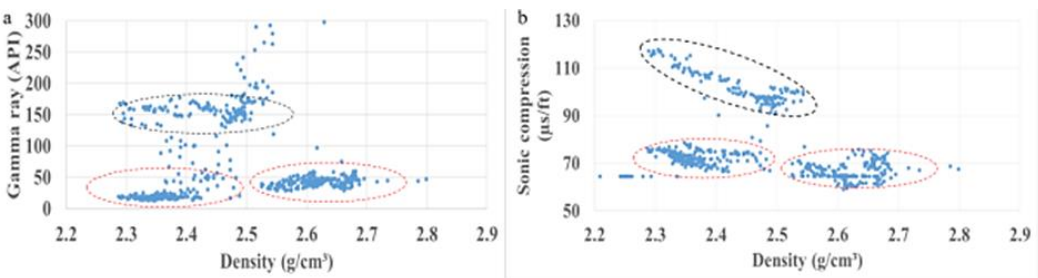

Figure** Error! No text of specified style in document..3: (a) Cross plot of gamma-ray against density log (b)Cross-plot of compressional sonic against density.***

The lithologies were identified using the Gamma-ray, sonic, and density log cross plots which reveal that there is one shale zone and two reservoir zones; the shale zone are the black dash circles, and sand zones are the red dash circles (figure 3.1) while the Shale volume was estimated from the gamma-ray (GR) log using equation 1 (Amigun and Odole (2013)). Where GRmeasured is the actual gamma-ray signal from any depth, GRsand is the minimum gamma signal taken to represent pure sand, and GRshale is the maximum gamma signal taken to represent pure shale.

Shale fraction = $\frac{GR_{measured} - GR_{sand}}{GR_{shale-}GR_{sand}}$ ……………Equation *1*

Density porosity was estimated from the density log using equation 2. Pb is the measured formation density, Pma is the average density of the rock matrix (2.65g/cm3), and Pf is the density of the interstitial fluid (1.1g/cm3) (Bowen, 2003).

Porosity Φ (fraction) $=\frac{P_{ma}-P_b}{P_{ma}-P_f}$............................. Equation *2*

Sonic porosity was estimated from the porosity log using equation 3. *Δ*tc is measured compressional slowness, *Δ*tma is the compressional slowness of the rock matrix (60 μs/ft), and *Δ*tf is the compressional slowness of the interstitial fluid (185 μs/ft).

Porosity Φ (fraction) $=\frac{\Delta t_c-\Delta t_{ma}}{\Delta t_f-\Delta t_{ma}}$.............................. Equation 3

Density and Core porosity were calibrated against depth to achieve a good correlation in the well. Core porosity and density porosity yield a coefficient of R^2 of 0.9025 (figure 3.2).

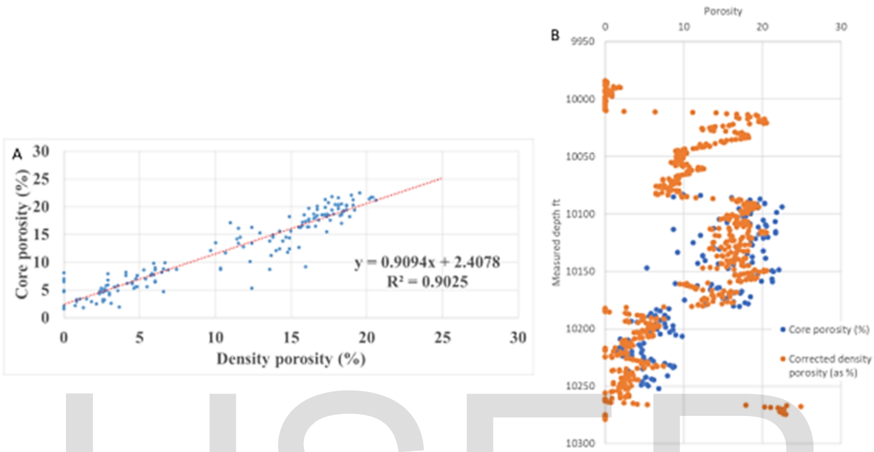

Figure** Error! No text of specified style in document.**.4: (a) core porosity and density porosity correlation coefficient (b) core porosity calibrated with density porosity against the depth.

The quantitative use of the resistivity logs was determined using Archie's method equation 4 (Archie, 1942). Where Sw is water saturation, Φ is the porosity, Rw is the formation water resistivity (0.03 ohm.m), Rt is the observed bulk resistivity, a is the constant (taken to be 0.9), m is the cementation factor (take to be 2.2), and n is the saturation exponent (taken to be 2.2) the water saturation (Khayer et al. (2021)).

Sw=$\left[\frac{a*Rw}{Rt*\Phi^m}\right]^{\frac{1}{n}}$ …………………………… Equation 4

Hydrocarbon saturation (Shc) was calculated using equation 5. Where Shc is the hydrocarbon saturation and Sw is the water saturation.

Shc=1-Sw…………………………… Equation 5

The Petrophysical analysis helped identify high and low porosity zones. The Well log data was used to create different cross plots. These plots were very helpful in identifying poor to excellent reservoir quality zones on the Well log data with the petrographic data.

II. Sedimentological Analysis

A sedimentary logging sheet was used for logging the cores on a scale of 1:20 for grain size, sedimentary structure, bioturbation, and color. Nine different lithofacies and six facies associations were identified from the cores and logged (Howell et al. (1996). A detailed description of each lithofacies was given, including their environment of deposition. Sedlog software was used to create a graphic lithology of the cores and was grouped into nine different facies based on grain size, sedimentary structure, depositional environment, and observations.

III. Petrographic Analysis

Ten petrographic (thin section) samples were taken directly adjacent to plug points for conventional core analysis to ensure that the petrographic data was tied to the core analysis data. These thin sections represent the different lithofacies logged. Optical microscopy was first used for mineralogical identification and studying diagenetic features such as feldspar dissolution, which leads to the generation of secondary porosity. Scanning Electron Microscope (SEM) examination of all samples was undertaken using Hitachi TM3000 SEM. The SEM analysis optically identifies the grain coating, clay coating, quartz overgrowth, and various types of cementation, such as pyrite. The permeability of each thin section was calculated using equation 6 derived from a cross-plot of core porosity versus core horizontal permeability. Y is permeability, e is the natural logarithm, and x is thin section porosity.

Y= $0.0013e^{0.7627x}$ …………………………… Equation

4. Results and Discussion

4.1 Depositional Environment and Facie Association of the Upper Jurassic Fulmar Sandstone.

Detailed sedimentary logging of the cores from well 16/21a-13 in the Blair oil field identified nine different lithofacies deposited in a fluvial-deltaic and shallow marine environment (figure 4.1). The Upper Jurassic Fulmar Formation depositional environment ranges from shoreface to shallow marine environment, and the lithofacies are differentiated based on lithology, grain size, sedimentary structures, silt/clay content, and the degree of bioturbation. Three different lithologies were identified in the cores: sandstone, conglomerates, and shale. The sedimentary structures observed on the logged cores are wave ripple cross-lamination, horizontal planar lamination, and hummocky cross-stratification. The rate of bioturbation noticed on the cores varied with depth and was identified as minor, moderate, and intense bioturbation.

Sedimentary facies	Facies code	Description	Environmental interpretation
Facies 1 (F1): Hummocky cross stratification and wave ripple cross-lamination	F1	Claystone (Kimmeridge clays) with dark brown-black colour, sub-fissile to fissile, micaceous and contains fine disseminated pyrite and occasional nodular pyrite	Shallow marine, inner shelf with anoxic bottom conditions
Facies 2 (F2): Horizontal planar laminations	F2	Conglomerate, sub-angular quartz pebbles, poorly sorted, white opaque, in matrix of very coarse to granule grained sandstone. Presence of low angle bed form	Shallow marine, inner shelf
Facies 3 (F3): Horizontal planar laminations	F3	Dark-light grey moderately sorted coarse to very coarse-grained sandstone, slightly friable	fluvial to deltaic
Facies 4 (F4)	F4	Moderately sorted medium to coarse grained sandstone	fluvial to deltaic
Facies 5 (F5)	F5	Fine to medium grained sandstone, moderately sorted	deltaic
Facies 6 (F6): Hummocky cross stratification	F6	Very fine to fine tight quartz grained sandstone, well sorted and moderate to intense bioturbation.	Distributary mouth bar
Facies 7 (F7)	F7	Poorly sorted granule to pebble grained sandstones, quartz pebbles are angular to well-rounded and are mud supported. Presence of lens of fine-grained sandstone, elongated grains are in alignment and gravels are a bit moderately sorted.	fluvial to deltaic
Facies 8 (F8)	F8	Fine to medium grained sandstone, moderately sorted. Pebbles are grain supported and are in contact with each other.	fluvial to deltaic
Facies 9 (F9)	F9	Silt to very fine-grained sandstones, well sorted, grey to brown colour possibly due to oxidation	fluvial to deltaic

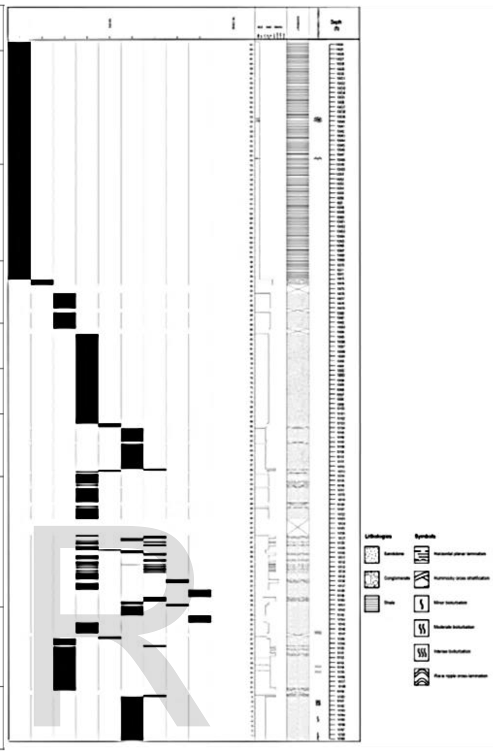

Figure** Error! No text of specified style in document..**5: Facie description and sedimentary log of well 16/21a-13 of the Upper Jurassic Formation Sandstone.

The succession of the Upper Jurassic Fulmar sandstones belongs to the Humber group, and they consist of Brae, Heather, Piper, Seeley, Emerald, Kimmeridge Clay, and Fulmar formation (Worden & Burley (2009)). The identified facie association within the Upper Jurassic Fulmar Sandstone of well 16/21a-13 in the Blair oil field are the upper shoreface facies association, middle shoreface facies association, transition zone, and offshore facie association facie association.

The upper shoreface facies association is composed of well-sorted fine to medium sand grains, “clean” bioturbated sandstone, and massive sandstone (figure 4.2b) (Howell et al. (1996)). These lithofacies also consist of primary sedimentary structures such as parallel lamination, cross-stratification, swales laminae-sets, and flow ripple cross lamination (figure 4.2a) (Burns et al. 2005). Facie 2, 4, and 5 have sedimentary textures of the upper shoreface association, such as grain size, sedimentary structures (hummocky cross-stratification and horizontal planar laminations), and bioturbation (figure 4.1).

The Middle shoreface facies association (Facies 7 and 8) represents high wave and current energy, which is indicated by the low clay content and the presence of horizontal and low-angle (swales or hummocky cross-stratification). Other indicators of high energy conditions in these facies are the presence of winnowed shells and pebble lags (Burns et al., (2005); Dey & Sen, (2017)). The lower shoreface facies association (Facie 6) consists of moderately to well-sorted, very fine, and medium to very coarse sand grains with preserved sedimentary structures such as hummocky cross-stratification (figure 1)(Cannon & Gowland (1996)). The high rate of bioturbation led to an interpretation that the sediments were deposited in an open-marine lower shoreface setting (Howell et al., 1996; Aliyuda et al. (2018)). The offshore and transition zone facie association (Facie 1 and 9) consists of argillaceous sandstones, micaceous and silty sandstones (figure 4.1) (Aliyuda et al. 2018), and they are considered to be very heterolithic in nature (Gowland, 1996). The bioturbation indices (BI) are lower than the previous association, indicating that rapid sedimentation occurred (Browne et al., (2018)). (Howell et al. 1996) stated a lack of primary sedimentary structures, such as hummocky cross-stratification within the sandstone beds, indicating that storm events occurred in low frequency and low magnitude. However, Gowland (1996) stated that rare sandstone event beds displayed hummocky cross-stratification (Facie 1), supporting the reduced current energy theory.

***Figure** Error! No text of specified style in document..6: Shows the depositional elements present in the cored intervals of Upper Jurassic Fulmar formation of well 16/21a-13 in Blair oil field (a) the black arrow points towards a hummocky cross-bedding (b) the pebbles are quartz; they appear to be poorly sorted, well rounded (blue arrows) and semi-opaque (c) the pebbles are sub-angular, moderately sorted with the lens of fine-grain sandstones deposited on a low angle bedform (black dashed circle)*

4.2 Diagenesis

The Upper Jurassic Fulmar sandstones contain varieties of authigenic minerals (calcite, pyrite, feldspar, dolomite, and predecessor minerals of chert) resulting from diagenetic reactions which take place both during early burial and deep burial (Burns et al. 2005). Late diagenetic reactions are considered the dominant process for deeply buried Fulmar sandstones (Wilkinson et al. (2014a)). The Upper Jurassic Fulmar sandstone in well 16/21a-13 from Blair oil field showed various factors influencing the reservoir quality, such as pyrite cement (Pc) (figure 4.3), barite cement (Bc) (figure 4.4a), kaolinite (K) (figure 4.5a) and quartz overgrowth (Qo) (figure 4.5b). The Upper Jurassic Fulmar sandstones have exceptional reservoir quality even at significant burial depths for early cementation and overpressure development (Burns et al. 2005). Most Jurassic sandstones in the North Sea have undergone early diagenesis, which results from rapid burial in a closed system and a dispersed or regional concentration of authigenic minerals (Kuhn et al. (2008)). Further petrographic analysis showed that feldspar dissolution (secondary porosity) is widespread in the Fulmar sandstones, constituting about 30% of the total porosity (Burns et al. 2005). Well 16/21a-13 showed that the Upper Jurassic Fulmar formation has porosity values ranging between 8% to 21% and permeability values ranging between 0.3 to 4000 (mD) in the Blair oil field (Table 4.1), which can be attributed to pyrite cement, Barite cement, and kaolinite occluding porosity fig such reduction in porosity and permeability makes it difficult to extract oil from the reservoir (Wilkinson et al. 2014a).

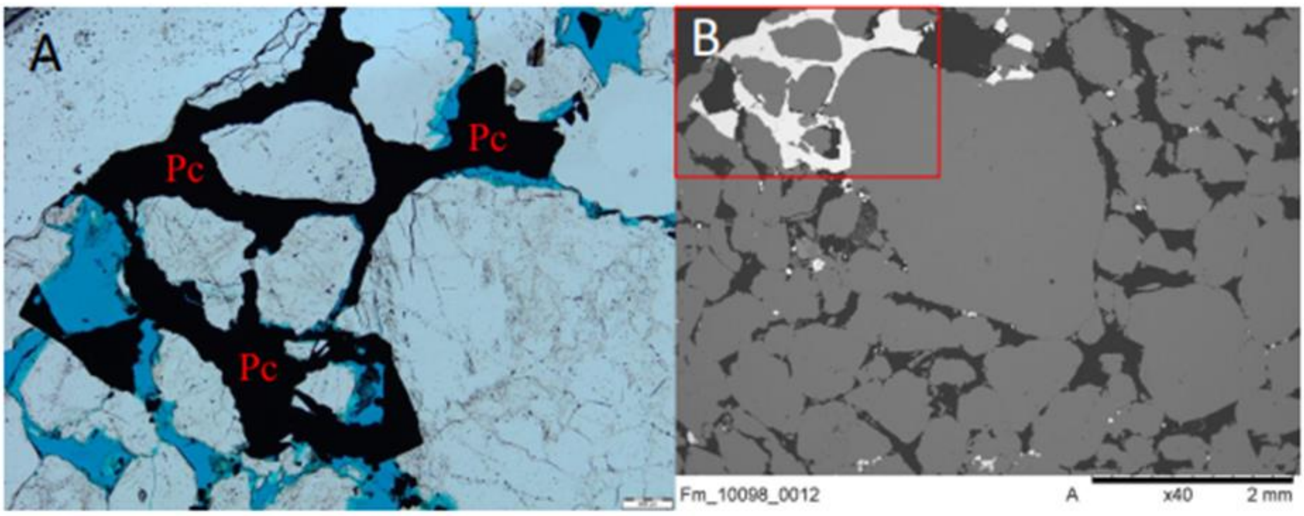

***Figure** Error! No text of specified style in document..7: (a) Optical microscope showing Pyrite cement (Pc) at a depth of 10098ft. (b) SEM analysis of the pyrite cement occluding porosity as shown by the red box.*

4.3 Effect of quartz overgrowth on reservoir quality

Quartz overgrowth is a syntaxial quartz overgrowth larger than 20 µm in optical continuity with the detrital quartz grain at temperatures greater than 70º C, and they occur where grain coats like micro-quartz and clay coats are absent (figure 4.5b) (Harwood et al. (2013)). In deeply buried sandstone reservoirs in the North Sea, quartz overgrowth and carbonate cement are the principal causes of poor reservoir quality (Worden et al., (2012); Harwood et al., 2013). Quartz cementation develops from an increase in temperature as burial depth increases. However, the precipitation of quartz is also a function of the surface area available for quartz cementation, and as quartz cement fills the pores, the surface area decreases (Howell et al., 1996; Harwood et al., 2013).

4.4 Plagioclase-feldspar Occurrence and dissolution

Based on petrographic evidence (figure 4.5b), the Fulmar Formation contains about 35% feldspar, and several studies have demonstrated the creation of secondary porosity through the dissolution of k-feldspars (Scotchman (2006); Wilkinson et al. (2006)). The Mesozoic sandstones within the North Sea are arkosic, and studies on the Fulmar formation, Pentland formation, and Skagerrak formation have recorded significant feldspar dissolution during burial (Wilkinson et al. (1997), (2001), (2014b)). Feldspar dissolution in deeply-buried Upper Jurassic Fulmar formation significantly affects reservoir quality Bowen et al. (2018).

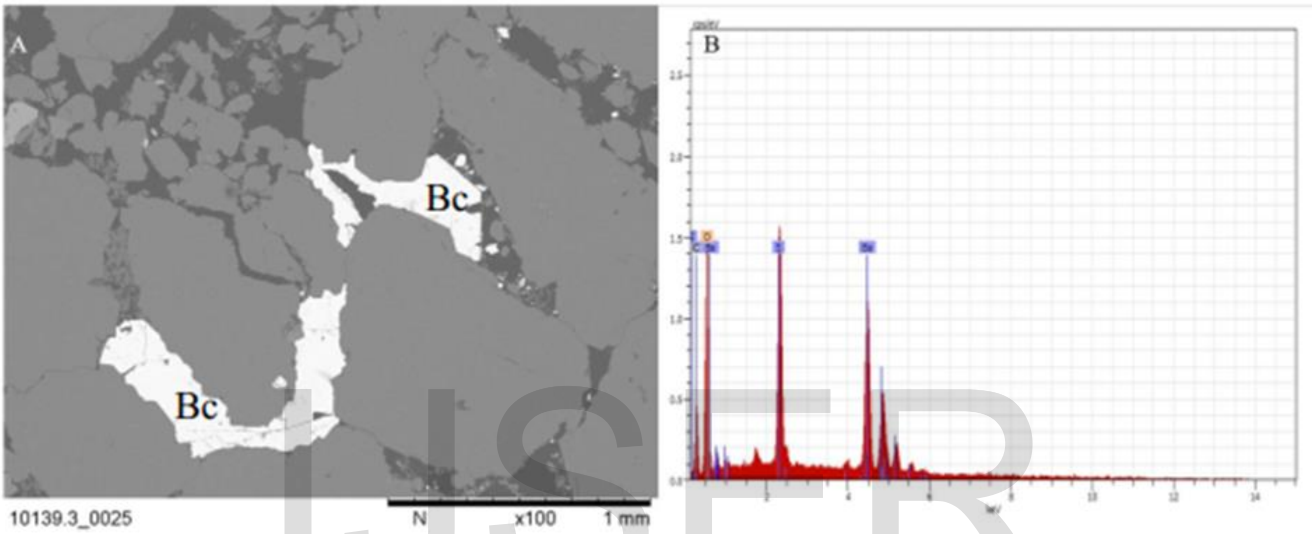

Figure** Error! No text of specified style in document..**8: (a) SEM analysis showing Barite cement (Bc) at a depth of 10139ft occluding porosity. (b) The Barite cement precipitated after quartz cementation.

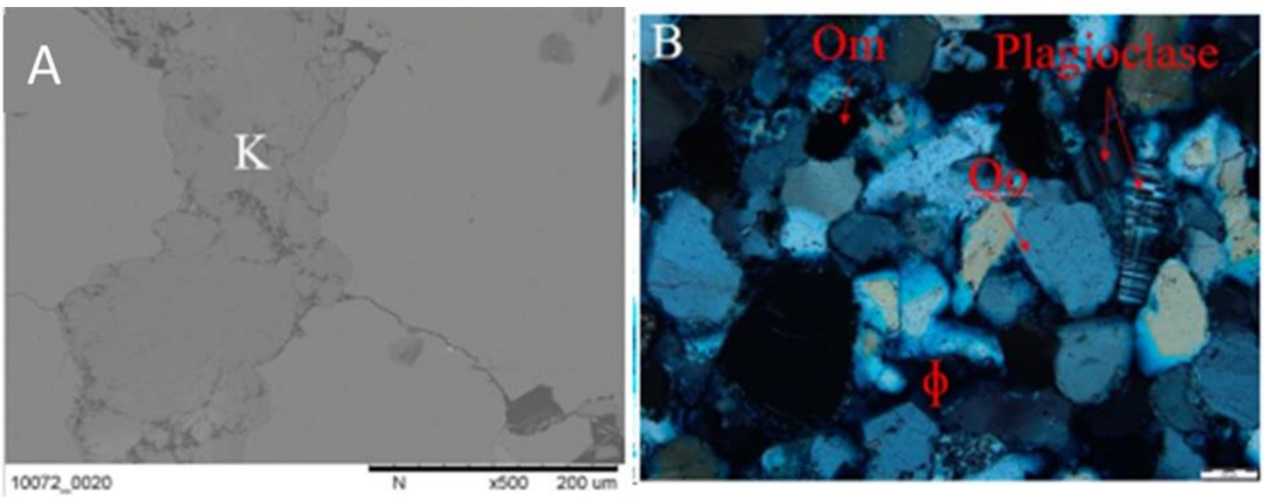

Figure** Error! No text of specified style in document..**9: (a) SEM analysis showing kaolinite (K) at a depth of 10072ft occluding porosity. (b) Minerals identified using optical microscopy are opaque mineral (Om), Plagioclase Feldspar (twining structure), and Quartz overgrowth (Qo).

4.5 Effects of clay coating on reservoir quality

Clays play a crucial role in the variability of reservoir quality in Jurassic sandstones in the Central Graben of the UK North Sea and are well known to enhance porosity at depths greater than 10,000 ft in deeply buried Fulmar sandstones despite mechanical compaction (Raghavan, 2018). However, the authigenic clay minerals present in the Fulmar formation are chlorite and illite minerals (Wilkinson et al. 2014a; Wooldridge et al. (2018)). Petrographic analysis shows that the authigenic clay mineral in the Upper Jurassic Fulmar formation is illite and has been seen coating the grain rim of quartz grain (figure 4.6), thus preventing quartz overgrowth (Bowen et al. 2018). The authigenic illite is considered to have been precipitated due to feldspar dissolution in the Upper Jurassic Fulmar formation (Bowen et al., 2018).

Depth (ft)	Facies Code	Thin section Porosity	Thin section Permeability	Core porosity (%)	Core Vertical Permeability (mD)	Core Horizontal Permeability (mD)	Density Porosity (%)	Sonic porosity (%)	Water Saturation (%)
1060.4	F7	7.89	0.5	12.1	0.28	0.54	9.7	20.6	0.15
1064.2 - 10079	F3	16.63	617	17.6	2590	3807	17.25	11.6	0.14
10087	F4	18.33	1536.8	19.5	2410	4420	16.72	10.7	0.15
10089	F2	10.32	3.4	8.66	273	166	13.59	5.6	0.16
10095 - 10124.2	F4	15.18	328	17.8	3304.6	2524	17.06	9.6	0.14
10130	F6	14.07	59.5	18.5	1670	2410	17.04	10.1	0.14
10139.3	F9	16.92	521.8	14.5	6.7	15	11.65	11.6	0.14

Table** Error! No text of specified style in document.**.1: Displays all petrographic data and related wireline and core-analysis data of each sample at their respective depth in the Upper Jurassic Fulmar Formation of Blair oil Field in well 16/21a-13.

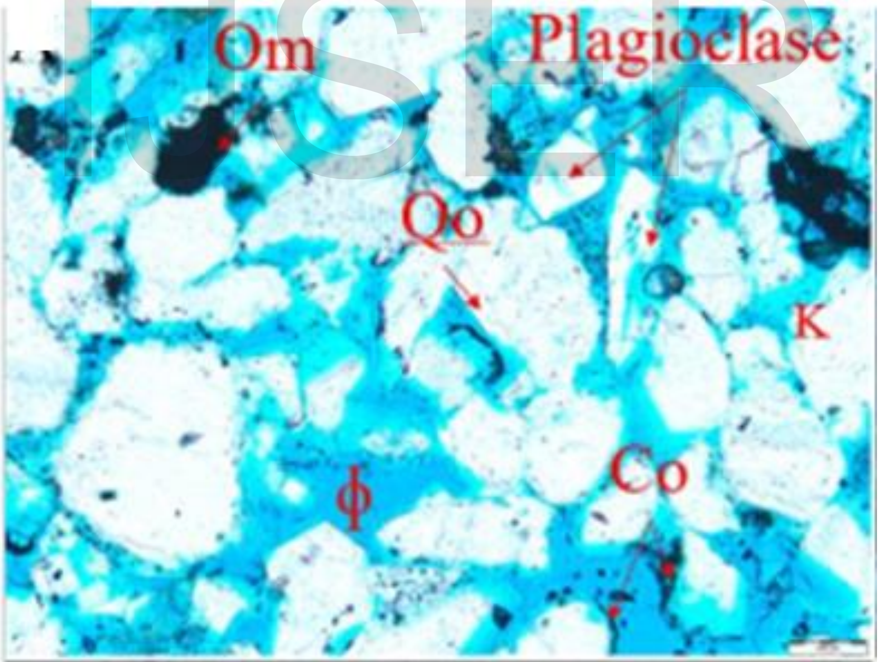

Figure** Error! No text of specified style in document.**.10: Minerals identified using optical microscopy are opaque mineral (Om), Plagioclase Feldspar (twining structure), Quartz overgrowth (Qo), Kaolinite (K), and Clay coats (Co) around rims of quartz grain at a depth of 10143ft.

4.6 Petrophysical analysis

The GR, density, and sonic logs are used to mark various lithologies (red dashed lines) encountered in well 16/21a-13 of Blair oil field (figure 4.7). Depths from 10084 to 10280 ft are sandstones with low gamma, and sonic responses figure 4.7. The wireline log response also indicates that there are high gamma (162.38 to 293 API in figure 4.7a and sonic compressional (99 to 117 µs/ft in figure 4.7c) values from the wireline data within the depth range of 10010 to 10084 ft, this marks the shale region (Kimmeridge clay) in the well, which means that the base of the shale line is 10084 ft and it marks the transition from shale to sandstone. The effective water saturation in the Upper Jurassic Fulmar sandstone has an average value of 0.3 (table 4.1). Depths greater than 10084 ft are sandstones of various grain sizes and densities, as seen on the density log response (figure 4.7e). In the shale zone, resistivity values range from 3 to 5.7 ohm.m. density log values range from 2.3 to 2.54 g/cm3 with an average density porosity of 11.73% and average sonic porosity value of 33%. In the sandstone zone, low gamma (23 to 47.78 API) and low sonic compressional (64.88 to 76.88 µs/ft) values are observed at depths greater than 10084 to 10250 ft, and resistivity values range from 3.18 to 11 ohm.m, density log values range from 2.41 to 2.79 g/cm3 with an average density porosity of 10.24% and average sonic porosity of 6.27% (table 4.1). However, there is a gamma spike within 10160 to 10174 ft, and detailed logging showed that the region is not a shale zone but a clay-rich sandstone. Also, the presence of oil-bearing sandstones is indicated by high resistivity (> 9 ohm.m) and average water saturation of 0.36 (figure 4.7h).

4.7 Influence of oil emplacement on reservoir quality

Several published articles have concluded that sandstone diagenesis is inhibited by oil in sandstone reservoirs (Figure 4.7) (Worden et al. (2010); Wilkinson & Haszeldine (2011); Ershadi et al. (2015)). However, contemporary authors claim that oil emplacement in sandstone reservoirs does not inhibit quartz overgrowth, based on various fluid inclusion data (Lander & Walderhaug (1999); Aase & Walderhaug (2005)). The Fulmar formation is an unusually homogenous sandstone lacking internal barriers to fluid flow such as shale units and has a specific grain-size variation; invariably, oil fills the sandstone below the top seal, thereby preserving the highest porosity by inhibiting cementation and chemical compaction (figure 4.7) (Wilkinson and Haszeldine (2011)). A maximum hydrocarbon-filled porosity value of about 0.16 (16%) and a maximum water-filled porosity value of 0.09 (9%) were estimated for the Upper Jurassic Fulmar Formation in the Blair Field well 16/21a-13 figure 4.8. Therefore, this analysis supports the debate that diagenesis in oil-wet sandstones (figure 4.8) is greatly influenced by the presence of oil than in water-wet sandstones because the surface of the quartz grains is coated with water (Worden et al. 1998).

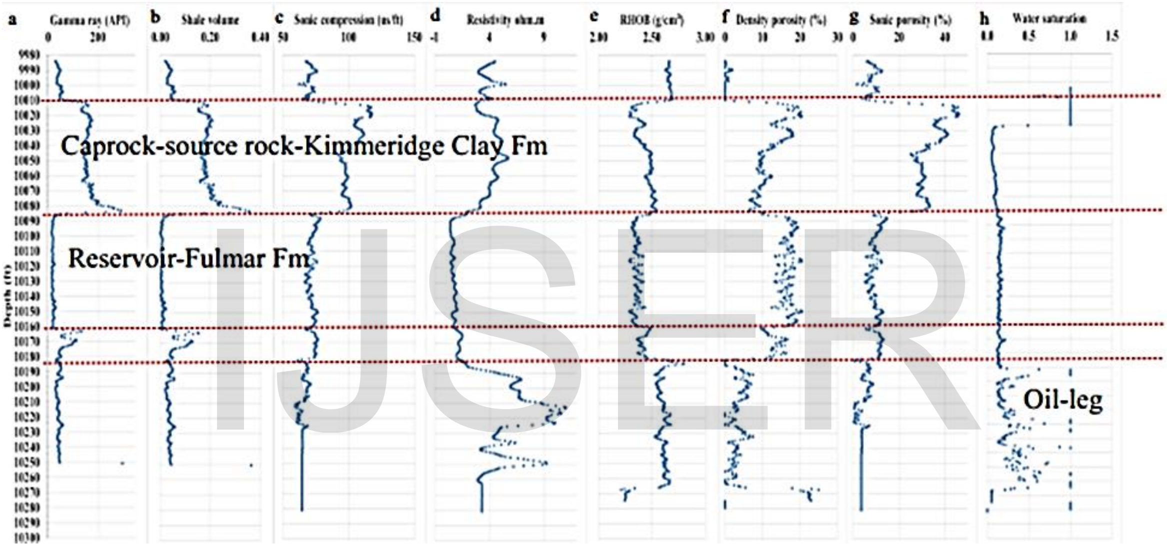

Figure** Error! No text of specified style in document.**.11: Derived petrophysical log delineating the petrophysical properties of the Upper Jurassic Formation.

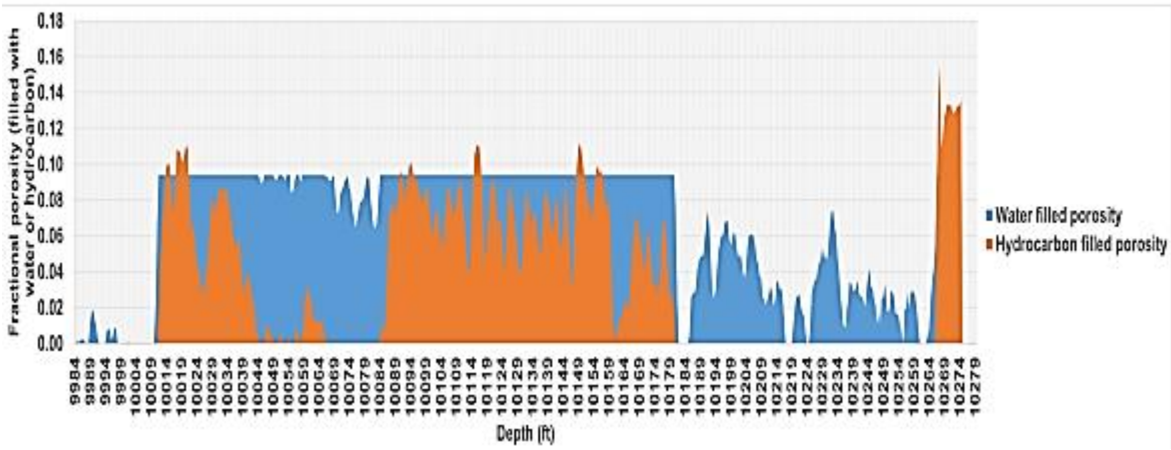

Figure** Error! No text of specified style in document.**.12 shows how much water or hydrocarbon is stored at specific depth intervals of Upper Jurassic Fulmar sandstones in Blair oil field from well 16/21a-13.

5. Conclusion

Log analysis, core analysis, core description, and petrographic analysis helped determine the reservoir quality of Upper Jurassic Fulmar sandstones. Reservoir quality of the Fulmar Formation within the Blair Field is influenced by various factors such as depositional environment, grain size, sorting, bioturbation rate, diagenesis, oil emplacement, quartz-overgrowth, and feldspar dissolution. The identified mechanisms responsible for the high porosity and permeability in Upper Jurassic Fulmar sandstones are oil emplacement, dissolution of plagioclase feldspar, and clay coating. Oil emplacement enhances the reservoir quality by inhabiting cementation and chemical compaction, the dissolution of potassium feldspar grains enhances the reservoir quality by generating secondary porosity, and the clay coating around quartz grains in the reservoir inhabits quartz overgrowth. However, deformation bands and fractures can also influence the reservoir quality by either enhancing or inhibiting fluid flow depending on whether the reservoir is compartmentalized or non-compartmentalized. Failures to inhibit quartz overgrowth and pyrite cement, barite cement, and kaolinite filling the pore spaces lead to the destruction of reservoir quality (porosity). The average porosity and permeability estimated for the Fulmar Formation are based on sedimentological, petrophysical, core, and petrographic results, the reservoir quality of Upper Jurassic Fulmar sandstones in Blair oil field is good.

Authors' contributions

JEE: Data interpretation, analyzing data, writing the manuscript. ASA: correcting data, data Interpretation from software, writing manuscript. All authors read and approved the final manuscript.

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Availability of data and materials

All materials and data should be available at the Department of Earth, Ocean and Ecological Science, University of Liverpool, United Kingdom.The datasets used and analyzed during the current study are available from the corresponding authors on reasonable request.

Declarations

Competing interests

The authors have declared no conflict of interests for this research.

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