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Petrographic and Petrophysical Analysis of Barail Group Reservoir Sandstones of an Oilfield of Upper Assam Basin, India

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Abstract- The aim of this research work is to evaluate petrographic and petrophysical characteristics of the Barail Group sandstone reservoirs in a part of Upper Assam Basin. The diagenetic constituents, processes and their impacts on reservoir quality were evaluated. The sandstone of the present study found to be quartz dominant followed by feldspar and rock fragments. From thin section and Scanning Electron Microscope analysis, the different diagenetic changes observed include crystallization of cementing material, bending of mica grains, fracturing of detrital quartz grains, dissolution and replacement of framework grains etc. From X-Ray Diffraction analysis the different clay minerals identified were kaolinite, illite, smectite, and chlorite. From petrophysical analysis of the core samples it was seen that the porosity and permeability values decreased with depth and ranged from 29% to 17.7% and 0.90 md to 0.18 md respectively.

Keywords—Barail Group, Diagenetic Constituents, Petrography, Petrophysical characteristics, Upper Assam Basin, Sandstone

I. INTRODUCTION

Sandstone reservoir properties are affected by several interrelated factors such as mineralogy, depositional facies, diagenetic events etc. According to Boggs (2009) [1] particle composition has a considerable influence on the course of diagenesis in sandstones as it ultimately affects the porosity and permeability. Mansurbeg et. al. (2008) [2] and Worden et. al (2009) [3] have studied the different processes and reactions involved in diagenesis which can result in either a positive or negative deviation from a simple trend of deteriorating porosity and permeability with increasing depth. The Barail Group of rocks within the Upper Assam Basin is of wide areal extent with depositional and diagenetic complexities. Porosity distribution in these rocks is greatly affected by diagenetic changes. Bhattacharya (1984) [4] conducted clay mineral studies of the Barail reservoir sands in Assam and concluded that matrix material are characterized by illite, chlorite and kaolinite which have undergone pronounced diagenetic changes. Studies made by Gilfellon & Saharia (2010) [5] on the Barail Group in the Jorajan oilfield of Assam observed that microfracturing and dissolution are the root causes for development of secondary pores in the reservoir

sandstones, while quartz overgrowths are an important cementing material within the reservoir sandstones. reducing porosity and permeability. The important clays identified in the area are kaolinite, illite, chlorite and smectite. Borgohain et.al. (2010) **[6]** in their studies on the impact of sandstone diagenesis on the reservoir quality of the arenaceous unit of the Barail Group of the Naharkatiya Oilfield of Assam concluded that due to heterogeneity in the distribution of diagenetic properties, there is a variation in crude oil production from well to well within the same reservoir.

In this present paper an attempt is being made to study the nature of the detrital framework grains, the textural properties, different diagenetic alterations affecting the quality and heterogeneity of Barail reservoir sandstones in a part of Upper Assam Basin. Petrophysical properties viz., porosity and permeability of a few samples were also determined.

II. GEOLOGICAL SETTING

The Upper Assam Basin is a typical polyhistory basin having more than one phase of sedimentation and tectonism. The movement of the Indian plate in relation to Eurasian and Burmese plates has essentially influenced the basin evolution. The Upper Assam Basin extends over a large area of North Eastern India, Myanmar and Bangladesh. and includes the Assam Plain, Cachar, Meghalaya, Nagaland, Mizoram, Manipur, Tripura and parts of Arunachal Pradesh India. The basin has nearly 13 kms of Mesozoic and Tertiary sediments in its deepest part. The generalized stratigraphy of the Upper Assam

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Basin is shown in the Fig. 1. The basin is covered over a large part by shelf sediments that grade into geosynclinals facies. The dividing line between the two facies occurs in the vicinity of the Naga Thrust, the northwestern margin of the Belt of Schuppen .Majority of the faults coupled with depositional environment played a major role in the accumulation and distribution of hydrocarbons in the region. Oil companies like Oil and Natural Gas Corporation Limited (ONGCL) and Oil India Limited (OIL) have carried out extensive exploration activities within the Upper Assam Basin, during the last four decades which have resulted in the discovery of a large number of new structures with potential hydrocarbon reserves.

Epoch	Lithostratigraphic units: Group	Lithostratigraphic units: Formation		Thickness (m)	Major lithological types
Recent	–	Alluvium[1]			
Pliestocene	Dihing	Dhekiajuli[1]		1300–2000	Unconsolidated sands with clay and lignitic sands
			Unconformity		
Pliocene Miocene	Dupitila	Namsang beds		0–1000	Poorly consolidated sandstone with clay and lignitic sands
			Unconformity		
Miocene	Tipam	Girujan clays		100–2300	Mottled clay with sandstone lenses
		Tipam sandstones	Upper	300–500	Essentially arenaceous sequence
			Middle	100–200	Sand/shale alteration sequence
			Lower	100–200	Arenaceous sequence
	Surmas[2]	Not subdivided			Sandstone with shale and grit bands
			Unconformity		
Oligocene	Barail	Not subdivided		500–1200	Upper part: Mudstone/sale with sandstone beds and coal bands (Argillaceous sequence) Lower part: Sandstone with shale bands (Arenaceous sequence)
Eocene[3]	Jaintia	Kopili alterations		280–500	Splintery shale with sandstone and fine-grained sandstone with coal bands
		Sylhet limestone	Prang Nurpuh Lakadong	350–450	Splintery shale with sandstone and limestone bands
	Therria			60–170	Sandstone, calcareous sandstone and limestone
			Unconformity		
Precambrian granitic basement					

Fig 1: Tertiary succession of Upper Assam Shelf sediments (modified after Handique et. al.,1989) [7]

III. MATERIALS AND METHOD

For petrographic analysis of the studied sandstones, the standard Petrographic Microscope and Scanning Electron Microscope (SEM) were used. Rock thin section slides have been prepared by cutting and grinding the core samples (depth range 3382.36m – 3457.95m) to a standard 30 mm thickness. A Leica DM 750 P Microscope with Leica DFC 295 digital camera attachment was used for capturing the images of the thin sections. For SEM analysis the sample preparation was done by removing small freshly fractured rock fragments measuring <1 cm diameter. Samples were analyzed using a JEOL JSM-IT00300LV Scanning Electron Microscope (SEM) at Central Sophisticated Instrumentation Center, Dibrugarh University.

Identification and analysis of the clay minerals (< 2 µm fractions obtained by gently crushing the samples into fine powder using Agate mortar and pestle) of the sandstones of the present study was done using a Rigaku Ultima IV X-Ray Diffractometer at Central Sophisticated Instrumentation Center, Dibrugarh University, Assam.

Porosity of the core samples, were determined using a TPI-219 He-Porosimeter at Dept. of Petroleum Engineering, Dibrugarh University. A TKA-209 Liquid Permeameter was used for determination of permeability, at Dept. of Petroleum Engineering, Dibrugarh University, Assam.

IV. RESULTS AND DISCUSSION

A. *Petrographic Analysis*

1) Sandstone Composition and Texture

Quartz (Fig. 2b) is the dominant mineral in the sandstones of the present study. Both monocrystalline (undulose and non-undulose) as well as polycrystalline varieties (Fig. 2i) have also been recorded. In case of polycrystalline quartz, the > 3 crystal units are dominant over the 2–3 crystal units per grain variety. Some grains are seen to have inclusions (Fig. 2d). A few feldspar grains are also observed and include both plagioclase (Fig.2b, 2f) and K-feldspar (Fig. 2d). Chert grains (Fig. 2b) are composed of microcrystalline and chalcedonic quartz. Both muscovite and biotite varieties of mica have been observed. In a few cases, authigenic micas (Fig. 2i) are seen to develop at the expense of argillaceous cement and matrix. Rock fragments (Fig. 2h) identified include mainly metamorphic varieties like schist and gneiss. Owing to the abundance of quartz in comparison to feldspars and rock fragments, the analyzed sandstones are considered to be mineralogically sub-mature. Matrix (Fig. 2a) present in the sandstones of the present study is siliceous and argillaceous in nature. Mainly argillaceous (Fig. 2d), siliceous and calcite cements (Fig. 2e), have been observed in the present study [8].

The investigated Barail Group sandstones are mostly medium grained. The framework grains are subrounded to subangular grains. A few rounded grains are also observed. The sandstones are found to be moderately sorted.

2) Diagenesis

The most important diagenetic change observed in the present study from thin section and Scanning Electron Microscope analyses is compaction of the framework grains. Due to the overburden pressure, physical compaction of sediments was initiated with increasing depth of burial. Compaction effects of the investigated samples are evident from packing readjustment, bending

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of flexible mica flakes (Fig. 2g), and plastic deformation of ductile grains. Other signatures include fracturing of detrital quartz grains (Fig. 2a), and development of different type of grain contacts (Fig. 2c), viz., long contacts, concavo concave contacts and sutured contacts. The long contacts between the framework grains generally represent an early stage of diagenesis, while the concavo-concave and sutured contacts indicate a relatively late stage of diagenesis [9]. Siliceous cements in the form of quartz overgrowths (Fig. 2f, 3b), are formed as a result of pressure solution. Calcite cement (Fig. 2e), occurs as intergranular pore-filling cement.

Cementation occurs during burial diagenesis owing to changes in pressure, temperature and ion concentration in pore water. In the present study compaction effects together with the precipitation of different type of cements, development of authigenic mica from argillaceous cement and post depositional accumulation of argillaceous sediment patches (Fig. 2g), may have significantly reduced the porosity and permeability of the sandstones. In the analyzed sandstones, several detrital minerals grains are observed as dissolved and replaced either partially or fully. Partial dissolution of feldspars (Fig. 2a, 3a), corrosion of detrital grains by cementing materials (Fig. 2a, 2e), and grain fracturing enhanced the porosity as well as permeability in the sandstones.

3) Clay mineralogy

In the present study the clay minerals, as identified from X-Ray Diffraction and Scanning Electron Microscope analyses are Illite, Kaolinite, Chlorite, and Smectite. Authigenic Illites under Scanning Electron Microscope occur as flake-like platelets (Fig. 3a), within pore spaces as well as thin coating around detrital grains (Fig. 3b). From X-Ray diffractogram, illite has been identified by the prominent (001) reflection at 8.81°2ϴ (10.03 Å) [10]. Illite apparently develops under acidic condition [11]. Presence of illite typically has a huge effect on reservoir properties such as permeability, water saturation (Sw), resistivity and wettability [12] [13]. From Scanning Electron Microscope photomicrographs, kaolinite is recorded in the form of cluster of books with pseudo hexagonal platelets (Fig. 3a), while from X-Ray diffractogram, it was identified by the prominent (003) reflection at 12.392°2ϴ (7.137 Å) [10] . Formation of authigenic kaolinite is related to the dissolution of framework grains, especially K-feldspars [14]. In the present study authigenic kaolinite, might have originated as a result of leaching of feldspar minerals as evidenced by its occurrence in proximity to partially dissolved grains (Fig. 3a). Presence of authigenic kaolinite reduces the porosity and permeability of sandstones, since they have a tendency to migrate into the pore spaces [6]. Chlorite has been identified by the prominent (001) reflection at 6.267°2 ϴ (14.091 Å) from X-Ray diffractogram [10]. Authigenic chlorites most commonly forms in an alkaline environment rich in iron-and magnesium; thus, the iron and magnesium sources are important in determining the genesis of the chlorite [15] [16] [17] [18]. Another clay mineral reported in the analyzed sandstones is smectite identified by the (004) reflection at 61.79 °2ϴ (1.5001 Å) [10]. Smectite tends to plug the pore throats, which reduces permeability.

B. Petrophysical Analysis

Routine core analysis involves the measurement of the most fundamental rock properties like porosity (storage capacity for reservoir fluids), permeability (reservoir flow capacity), saturation (fluid type and content), under atmospheric conditions. All these together with gross lithology provide critical information in deciding whether a wellbore will be economic [19]. In the present study only porosity and permeability of the core samples were determined. At first the core was plugged to its desired length with the help of a core plugging machine and end faced with an end-facing machine. Thereafter the fluids contained in the pore space of the core plugs were extracted (cleaned) by continuously treating it with a solvent (50% of methanol and 50% of toluene) in a Soxhlet extractor for a period of 72 hours. The core plugs were then further cleaned in an Ultrasonic Cleaner that uses ultrasound usually from 20-400 KHz and an appropriate cleaning solvent (acetone) to clean the core plugs for about six minutes. After the impurities were removed, the core sample was dried for removing connate water from the pores, or to remove solvents used in cleaning the cores. Drying was performed in a Humidity Cabinet for 70 hours. In the present study, API recommended practices for core analysis was followed [20].

1) Porosity determination

Porosity is the measure of storage capacity of the reservoir. The porosity of a core sample is determined by measuring any two of the three quantities viz., bulk volume, pore volume or grain volume. The average diameters and lengths of the core plugs have been determined with the help of a Vernier Caliper. The bulk volumes of the samples were then determined using the equation:

$$\text{Bulk volume} = \frac{\pi d^2 L}{4}$$

where, d = Diameter of the sample

L = Length of the sample

In the present study Coretest TPI-219 Helium Porosimeter which is based on Boyle's Law, was used for measuring the porosity of the core samples. The grain volume of the samples was determined using a pressure chamber, virtually any non-reactive gas (helium in this case) and an accurate pressure measuring device.

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The following equations were used for calculation of the porosity of the core plug:

Grain volume:

$$V_{grain} = V_{billets\ removed} + (P_{ref\ full}/P_{cup\ full})\, V_{ref} - (P_{ref\ sample}/P_{cup\ sample})\, V_{ref}$$

Where,

V_{grain} = Grain volume, cm^3
$V_{billets\ removed}$ = Volume of removed billets, cm^3
$P_{ref\ full}$ = Reference system pressure prior to full cup measurement, psi

$P_{cup\ full}$ = Cup pressure when all billets are in cup, psi

V_{ref} = Reference volume of the system, cm^3

$P_{ref\ sample}$ = Reference system pressure prior to core measurement, psi

$P_{cup\ sample}$ = Cup pressure with sample inside, psi

Grain density:

$$\text{Grain density} = \frac{\text{Dry weight of the core plug}}{\text{Grain Volume}}$$

Porosity:

$$\text{Porosity} = \frac{\text{Bulk Volume} - \text{Grain Volume}}{\text{Grain Volume}}$$

The porosity of the analyzed samples of the Barail Group of the study area ranged from 17.7% to 29%.

2) Permeability determination

Permeability is the measure of the ability of a porous medium to transmit fluid. For measurement of permeability a fluid of known viscosity is passed through a core sample of measured dimensions and then recording the flow rate and pressure drop. Depending on the sample shape and dimensions, degree of consolidation, type of fluid used, ranges of confining and fluid pressure applied, and range of permeability of the core, different techniques are used for measurement of core permeability. In the present study, a TKA-209 Liquid Permeameter was used for determining the permeability values of the core plugs. After cleaning the core plugs they were immersed in water, till they were fully saturated. The permeability is calculated from Darcy's law,

The calculation of permeability is derived from Darcy's law which for liquids, under steady state conditions of viscous or laminar flow may be expressed as:

$$K = \frac{\mu Q L}{A\, \Delta P}$$

Where,

K = liquid permeability, Darcy
μ = viscosity of flowing liquid, Cp
Q = flow rate of liquid, cc/sec
L = length of core sample, cm
A = cross sectional area of the core sample, cm

The permeability of the analyzed sandstones of the present study ranged from 0.18 to 0.90 md.

Thus it is observed that the studied core samples have good to very good porosity values, but the permeability is low. It has been inferred that this high porosity low permeability value may be attributed to the presence of platy and fibrous illite in the analysed sandstones, which reduces the permeability, not much affecting the porosity. For illite-cemented sandstone the permeability may not exceed 1 mD, even for samples with porosities >10 % [21]. Sandstones with large amounts of clay, such as illite have high porosities (mainly in the form of micro-porosity). The micropores within clay minerals contain bound-water which is immobile. This often causes a reduction in rock permeability.

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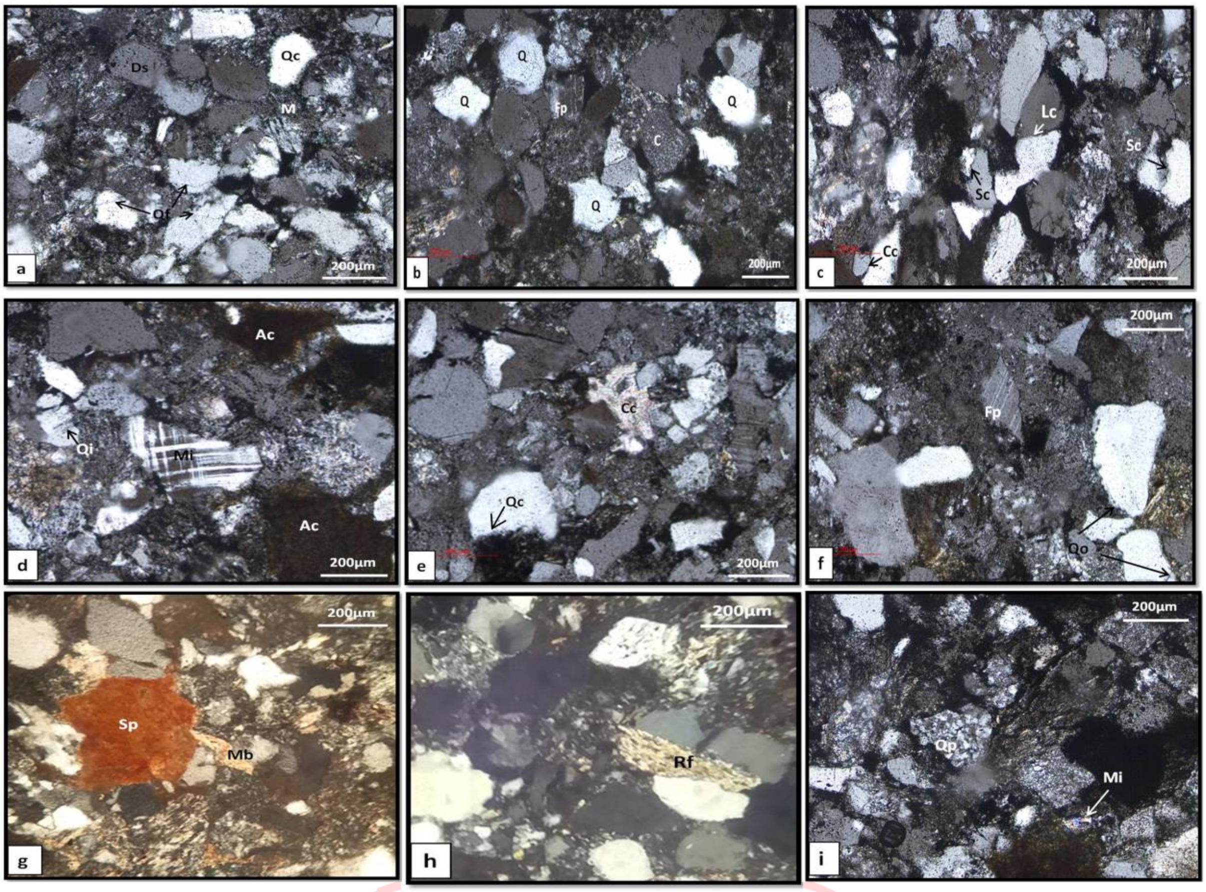

Fig 2: Rock Thin section Photomicrographs showing : (a) Dissolution in detrital grain (Ds), Matrix (M), Quartz fracturing (Qf) and Corrosion along the boundary of Quartz grain (Qc), (b) Association of Quartz (Q), Chert (C) and Plagioclase feldspar (Fp) grains, (c) Development of different type of grain contacts due to compaction effects: Long contact (Lc), Concavo-concave contact (Cc) and Sutured contact (Sc), (d) Inclusion in Quartz grain (Qi), Microcline (Mi) and Argillaceous cement (Ac) (e) Calcite Cement (Cc) and Corrosion in quartz grain by argillaceous cement (Qc). (f) Plagioclase Feldspar (Fp) and Quartz overgrowth (Qo), (g) Bended Mica flakes (Mb) between detrital grains indicating advanced mechanical compaction and post depositional accumulation of argillaceous sediment patches (Sp), (h) Rock fragment (Rf), (i) Polycrystalline Quartz grain (Qp) and development of Authigenic Mica (Mi)from argillaceous cement (Mi).

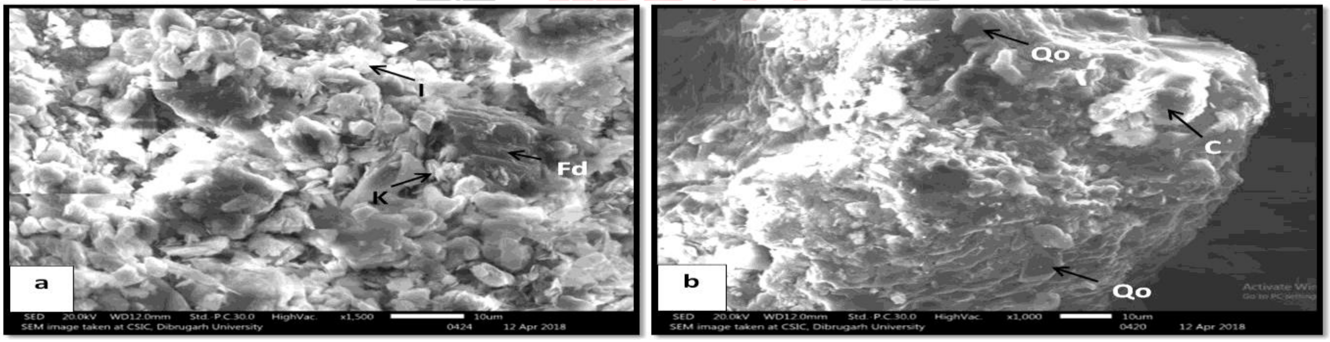

Fig 3: SEM Photomicrographs of some representative samples showing the presence of: (a) Illite (I), Kaolinite (K), Feldspar dissolution (Fd) (1500 X), (b)Quartz overgrowth (Qo) and Clay coating around detrital grain(C) (1000 X).

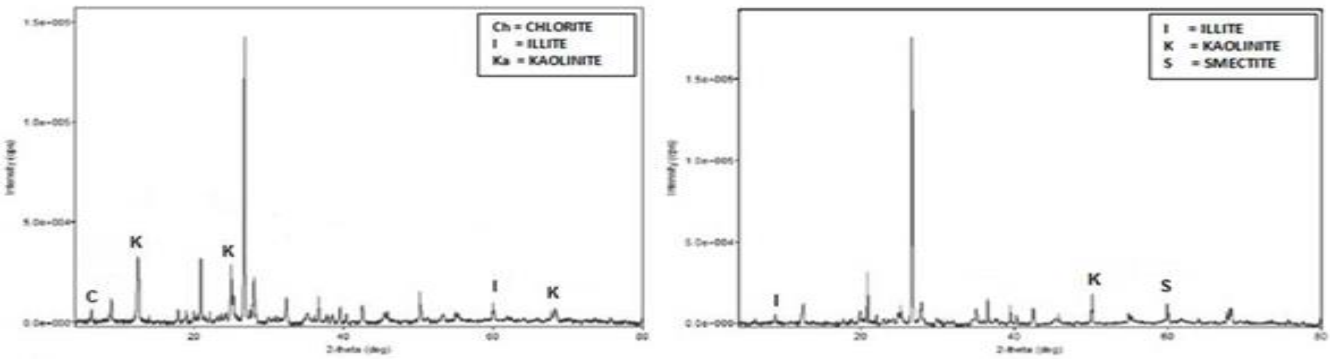

Fig 4. X-Ray Diffractogram showing the different clay minerals identified in the analyzed sandstones of the Barail Group (a) Kaolinite(K), Chlorite(C) and Illite(I) and (b) Kaolinite(K), Smectite(S) and Illite(I). [6]

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V. CONCLUSION

Petrographic studies carried out to find out the mineralogical composition of the sandstones reveals that quartz is the dominant mineral followed by feldspar and rock fragments. Both monocrystalline and polycrystalline varieties of quartz were observed. Feldspar constitutes both plagioclase and K-feldspar. Among the rock fragments, chert and metamorphic varieties are seen. Mica constitutes both muscovite and biotite. Argillaceous and calcite cement are mainly observed in the sandstones of the present study. The sandstones are mineralogically sub-mature, medium grained and are moderately sorted. The chief diagenetic changes observed from thin section and SEM analysis in the present study are compaction as evident from bending of mica flakes, fracturing of detrital grains and development of different type of grain contacts (like long contact, concavo-concave contact and sutured contact). While intra-particle micro-fracturing leads to porosity enhancement, different grain contacts with increasing depth reduced the porosity of the sandstones. Other diagenetic changes observed include feldspar dissolution and corrosion of detrital grains which enhanced the porosity as well permeability in the sandstones. Development of authigenic mica at the expense of argillaceous matrix is also observed in a few cases. The important clay minerals present in the sandstones include Illite, Kaolinite, Smectite and Chlorite as observed from XRD and SEM analysis. In the present study authigenic kaolinite, might have originated as a result of feldspar leaching and their presence leads to the reduction of porosity and permeability of sandstones. Presence of smectite tends to plug the pore throats, thereby reducing permeability.

Determination of the petrophysical properties of the core samples revealed that the porosity and permeability values decreased with depth and ranged from 29% to 17.7% and 0.90 md to 0.18 md respectively. The studied core samples have low permeability despite having good to very good porosities which may be attributed to the presence of clays especially illite.

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