

**FORMATION EVALUATION AND RESERVOIR PROPERTIES ESTIMATION OF
HYDROCARBON ZONES IN ‘AZOH’ FIELD ONSHORE NIGER DELTA**

BY

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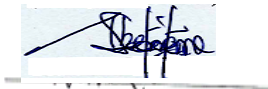
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CERTIFICATION


This is to certify that this work "FORMATION EVALUATION AND RESERVOIR PROPERTIES ESTIMATION OF HYDROCARBON ZONES IN 'AZOH' FIELD ONSHORE NIGER DELTA" was carried out by OZAH, EDWARD (20124765838) in partial fulfilment of the requirements for the award of the degree of Master of Science (M.Sc.) in the Department of Geology, Federal University of Technology, Owerri, and hereby certified:


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DEDICATION

This research is dedicated to Almighty God for His guidance and protection throughout the period of this work.

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Ozah Edward, 2023

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ABSTRACT

Formation evaluation of three wells in the 'Azoh' field, Northern Delta Depobelt, was carried out in this study in order to identify potential prospective pay zones, their potential hydrocarbon fluid content and reservoir quality. An integrated methodology involving the use of well logs, mud logs and core data (sidewall core descriptions and core photos) was adopted to delineate three reservoir sand units, designated D2000, E3100 and F1000 reservoir sands respectively. Reservoir properties including water saturation, effective porosity and net reservoir thickness were computed and used to estimate the volume of in-place hydrocarbons within these reservoirs. In addition, the depositional environments were characterized using gamma ray log shape. Results of the petrophysical analysis revealed that these reservoirs are high quality sands, with estimated average effective porosity values of 20% for D2000 sand, 30% for E3100 sand and 25% for F1000 sand, respectively, which are within the range for commercial accommodation of hydrocarbon. Generally, the petrophysical characteristics of the reservoirs are good especially at the areas of interest (hydrocarbon zones). This can be attributed to their depositional environment which ranges from distributary mouth bars to shoreface deposits. The volume of shale values for some of the reservoirs are within the limits that could not affect the water saturation, while the water saturation in some zones is appreciably low (1%- 21%), indicating that hydrocarbon production from these reservoirs are likely to be water free. D2000 sand and F1000 sand tested oil in the three wells, while E3100 sand tested gas in the wells. Each of the reservoir sand have an average estimated permeability value of 16.92mD for D2000 sand, 47.80mD for E3100 sand and 28.05mD for F1000 sand respectively, indicating that the reservoirs have good interconnected pores. Estimates of hydrocarbon volumes showed that D2000 and F1000 sands both have 2.9 and 2.4 billion barrels of recoverable oil respectively, while E3100 have 3.1 trillion cubic feet of recoverable gas. These results on the whole suggest that the reservoir sand units of 'Azoh' Field contain significant accumulations of hydrocarbon.

Keywords: Hydrocarbon, Permeability, Petrophysics, Reservoir Quality, Water Saturation, Well Log.

CHAPTER ONE

INTRODUCTION

1.1 Background Information

A greater portion of the world's energy mix comes from hydrocarbon sources and its derivatives coming from the deeper portion of the various hydrocarbon habitats. It has therefore become imperative to apply newly emerging exploration and production tools and skills to adequately harness these resources (Rotimi & Olori 2010).

As oil and gas resources diminish around the globe, exploration and production companies are forced to pursue and develop smaller and more complex reserves. New oil and gas prospects need to be found and explored areas should be reassessed for additional bypassed hydrocarbon resources. Even though there have been reported successes of new prospects in the Niger Delta province, long term oil and gas production has depleted hydrocarbon reserves in the well in over 300 traditional onshore and offshore fields. Nevertheless, it is believed that undiscovered oil and/or gas fields/pools exist in the Niger Delta. However, finding the subtle reserves that can match a global demand require modification of earlier conventional techniques and concepts (Ejeh, 2010).

Formation evaluation in the area of study within Niger Delta Basin will, therefore, provide a platform for the estimation of petrophysical properties such as porosity, water saturation and lithology, which are an invaluable aid to describing subsurface geology and hydrocarbon occurrence therein (Aigbedion & Iyayi 2007).

Proper understanding of the underlying geology helps to accurately predict the hydrocarbon potentials and reserve estimation of a petroleum field. Information gathered from cores, seismic, well logs and other subsurface data help to resolve the underlying geologic properties used in characterizing the hydrocarbon reservoir (Tinker, 1996).

Reservoirs in the Niger Delta exhibit a wide range of complexities in their sedimentological and petrophysical characteristics due to facies variability. Estimation of hydrocarbon volumes in the reservoirs is therefore based on the field wide distribution of these reservoir properties. Petrophysics plays a fundamental role in the description, characterization and evaluation of these reservoirs properties. There is a need to integrate petrophysical data with geological and engineering data to accurately predict potential hydrocarbon prospects and reservoir quality within the study area (Weber, 1971).

Formation evaluation is the application of scientific principles, engineering concepts and technological innovations in the exploration and prospecting of hydrocarbon resources in geological formations in an environmentally sustainable and responsible manner. It involves detailed and systematic data acquisition, gathering, analysis and interpretation both qualitatively and quantitatively while applying scientific and engineering principles. It is an ever growing and evolving field of both petroleum engineering and geosciences (Abiodun, 2013). Formation evaluation techniques encompass reservoir rock sampling and analysis, reservoir fluid sampling and analysis, well pressure and flow test analysis and well logging (Bassiouni, 1994).

The present study focuses on the critical evaluation of petrophysical properties estimated from well-logs, mud logs and core data in order to identify potential hydrocarbon targets in the study area for increased hydrocarbon recovery.

1.2 Statement of the Problem

The prediction of spatial distribution of petrophysical properties within a heterogeneous reservoir is affected by significant uncertainties. In order to avoid the bias, knowledge of rock matrix and pore fluid types is required to allow for proper calibration or correction of the estimated values.

The breakthrough most of the indigenous company are encountering in the marginal fields abandoned by most multinational companies due to their focus on giant fields offshore Niger Delta have shown that there are much to expect in terms of petroleum prospect in the onshore part of the basin.

That is to say with proper application of petrophysical studies in these marginal fields, more and even bigger oil fields or traps that had been bypassed (missed) by previous explorers could be discovered; Non detection of the traps could be caused by either complex distinctive structural characteristics or the complexity of the stratigraphic nature of the delta which may have mislead them and hinder the discovering of some trap.

1.3 Aim and Objectives

The aim of this study is to identify potential prospective pay zones in the study area by critically evaluating the reservoir properties estimated from well logs, mud logs and core data.

The specific objectives of this study are to:

- i. Delineate the reservoir sands from non reservoir units using gamma ray, neutron and density log signatures.
- ii. Carry out lithological correlation of the reservoir sands and shales using stratigraphic markers (shale markers).
- iii. Quantitatively estimate reservoir properties (ϕ_e , S_w , N/G , V_{sh} , etc.) from well logs.
- iv. Identify hydrocarbon-bearing sands and gas/oil contact from density log in combination with the neutron porosity log and resistivity log.
- v. Integrate all the available data to evaluate the production potential of the wells.

1.4 Justification of the Study

Integrated interpretation of well data can strongly reduce uncertainties in Formation Evaluation for hydrocarbon exploration. Through integrated interpretation of well log data extra value is added to the exploration process. The extra value gained through integration can be expressed in reliable geological models for improved hydrocarbon recovery.

This study is focused on evaluating the petrophysical parameters estimated from well logs, mud logs and core data to understand the spatial distribution of reservoir properties in a mature producing field, onshore Niger Delta, for optimum hydrocarbon recovery.

1.5 Scope of the Study

This study covers the editing and correction of well log data for borehole and environmental effects such as washouts, cave-ins, invasion, etc., evaluation of petrophysical properties from well logs and core data. It also attempts an interpretation of the depositional environment using gamma ray log motifs, interpretation of reservoir geometry and architecture from correlation of the sand bodies and characterization of the reservoir zones across the entire field with respect to the reservoir properties, including hydrocarbon volumetric calculation.

CHAPTER TWO

LITERATURE REVIEW

2.1 Location of the Study Area

The “Azoh” field is located in the Northern Delta Depobelt of the Niger Delta Basin in a land environment (Fig. 2.1). The Niger Delta which covers an area of about 7500 km² is a large acute delta extending between longitudes 3°E and 9°E and latitudes 4°N and 8°N (Doust and Omatsola, 1990). The province contains known resources (cumulative production plus proved reserves) of 34.5 BBO and 93.8 TCFG (Petroconsultants, 1996).

2.2 Geology of the Niger Delta

Situated on the continental margin of the Gulf of Guinea in equatorial West Africa is the Niger Delta Basin (Fig. 2.2). Two arms of a triple junction comprising of collapsed margin of south Atlantic gave rise to the Niger Delta following the early Cretaceous subsidence of the African continental margins and deposition of clastic materials (Weber & Daukoru, 1975). During the middle and late Eocene times regional deltaic deposition has been established with sediments largely derived from the weathering flanks of Niger-Benue drainage system (Stacher, 1995). In the Tertiary, it prograded into the Atlantic Ocean at the mouth of the Niger-Benue river system producing a delta of about 75,000km² and a clastic fill of about 12,000m thick at its central part.

The Tertiary sedimentary fill of the Niger Delta is divided into tripartite diachronous lithostratigraphic units representing prograding depositional facies distinguished mostly on the basis of sand-shale ratios. These are the Akata Formation of mostly marine prodelta shales, the Agbada Formation of alternating paralic sands and shales and the Benin Formation of mostly continental freshwater bearing sands (Short & Stauble, 1967).

The total sedimentary sequence was deposited in a series of mega-sedimentary belts (depobelts or mega-structures) in a succession temporally and spatially with southward

progradation of the delta (Doust and Omatsola, 1990). Five major depobelts can be distinguished along the north-south axis of the delta: Northern Delta, Greater Ughelli, Central Swamp, Coastal Swamp, and Offshore depobelts (Fig 2.3). These mega-units range in width from 30 to 60km each bounded to the north by major structure building fault and south by a change in regional fault. Within each both the Akata and Agbada Formations are thought to have sourced to varying degrees oil and gas (Evamy, Haremboure, Kamerling, Knaap, Molloy & Rowlands, 1978). Growth faults and rollover anticlines are the dominant structural styles of the Niger Delta with complexity increasing southwards.

The occurrence of hydrocarbons in the Niger Delta in rocks of Paleocene to Pliocene age has been divided into pollen and foraminifera zonations each having an alphanumeric code. The zonal and sub-zonal boundaries are quite sharply delineated not only by marker species but also by dated transgressive marker shales carrying coded names of foraminifera which are characteristic of the assemblage occurring in them (Evamy, et al, 1978; Stacher, 1995). Reijers (1996) reported that planktonic foraminifera recovered from some of the major regional markers shales suggest several third order transgressive pulses within late Paleocene, early Eocene, late Oligocene-early Miocene, middle Miocene- late Miocene and Pliocene. The fundamental sequence stratigraphic building blocks of the Niger Delta succession are eleven well defined third-order sequence (Niger Delta cycles) which are mainly made up transgressive and highstand system tracts (Stacher, Ozumba & Elochie., 1993).

Studies of depositional environments and sedimentary facies in the Niger Delta dates back to the sixties and has established a lithogenetic model that relates facies variations with a high energy, wave-dominated, constructional, arcuate-lobate tropical delta (Reijers, 2011). This model is the basis for the paleoenvironmental, sedimentological and stratigraphic interpretations of the Cenozoic successions in the Niger Delta. It displays a concentric

arrangement of terrestrial and transitional depositional environments that can be broadly categorized into three distinct facies belts: the continental delta top facies, the paralic delta front facies and the prodelta facies (Short and Stauble, 1967).

This Niger Delta model is an attractive scheme, but such an idealized vertical sequences cannot summarize deltaic facies patterns, which are ubiquitously characterized by extreme vertical and lateral variations. It is therefore imperative that the sedimentary fills be modeled to characterize the sub-environments of the deltaic framework and their inherent implications on hydrocarbon potentials. A development in sequence stratigraphy that this paper is highlighting is forward modeling of sedimentary fill of a basin taking a portion of it as study area. Computer modeling of basin's fill is very important because it replicates its sequence stratigraphy, the subdivision of the sedimentary fills into time stratigraphically constrained depositional packages reflecting the basinal evolution (Ejeh, 2010).

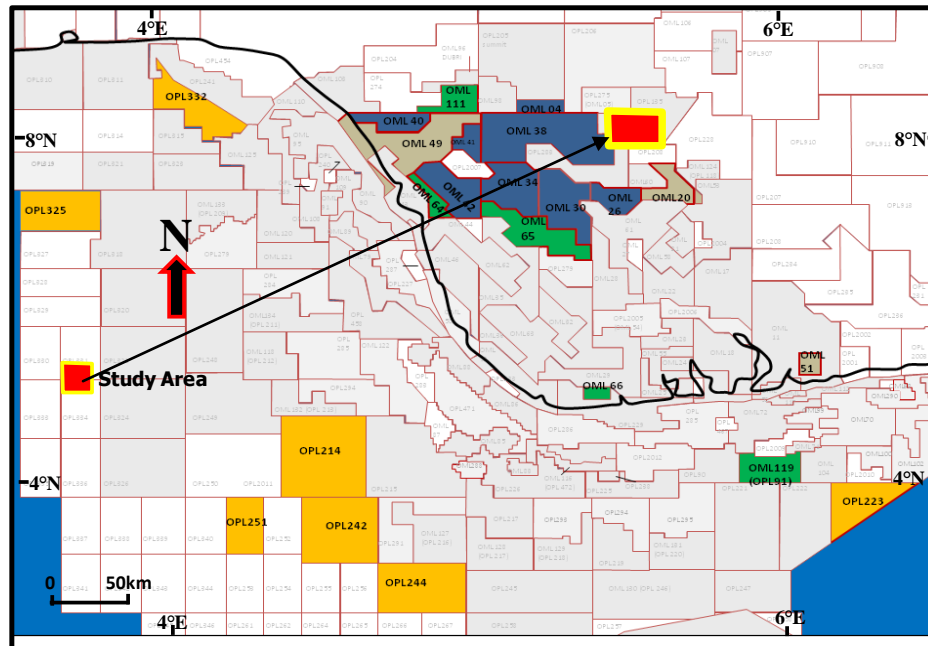


Fig 2.1. Concession map of Niger delta showing the study area (After (Doust and Omatsola, 1990)

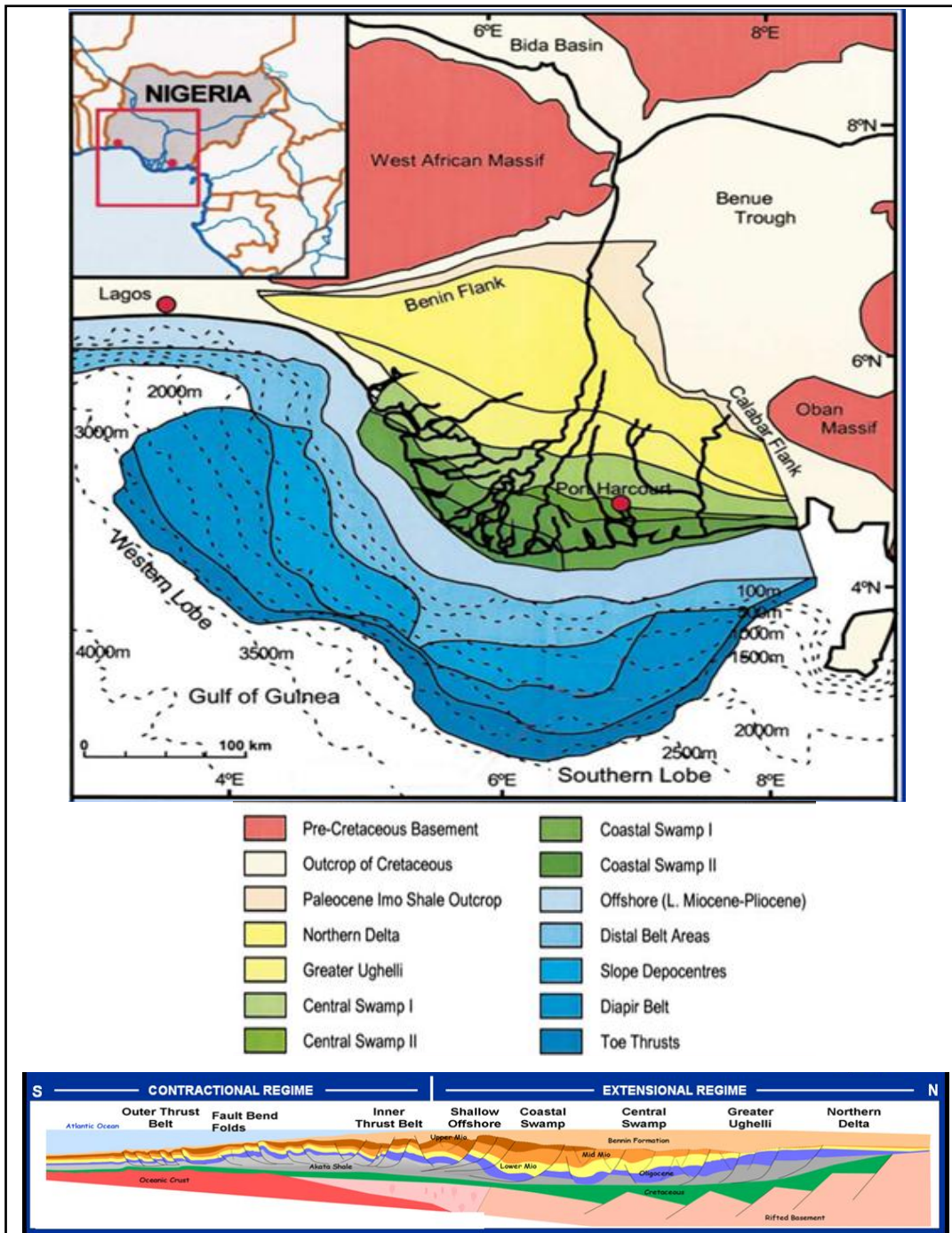


Fig 2.2. Schematic Niger Delta regional dip cross-section showing structural belts (Modified after Shannon & Naylor, 1989)

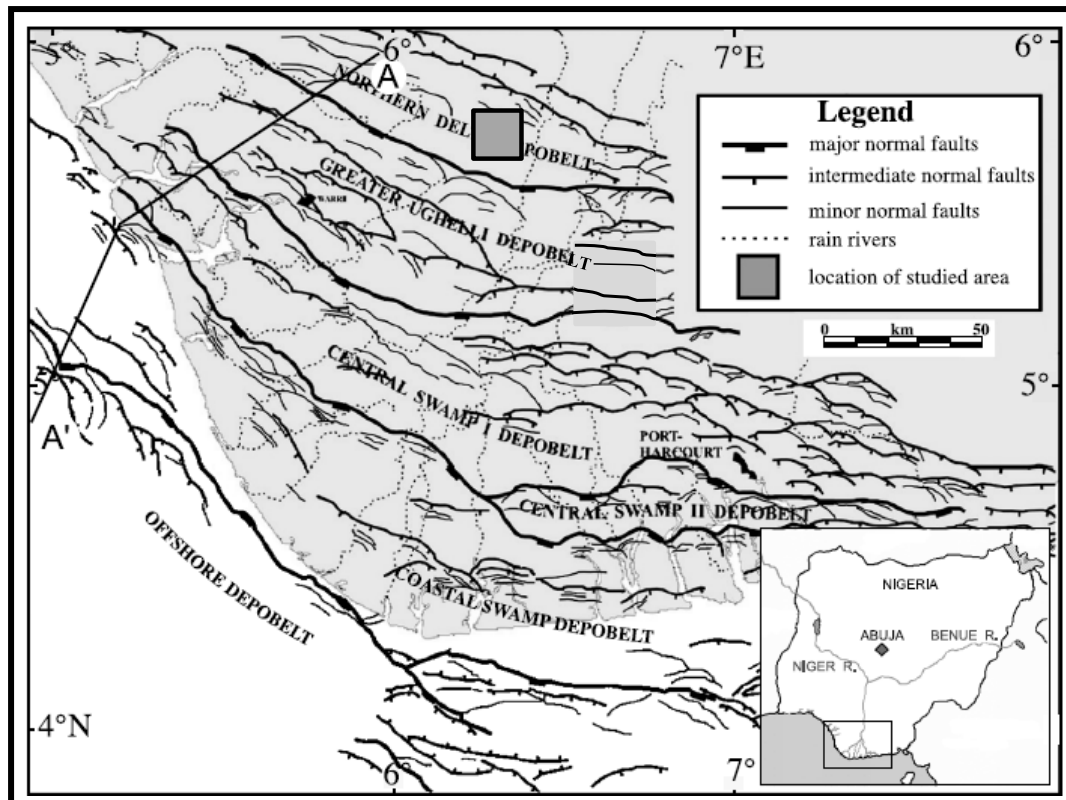


Fig 2.3 Regional structural map Niger Delta showing the depobelts. (Bouroullec, 2002)

2.2.1 Basin Boundary Definition

The onshore portion of the Niger Delta Province is delineated by the geology of southern Nigeria and southwestern Cameroon. The northern boundary is the Benin flank- an east-northeast trending hinge line south of the West African Basement Massif. The northeastern boundary is defined by outcrops of Cretaceous sediments on the Abakaliki High and further east-south-east by the Calabar flank-a hinge line bordering the adjacent Precambrian rocks. (Short & Stauble, 1967). The offshore boundary of the province is defined by the Cameroon volcanic line to the east, the eastern boundary of the Dahomey basin (the eastern-most West African transform-fault passive margin) to the west, and the two-kilometer sediment thickness contour or the 4000m bathymetric contour in areas where sediment thickness is greater than two kilometers to the south and southwest (Weber & Daukoru, 1975).

Sedimentary deposits in the basin have been divided into three large-scale lithostratigraphic units (Fig.2.4 & 2.5): the basal Paleocene to Recent pro-delta facies of the Akata Formation, Eocene to Recent, paralic facies of the Agbada Formation and Oligocene-Recent, fluvial facies of the Benin Formation (Evamy et al., 1978; Short and Stauble, 1967; Whiteman, 1982). These formations become progressively younger farther into the basin, recording the long-term progradation of depositional environments of the Niger Delta onto the Atlantic Ocean passive margin.

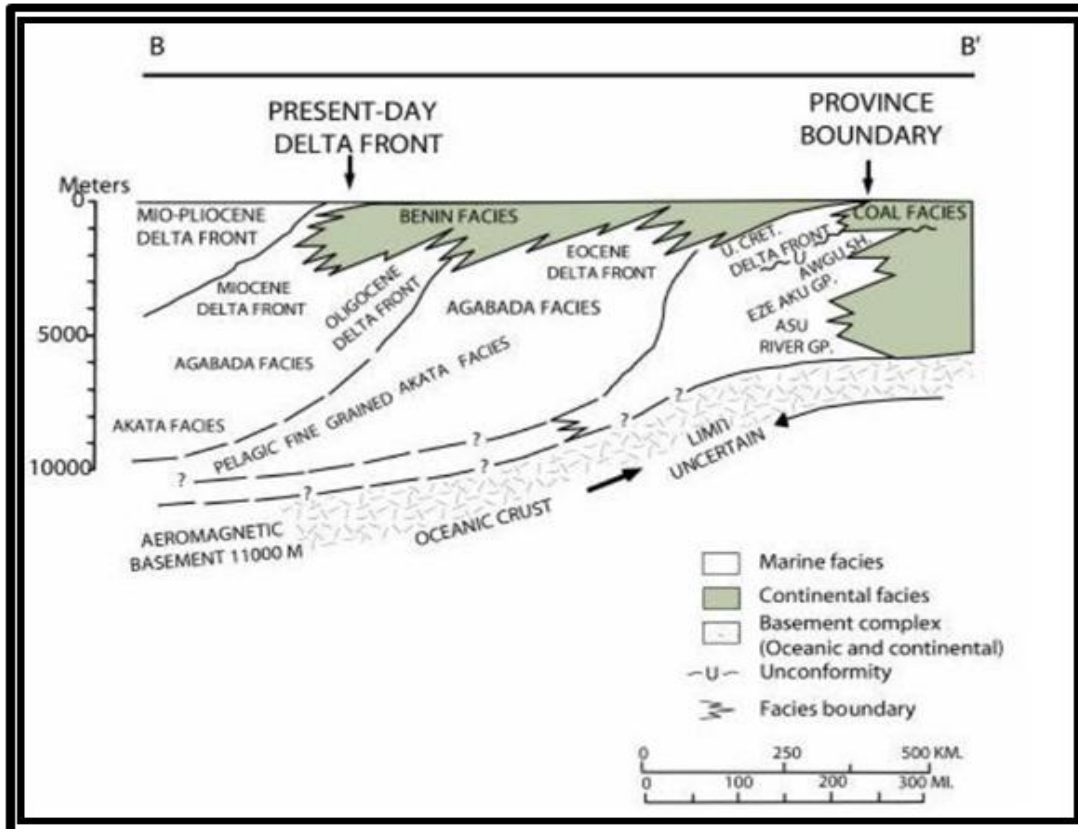


Fig 2.4. Southwest-Northwest (B-B) cross section through the Niger Delta (Modified after Whiteman, 1982)

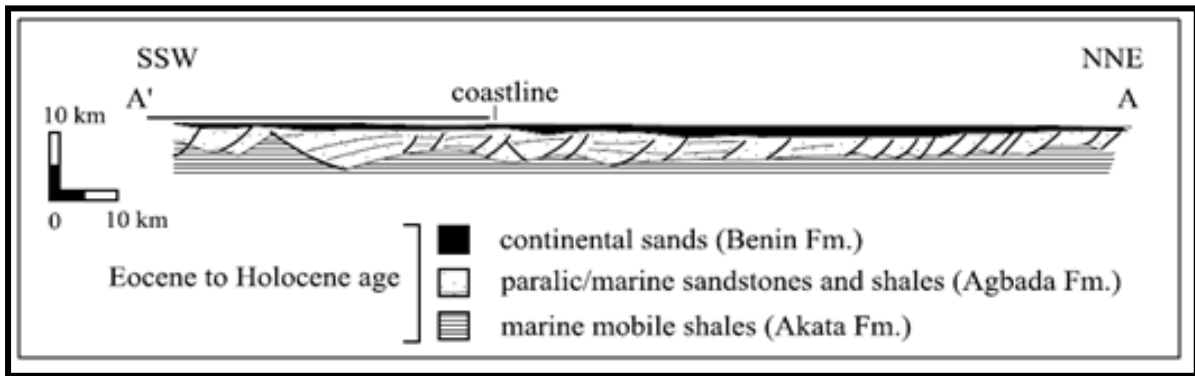


Fig 2.5. Schematic north-northeast-southwest cross section of the upper extensional part of the region of Niger Delta (Modified after Cohen & McClay, 1996)

2.2.2 Stratigraphy

The stratigraphy of the study area is complicated by syndepositional collapse of clastic wedges as shales of the Akata Formation are mobilized under the load of prograding deltaic Agbada and fluvial Benin Formation deposits. A series of large-scale, basinward-dipping listric normal faults were formed as underlying shales diapired upward. Blocks down-dropped across these faults and filled with growth strata, changed local depositional slopes and complicated sediment transport paths into the basin. For any given depobelt in the Niger Delta province, gravity tectonics was completed before deposition of the Benin Formation, which are expressed in complex structures, including shale diapirs, roll-over anticlines, collapsed growth fault crests, back-to-back features and steeply dipping, closely spaced flank faults (Evamy et al., 1978; Xiao and Suppe, 1992). These faults mostly offset different parts of the Agbada Formation and flatten into detachment planes near the top of the Akata Formation.

From the Eocene to the present, the delta has prograded southwestward, forming depobelts that represent the most active portion of the delta at each stage of its development (Doust and Omatsola, 1990). These depobelts form one of the largest regressive deltas in the world with an area of some 300,000 km² (Kulke, 1995), sediment volume of 500,000 km³ (Hospers, 1965), and a sediment thickness of over 10 km in the basin depocenter. The Niger Delta Province has been identified to be a prolific hydrocarbon habitat and is known to contain one identified petroleum system (Ekweozor and Daukoru, 1984; Kulke, 1995) referred to as the Tertiary Niger Delta (Akata – Agbada) petroleum System. The sandstones and unconsolidated sands from which petroleum is produced in the Niger Delta have a geometry that has been grossly affected and controlled by the dominant growth fault configuration. The

sand units are seen to thicken in the downthrown portion towards the fault dip direction (Rotimi, Adeoye, & Ologe., 2010, Weber & Daukoru, 1975).

Stratigraphic evolution of the Tertiary Niger Delta and underlying Cretaceous strata is described by Short and Stauble (1967). Petroleum Geology of the Niger Delta is described in Evamy et al. (1978), Doust and Omatsola (1990) and Tuttle et al. (1999). Stacher (1995) developed a hydrocarbon habitat model for the Niger Delta based on sequence stratigraphic methods. Allen (1965) and Oomkens (1974) described depositional environments, sedimentation and physiography of the modern Niger Delta. The three major lithostratigraphic units defined in the subsurface of the Niger Delta (Akata, Agbada and Benin Formations, (Fig 2.6) decrease in age basinward, reflecting the overall regression of depositional environments within the Niger Delta clastic wedge.

Stratigraphic equivalent units to these three formations are exposed in southern Nigeria as shown in (Table 2.1). The formations reflect a gross coarsening-upward progradational clastic wedge (Short and Stauble, 1967), deposited in marine, deltaic, and fluvial environments (Weber and Daukoru, 1975; Weber, 1986). The type section of the Akata Formation was defined in Akata 1 Well, 80 km east of Port Harcourt (Short and Stauble, 1967). A total depth of 11,121 feet (3, 680 m) was reached in the Akata 1 well without encountering the base of this formation. The top of the formation is defined by the deepest occurrence of deltaic sandstone beds (7,180 feet in Akata well). The formation is estimated to be 21,000 feet thick in the central part of the clastic wedge (Doust and Omatsola, 1989). The lithologies are dark grey shales and silts, with rare streaks of sand of probable turbidite flow origin (Doust and Omatsola, 1989). Marine planktonic foraminifera make up to 50% of the microfauna assemblage and suggest shallow marine shelf deposition (Doust and Omatsola, 1989).

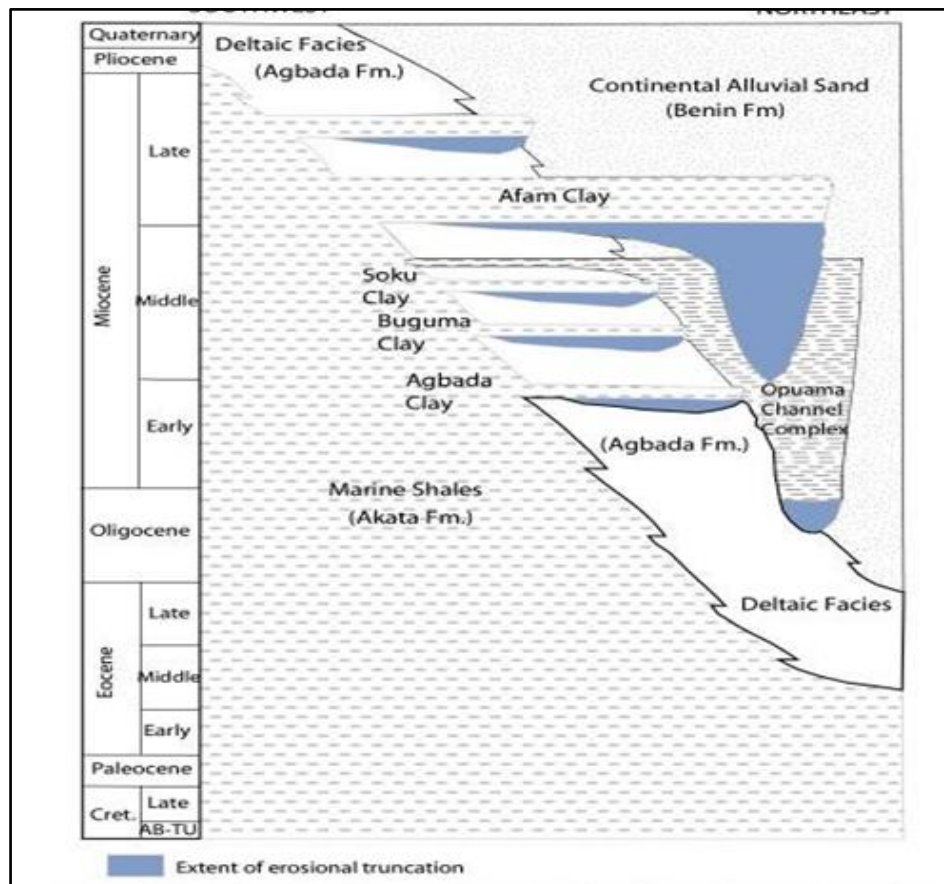


Fig 2.6. Stratigraphic column showing the three formation of the Niger delta (modified after Doust & Omatsola, 1990)

Table 2.1: Stratigraphic chart of Niger Delta Area, Nigeria. (Modified from Short and Stauble, 1967).

Subsurface			Surface Outcrops		
Youngest known Age		Oldest known Age	Youngest Known Age		Oldest Known Age
Recent	Benin Formation (Afam clay member)	Oligocene	Plio/Pleistocene	Benin Formation	
Recent	Agbada Formation	Eocene	Miocene Eocene	Ogwashi-Asaba Formation Ameki Formation	Oligocene Eocene
Recent	Akata Formation	Eocene	Lower Eocene	Imo shale Formation	Paleocene
Unknown			Paleocene	Nsukka Formation	Maestrichtian
			Maestrichtian	Ajali Formation	Maestrichtian
			Campanian	Mamu Formation	Campanian
			Campanian/Maestrichtian	Nkporo Shale	Santonian
			Coniacian/Santonian	Awgu Shale	Turonian
			Turonian	Eze Aku Shale	Cenomanian
			Albian	Asu River Group	Albian

Age of the formations ranges from Paleocene to Recent (Doust and Omatsola, 1989). Those shales, formed during the early development stages of Niger Delta progradation, are thickest along the axis of the Benue and Bida Troughs. Where exposed onshore in the northeastern part of Nigeria, this formation is called the Imo Shale. The formation also crops out offshore in diapirs along the continental slope. When deeply buried, these marine shales are typically overpressured. Akata shales were interpreted to be deepwater lowstand deposits by Stacher (1995). The formation grades vertically into the Agbada Formation with abundant plant remains and micas in the transition zone (Doust and Omatsola, 1989).

The Agbada Formation is defined in the Agbada 2 well, drilled about 11 km north-northwest of Port Harcourt (Short and Stauble, 1967). The well reached a total depth of 9500 feet without penetrating the base of the formation (the base was defined as the top of the Akata Formation in Akata 1 well). According to Doust and Omatsola, (1989), the formation occurs throughout Niger Delta clastic wedge and has a maximum thickness of about 13,000 feet. Where it outcrops in southern Nigeria (between Ogwashi and Asaba), it is called the Ogwashi-Asaba Formation. The lithologies consist of alternating sands, silts and shales arranged within ten to hundred feet successions defined by progressive upward changes in grain size and bed thickness. The strata are generally interpreted to have formed in fluvial-deltaic environments. The formation ranges in age from Eocene to Pleistocene.

The Benin Formation comprises the top part of the Niger Delta clastic wedge, from the Benin-Onitsha area in the north to beyond the present coastline (Short and Stauble, 1967). Its type section is Elele 1 Well, drilled about 38 km north-northwest of Port Harcourt (Short and Stauble, 1967). The top of the formation is the recent subaerially-exposed delta top surface and its base extends to a depth of 4600 feet. The base is defined by the youngest marine

shale. Shallow parts of the formation are composed entirely of non-marine sand deposited in alluvial or upper coastal plain environments during progradation of the delta (Doust and Omatsola, 1989). Although lack of preserved fauna inhibits dating using foraminifera however, palynological data indicate age of Oligocene to Recent (reijers, 2011; Short and Stauble, 1967). The formation thins basinward and ends near the shelf edge. Short and Stauble (1967) defined formations based on sand/shale ratios estimated from subsurface well logs. Such definitions, based on subsurface well logs that incompletely penetrate type sections, do not conform to the international stratigraphic code and thus are informal. Conflicting definitions of tops and bases of formations are used by local geologists. The top of the Agbada Formation is often defined as the base of fresh water sand. The top of the Akata Formation is commonly defined as the top of overpressured shale encounter during drilling. Doust and Omatsola (1989) acknowledge problems with their formation definitions (first thick sand defining the Akata-Agbada Formation boundary and last thick marine shale defining the Agbada-Benin Formation boundary) may arise due to local argillaceous intercalations of considerable thickness in sands of the Benin Formation, and the local presence of turbidite sands at considerable depth within the Akata Formation.

2.3 Review of Related Literature

In 1928, the Schlumberger brothers in France developed the workhorse of all formation evaluation tools: the electric log. Electric logs have been improved to a high degree of precision and sophistication since that time, but the basic principle has not changed (Fertl, 1981). Most underground formations contain water, often salt water, in their pores. The resistance to electric current of the total formation—rock and fluids—around the borehole is proportional to the sum of the volumetric proportions of mineral grains and conductive water-filled pore space. If the pores are partially filled with gas or oil, the bulk formation resistance

is higher than for water filled pores. This is because of the resistant to the passage of electrical current. For the sake of a convenient comparison from measurement to measurement, the electrical logging tools measure the resistance of a cubic meter of formation. This measurement is called resistivity.

Hill and Milburn (1956) indicated a non-linear logarithmic relationship between formation resistivity and formation water resistivity using large amount of water saturated shaly sand core samples. They also demonstrated that cation exchange capacity (CEC) can be used as an effective shaliness indicator. Waxman-Smits (1968) proposed a shaly sand model based on the data from Hill and Milburn (1956) in addition to data from their own measurements. The model showed that the conductivity of water saturated shaly sand (C_o) was directly related to the shaliness factor (Q_v), conductivity of formation water (C_w), and porosity (\emptyset).

Clavier, Coates & Dumanoir, (1984) proposed a model called “Dual water”. The model considers that the conductivity of water is contributed by two types of water (clays bound water and free water). It suggested that shaly sand behaves just like clean sand but with the water conductivity of mixture from both components while Simandoux (1963) proposed a model based on experimental work on homogenous mixtures of sand and montmorillonite. Poupon and Leveaux (1971) developed a model based on field data from Indonesia where the reservoir rock has fresh formation water and high degree of shaliness. The model is known as “Indonesia formula”.

Archie (1942) showed how the electrical resistivity log can be used as an aid in determining some reservoir characteristics in porous formations, while Witte (1950) established relations between resistivity and fluid contents of porous rocks.

Anyiam, Mode and Ekwe (2010) conducted formation evaluation of an onshore appraisal well ‘KG-5’, “Green” field, Niger Delta, Nigeria and discovered a significant oil column within the sandstone reservoir intervals. Dieokuma, Gu, Liping, Etim, & Warmate, (2014)

studied the petrophysical characteristics of a reservoir in the Coastal Swamp Depobelt the Niger Delta using well-log data, while Alao, Ata, & Nwoke, (2013) carried out subsurface and petrophysical studies of shaly-sand reservoir targets in “Apete” field, Niger Delta. Aigbedion and Iyayi (2007) performed formation evaluation of “Oshioka” field in the Niger Delta Basin to identify hydrocarbon-bearing reservoirs and studied the petrophysical properties using geophysical well-log data.

Fidelis & Thomas, (2014) conducted the petrophysical evaluation and depositional environment of interpretation of the sediments penetrated by Harrison-1 well using core data and wireline logs.

Eze, Mode, & Ugbo,. (2013) performed formation evaluation of “X7” field in the Niger Delta using petrophysical data in order to assess the qualities of the reservoirs and their depositional environments.

Adeogba, McHargue & Graham, (2005) have interpreted a near surface, 3D seismic data set from the Niger-Delta continental slope, offshore Nigeria and reveal important stratigraphy and architectural features and sediment deposits interpreted from seismic character and seismic stratigraphy in the absence of borehole data including mass transport complexes, distributary channels, sub marine fans and hemi pelagic drape complexes.

Ayiam and Mode (2008) did also some work on the Sequence Stratigraphic Framework of “Paradise-Field” Niger Delta, located within the Coastal Swamp II. They used high resolution biostratigraphic tool for the representative well P-1 in the “Paradise Field” in the sequence stratigraphic analysis. The eustatic cycles recorded in the penetrated stratigraphic intervals have been correlated to the regional chronostratigraphy of the Niger Delta for the prediction and dating of sequences recognized from the well logs. One of the maximum flooding surfaces (MFS) which dated 11.5Ma was recognized based on the maximum shale peak, the separation of high neutron and low density values with corresponding high gamma readings.

Chiaghanam, Ozumba, Ladipo, Orajaka, Ofoma, & Chiadikob. (2011) carried out a work on The Role Of Accommodation/Sediment Supply Regime/Basin Morphology in Predicting Coastal Depositional Style: A Sequence Stratigraphic Framework Approach for Selected Deep Wells Of Oligocene-Miocene Sediments Of Coastal Swamps In Niger Delta. The aim of their work was to integrate Oligocene-Miocene log responses from selected deep wells, located in the Coastal swamps of the Niger Delta, to investigate potential causes and feedback loops related to vertical and lateral changes in fluvial, wave and tide process dominance and to place these changes in a sequence stratigraphic context, with the view that fluvial and wave effectiveness regimes, basin morphologies, shoreline trajectories and low and high accommodation /sediment supply sceneries are essential in predicting depositional switches and style.

Agraka, Utuedor, Chiaghanam, Thompson, & Chukwuma. (2015) conducted a study on Sequence Stratigraphic Studies of X-Field, Central/Coastal Swamp Depobelts, Niger Delta; their work was carried out using wireline logs, biofacies data and seismic section. They delineated five bounding stratigraphic surfaces comprising three candidate maximum flooding surfaces and two candidate sequence boundaries using progradational and retrogradational stacking pattern. Four maximum flooding surfaces; MFS 17.4Ma, 15.9Ma, 15.0Ma, and 12.8Ma, and four sequence boundaries; SB16.7Ma, 15.5Ma, 13.1Ma and 12.1Ma which subdivided the field under study into four major third-order genetic sequences were delineated. The associated systems tract, highstand and transgressive systems tracts, show variable reservoir development across the field. The highstand systems tracts act as reservoir rocks while the transgressive systems tracts act both as seal and source rocks. They quipped that the structural patterns across the study area are simple synthetic, antithetic and associated roll over anticlines, while the depositional environments determined from the

wireline log motif include fluvial channels, distributary channels, distributary mouth bar, tidal channels, tidal flats and Barrier Island.

Amigun, Olisa, & Fadeyi. (2012) did a study on Petrophysical Analysis of Well Logs for Reservoir Evaluation: A case Study of 'Laja' Oil Field, Niger Delta. This study presents the log analysis results of a suite of geophysical logs comprising gamma ray (GR), neutron (PHIN), resistivity (LLD), and density (PHID) logs from six wells in 'Laja' Field located in the Niger delta area. The analysis was carried out to evaluate the field's hydrocarbon prospect, which is to identify hydrocarbon bearing reservoir(s) and also to study reservoir properties based on log data from the six wells. Eleven zones of interest (sand bodies) were delineated and correlated across this field. Six of these sands were further identified as potential hydrocarbon reservoirs. The computed petrophysical parameters for the reservoir layers have porosity, range of 13% – 38% and hydrocarbon saturation, Sh range of 0.16% to 22.2%. The analysis indicates that reservoirs (sands) are encountered at depth range of 4350m to 7650m with relative permeability of the reservoir ranging from 314.0 to 18521.8md. These results on the whole suggest that the reservoir sand units of 'Laja' Field contain significant accumulations of hydrocarbon.

Adegoke (2012) also undertook a research work on Sequence Stratigraphy of Some Middle to Late Miocene Sediments, Coastal Swamp Depobelts, and Western Offshore Niger Delta. In this work, an integrated interpretation of well logs and biostratigraphic data of three selected oil wells (Exxit 73, 75 and 78) of OML 99 within the western offshore Niger Delta was carried out for the sequence stratigraphic analysis of sediments penetrated by the wells. This enabled the subdivision of the stratigraphic column within the wells into depositional sequences and sedimentary cycles. Three depositional sequences were identified and they are characterized as highstand systems tract, transgressive systems tract and lowstand systems

tract. Three maximum flooding surfaces and three sequence boundaries were also recognized. The depositional environment of the study area is inferred to be of deltaic shelfal-transitional type. These depositional sequences have potential to serve as excellent source rock and seals. Sand percentage calculation showed that the maximum flooding surfaces correspond to the major shale break i.e. high shale content. Further studies also identified the major fault planes and a hydrocarbon potential, speculated probably at 11800ft. Utilizing the Palynological Zonation of Exxit 73, 75 and 78, the ages of the sediments penetrated in the wells were inferred to range from Middle - Late Miocene.

Adeoye and Ofomola (2013) undertook a work on Reservoir Characterization of “Meri-T” Field (South Western, Niger Delta) from Well Log, Petrophysical Analysis and Sequence Stratigraphy. In this study, reservoir petrophysical analysis, and sequence stratigraphy of the “Meri-T” field, Southwestern Niger Delta, was carried out using well logs with a view to characterizing the reservoir. Petrophysical analysis began with lithology identification. Lithologic panels interpreted from well log data show that the study area is characterized by sand-shale interbedding. They were able to delineate reservoirs from their fluid content using appropriate logs. Consequently, hydrocarbons versus water bearing zones were delineated. In all, five hydrocarbon bearing sands were discovered, and porosity estimates in the reservoirs were very high varying between 0.17 and 0.39. Sequence stratigraphic interpretation was carried out to interpret the depositional environment of the area using well log motifs. Sequence stratigraphic interpretation of the area shows that the four main depositional environments that are dominant in the area include the following: channel sands and shoreface sands, reworked sandstones, coastal deposits, and the basin floor fan environment. From these depositional environments, the shoreface sand, reworked sandstones and channel sands are located within hydrocarbon bearing zones.

They inferred that the shoreface sands should be the most favorable region for hydrocarbon accumulation as reservoir petrophysical properties like porosity has shown high values recorded in this area. The interpretation that there have been slope stability, unhurried deposition of sediments and longer period of deposition in the region has been predicted to be one of the contributing factors for the hydrocarbon accumulation observed in the area.

The purpose of their paper was to illustrate why petrophysics is so important to hydrocarbon exploration and to demonstrate how carefully interpreted analysis can help the geoscientist relate the petrophysical analysis to environment of deposition.

Amigun and Odole (2013) carried out a work on Petrophysical Properties Evaluation for Reservoir Characterisation of SEYI Oil Field (Niger-Delta). This work was carried on to determine and evaluate the petrophysical properties of “SEYI” oil field, Niger delta with a view to understand their effects on the reservoirs hydrocarbon prospect and oil productivity of the field. The evaluated properties include porosity, permeability, fluid saturation, net / gross thickness and mobility which are all inferred from geophysical wire-line logs. A suite of wire-line logs comprising of gamma ray, resistivity, spontaneous potential and density logs for four wells from ‘SEYI’ oil field were analysed for reservoir characterisation of the field. The analyses they carried out involve delineation of lithologies, identification of reservoirs and fluid types, wells correlation and determination of petrophysical parameters of identified reservoirs. Seven reservoirs namely: A, B, C, D, E, F and G were delineated with their tops and bases at depth from 2396m to 3429m. Their analyses indicate the presence of hydrocarbon in all the reservoirs. Computed petrophysical parameters across the reservoirs gave porosity range of 0.22 to 0.31; permeability 881.58md to 14425.01md and average hydrocarbon saturation of 41.44%, 20.29%, 30.82%, 37.92%, 51.20%, 91.97% and 85.11% for reservoir A, B, C, D, E, F and G respectively. These results together with the determined

movable hydrocarbon index (MHI) which have values of (0.05 to 0.75) were suggested to be of high hydrocarbon potential and constitute a reservoir system whose performance is considered satisfactory for hydrocarbon production.

2.4 Theoretical Review

2.4.1 Basic Formation Evaluation Concept

In petroleum exploration and development, formation evaluation is used to determine the ability of a borehole to produce petroleum. Essentially, it is the process of "recognizing a commercial well when you drill one".

Formation evaluation is a very important stage in prospecting for reservoirs and hydrocarbon bearing zone identification. It is a subdiscipline of petroleum engineering and geosciences which specializes in the gathering of data and the quantification of parameters needed for the practice and decision making in drilling, production and reservoir engineering. Formation evaluation methods include rock-and fluid-sample analysis, well logging, and pressure and production testing. A combination of these methods is usually required for a complete and thorough evaluation (Bassiouni, 1994).

According to Bora (2013), the fundamental questions that have to find answers during formation evaluation are:

- i. What kind of rock is present (reservoir or non-reservoir rock)?
- ii. If reservoirs exist, are any hydrocarbons present?
- iii. What type of hydrocarbon is present (oil or gas)?
- iv. How much hydrocarbon is there (pay thickness, porosity, saturation etc. and finally the estimation of reserve)?
- v. How much can we produce, which answers the question, "How much money can we make?"

By finding answers to these questions, the petrophysicist will be able to make decisions on the best cost-effective way to tap the discovered hydrocarbon resource.

The ultimate goal of formation evaluation, as stated by Asfan (2002) is:

- i. To evaluate the presence or absence of commercial quantities of hydrocarbons in formations penetrated by, or lying near the wellbore.
- ii. To determine static and dynamic characteristics of a productive reservoir.
- iii. To detect small quantities of hydrocarbon which nevertheless may be very significant from an exploration stand point.
- iv. To provide a comparison of an interval in one well to the correlation interval in another well.

Fig. 2.7 is a simplified sequence usually followed by petrophysicists when performing a formation evaluation task.

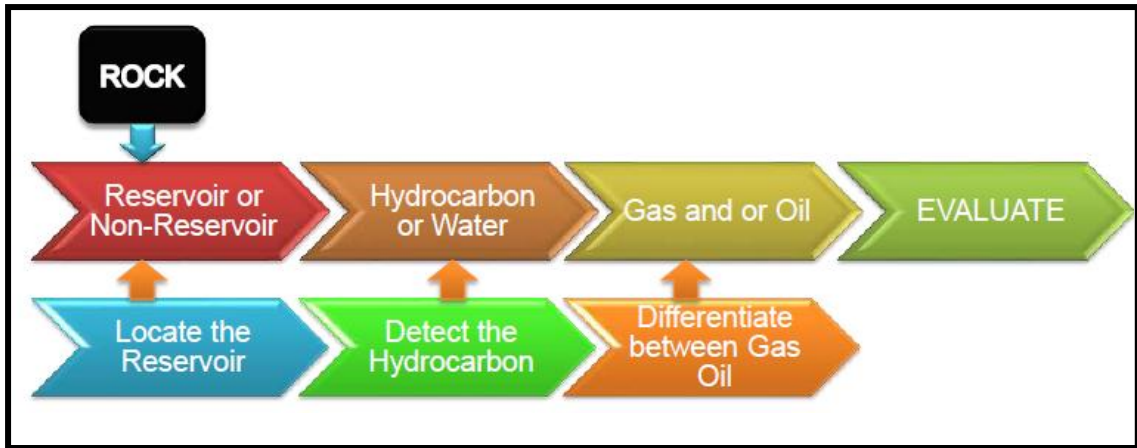


Fig 2.7. Formation evaluation sequence (After Asfan, 2002)

Formation evaluation is critical to understand the reservoir by determining the value of hydrocarbon in-place (i.e. the hydrocarbon potential of the reservoir), the ease with which the hydrocarbons flow through the porous rocks and the best and most cost-effective means of drilling and completing a well to retrieve the hydrocarbon from the subsurface. This could be achieved by evaluating the reservoir properties including porosity, permeability, water saturation, hydrocarbon thickness and type, lithology, pressure, depth, temperature and surface area (Asfan, 2002).

2.4.2 Formation Evaluation Methods

Modern rotary drilling usually uses a heavy mud as a lubricant and as a means of producing a confining pressure against the formation face in the borehole, preventing blowouts. This has drawbacks as mud filtrate soaks into the formation around the borehole and a mud cake plasters the sides of the hole. These factors obscure the possible presence of oil and gas in even very porous formations. Formation Evaluation is the process of interpreting a combination of measurements taken inside a wellbore to detect and quantify oil and gas reserves in the rock adjacent to the well. Formation evaluation data can be gathered with wireline logging instruments or logging-while-drilling tools. Data are organized and interpreted by depth and represented on a graph called a log (Wikipedia, 2008).

Tools to detect oil and gas have been evolving for over a century. Today, some of the methods adopted by geoscientists for evaluating the formation being drilled and to estimate porosity and possible oil staining include:

- i. Mud Logging
- ii. Coring
- iii. Well Logging
- iv. Testing and Sampling

2.4.2.1 Mud Logging

Mud logging (or Wellsite Geology) is a well logging process in which drilling mud and drill bit cuttings from the formation are evaluated during drilling and their properties recorded on a strip chart as a visual analytical tool and stratigraphic cross sectional representation of the well (Fig.2.8). The drilling mud which is analyzed for hydrocarbon gases, by use of a gas chromatograph, contains drill bit cuttings which are visually evaluated by a mud logger and then described in the mud log. The total gas, chromatograph record, lithological sample, pore pressure, shale density, D-exponent, etc. (all lagged parameters because they are circulated up to the surface from the bit) are plotted along with surface parameters such as rate of penetration (ROP), Weight On Bit (WOB), rotation per minute etc. on the mudlog which serve as a tool for the mudlogger, drilling engineers, mud engineers, and other service personnel charged with drilling and producing the well (Wikipedia, 2008).

Analyzing, evaluating and monitoring drill cuttings and circulating mud during the drilling process can provide information from which we can determine lithology, mineralogy and their estimated depths, hydrocarbon shows and type, fossil record, overpressure zones and drill cutting porosity (Abiodun, 2013).

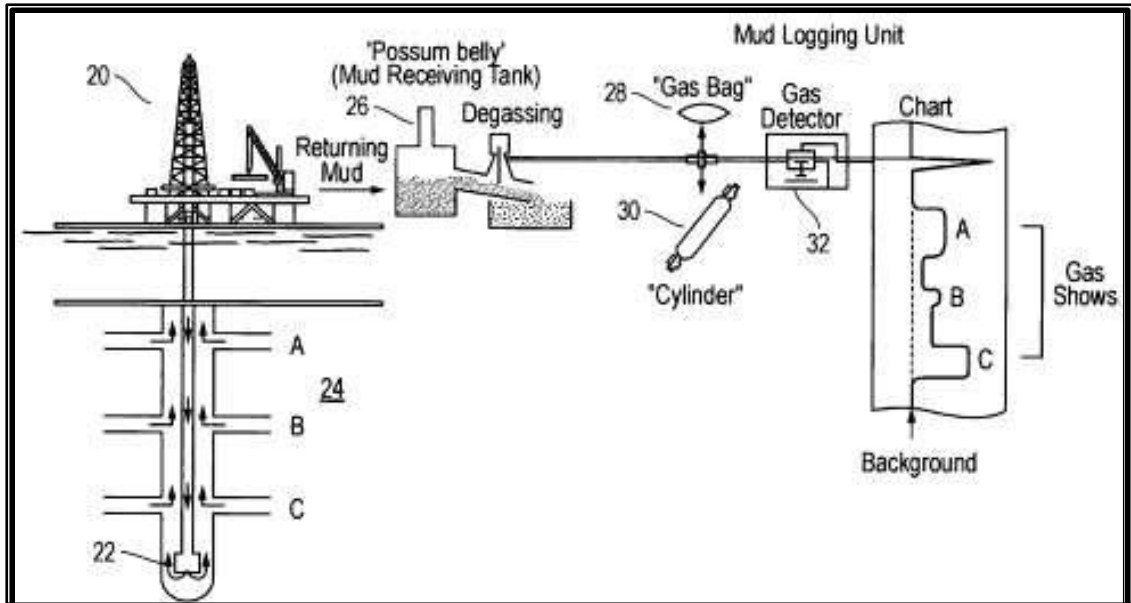


Fig 2.8 Mud logging procedure (modified from Asfan, 2002)

2.4.2.2 Coring

One way to get more detailed samples of a formation is by coring. Two techniques are commonly used at the present. The first is the "whole core", a cylinder of rock, usually about 3" to 4" in diameter and up to 50 feet (15m) to 60 feet (18m) long (Fig.2.9). It is cut with a "core barrel", a hollow pipe tipped with a ring-shaped diamond chip-studded bit that can cut a plug and bring it to the surface. Often the plug breaks while drilling, usually in shales or fractures and the core barrel jams, slowly grinding the rocks in front of it to powder. This signals the driller to give up on getting a full length core and to pull up the pipe (Coate, & Dumanoir, 1974).

Taking a full core is an expensive operation that usually stops or slows drilling for at least the better part of a day. A full core can be invaluable for later reservoir evaluation. Once a section of well has been drilled, there is, of course, no way to core it without drilling another well.

Another, cheaper, technique for obtaining samples of the formation is "Sidewall Coring". One type of sidewall cores is percussion cores. In this method, a steel cylinder—a coring gun—has hollow-point steel bullets mounted along its sides and moored to the gun by short steel cables. The coring gun is lowered to the bottom of the interval of interest and the bullets are fired individually as the gun is pulled up the hole. The mooring cables ideally pull the hollow bullets and the enclosed plug of formation loose and the gun carries them to the surface. Advantages of this technique are low cost and the ability to sample the formation after it has been drilled. Disadvantages are possible non-recovery because of lost or misfired bullets and a slight uncertainty about the sample depth. Sidewall cores are often shot "on the run" without stopping at each core point because of the danger of differential sticking. Most service company personnel are skilled enough to minimize this problem, but it can be significant if depth accuracy is important (Bryant, Robert & Truman, 2002)



Fig 2.9. Tools for coring on different scale (After Abiodun, 2013)

A second method of sidewall coring is rotary sidewall cores. In this method, a circular-saw assembly is lowered to the zone of interest on a wireline, and the core is sawed out. Dozens of cores may be taken this way in one run. This method is roughly 20 times as expensive as percussion cores, but yields a much better sample (Asfan,, 2002).

A serious problem with cores is the change they undergo as they are brought to the surface. It might seem that cuttings and cores are very direct samples but the problem is whether the formation at depth will produce oil or gas. Sidewall cores are deformed and compacted and fractured by the bullet impact. Most full cores from any significant depth expand and fracture as they are brought to the surface and removed from the core barrel. Both types of core can be invaded or even flushed by mud, making the evaluation of formation fluids difficult. The formation analyst has to remember that all tools give indirect data (Wikipedia, 2008).

Data gotten from cores, using the major core analysis techniques, are (i.e. direct measurements done on the core samples):

- i. *Routine core analysis*: Porosity, Permeability, Lithology, grain density, Fluid saturation etc.
- ii. *Special core analysis*: Relative permeability, pore-size distribution, mineralogy, SEM, CT-Scan, Electrical properties, mechanical properties, Capillary pressure, etc. (Abiodun, 2013).

2.4.2.3 Well Logging

The oil and gas industry uses well logging to obtain a continuous record of a formation's rock properties. Wireline logging can be defined as being "The acquisition and analysis of geophysical data performed as a function of well bore depth, together with the provision of related services. The measurements are made referenced to True Along Hole (TAH) depth. These and the associated analysis can be used to infer further properties, such as hydrocarbon

saturation and formation pressure, and to make further drilling and production decisions (Asquith & Gibson, 1982; Wikipedia, 2008).

Well logging is performed by lowering a 'logging tool' - or a string of one or more instruments - on the end of a wireline into an oil well (or borehole) and recording petrophysical properties using a variety of sensors. Logging tools developed over the years measure the natural gamma ray, electrical, acoustic, stimulated radioactive responses, electromagnetic, nuclear magnetic resonance, pressure and other properties of the rocks and their contained fluids (Archie, 1953).

The data itself is recorded either at surface (real-time mode) or in the hole (memory mode) to an electronic data format and then either a printed record or electronic presentation called a "well log" is provided to the client, along with an electronic copy of the raw data. Well logging operations can either be performed during the drilling process to provide real-time information about the formations being penetrated by the borehole, or once the well has reached Total Depth and the whole depth of the borehole can be logged.

There are many types of wireline logs and they can be categorized either by their function or by the technology that they use. "Open hole logs" are run before the oil or gas well is lined with pipe or cased. "Cased-hole logs" are run after the well is lined with casing or production pipe (Wikipedia, 2008).

Well logs are usually the main tool of investigation and evaluation of the subsurface formations. The formation parameters such as porosity, permeability and water saturation are usually obtained from log analysis. The dominant function of those parameters is to assess the hydrocarbon content of subsurface formations (Rashid & Motaz, 2012).

Well logging technology embraces three distinct areas. The first area consists of the definition of mathematical and empirical models that relate a formation property of interest to the property measured with the logging tool. The second area consists of the log

measurement itself and encompasses tool design and calibration. The third area is analysis and interpretation (Schlumberger, 1989).

2.4.2.4 Testing and Sampling

This formation evaluation method is used to provide a more definitive idea of the production capacity of the well. Reservoir fluid is sampled using the following methodology;

- i. Drill stem testing (DST) or Production Tests
- ii. Wireline formation testers
- iii. Logging While Drilling (LWD) Formation Testers
- iv. Surface Samples at the wellhead or separator

Data acquired include;

- i. Fluid Type,
- ii. Pressure-Volume-Temperature (PVT) data, Fluid Composition from Lab tests
- iii. Pressure and temperature
- iv. Viscosity, Gas-Oil Ratio (GOR) American Petroleum Institute (API)
- v. Asphaltene and wax content
- vi. Presence of H₂S

Drill Stem Tests identifies the types of fluids within the well, as well as the flow rate of these fluids, formation permeability and reservoir pressure. Drill stem tests involve connecting a measurement device to the bottom of the drill stem, also in place of the drill bit, and lowering the system into the well, all the way to the formation (Fig.2.10). The instrument is activated at the bottom of the well, measuring the flow of oil or gas for a specified amount of time, usually on hourly basis (Fig 2.11)

Well testing is possible because pressure and flow rate can easily be measured in a well and an analysis of the measurement history reflects reservoir parameters (Abiodun, 2013).

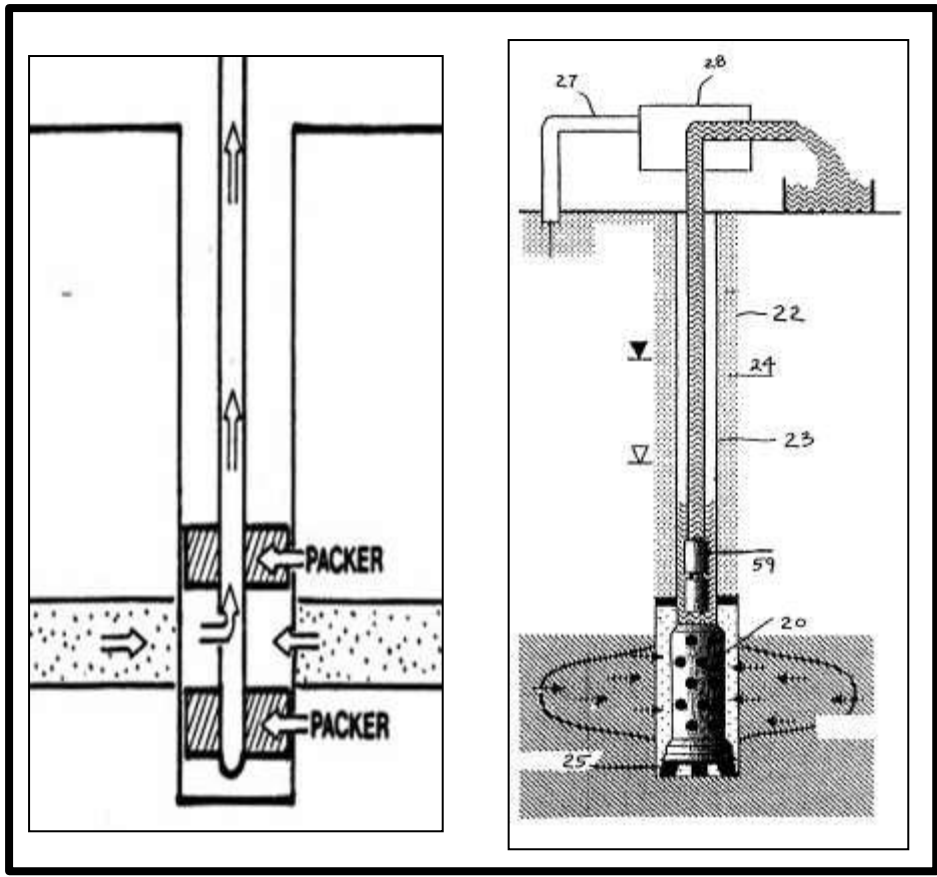


Fig 2.10. Drill stem test (modified from Asfan, 2002)

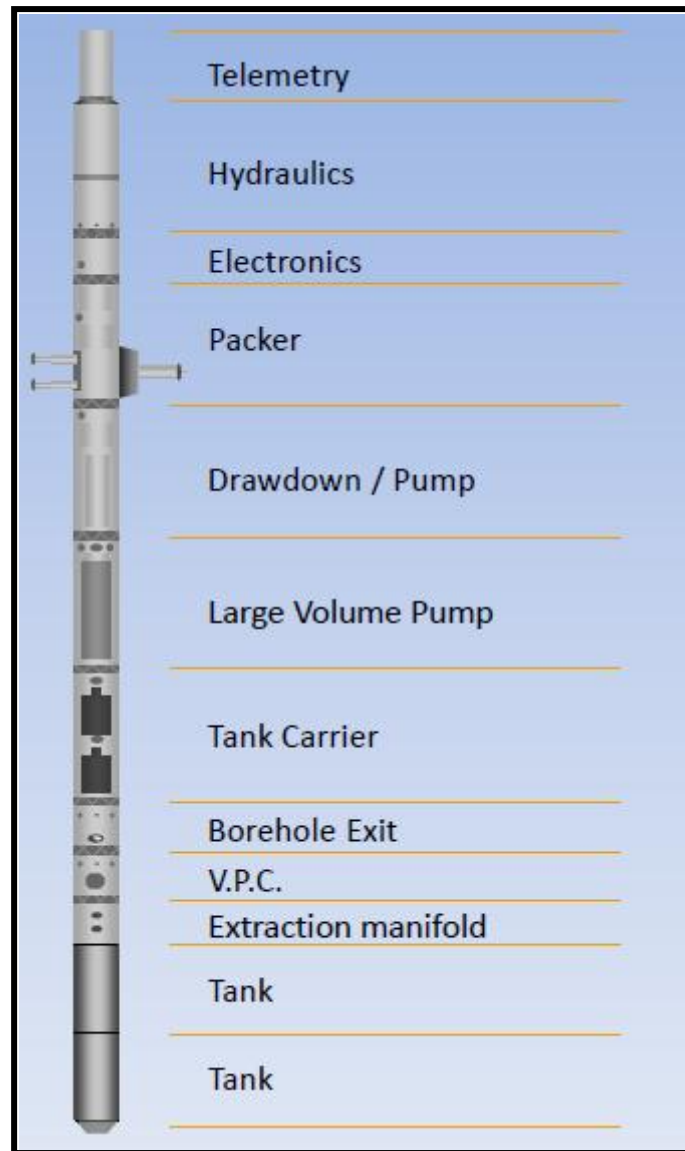


Fig 2.11 Diagram of a formation tester (modified from Asfan, 2002)

Formation testers are a class of wireline tools used to measure the downhole pressure of formations. Stationary measurements of formation pressure in an open hole are made at any number of depths during a single trip into the hole. These pressure measurements are useful in determining

1. variations in pressure among various formations,
2. gradients of fluid pressure within a formation that can indicate fluid content,
3. gas-oil or water-oil contacts, and
4. local permeability.

Comparison with initial reservoir pressures in development wells may indicate zonal pressure depletion. Formation testers are also used to retrieve samples containing fluids.

Logging while drilling (LWD) refers to the addition of wireline-quality formation measurements to the directional data of a Measurement While Drilling (MWD) service. Although attempts to deliver LWD services date back to the 1920's, the first viable tools were by J.J. Arps in the 1960's, but these did not become a commercial service. The growth of MWD in the late 1970's and early 1980's delivered the first commercial LWD services by the major service providers. The initial tools were natural gamma and resistivity, and these made geosteering possible, as horizontal drilling grew. Information is returned to the surface using the same methods as MWD telemetry options.

Surface sampling of reservoir fluids primarily involves sampling individual gas and liquid streams from a production separator or similar installation, and it is by far the most common method of sampling pressurized hydrocarbon fluids. Usually, the objective of separator sampling is to obtain a fluid representative of the production of one well that enters the

separator in its entirety, but the method also can be used to obtain a fluid representing commingled production from a number of wells into a single gas/oil separation plant. In either case, the objective is to collect separate samples of the gas and liquid exiting the separator and to measure the separate flow rates of the two phases and obtain the gas-oil ratio (GOR). Although the two phases are never in perfect equilibrium, providing that the two samples are representative of the separate flows, it is possible to mix the two samples together in the same proportion in which they are produced to obtain a recombined sample that represents the fluid entering the separator.

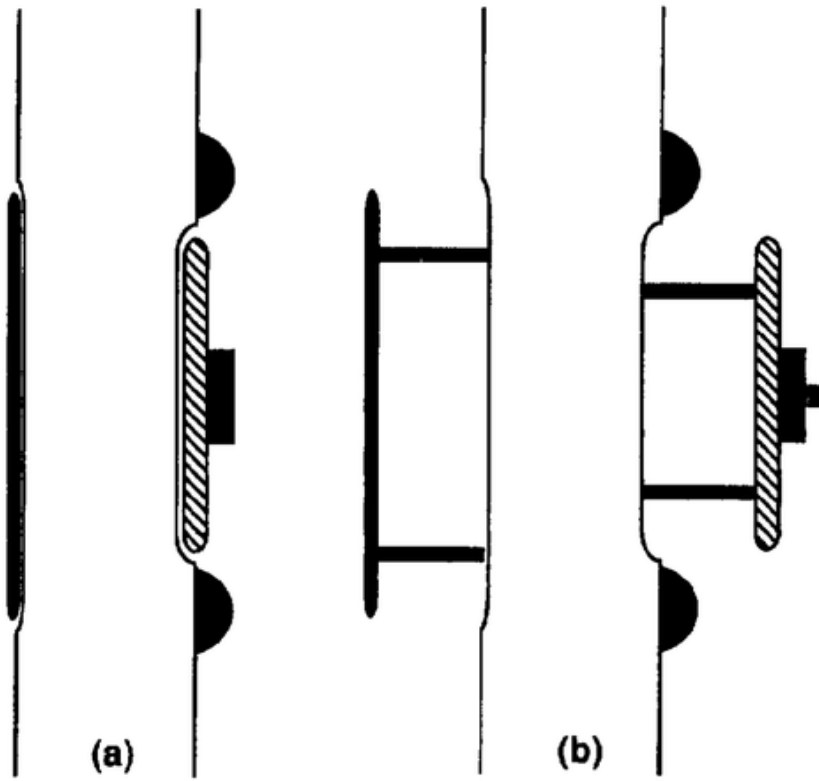


Fig 2.12. Wireline formation tester. (a) Retracted configuration (tool closed). (b) Set configuration (tool set).Smolen, J., Litsey, L. R., (1979)

CHAPTER THREE

MATERIALS AND METHODS

3.1 Materials

The data sets used for this work include well heads and well deviation data, composite log suites from three wells in the “Azoh” Field, Northern Delta depobelt, logged with gamma ray, neutron, sonic, density and resistivity logs, mud logs, core data, 3D seismic volume covering the study area and checkshot data.

Software tools used for the interpretation include Petrel 2012.1, MS Excel, Notepad and MS Power Point. The wells were named Azoh-001, Azoh-002 and Azoh-003

Composite wireline log data from the three wells were interpreted. The basic analysis procedure used involved the following steps; each of which is described in the following headings: (1) well log correlations (2) determination of lithology and volume mineralogy (3) petrophysical analysis and (4) core and mud log data analysis (5) hydrocarbon volumetric calculation.

3.2 Methods

3.2.1 Well Log Correlation

Lithological correlation between the wells was established using the marker shale identified in wells based on its high gamma ray and low resistivity signatures. This aided the delineation of appropriate sand markers chosen in order to define the various reservoirs and sands of interest. The hydrocarbon bearing sands were also noted and utilized for the evaluation of reserve potentials of the field. The reservoir sand units were delineated in True Vertical Depth Sub-Sea (TVDSS), while the marker shales were correlated using the log motifs. Well correlation helped in determining the direction of thickness of sand being mapped and the lateral continuity of these reservoirs (PETROCONSULTANTS, 1996).

3.2.2 Determination of Lithology and Volume of Mineralogy

Gamma ray log was used to delineate the lithologies at the pre-determined depth intervals. The scale of the gamma ray log was set to the standard of the American Petroleum Institute (API) with values ranging from 0 (sandstone line) to 150 (shale line). As the signature of the log moves towards the higher values, the formation becomes shalier. The delineation approach enabled us to estimate and establish the lithological sequence of the formations penetrated by the wells in the study area.

The sand-shale ratio was determined using the gamma ray log which delineated the signatures into sections with two lithofacies, namely, sandstones and shales. The gamma ray log reflects the shale content of sedimentary formations. Clean sandstones and carbonates normally exhibit a low level of natural radioactivity, while clay minerals in shales show higher levels of radioactivity due to adsorption of the heavy radioactive elements (Schlumberger, 1989).

Decreasing gamma ray log values indicated clean sandstones, with log signatures increasing towards the sand-line (i.e. low API units ranging between 0 and 20). For sandy-shales it ranges from 20 to 100 API units, while shales have API values of 100 and above with log signatures moving towards the shale line.

The percentages of sandstones and shales were also estimated from the gamma ray logs

The API values indicated sand and shale domains. As the values increases, the formation lithology becomes shalier. This delineation approach enabled us to estimate the ratio of sand to shale and established the subsurface lithological sequence in the study area.

3.2.3. Zoning and Point Selection

Zoning is of vital importance in the interpretation of well logs. The logs were split into potential reservoir zones and non reservoir zones. Hydrocarbon bearing intervals were identified and differentiated based largely on the readings from the shallow and deep reading

resistivity tools. However, hydrocarbon typing (oil and gas differentiation) was based on density-neutron logs overlay (Poupon, & Leveaux, 1971).

3.2.4 Petrophysical Analysis

Petrophysical evaluation techniques were used to construct logs of volume of shale (V_{sh}), water saturation (S_w), porosity and permeability. This procedure comprised the following steps:

1. Generation of V_{sh} from gamma ray logs using linear shale index.
2. Porosity estimation from density logs.
3. Computation of net-to-gross from V_{sh} logs.
4. Water saturation (S_w) and fluid corrected effective porosity using dual water model.
5. Permeability derivation from logs using the equation of Coates and Dumanoir (1974).

These petrophysical properties were determined from well logs in order to understand the distributions of these parameters across the field. This was preceded by thorough quality-check and control of the well data used in this study, and then applying corrections where necessary. The shale, clean sand, and sand-clay trends were then determined and used in the petrophysical analysis to estimate clay volume, porosity, net-to-gross and water saturation parameters for the selected reservoir sands of interest. The obtained values were populated throughout the study area by modeling.

3.2.4.1 Determination of Shale Volume

The volume of shale, which is the percentage of shale contained in a sandstone or heterolithic reservoir, was calculated using the Larionov (1969) equation for Tertiary rocks

$$V_{sh} = 0.083 * (2^{3.7 * I_{GR}} - 1) \dots\dots\dots 3.1$$

where I_{GR} is the gamma ray index and is given by:

$$I_{GR} = \frac{(GR_{log} - GR_{min})}{(GR_{max} - GR_{min})} \dots\dots\dots 3.2$$

GR_{log} is the gamma ray reading of the formation, GR_{min} is the minimum gamma ray reading (sand baseline) and GR_{max} is the maximum gamma ray reading (shale baseline).

3.2.4.2 Determination of Total Porosity and Effective Porosity

Total and effective porosity was estimated from the density, neutron, and sonic logs. It is generally accepted among geoscientists that porosity calculation from bulk density logs is more accurate (Rider, 2006; Calderon, & Castagna., 2007; Issler, 1992; Horsfall, Uko & Tamunobereton., 2013). To calculate the porosity (\emptyset), we used the rock matrix density, ρ_{ma} , the fluid density, ρ_f , and the bulk density, ρ_b . The average rock density in the sandstones research reports is 2.66gcm^{-3} . The average rock density in the shales is 2.65gcm^{-3} . The fluid density depends on whether the well encountered water or hydrocarbons. This was determined by the electrical resistivity log. The hydrocarbon density was calculated from composition and phase considerations, oil = 0.80 gcm^{-3} and gas = 0.6 gcm^{-3} . The water density used was 1 gcm^{-3} . Porosity was determined from the formula (Wyllie et al., 1956):

$$\emptyset_{density} = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} \dots\dots\dots 3.3$$

where ρ_{ma} = matrix (or grain) density, ρ_f = fluid density and ρ_b = bulk density (as measured by the tool and hence includes porosity and grain density).

Effective porosity was calculated using the equation given below:

$$\emptyset_e = (1 - V_{sh}) * \text{Por}_{den} \dots\dots\dots 3.4$$

3.2.4.3 Water Saturation Estimation

In order to calculate the saturation of the fluid content of the reservoir sands, the formation water saturation was first computed by using the Archie's equation (Archie, 1950) for water saturation given as:

$$S_w = (FR_w/R_t)^{1/n} \dots\dots\dots 3.5$$

where n is the saturation exponent (usually 2), R_w is the formation water resistivity and R_t is the true rock resistivity (i.e. resistivity of the uninvaded zone), and F is the formation factor. The formation factor was determined using the Humble's formula (Archie, 1953) for unconsolidated sands, given as:

$$F = 0.62/(\phi^{2.15}) \dots\dots\dots 3.6$$

where 0.62 is a constant value for the tortuosity factor and was used in this algorithm for unconsolidated Tertiary rocks of the Niger delta.

3.2.4.5 Net Pay Estimation

Calculate net pay using field-specific net pay cutoffs. Cutoff criteria used are water saturation < 50%, porosity > 10%, and volume of shale < 40%.

Net-to-Gross (NTG), which is the ratio of the thickness of the clean, porous and permeable, productive (Net) reservoir sand to the total (Gross) reservoir thickness, (Bora, 2013) was determined using the algorithm:

$$NTG = IF (V_{sh} \leq 0.40, (1 - V_{sh}), 0) \dots\dots\dots 3.7$$

It is usually not constant across a reservoir and may change over a short lateral distance from 1.0 (clean reservoir) to 0.0 (non-reservoir). Net pay is the portion of the net reservoir containing petroleum and from which petroleum will flow.

Reservoirs with low or unpredictable NTG ratios often require large number of wells to optimize recovery.

3.2.5 Determination of Permeability

Estimates of permeability can be made from empirical equations. Permeability is controlled by such factors as pore size and pore-throat geometry, as well as porosity. Permeability values for the reservoir zones were determined by first of all estimating the Formation factor (F) for shaly sands using the equation of Berg (1986) which is given as:

$$F = \frac{1.65}{\phi^{1.33}} \dots\dots\dots 3.8$$

Then, the formation factor (F) was related to irreducible water saturation using the equation:

$$S_{wi}^2 = \frac{F}{2000} \dots\dots\dots 3.9$$

The widely used Coates and Denoo (1981) equation which relates permeability to irreducible water saturation and porosity was then applied only in hydrocarbon-bearing zones. The equation is given below:

$$K = 100 \times \frac{\phi^2 \times (1 - S_{wi})}{S_{wi}} \dots\dots\dots 3.10$$

where K = permeability in millidarcies, ϕ = effective porosity as a bulk volume fraction and S_{wi} = irreducible water saturation.

3.2.6 Core and Mud Log Data Analysis

Core analysis form an integral part of formation evaluation and provide vital information unavailable from either log measurements or productivity tests. The analyzed core information includes detailed lithology, microscopic and macroscopic definition of the heterogeneity of the reservoir rock, capillary pressure data defining fluid distribution in the reservoir rock system, and the multiphase fluid flow properties of the reservoir rock, including directional flow properties of the system. Also, selected core data were used to calibrate log responses, such as acoustic, or neutron logs used to determine porosity. The core data formed an indispensable source in the collection of basic reservoir properties directed toward the ultimate evaluation of recoverable hydrocarbons in the reservoir.

The goal of core analysis is to reduce uncertainty in reservoir evaluation by providing data representative of the reservoir at in-situ conditions.

Core description (on the core photos) was done based on the lithofacies definition and identification. Lithofacies could be defined as the body of sediment or rock with specific lithological and organic characteristics (e.g. grain size, sorting, sedimentary structures) which

were impacted by a particular set of energy conditions within an environment of deposition (Boggs, 2006). Lithofacies constitute the smallest building blocks used in reservoir geology. The uniform physical characteristics of a particular lithofacies type (e.g. wavy-laminated, fine grained, well sorted sand) mean that they possess uniform reservoir properties. Although lithofacies can always be distinguished in cores, they cannot always be distinguished on logs because the resolution of logs does not allow subtle differences between some lithofacies types, or thin lithofacies intervals to be detected (Fidelis & Thomas, 2014).

Mud logging, in its conventional implementation, involves the rig-site monitoring and assessment of information that comes to the surface while drilling, with the exclusion of data from downhole sensors.

The mud log data analysis was done to identify potentially productive hydrocarbon-bearing formations, identify marker or correlatable geological formations and possibly to provide the driller with data that enables safe and economically optimized operations. The actions performed to accomplish these objectives include the following:

- i. Collecting drill cuttings.
- ii. Describing the cuttings (type of minerals present).
- iii. Interpreting the described cuttings (lithology).
- iv. Estimating properties such as porosity and permeability of the drilled formation.
- v. Estimating the pore pressure of the drilled formation.
- vi. Collecting, monitoring, and evaluating hydrocarbons released from the drilled formations.
- vii. Assessing the producibility of hydrocarbon-bearing formations.
- viii. Maintaining a record of drilling parameters.

The above operations are carried out by mud log service companies who focus on monitoring the drilling mud returns qualitatively for oil and gas content. This include watching the mud returns for oil sheen, monitoring the gas evolving from the mud as it depressures at the surface and examining the drill cuttings to determine the rock type that had been drilled, as well as looking for indication of oil on the cuttings.

3.2.7 Hydrocarbon Volumetric Calculation

Deterministic estimation of the volume of hydrocarbon in place involves the application of one or more simple equations that describes the volume of hydrocarbon filled pore space in the reservoir and the way that volume will change from the reservoir to the surface. The weighted mean hydrocarbon saturation of the net pay section and estimation of the ydrocarbon in place was considered. This quantity is the Oil in Place, abbreviated to OIIP which is given as:

$$OIIP = GRV * N/G * \phi * (1 - S_w) \dots\dots\dots 3.11 \text{ (Dean , 2008)}$$

Where GRV is the Gross Rock Volume, N/G is the net to gross (interval ratio). ϕ and S_{wi} are the corrected porosity and interstitial water saturation respectively. OIIP was converted into recoverable reserve in terms of stock tank oil initially in place (STOIIP) by applying three additional factors.

$$STOIIP = (7758 * GRV * N/G * (1 - S_{wi})) / FVF \dots\dots\dots 3.12$$

where FVF is the formation volume factor estimated from the production data. Recoverable reserve (N) is given as:

$$N = STOIIP * RF \dots\dots\dots 3.13$$

where RF is the Recovery factor which depends on drive mechanism, permeability, reservoir depth and hydrocarbon viscosity. RF was estimated using the equation below:

$$RF = \frac{100(1 - S_{wi} - S_{or})}{1 - S_{wi}} \dots\dots\dots 3.14$$

here S_{or} is the oil saturation.

Incorrect porosity value and water resistivity (R_w) can introduce significant error in reserve estimation. In order to quell the probability of an error in R_w , a resistivity-porosity crossplot of the sand section representing the pay zone was made. Choosing $F=0.62/\phi^m$ chart, since the lithology is sandstone, a scale that adequately covers interval time (Δt) ranges from sonic log was chosen. This crossplot presents a more accurate value of the water resistivity (R_w). Besides this, the resistivity-porosity cross plot was used to estimate the water cut which showed clearly if the reservoir would be producible or not by taking a quick glance at the cluster of points whether it is below or above the 60% water saturation line. The next step involved constructing a neutron-density cross-plot to determine the corrected porosity and shale volume in percent. This was done using a linear graph.

3.2.8. Use of Crossplots

Crossplots of the estimated reservoir properties were generated to understand the inter-dependence of the reservoir parameters. These included cross plotting porosity against permeability to understand their relationship, water saturation and effective permeability cross plots and porosity and density crossplots to understand the lithotypes in the studied wells.

CHAPTER FOUR

RESULTS AND DISCUSSION

4.1 Interpretation of Well Logs

Correct interpretation of well logs is critical to any reservoir evaluation and characterization. Log correlation provides the basis for the determination of reservoir geometry and architecture (Davies, 2002). The identified and correlated shale markers are presented in Fig. 4.1. Appropriate sand markers were also chosen to delineate the various reservoirs and sands of interest across the wells using the gamma ray logs and resistivity markers. The wells in “Azoh” field were arranged and interpreted according to spatial distributions in the well field which arranged the wells according to affinity and not with respect to well numbers. A type log (Azoh-001) was chosen for loop-tying the wells. This correlation type log shows a complete (unfaulted) interval of sediments representative of the thickest and stratigraphically deepest sedimentary section penetrated by the wells within the field. Lithological correlation in the study area revealed three reservoir sand intervals, namely D2000 sand, E3100 sand and F1000 sand (Fig. 4.2). It is possible that these reservoir units could be potential hydrocarbon prospects owing to their high effective porosity and permeability characteristics.

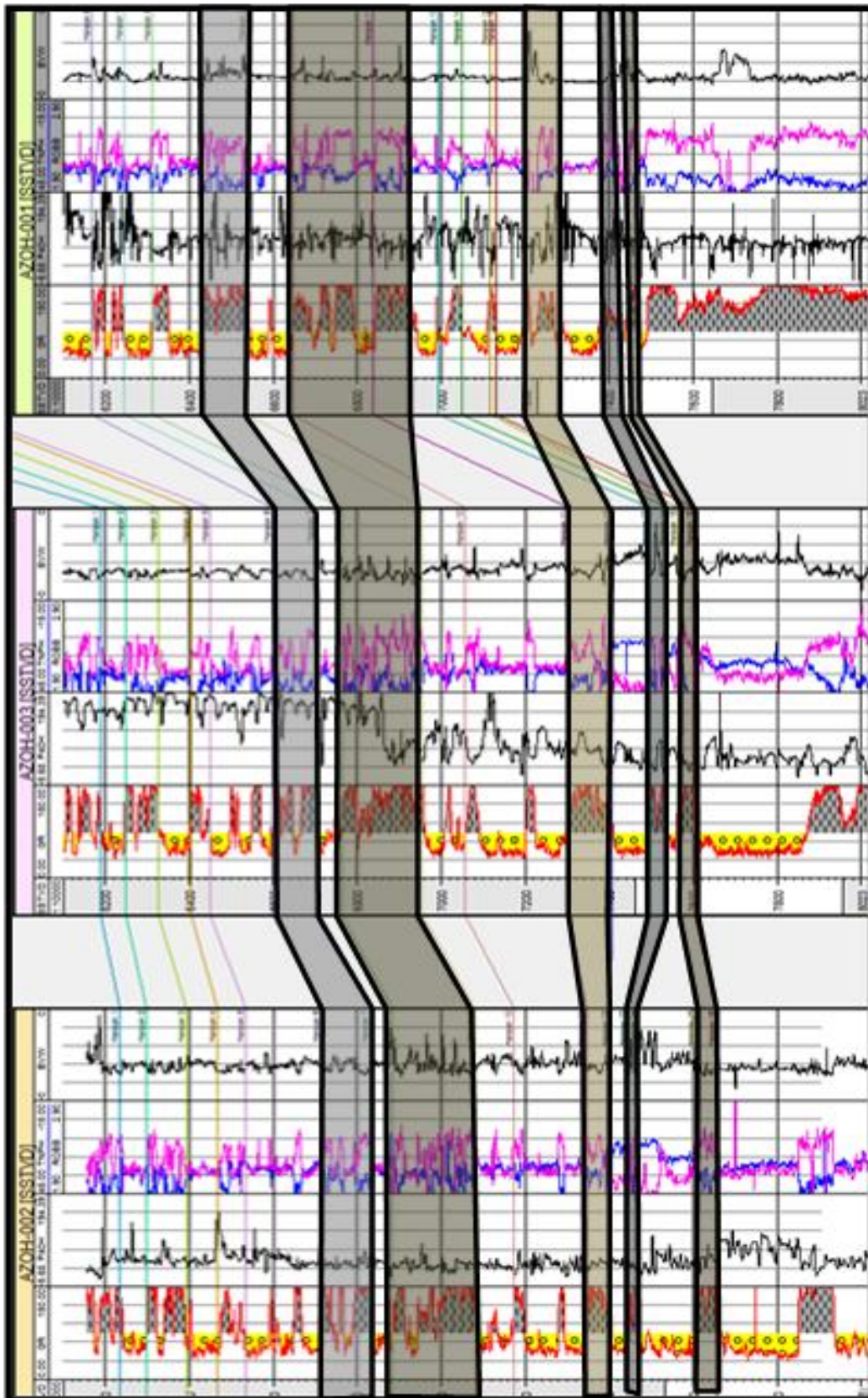


Fig 4.1 Correlated shale markers across the well field

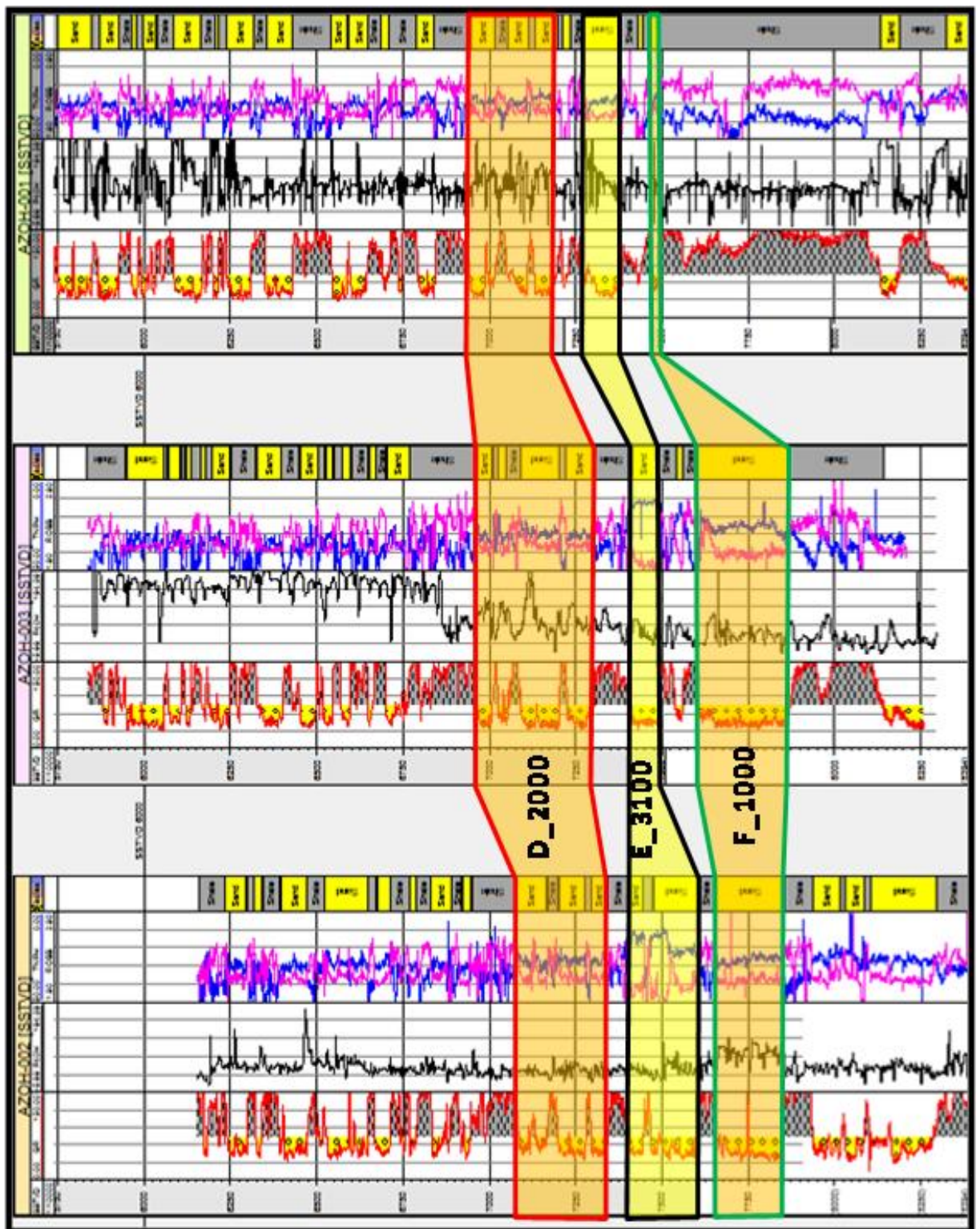


Fig 4.2. Delineated reservoir units in the study area

4.2 Interpretation of Lithology and Mineralogical Composition

Identification and interpretation of lithology and the mineralogical composition involved the integration of well log data such as the GR-log, resistivity log, neutron and density logs, including the mud logs and core data. Fig. 4.3 is a presentation of the lithologies penetrated by the wells in the study area. The identified lithological units are sands and shales, composed mostly of quartz grains (for the sands) and clay minerals (for the shales).

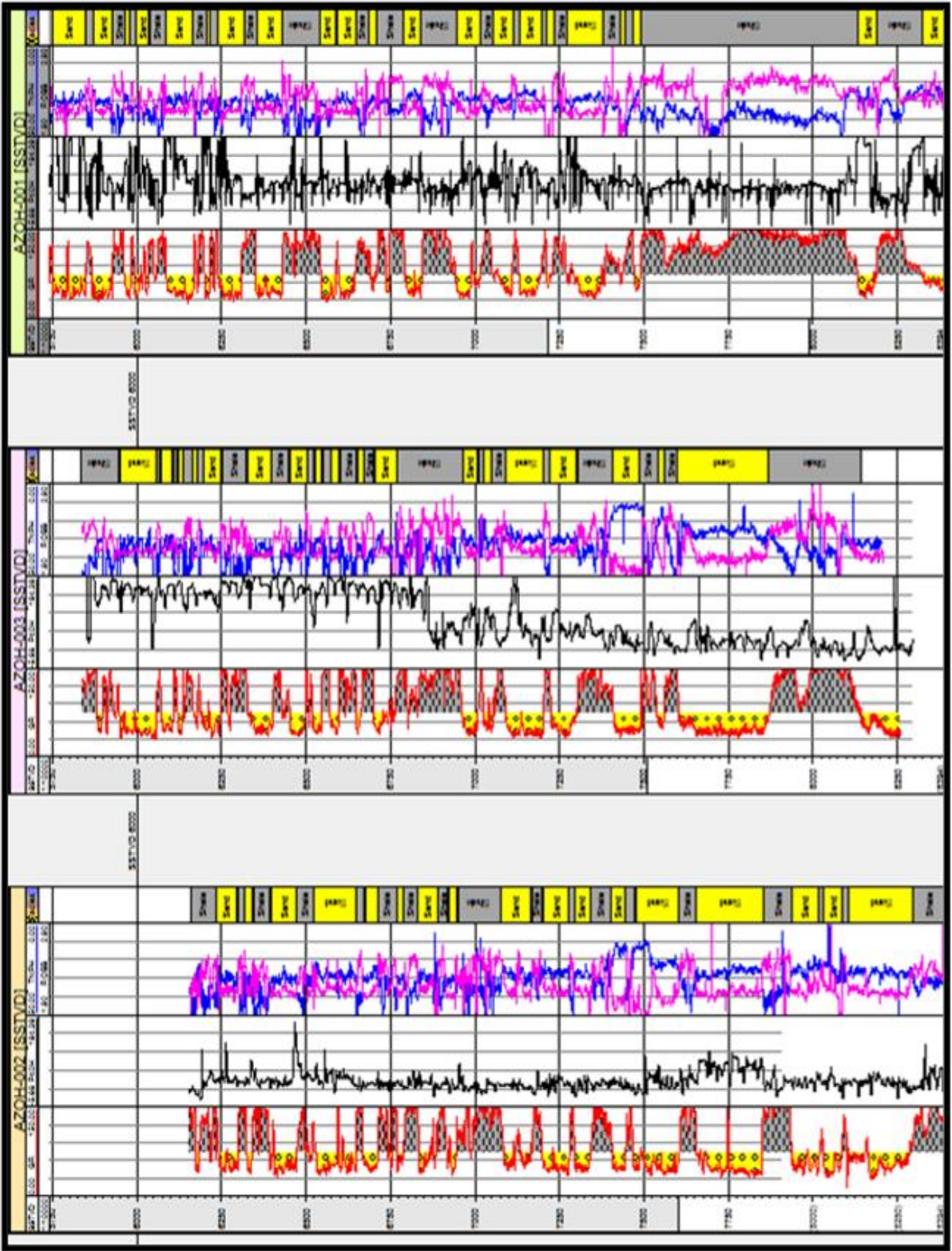


Fig 4.3 Lithological units penetrated by the wells

Description of the lithologies interpreted from mud log data from the three wells are presented in Fig. 4.4, Fig. 4.5 and Fig. 4.6. These are mostly sands, shales and lignite streaks encountered at several stratigraphic levels within the subsurface in the study area. Table 4.1 is a summary of the sidewall core description for Azoh-001, while the core photos presented in Fig. 4.7 to Fig. 4.9 further supports our argument for the observed lithologies in the study area.

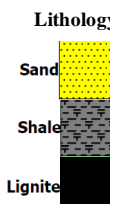
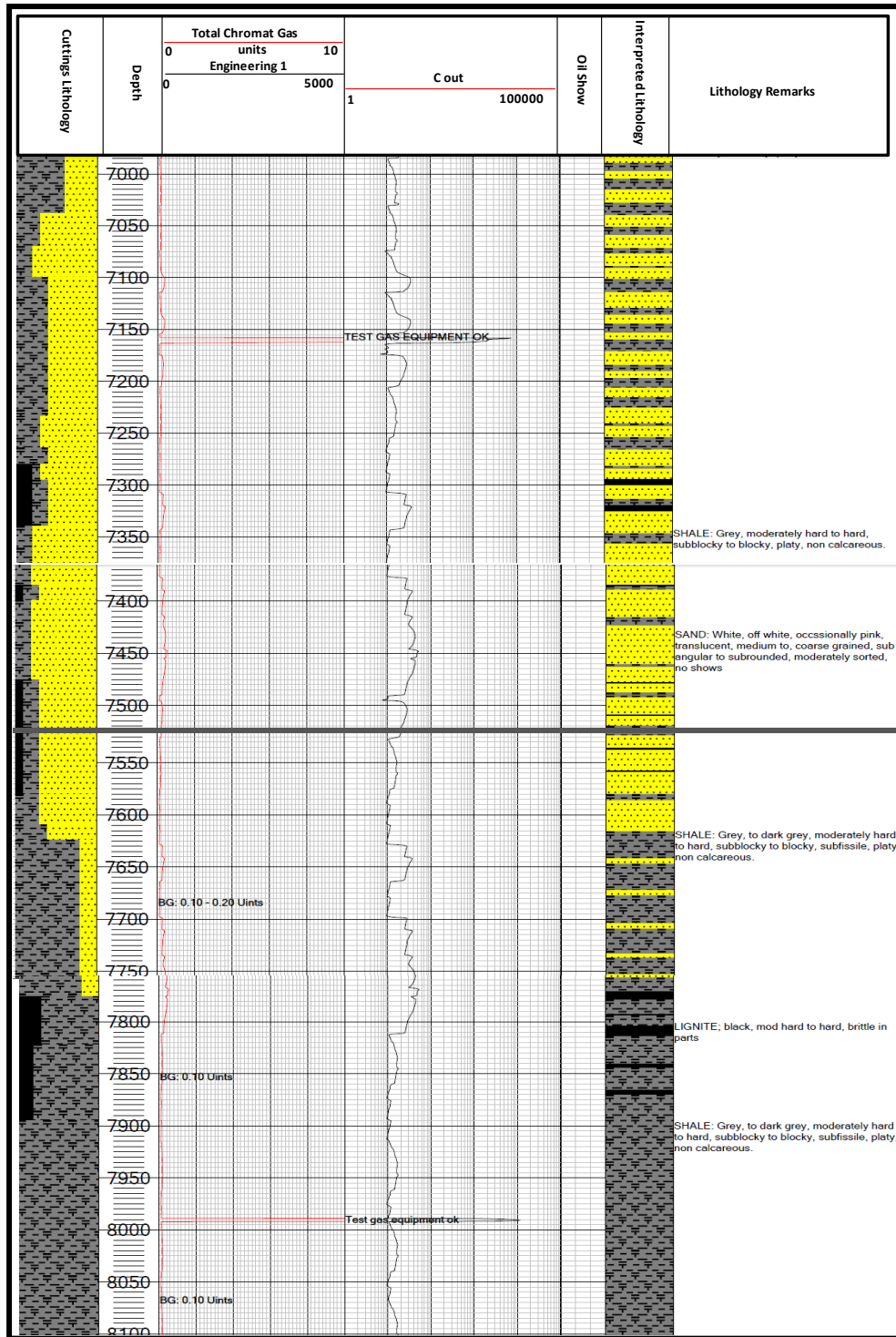


Fig.4.4. Lithology interpretation of Azoh-001 mud log

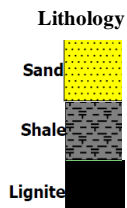
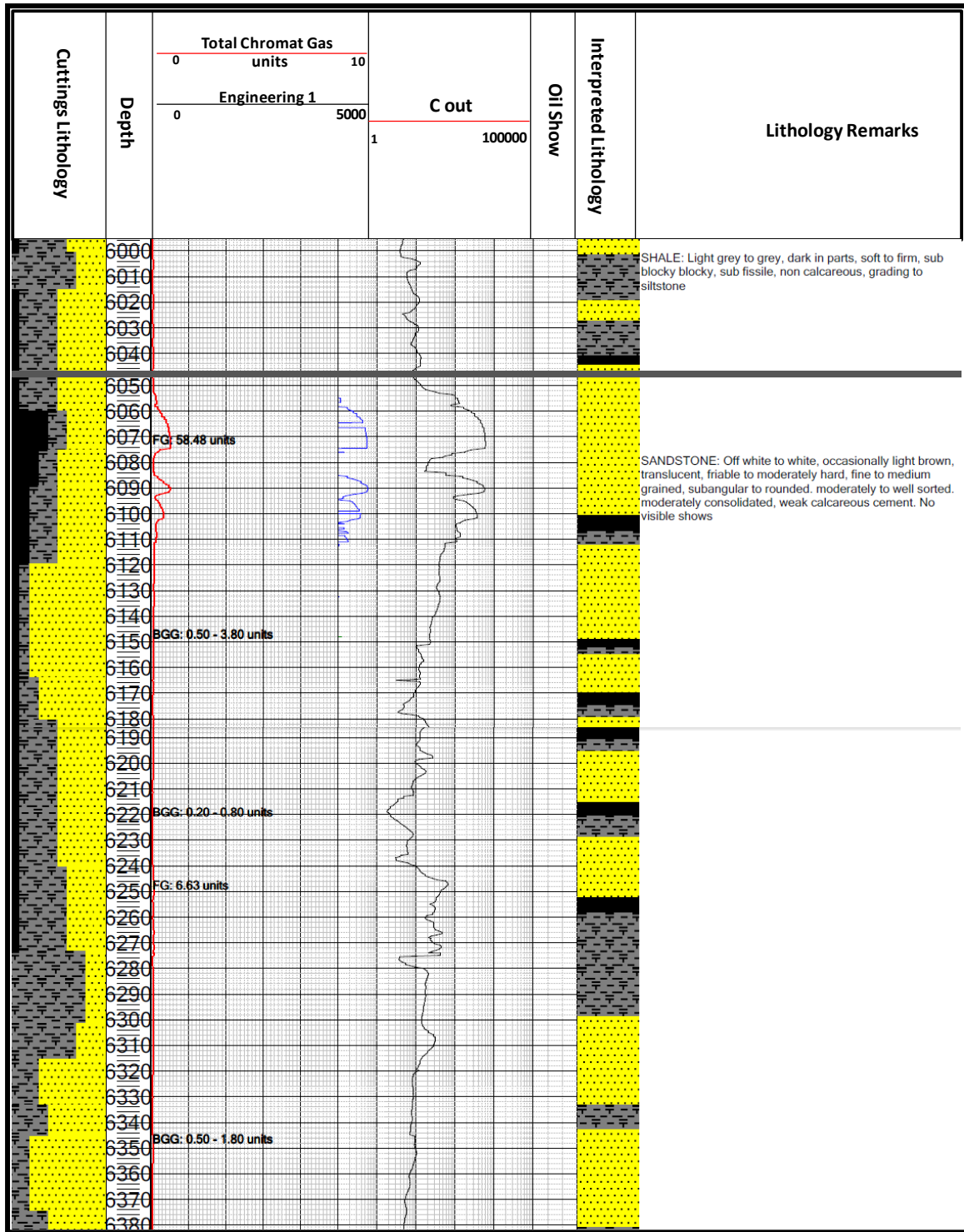


Fig.4.5. Lithology Interpretation of Azoh-002 mud log

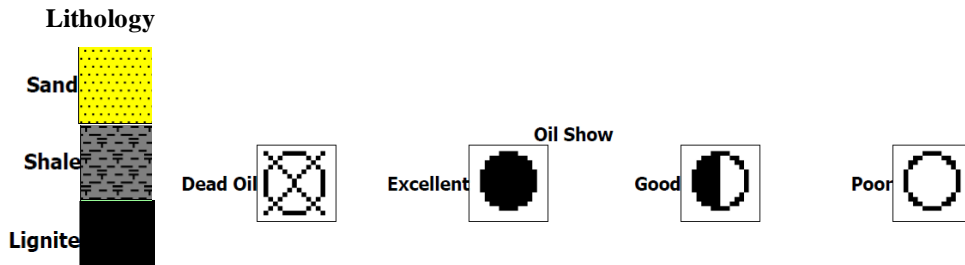
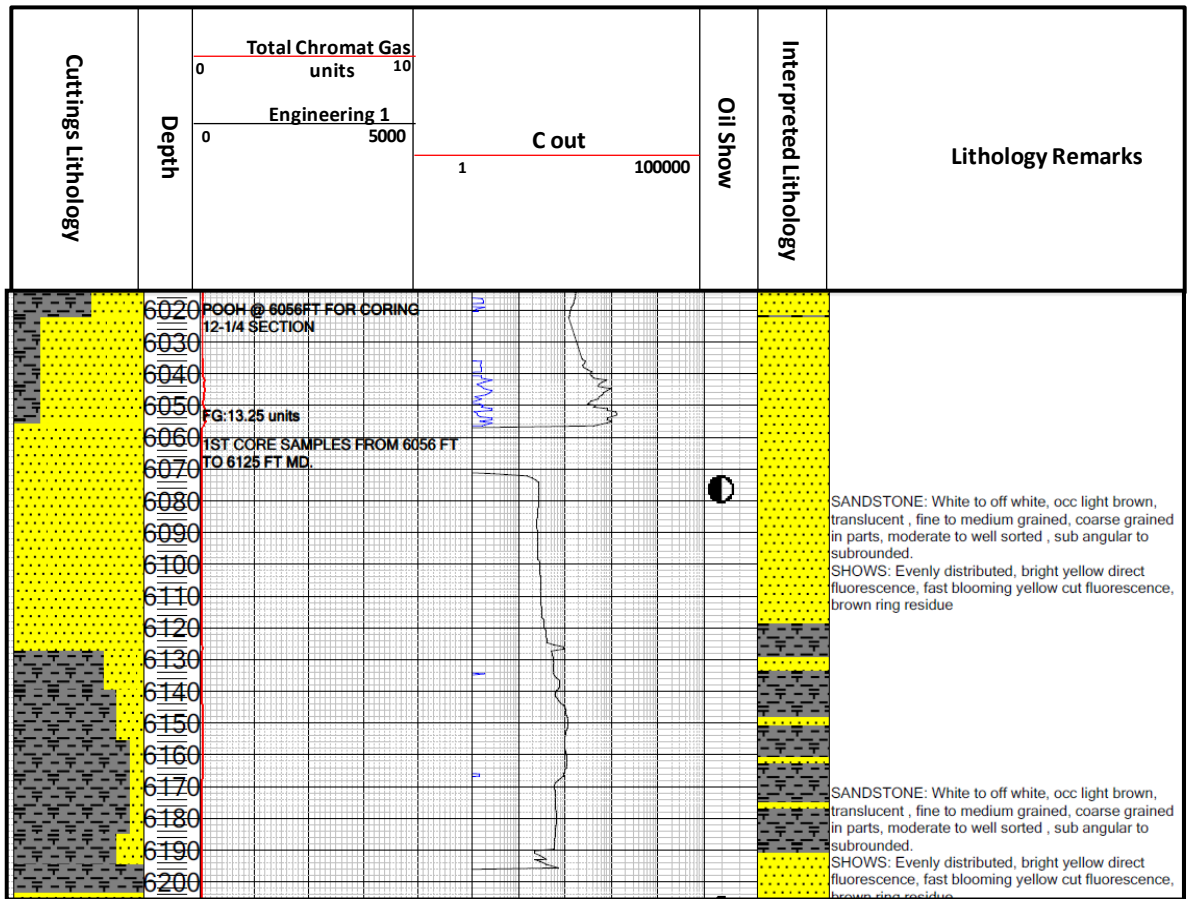


Fig. 4.6. Lithology Interpretation of Azoh-003 mud log

Table 4.1. Sidewall core description for Azoh-001 well

#	DEPTH mRKB	REC cm	ROCK TYPE	LITHOLOGY DESCRIPTION and COMMENTS (clr, hdness, texture, mineralogy, modifiers, cmt)	POR	STAIN		FLUORESCENCE			CUT		CUT FLUOR		RES COLOR	SHOW QUAL
						DIST	COLOR	DIST	INTEN	COLOR	RATE	COLOR	INTEN	COLOR		
	8361.41 (#1)		SAND: 100	Clear white, off white, very fine to fine grained, occasionally coarse grained, subangular to subrounded, moderately sorted. No visible shows.												
	8291.86 (#2)		SAND: 80 SHALE: 20	Clear white, off white, very fine to fine grained, occasionally coarse grained, subangular to subrounded, moderately sorted. No visible shows. Dark grey, mod hard to hard, blocky, silty in parts, non calcareous.												
	8176.05 (#3)		SAND: 100	Grey, opaque, translucent, medium to coarse grained, subangular to subrounded, moderately sorted. No visible shows.												
	7954.70 (#5)		SAND: 100	Grey, opaque, translucent, medium to coarse grained, subangular to subrounded, moderately sorted. No visible shows.												
	7859.58 (#6)		SHALE: 100	Dark grey to grey, moderately hard to hard, platy in parts, subfissile, non calcareous.												
	7741.20 (#7)		SHALE: 100	Dark grey to grey, moderately hard, subblocky, sandy, grading to very fine sandstone.												
	7650 (#8)		SAND: 100	Off white, opaque, translucent, occasionally clear, medium to fine grained, subangular to subrounded, moderately sorted. No visible direct fluorescence, slow streaming, pale yellow cut, no residue observed.												
	7565.89 (#9)		SAND: 100	Grey, opaque, translucent, coarse grained, subangular to subrounded, poorly sorted. No visible shows.												
	7527.20 (#10)		SHALE: 100	Dark grey to grey, firm to moderately hard, subblocky, sandy slightly calcareous.												
	7433 (#11)		SAND: 80 LIGNITE: 20	Grey, opaque, translucent, coarse grained, subangular to subrounded, poorly sorted. No visible shows. Black, moderately hard, brittle.												
	7300.51 (#12)		SAND: 100	Clear, white, off white, translucent, transparent, coarse grained, occasionally medium grained, subangular to subrounded, poorly sorted. SHOWS: No visible direct fluorescence, very faint cut fluorescence.	High	N/A	N/A	Poor	Low	Nonvis	SlwStrm	Nonvis	VFaint	Nonvis	N/A	Poor
	7234 (#13)		SAND: 100	Clear white, off white, translucent, coarse grained, occasionally medium grained, subangular to subrounded, moderately sorted. SHOW: Spotty bright yellow direct fluorescence, fast, milky white cut fluorescence, with brown ring residue.	High	N/A	N/A	Spotty	High	BrYel	FstStrm	NonVis	Fast	MlkyWh	BrwRing	Good
	7146.45 (#14)		SAND: 100	Off white, opaque, coarse grained, occasionally medium grained, subangular to subrounded, moderately sorted. No visible shows.												
	6975.06 (#16)		SAND: 100	Off white, opaque, coarse grained, occasionally medium grained, subangular to subrounded, moderately sorted. No visible shows.												
	6855.65 (#18)		SHALE: 100	Light grey to grey, firm to moderately hard, subblocky to blocky, non calcareous.												
	6791.96 (#19)		SAND: 100	Off white, translucent, fine to medium grained, subangular to subrounded, well sorted. No shows.												
	6709.27 (#20)		SAND: 100	Off white, translucent, fine to medium grained, subangular to subrounded, well sorted. No shows.												
	6516.85 (#22)		SHALE: 100	Dark grey to grey, firm to moderately hard, subblocky to blocky, non calcareous.												
	6405.06 (#23)		SAND: 70 SHALE: 30	Clear white, off white, translucent, coarse grained, occasionally medium grained, subangular to subrounded, moderately sorted. SHOW: Spotty bright yellow direct fluorescence, fast, milky white cut fluorescence, with brown ring residue. Dark grey to grey, firm to moderately hard, subblocky to blocky, non calcareous.	High	N/A	N/A	Spotty	High	BrYel	FstStrm	NonVis	Fast	MlkyWh	BrwRing	Good
	6220.01 (#26)		SAND: 80 SHALE: 20	Off white, translucent, brown in parts, medium to coarse grained, subangular to subrounded, moderately sorted. SHOW: Spotty pale yellow direct fluorescence, slow streaming milky white cut fluorescence, with brown ring residue. Dark grey to grey, firm to moderately hard, subblocky to blocky, non calcareous.	High	N/A	N/A	Spotty	High	PaleYel	SlwStrm	NonVis	Fast	MlkyWh	BrwRing	Good
	5561.15 (#27)	100	SAND: 100	Off white, translucent, brown in parts, medium to coarse grained, subangular to subrounded, moderately sorted. No visible shows.												

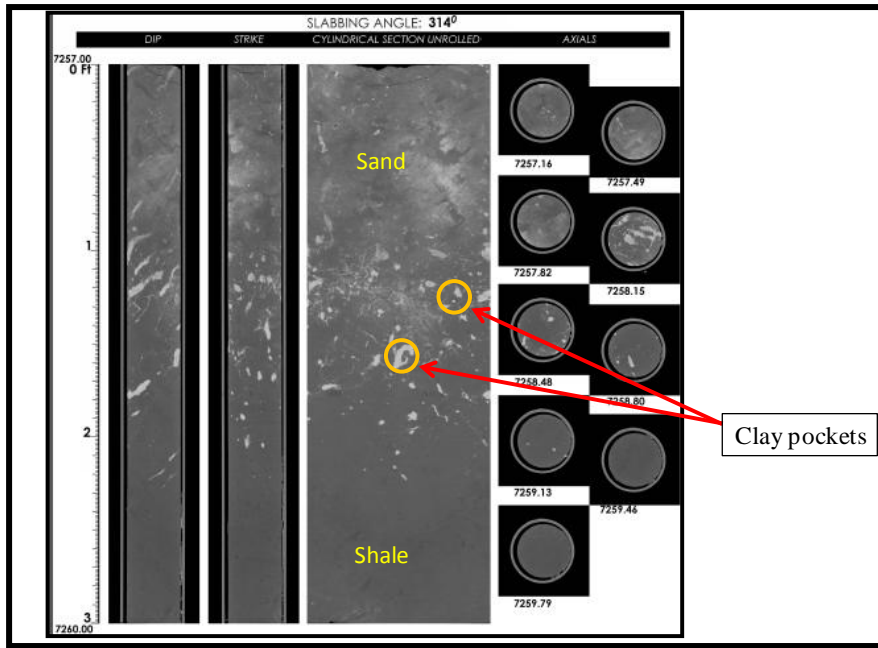


Fig 4.7 Recovered core in Azoh-002 well at depth of 7257-7260ft. the picture shows sand with pockets of clay

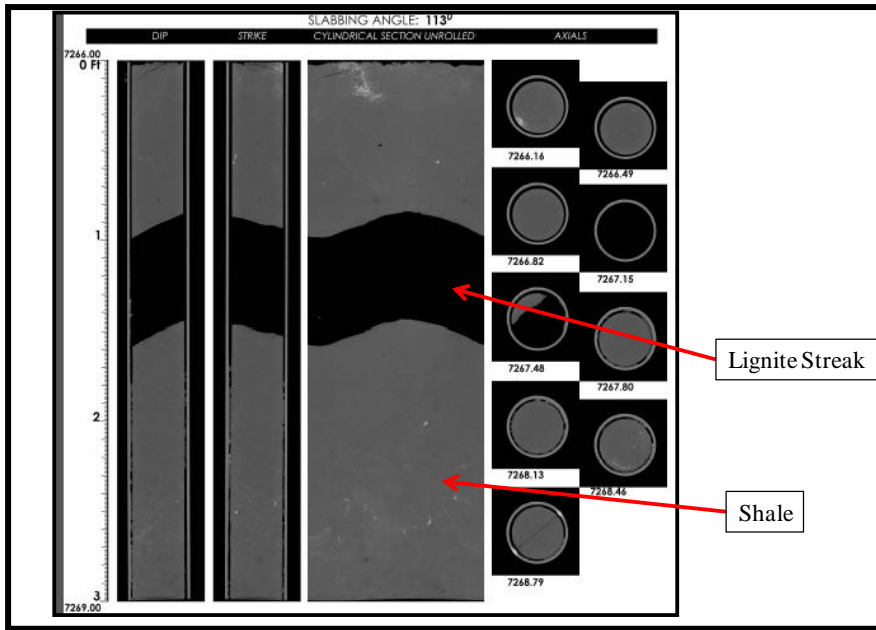


Fig 4.8 Recovered core in Azoh-002 well at depth of 7266-7269ft. the picture shows shale with lignite streak

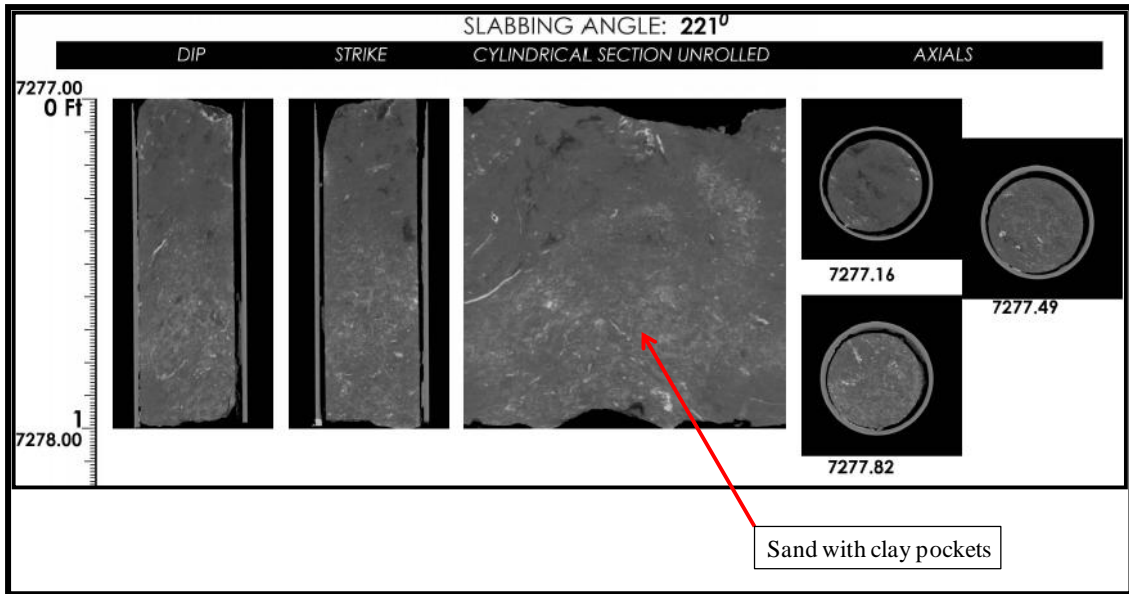


Fig 4.9 Recovered core in Azoh-002 well at depth of 7277-7278ft. the picture shows sand with pockets of clay

4.3 Delineated Reservoir Zones

Permeable reservoir sands were distinguished from the impermeable shales using a combination of log suites including resistivity, density, neutron and caliper logs. The subsurface lithology in the study area was interpreted using the natural gamma ray, which is used for distinguishing between clean sands formations and shaly formations. The more impermeable zones indicated shale intervals with high concentration of clay minerals which decrease the effective porosity and permeability. Permeable zones are likely to be one of the dominant mineralogies (sandstone/limestone/dolomite), but in this study sandstones are the only dominant mineralogy in permeable zones. According to the core (photo) interpretation, approximately most of the formations have clay contents.

A total of nine reservoir sands were identified, zoned in the three wells and designated R1, R2, R3, R4, R5, R6, R7, R8 and R9 respectively (Fig. 4.10). However, owing to the thin nature of a good number of these reservoir sands, they were grouped into three larger reservoir units namely D2000, E3100 and F1000 sands, respectively (Fig. 4.11).

Reservoir Zoning

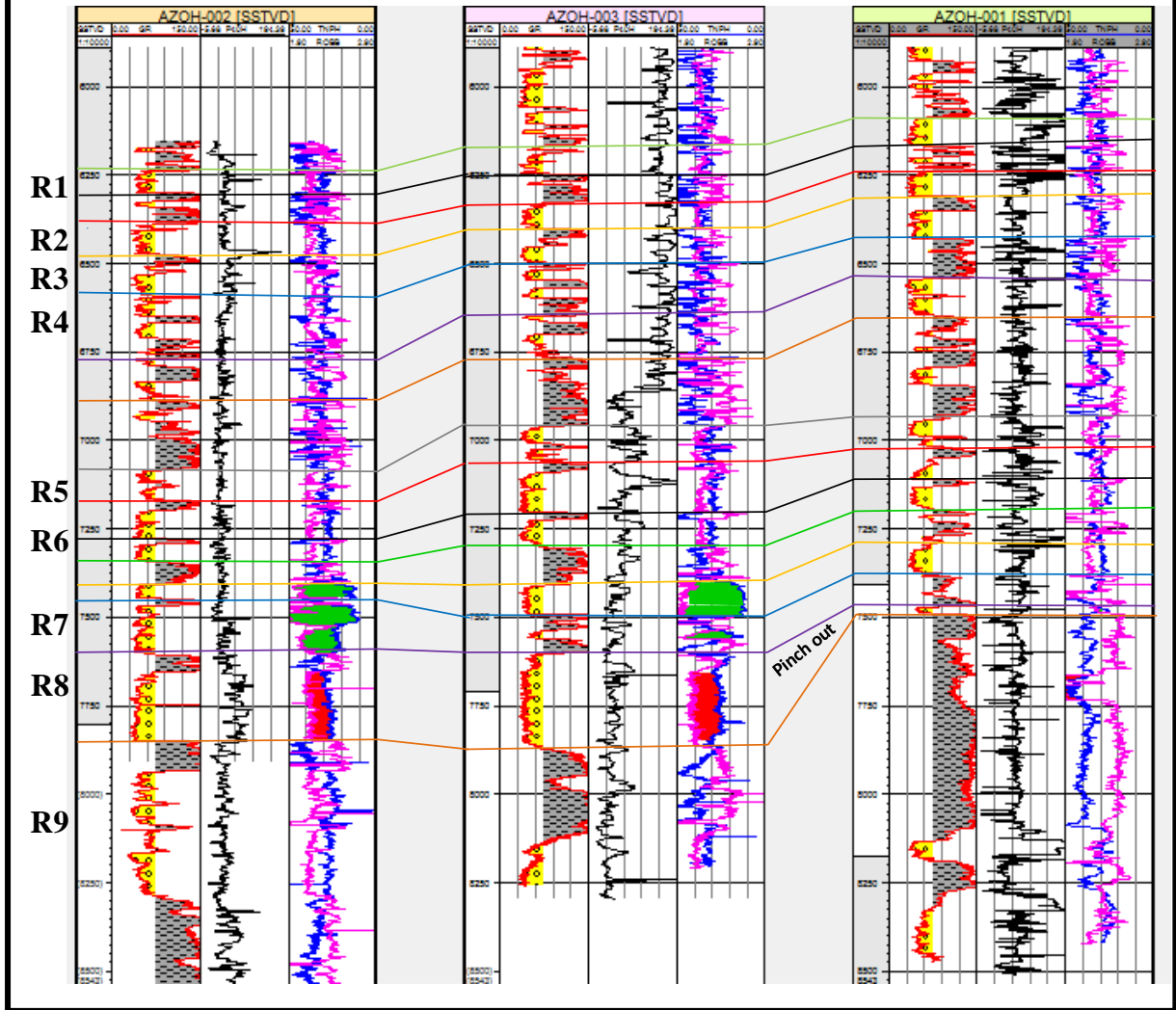


Fig 4.10 Delineated and zoned reservoir sands in the studied wells

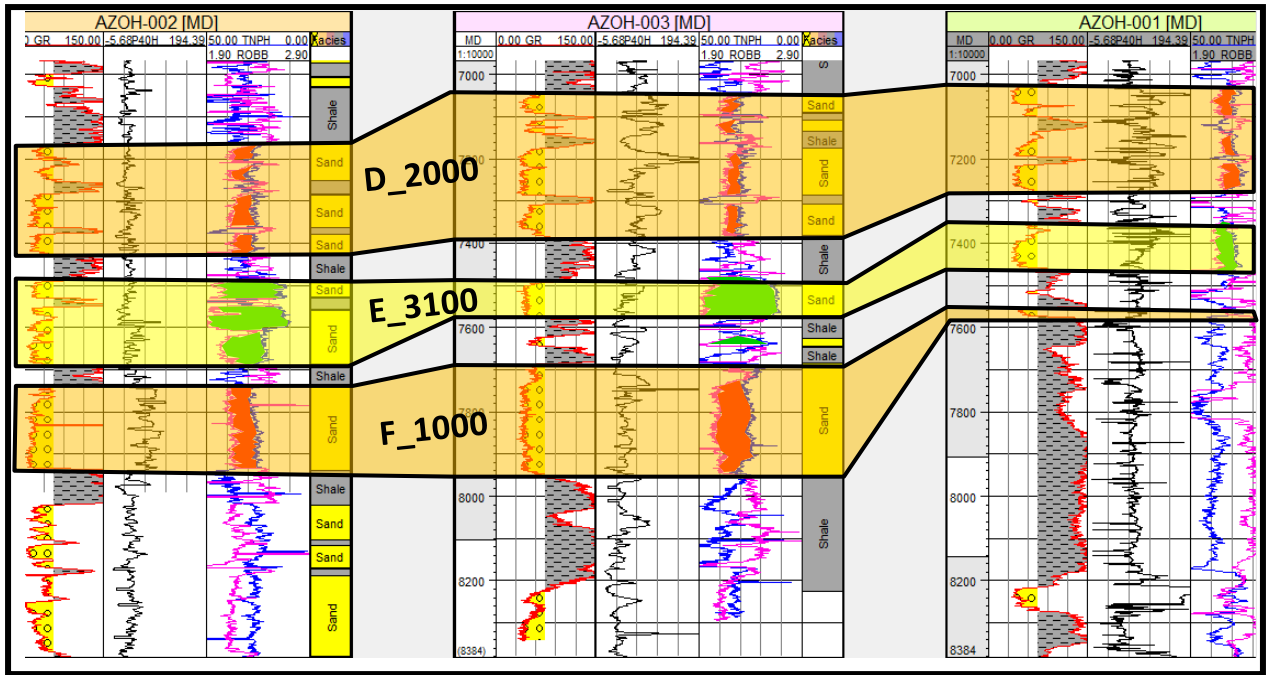


Fig 4.11 The evaluated major reservoir units

Table 4.2 is a summary of the measured depth (in feet) in which these three major reservoirs were encountered in each of the studied wells.

Table 4.2. Summary of the reservoir depth in the well field

Reservoir Sand	Azoh-001(MD) Top-Base (ft)	Azoh-002 (MD) Top-Base (ft)	Azoh-003 (MD) Top-Base (ft)
D_2000	7027-7279	7168-7423	7043-7383
E_3100	7356-7468	7489-7688	7494-7577
F_1000	7553-7571	7736-7935	7685-7959

4.4 Estimated Petrophysical Properties

Logs of the determined petrophysical parameters for each of the three wells are shown in Fig. 4.12 to 4.14. Tables 4.3 to 4.5 are summary of the average petrophysical results for the evaluated reservoir sands.

The petrophysical analysis revealed D_2000 sand to be the most viable reservoir unit with average net thickness as high as 208.33 ft. All the three reservoirs exhibited good petrophysical attributes with high porosity and hydrocarbon saturation.

The reservoirs are clean sands with high net to gross ratios and low volume of shale resulting in high effective porosities and low water saturation.

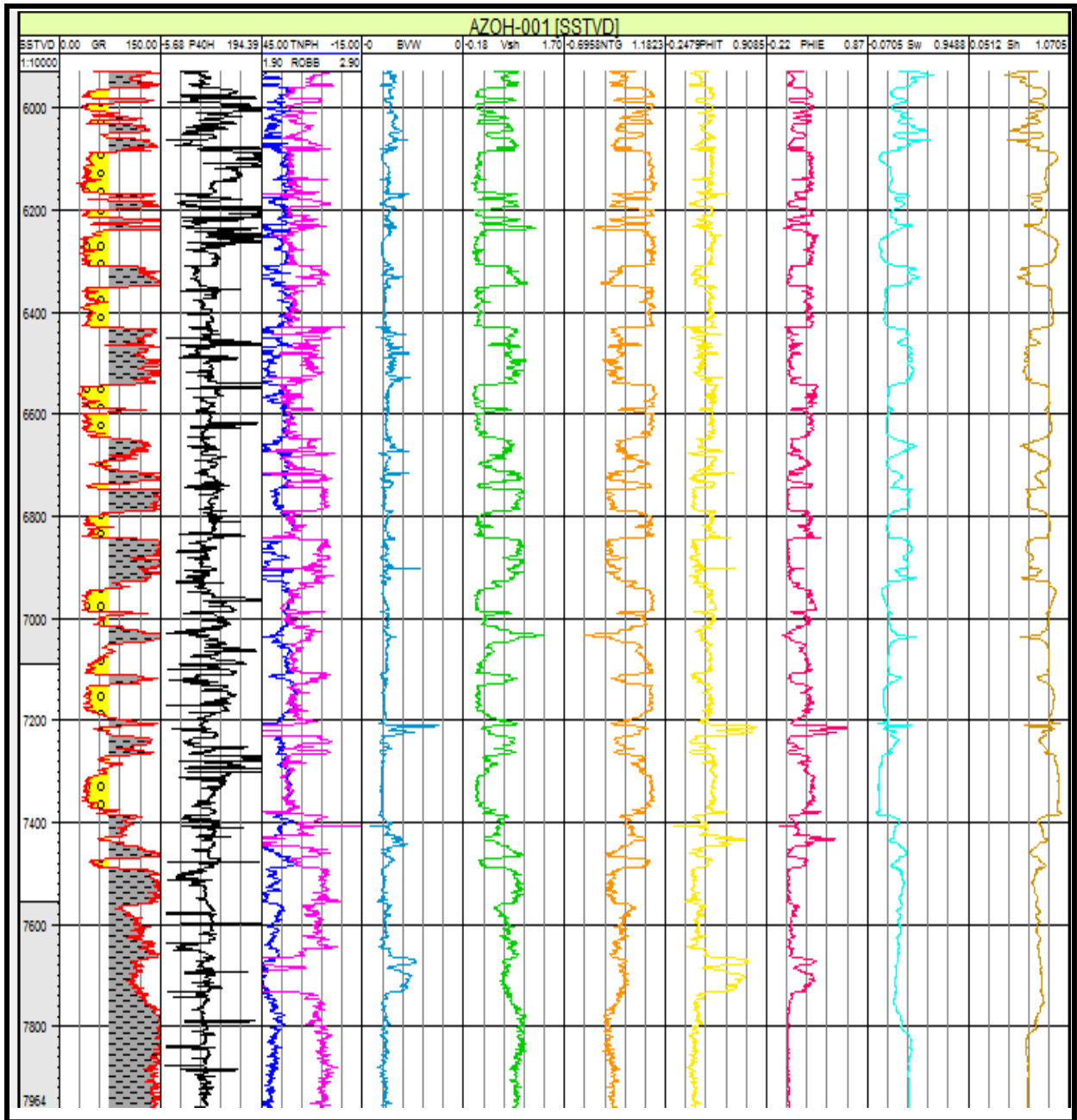


Fig 4.12 Estimated reservoir properties in Azoh-001 well

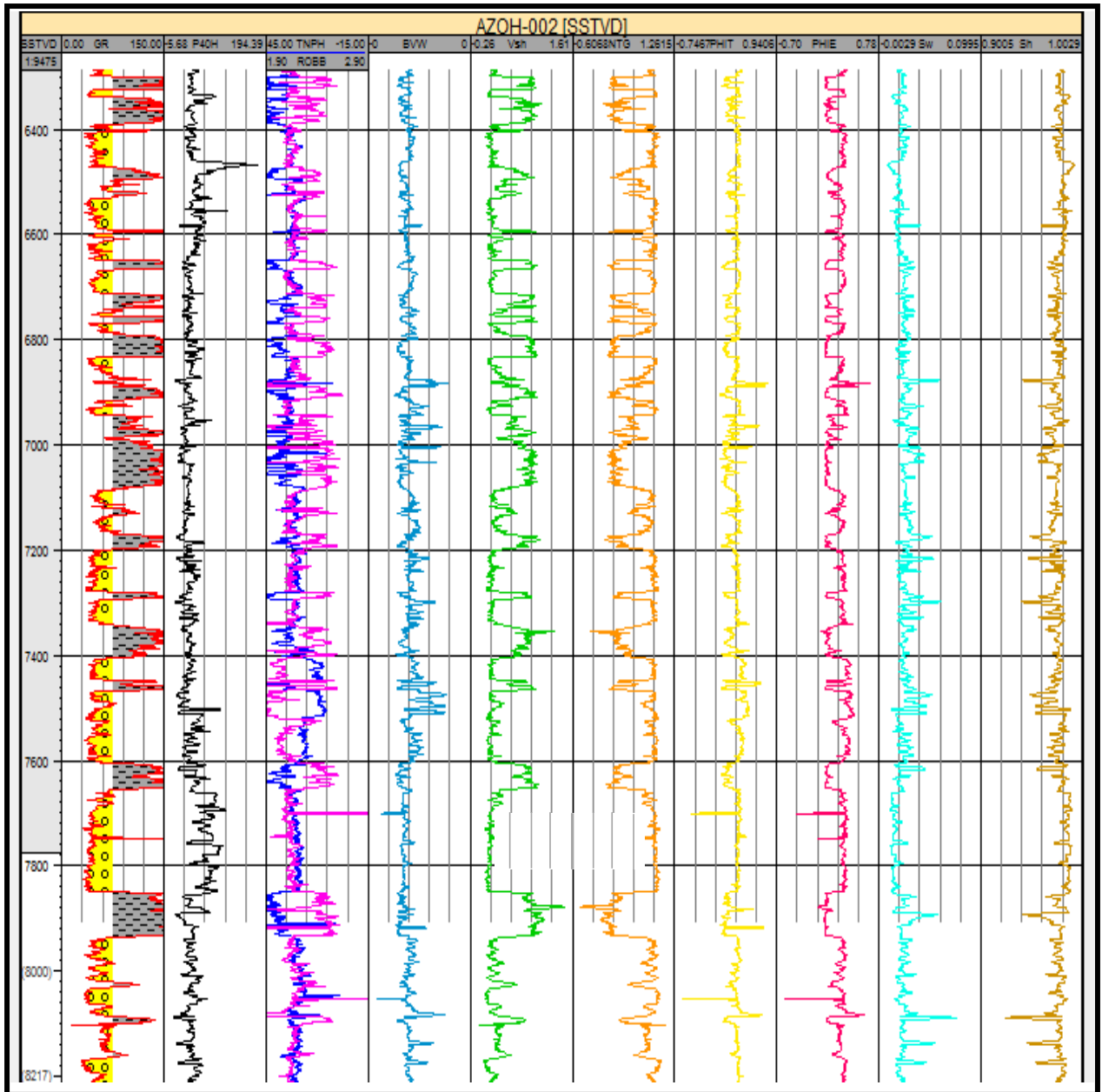


Fig 4.13 Estimated reservoir properties in Azoh-002 well

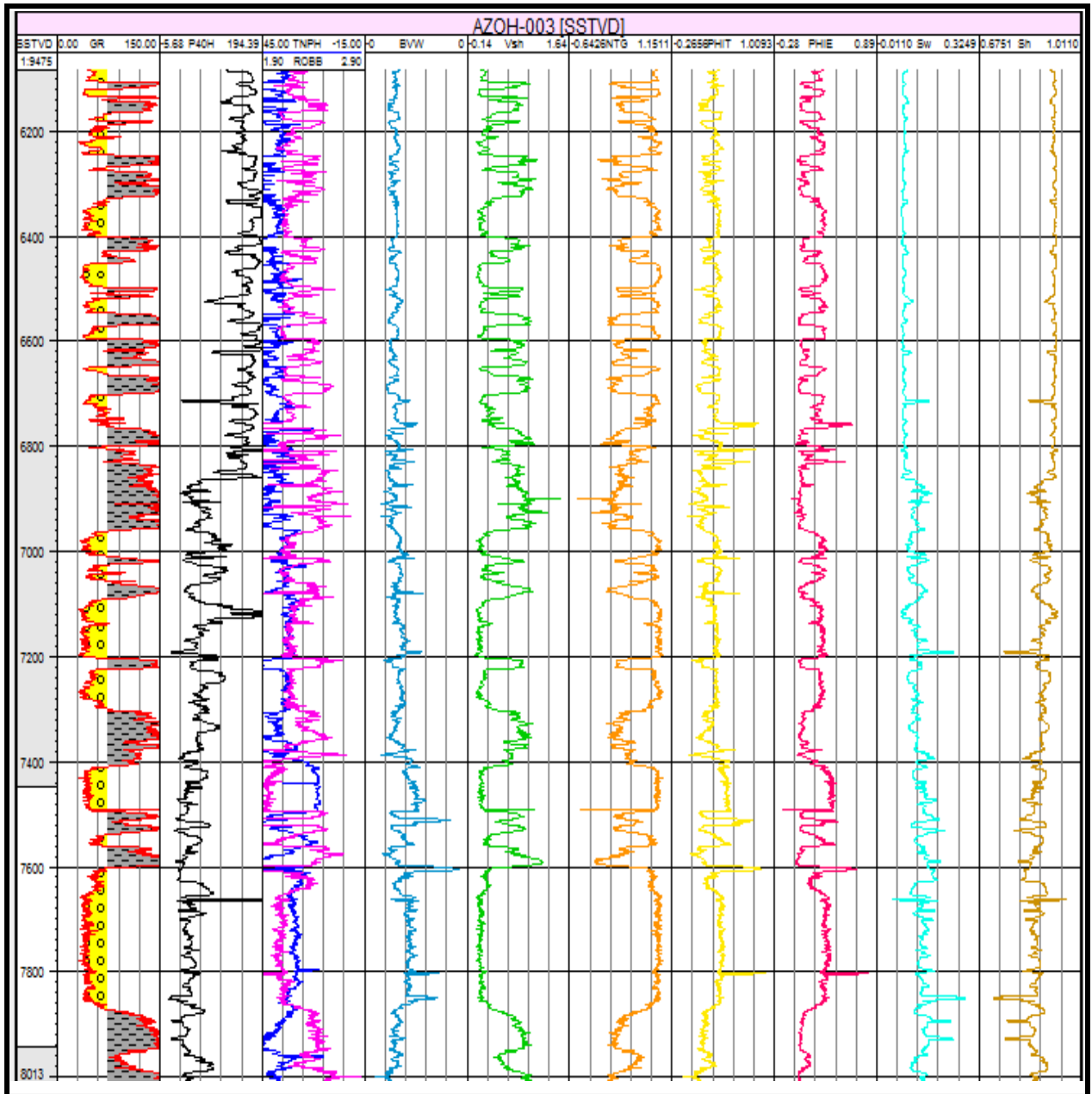


Fig 4.14 Estimated reservoir properties in Azoh-003 well

Table 4.3. summary of average petrophysical results for Azoh-001 well

Reservoir Sands	Gross Thickness (ft)	Net Thickness (ft)	Øe (%)	K (mD)	Sw (%)	Vsh	N/G	Ø (%)
D_2000	252	181	18	13.34	14	0.28	0.72	24
E_3100	111	91	24	24.02	5	0.18	0.82	30
F_1000	18	14	19	10.18	21	0.21	0.79	24

Table 4.4. summary of average petrophysical results for Azoh-002 well

Reservoir Sands	Gross Thickness (ft)	Net Thickness (ft)	Øe (%)	K (mD)	Sw (%)	Vsh	N/G	Ø (%)
D_2000	255	186	21	19.21	3	0.27	0.73	26
E_3100	199	159	29	52.17	2	0.20	0.80	35
F_1000	199	173	26	25.84	1	0.13	0.87	30

Table 4.5. summary of average petrophysical results for Azoh-003 well

Reservoir Sands	Gross Thickness (ft)	Net Thickness (ft)	Øe (%)	K (mD)	Sw (%)	Vsh	N/G	Ø (%)
D_2000	340	258	21	18.28	11	0.24	0.76	26
E_3100	83	72	36	67.22	14	0.12	0.87	41
F_1000	274	238	29	47.50	14	0.13	0.87	33

4.5 Lithologies-typing from Crossplots

Correlation analysis was performed to determine whether the petrophysical properties are interdependent. The most obvious control on permeability is porosity. Almost invariably, a plot of permeability (on a logarithmic scale) against porosity for a formation results in a clear trend with a degree of scatter associated with the influences controlling the permeability. For the best result, these poroperm crossplots should be constructed for clearly defined lithologies or reservoir zones (Glover, 2012). A crossplot of permeability versus effective porosity revealed that the reservoir units are clean sandstones (Fig. 4.15, Fig. 4.16 and Fig. 4.17).

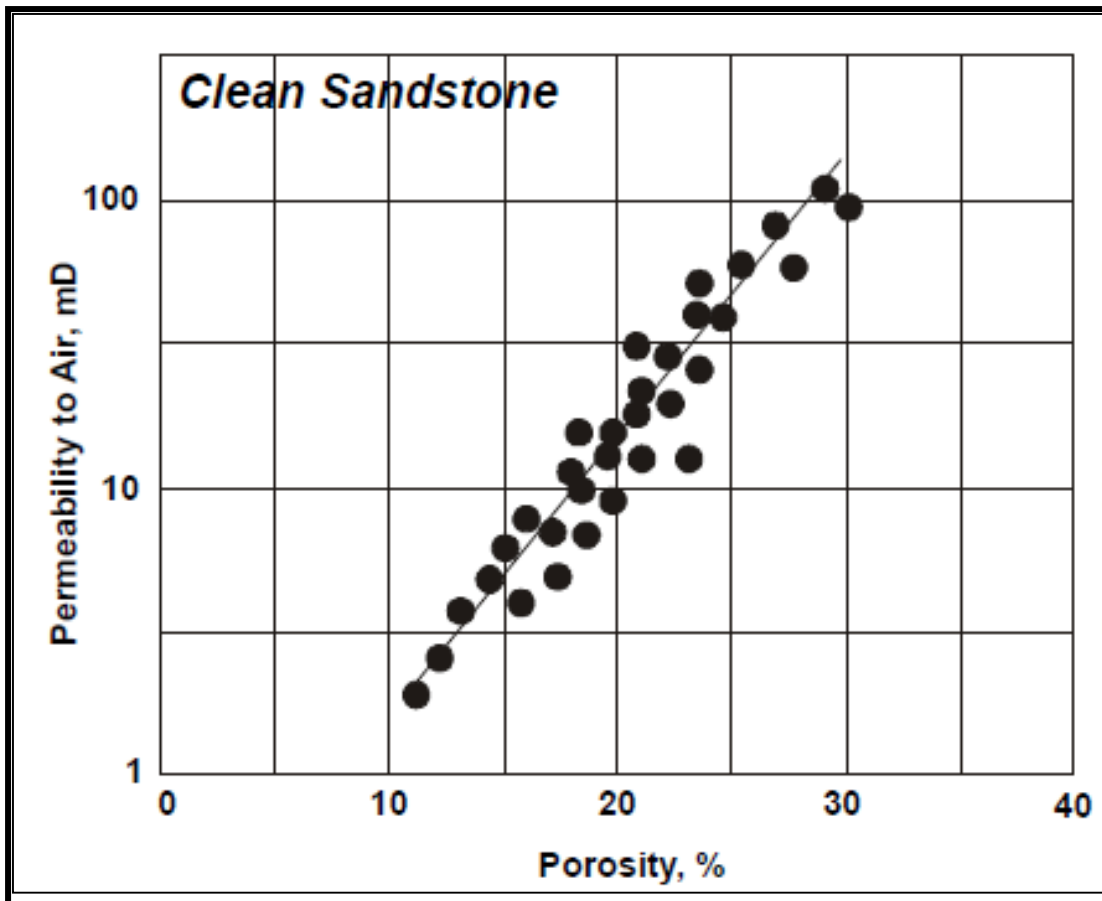


Fig 4.15 Typical porospERM crossplot (After Glover, 2012)

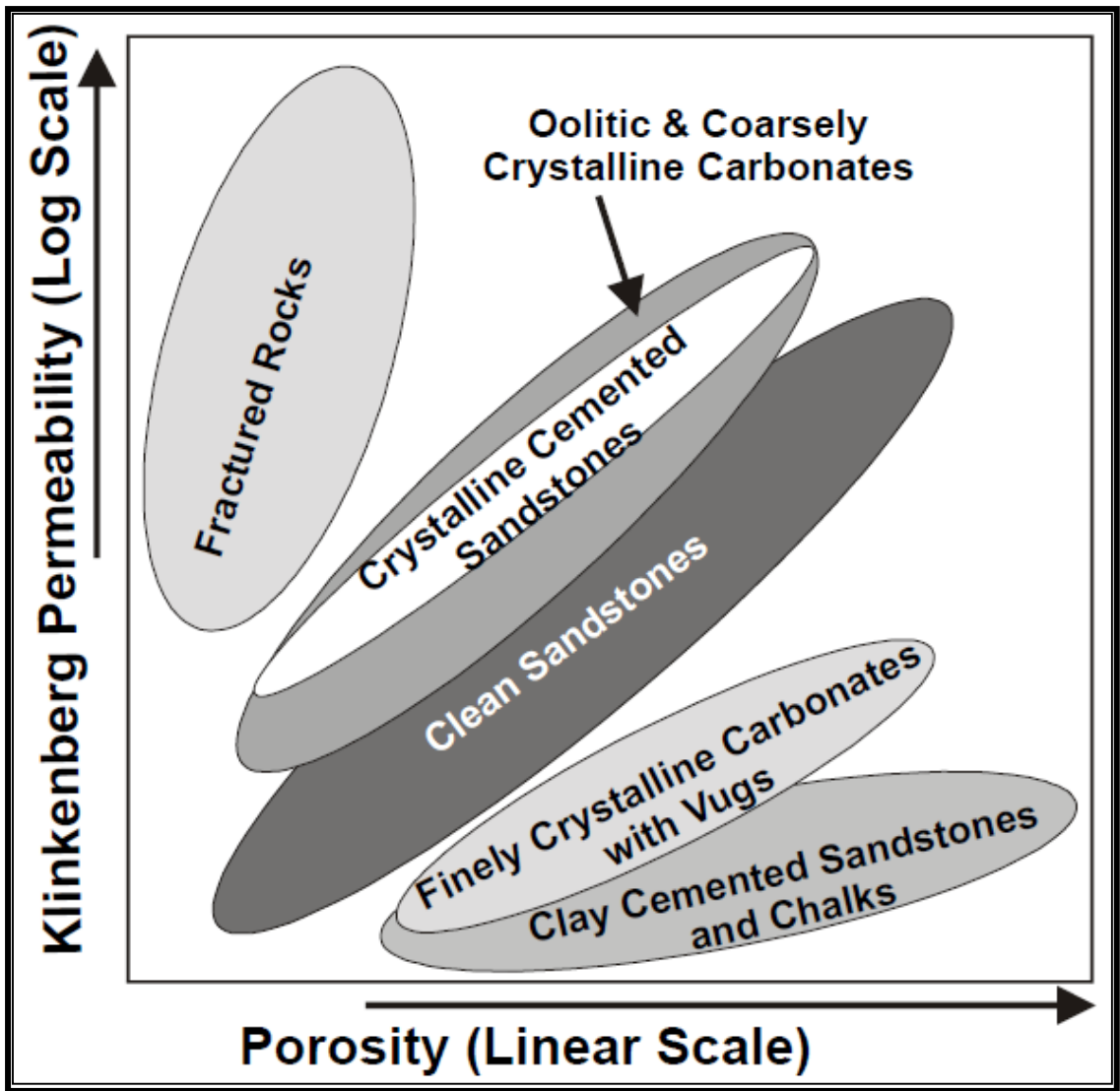


Fig 4.16 porospem relationships (After Glover, 2012)

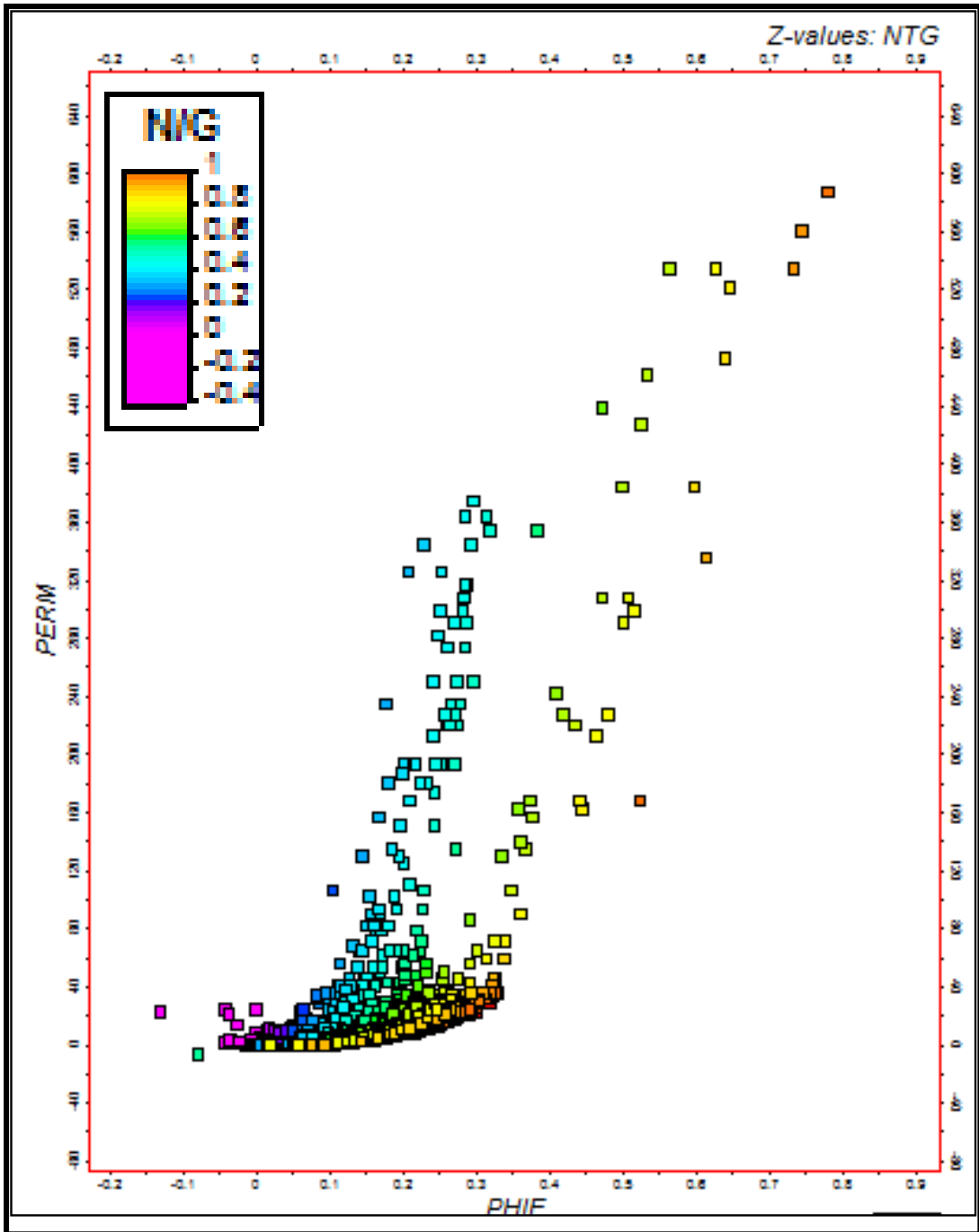


Fig 4.17. Poroperm crossplot for Azoh-001 well

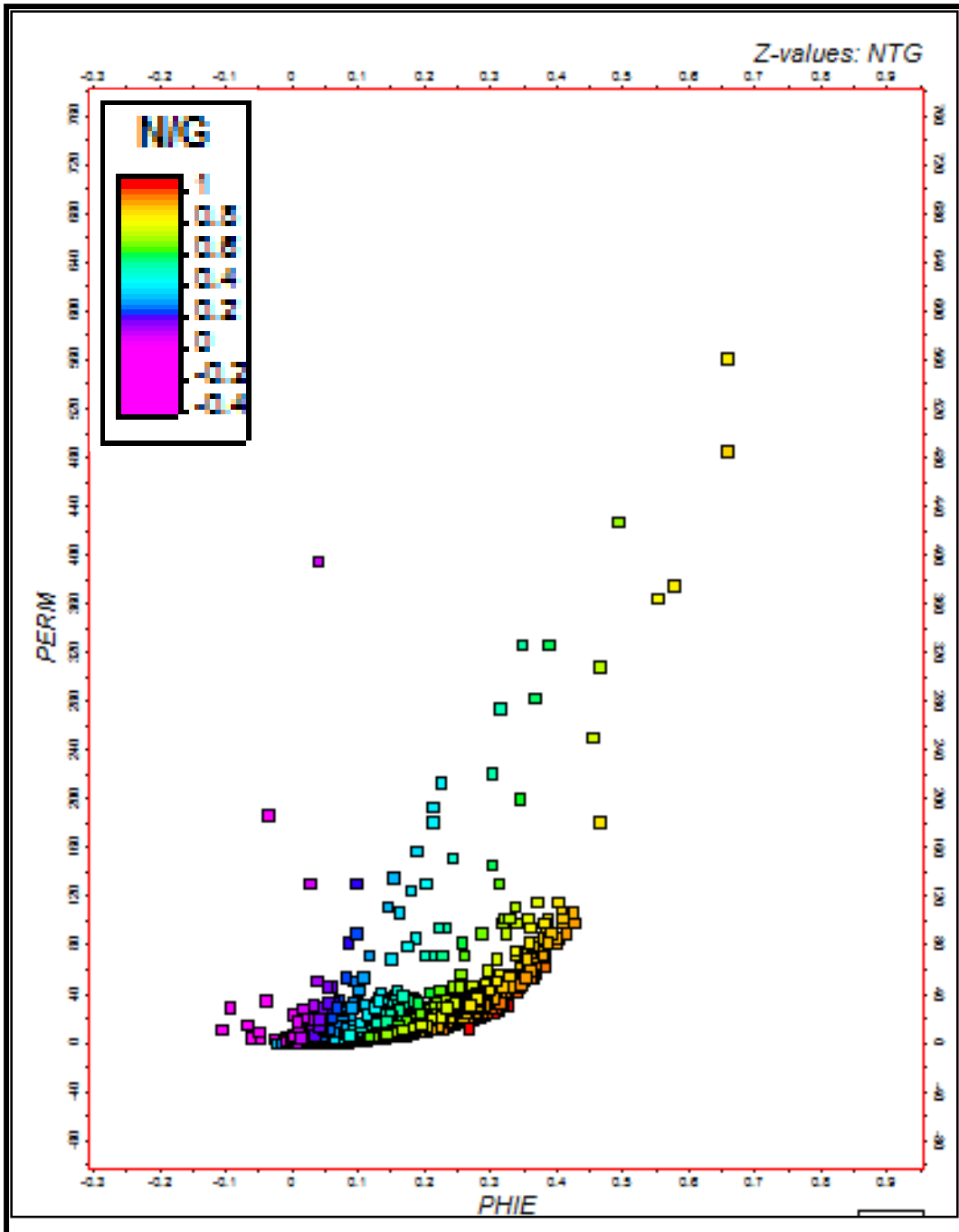


Fig 4.18. Poroperm crossplot for Azoh-002 well

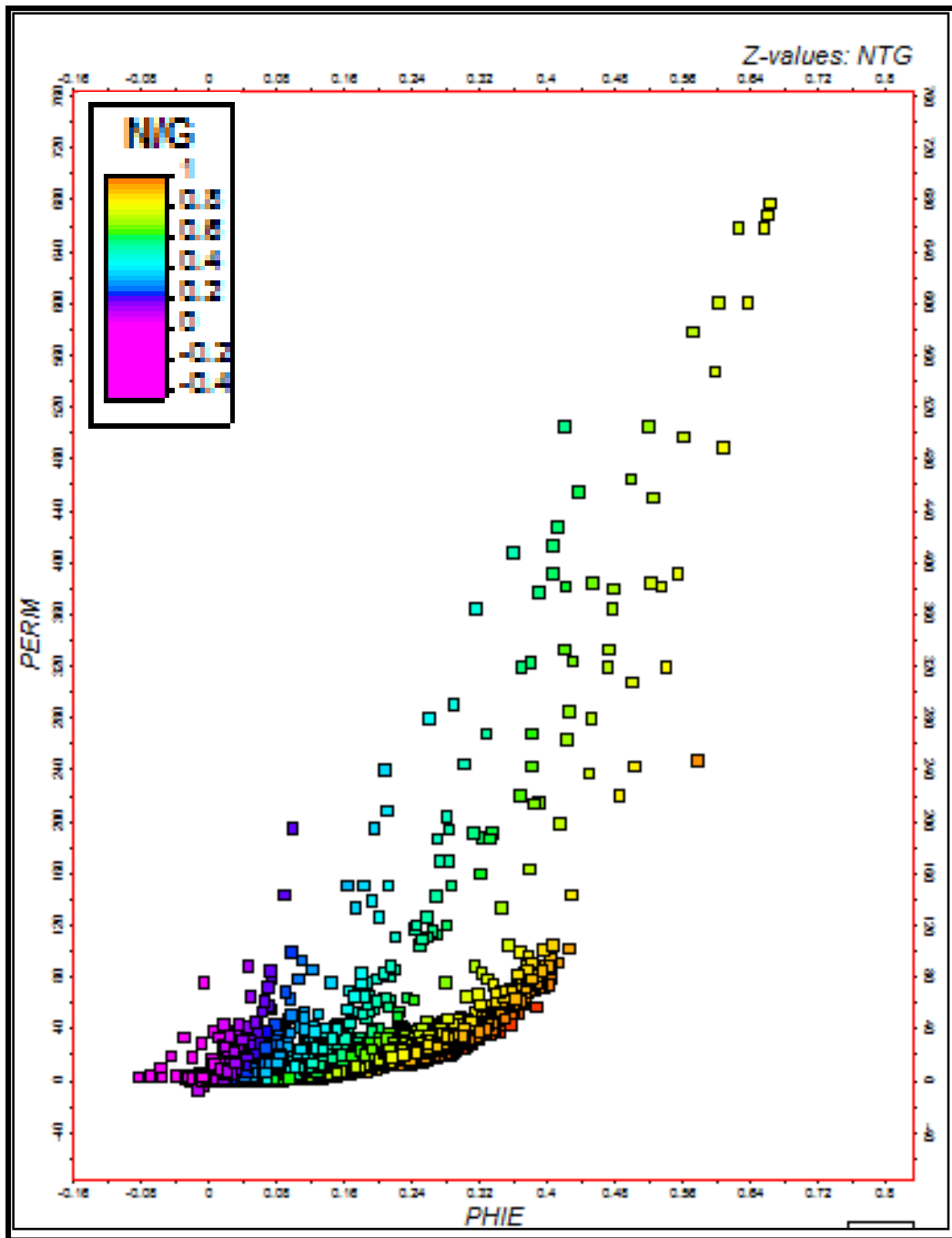


Fig 4.19. Poroperm crossplot for Azoh-003 well

Crossplots of water saturation (S_w) versus effective porosity (PHIE) revealed two lithofacies in the study area. These are sands and shales (Fig. 4.20 to 4.22).

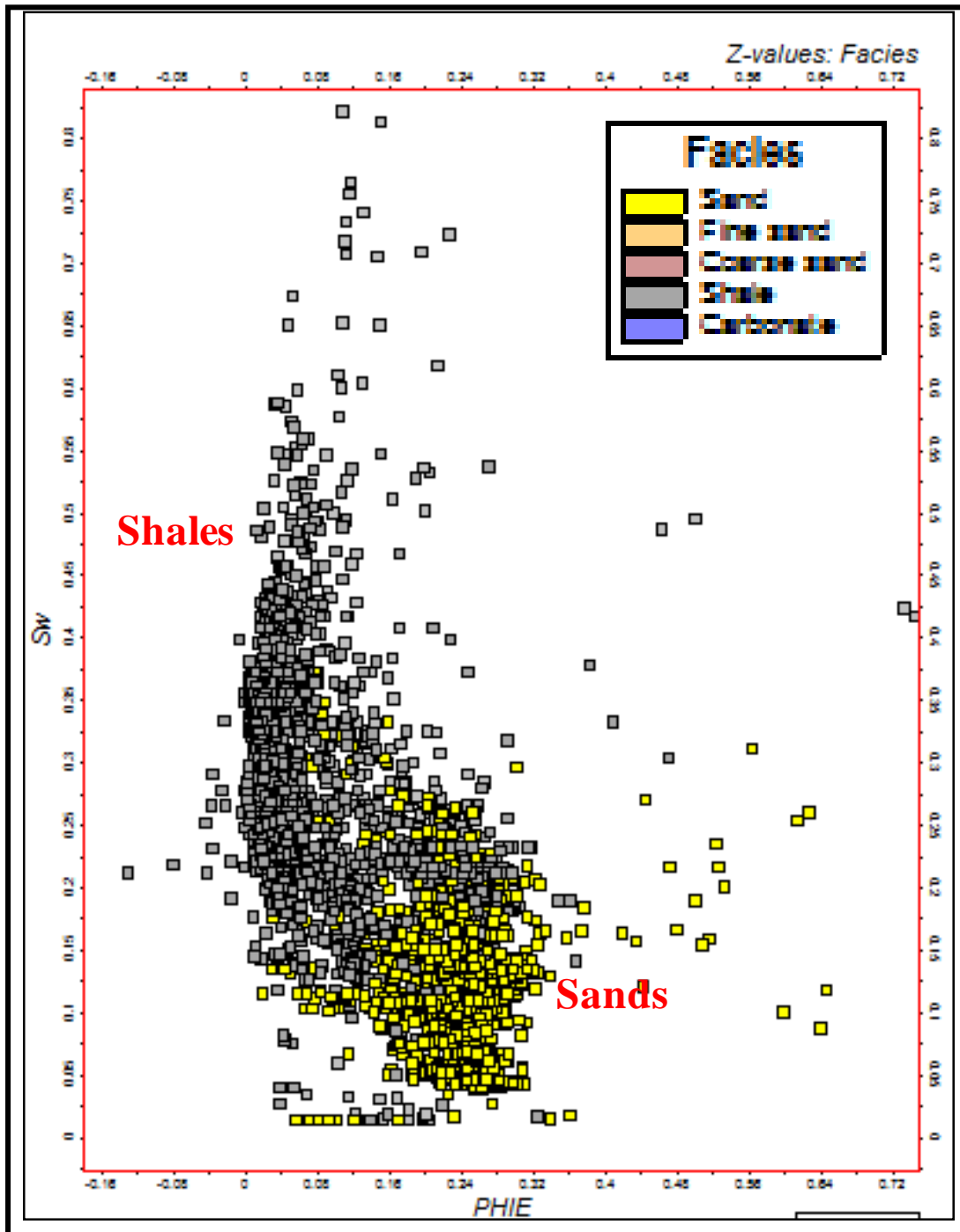


Fig 4.20. Crossplot of S_w and PHIE for Azoh-001 well

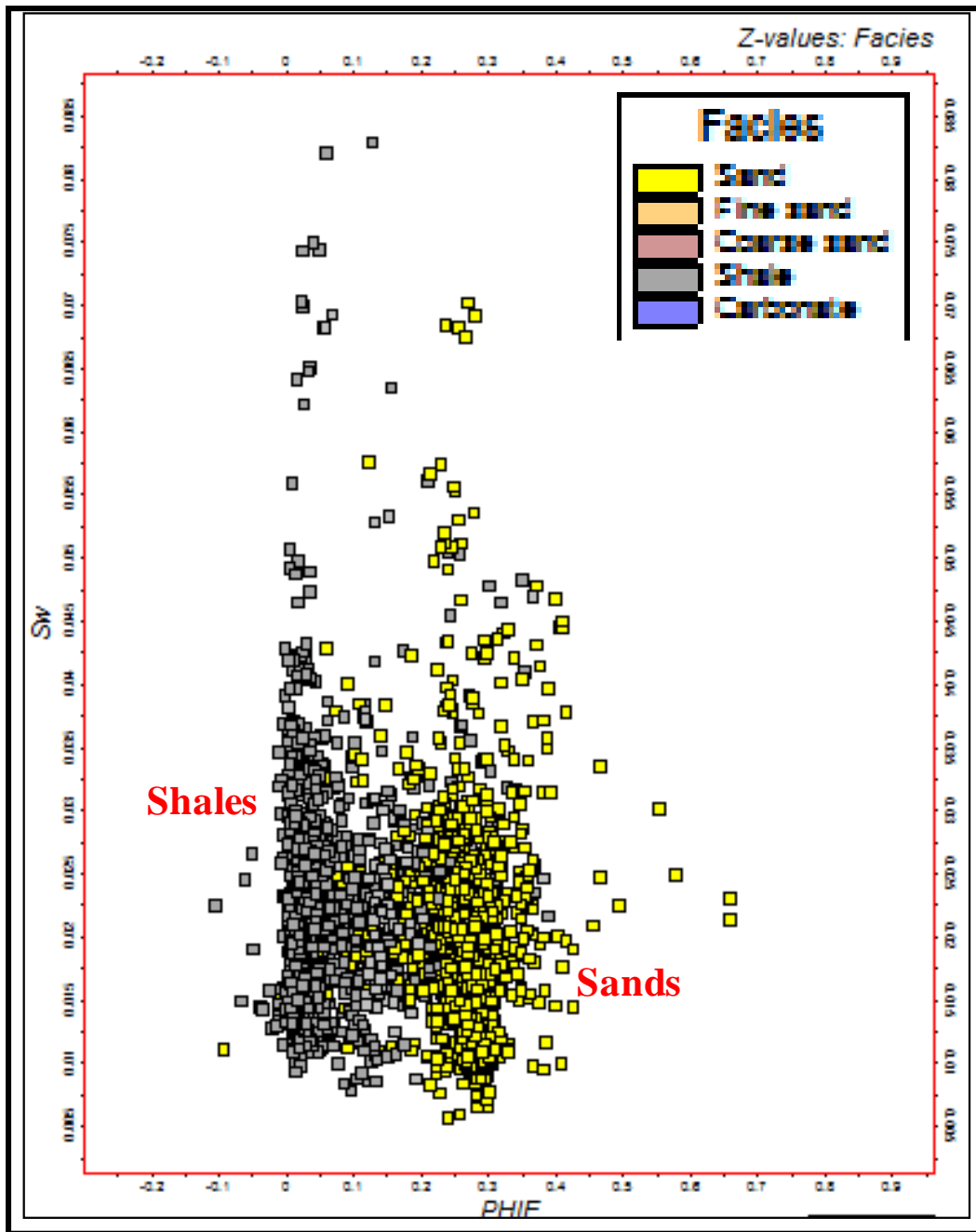


Fig 4.21. Crossplot of Sw and PHIE for Azoh-002 well

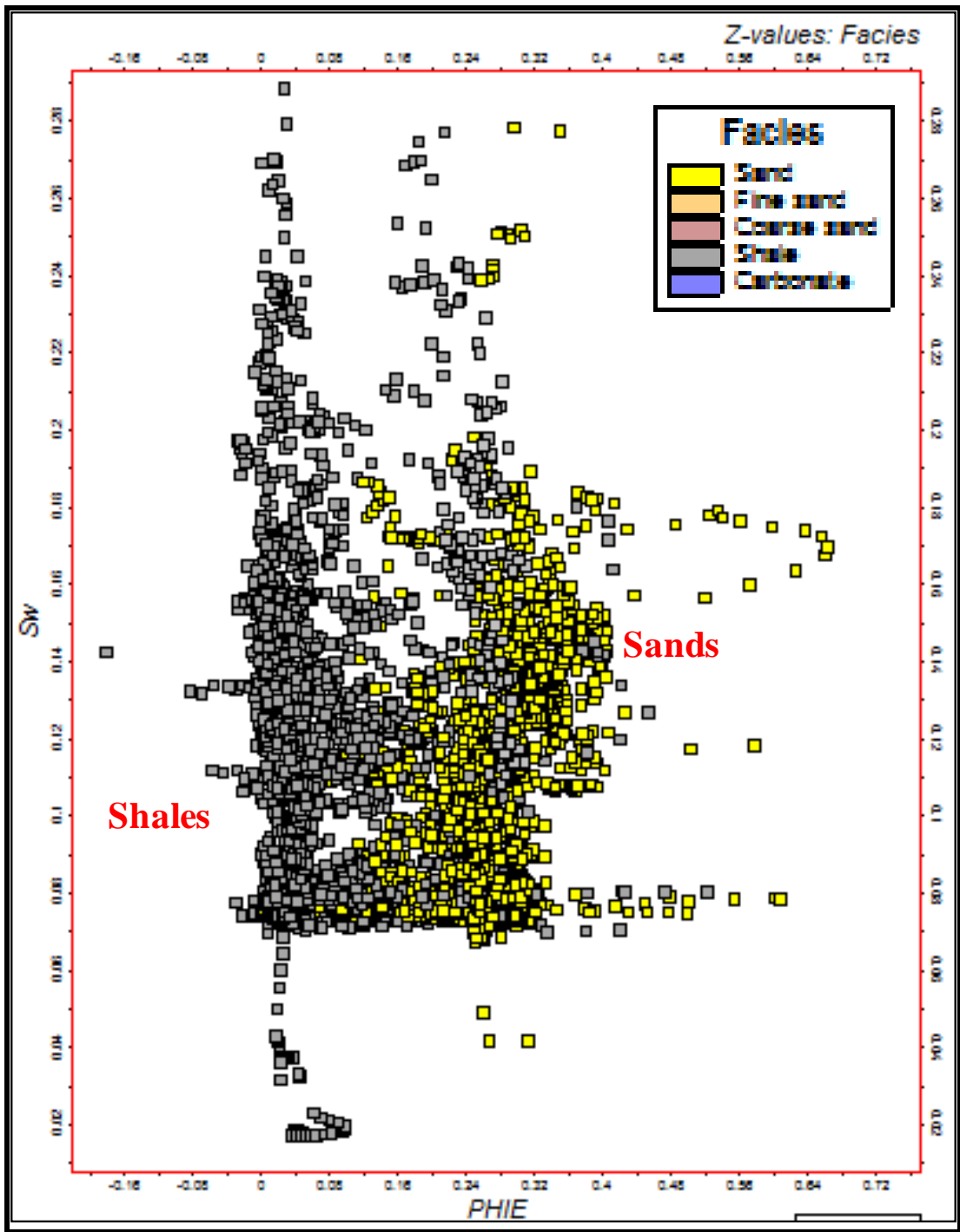


Fig 4.22. Crossplot of Sw and PHIE for Azoh-003 well

4.6 Facies Analysis and Depositional Environment Interpretation

Gamma ray log shapes is often used to measure the shaliness of a formation. In reality the shaliness often does not change suddenly, but occurs gradually with depth. Such gradual changes are indicative of the lithofacies and the depositional environment of the rock, and are associated with changes in grain size and sorting that are controlled by facies and depositional environment as well as being associated with the shaliness of the rock. Fig. 4.23 analyses the shape of gamma ray log responses for various depositional environments (Glover, 2012).

All possible combinations of these shapes may be encountered.







Shape	Smooth	Environments	Serrated	Environments
Cylinder Represents uniform deposition.		Aeolian dunes Tidal sands Fluvial Channels		Deltaic distributaries Turbidite channels Proximal deep-sea fans
Bell Shape Fining upwards sequences.		Tidal sands Alluvial sands Braided streams Fluvial channels Point bars		Lacustrine sands Deltaic distributaries Turbidite channels Proximal deep-sea fans
Funnel Shape Coarsening upward sequences.		Barrier bars Beaches Crevasse splays		Distributary mouth bars Delta marine fringe Distal deep-sea fans

Fig 4.23. The gamma ray and depositional environment (After Glover, 2012)

A bell-shaped log, where the gamma ray value increases regularly upwards from a minimum value indicates increasing shale (clay) content; while a funnel shape, with the log value decreasing regularly upwards, shows a decrease in shale (clay) content. The increase in gamma radiation corresponds to an increase in clay content regularly upwards. The increase in clay content is correlated to a decrease in the sand grain size (Rider, 2002).

Several workers have used log motifs that represent sub-environments with main environment in conjunction with other parameters (Selley, 1978). The log pattern is either blocky or cylindrical, funnel or bell shaped. A blocky or cylindrical log pattern indicates relics of fining and coarsening upward small scale, monolithic, high energy, rapid deposit of very coarse sand called channel sands. These sands have an abrupt base representing erosional base of channel fill sequence and are confined to proximal fluvio-marine environment.

The funnel-shaped log pattern is barrier sand (beach sand) which is coarsening upward with river mouth deposit of distributary channel and the energy of deposition is increasing upward with geologic time as the coastline advances seawards. This is most common in the shoreline environment and the associated lithofacies are shoreface sands and offshore silts with interbedded hemipelagic shales. It is characterized by regressive activities (Fig. 4.24).

In this study, depositional environments of the clastic sediments in the “Azoh” field were inferred from the analysis of lithofacies predicted from well logs (Fig. 4.24 to 4.27).

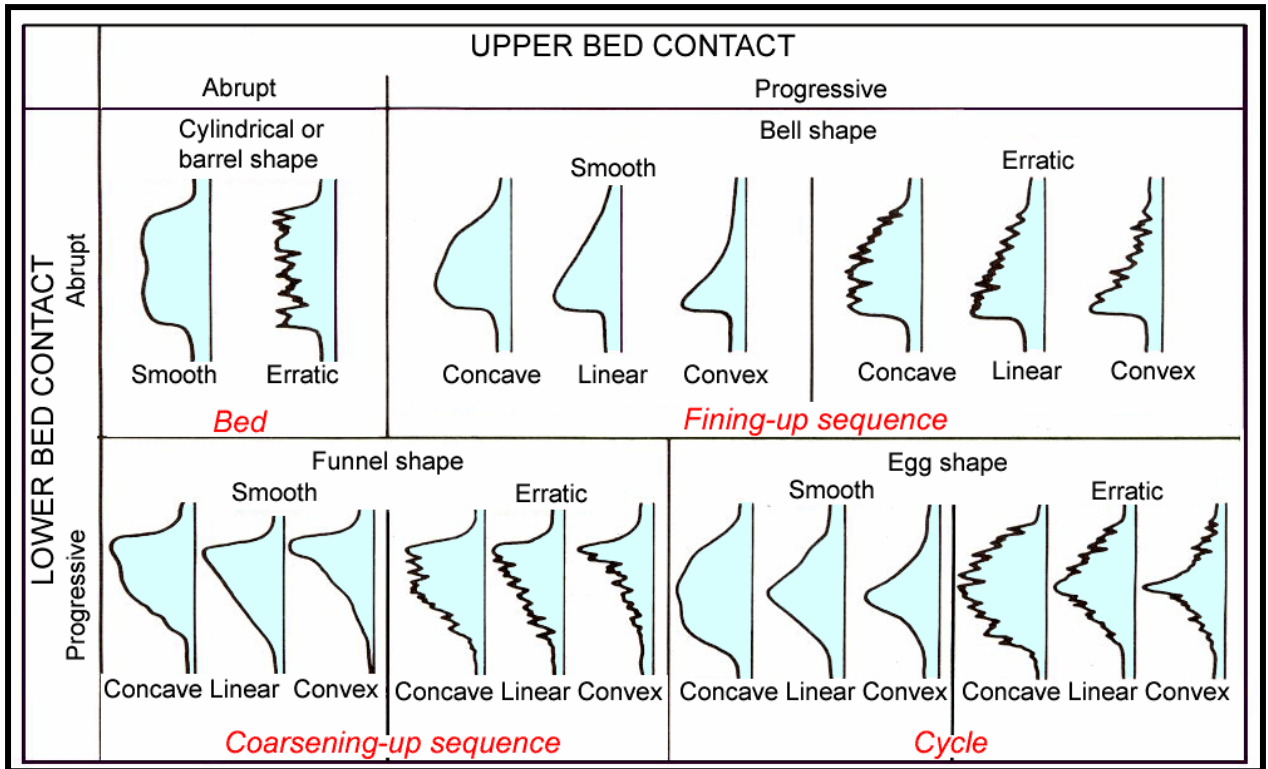


Fig 4.24 Classification of electrofacies by shapes of log responses (After Serra, 1985)

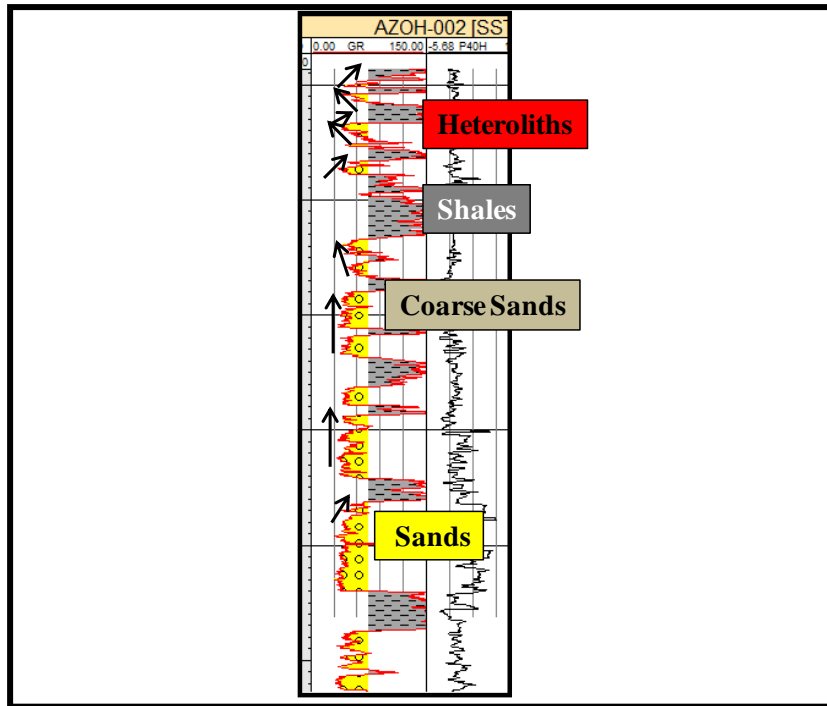


Fig 4.25. Identified lithofacies in the Azoh-002 well. (arrows showing fining upward and coarsening upward sequence)

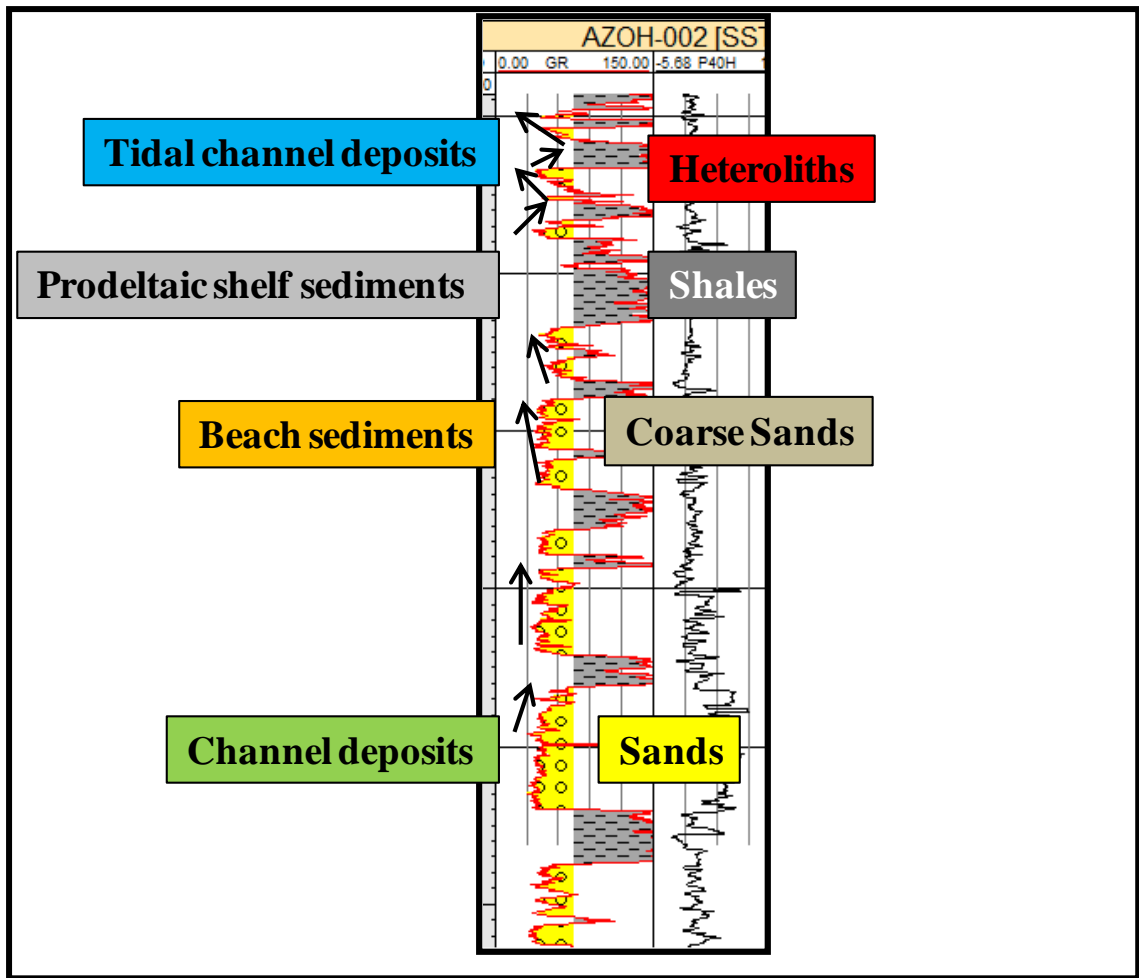


Fig 4.26. Depositional environment of Azoh-002 well interpreted from lithofacies

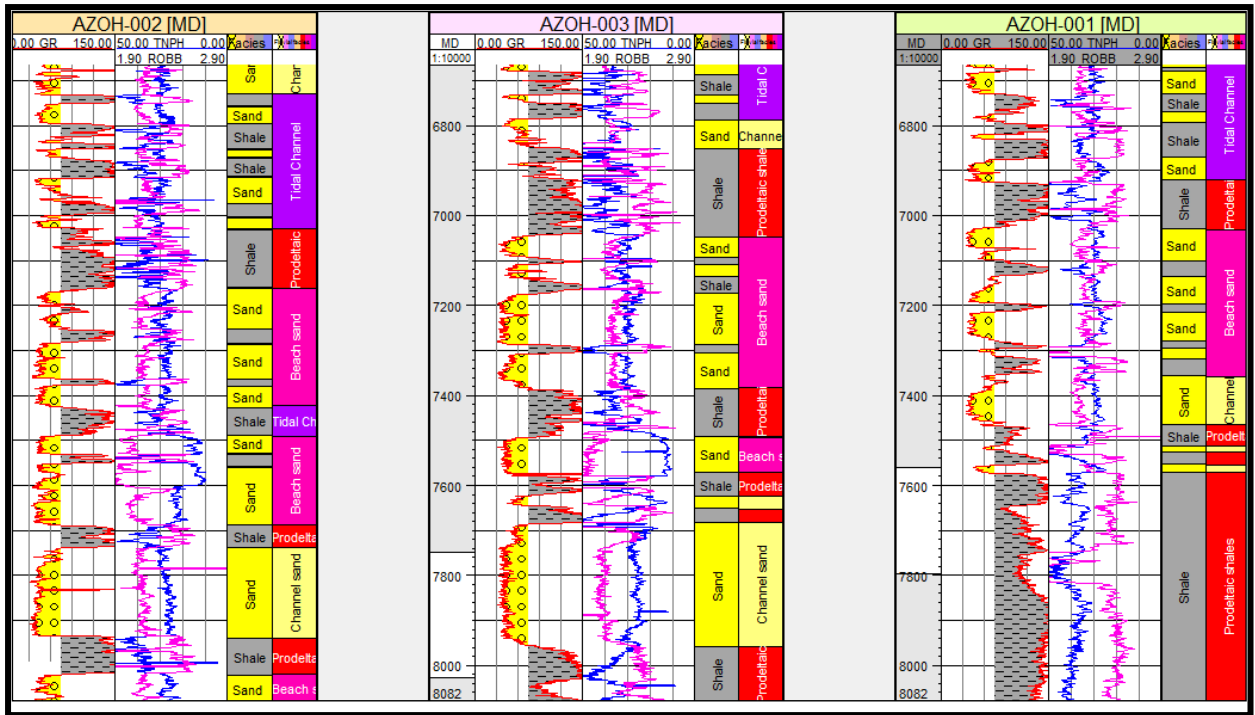


Fig 4.27. Lithofacies and depositional environments of the clastic sediments penetrated by the study wells

4.7 Reservoir-fluid Typing from Well Logs

Fig. 4.28 shows the fluid types encountered by the three wells in each of the evaluated reservoir sands. Interpretation of the reservoir-fluid typing was achieved by combining several logs including the resistivity logs, density and neutron logs for quick look evaluation of the reservoir sands (Fig. 4.28). This was further supported by the observation of oil and gas shows in the mud log data. From the diagram (Fig. 4.29), it can be readily observed that D_2000 and F_1000 reservoir sands contain oil while E_3100 reservoir sand contains gas.

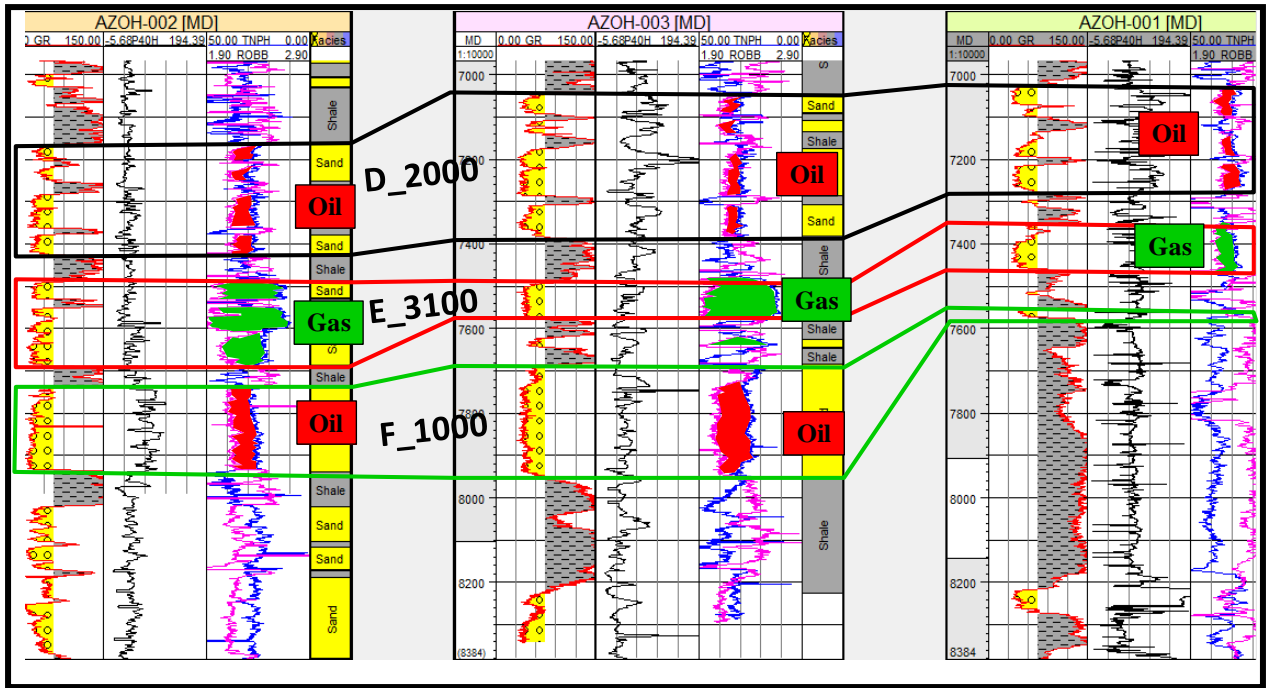


Fig 4.28. Fluid-types identified in the reservoirs

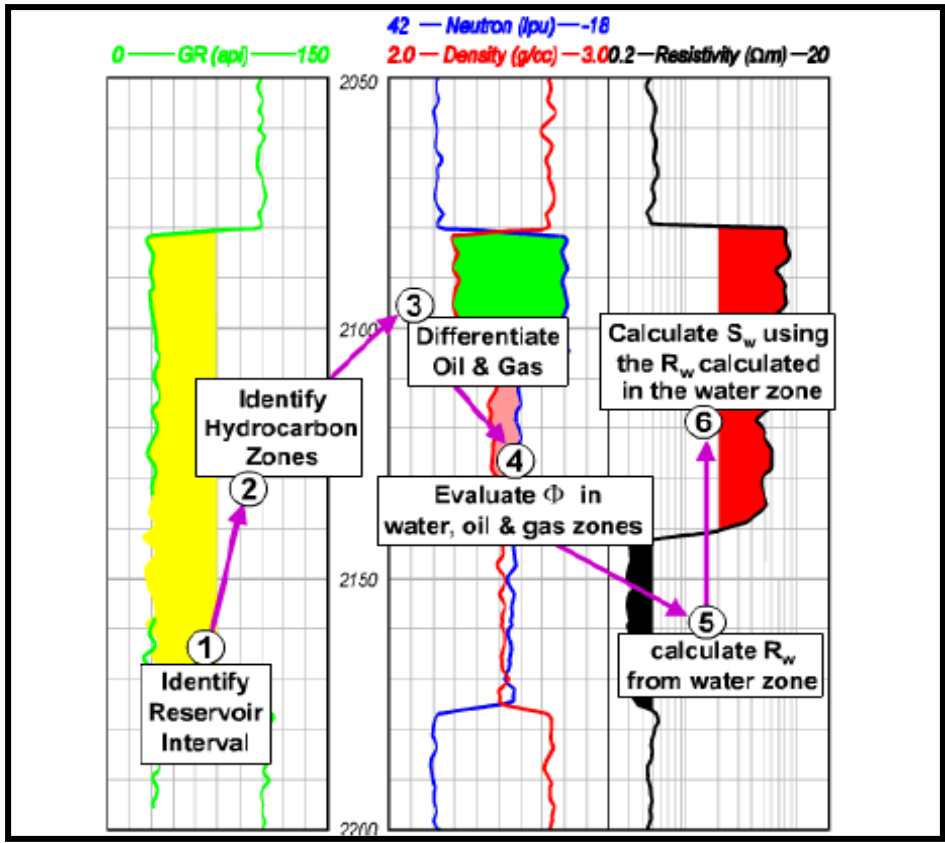


Fig 4.29. quick look evaluation for fluid-typing from well logs (After Bora, 2013)

4.8 Estimated In-place Hydrocarbon Volumes

Volumetric methods attempt to determine the amount of oil-in-place by using the size of the reservoir as well as the physical properties of its rocks and fluids. Then a recovery factor (RF) is assumed, using assumptions from fields with similar characteristics. The stock tank oil initially in place (STOIIP), or the gas initially in place (GIIP), is multiplied by the recovery factor to arrive at a reserve estimate. The recovery factors for gas cap fields (typical of the “Azoh” field) is usually within the range of 15-25% for solution gas drive, gas cap drive and water drive saturated reservoirs and is usually the first estimate for a new discovery until other production mechanisms have been observed in the field (Sandrea and Sandrea, 2007).

A simple weighted average among the major oil provinces gives an average recovery factor of 22% which is well within the range of the solution gas drive reservoirs. By analogy, the overall recovery factor for the bulk of the world’s conventional oil reserves would at best be about 20%. For the sake of this work however, a recovery factor of 20% is employed (Sandrea and Sandrea, 2007).

The oil reserve and gas reserve could be computed from the formulae below:

$$\text{Oil Reserve} = ((7758 * A * h * S_o * \emptyset) / B_o) * \text{RF}$$

$$\text{Gas Reserve} = ((43560 * A * h * S_g * \emptyset) / B_g) * \text{RF}$$

Where

7758 = conversion factor from acre-ft to bbl

43560 = conversion factor from acre-ft to ft³

\emptyset = average effective porosity of the reservoir (fractional)

A= Area of the field

h= net reservoir thickness

S_o = average oil saturation (fractional).

S_g = Hydrocarbon saturation (gas) fractional.

B_o = Formation oil volume factor = 1.2 bbls/STB

B_g = Formation gas volume factor = 0.005 cuft/scf

RF = Recovery factor (fractional)

The Area of the field gas reserve is approximately 240km^2 , which equals 59305.291 acres.

Table 4.6 is a summary of the average petrophysical values used as input for computation of hydrocarbon volumes in the evaluated reservoir sands, while table 4.6 is a summary of the estimated volumes of oil and gas in the reservoirs.

Table 4.6 summary of average petrophysical values of the reservoirs

Reservoir Sand	Average Net Thickness (ft)	Average Øe	Average Sh	Hydrocarbon Type
D_2000	208.33	0.20	0.91	Oil
E_3100	107.33	0.30	0.93	Gas
F_1000	141.67	0.25	0.88	Oil

Table 4.7. Volume calculation summary report sheet for the reservoirs

Reservoir Sand	STOIP (MMMSTB)	GIIP (TCF)	Recoverable Oil @ 20% (MMMSTB)	Recoverable Gas @ 20% (TCF)
D_2000	14.5	-	2.9	-
E_3100	-	15.5	-	3.1
F_1000	11.9	-	2.4	-

From table 4.7, it is readily observed that the three reservoirs contain considerable volumes of hydrocarbon enough to make an affirmative business decision. All the methods used in this study were geared towards determining the in-place hydrocarbon volume in the evaluated reservoir sands.

4.9 Discussion

Interpretation of lithology and volume mineralogy based on the data provided, which includes well logs, sidewall cores description, mud logs and core photographs, revealed that the subsurface geology of the study area is characterized by sand-shale sequences, with the occurrence of lignite streak at some stratigraphic levels as indicated in the mud logs.

Fig. 4.30 shows the formation analysis log of the three wells (Azoh-001, Azoh-002 and Azoh-003). These wells are presented as an example to exhibit the different lithological and rock units encountered in the study area as correlated with the estimated petrophysical parameters. The analysis log illustrates that sandstones (containing quartz minerals) and shales (containing clay minerals) are the dominant rock units in the study area. The sand units show low gamma ray values indicating that they contain little or no radioactive clay minerals. The shales on the other hand are associated with high gamma ray values significant of the abundances of fine-grained radioactive clay minerals.

Interpretation of the environment in which lithofacies were deposited from analysis of cored sequences involves relating the identified lithofacies to the physical and biological processes that produced them. This process-response relationship identifies the specific processes responsible for the sequence and, by inference, the depositional setting in which these processes occurred. The application of the process-response approach relies primarily on depositional models constructed through study of both modern and ancient analogs. Depositional models are important for predicting the distribution of permeability and porosity within different reservoir types. These models are never exact matches to a reservoir; rather, they serve as guides to aid in the interpretation of any one reservoir (Walker, 1984).

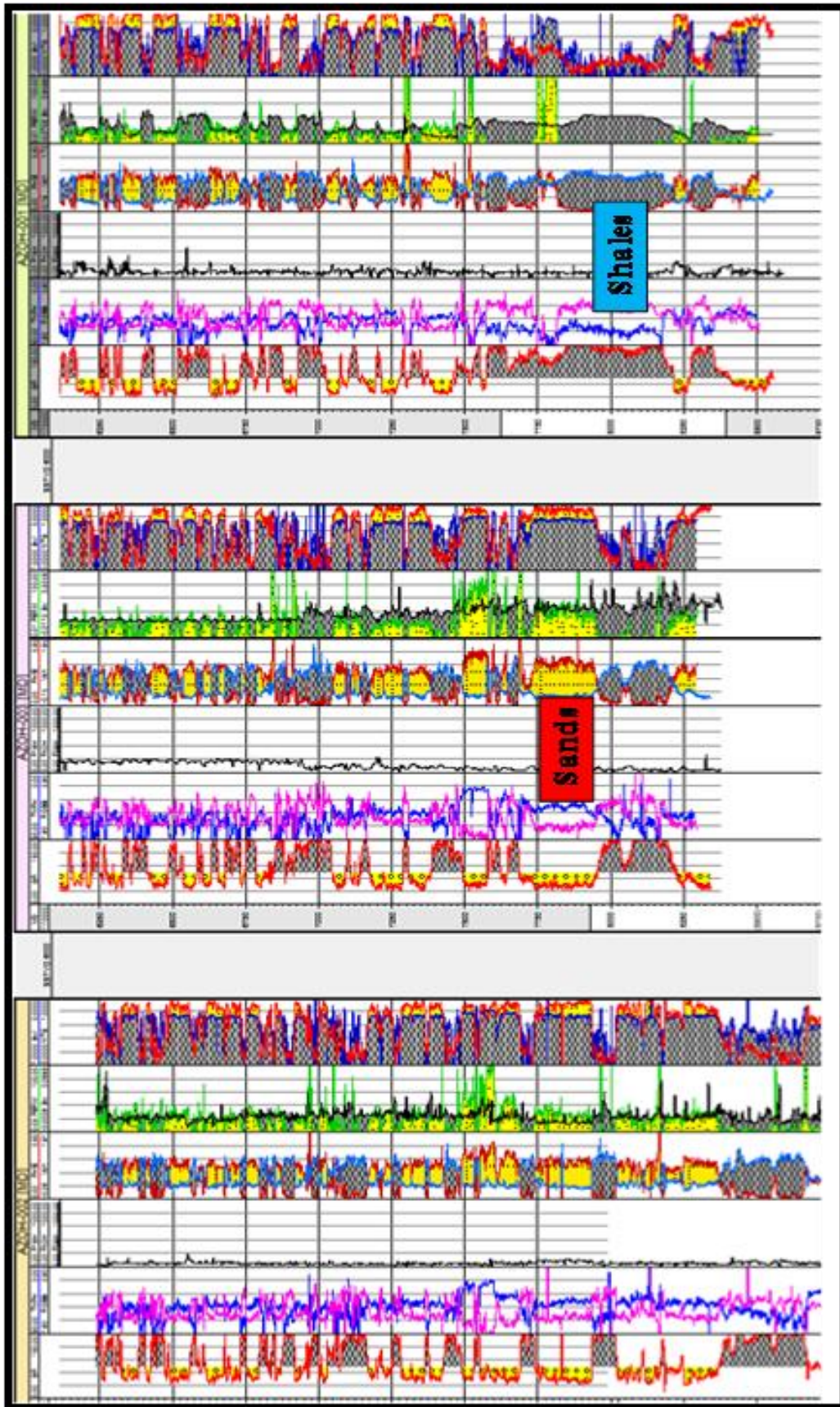


Fig 4.30 Form analysis of the three wells Azoh-001, (Azoh-002 and Azoh-003)

Reservoir properties are generally observed to be correlative with lithofacies types to one degree or another. This reflects the fundamental control on permeability and porosity by grain size, sorting, and spatial distribution of different lithofacies types. Even where rocks have experienced later physical and chemical diagenesis, permeability and porosity relationships are controlled, in large part, by the original sedimentary fabric of the rock (Beaumont & Fosterl., 1987).

Analysis of the identified lithofacies from the studied wells was used to infer the environment of deposition of the sediments. Reconstruction of the depositional environment in reservoir studies gives a correct idea of the lateral evolution of the facies and consequently of the petrophysical properties of the reservoirs, and to enable prediction of the existence, nature, importance and distribution of permeability barriers. This information is of utmost importance to evaluate the production potential of a field and to locate extraction and injection wells for a better oil recovery (Serra, 1985).

In a multi-well study, the facies and the environments will be more accurately recognized using correlation techniques and facies mapping, the geometry of sedimentary bodies being an important parameter for facies and environment recognition (Serra, 1985).

The observed lithofacies from the studied wells reflect deposition in a fluvio-marine or deltaic environment characterized by sediments that have been transported to the end of a channel (or a set of bifurcating channels), by a current of continental water and deposited mostly subaqueously but partly subaerially at the margin of the standing water into which the channel discharges or is still discharging (Friedman and Sanders, 1978).

The heterolithic facies reflects deposition in a tidal channel or delta plain environment with a significant tidal or marine influence. The shaly facies indicate sediment deposition in a prodeltaic environment and are composed of the finest materials deposited from suspension. The coarse sand facies are representative of delta front (beach, shoreface or distributary

mouth bars) deposits characterized by high energy subenvironments where the sediments are constantly reworked by tidal currents, marine longshore current and wave action (Serra, 1985), while the sandstone facies reflects deposition in a river channel (distributary channel bar) in which the sediment grain size become finer upwards.

Distributary mouth bars and channel deposits (Fig. 4.31) comprise the best reservoir quality bodies within a delta system. The general upward-coarsening character of distributary mouth bars tends to produce sandstone bodies that have their greatest permeability at the top. Conversely, distributary channel sandstone bodies are usually upward-fining and have their greatest permeability at the base. Preferred orientation of flow may be expected to follow paleochannel trends (Sneider, Tinker & Meckel, 1978). Distributary mouth bars typically may contain a high percentage of interstratified clay that reduces vertical permeability as documented by Hartman and Paynter (1979).

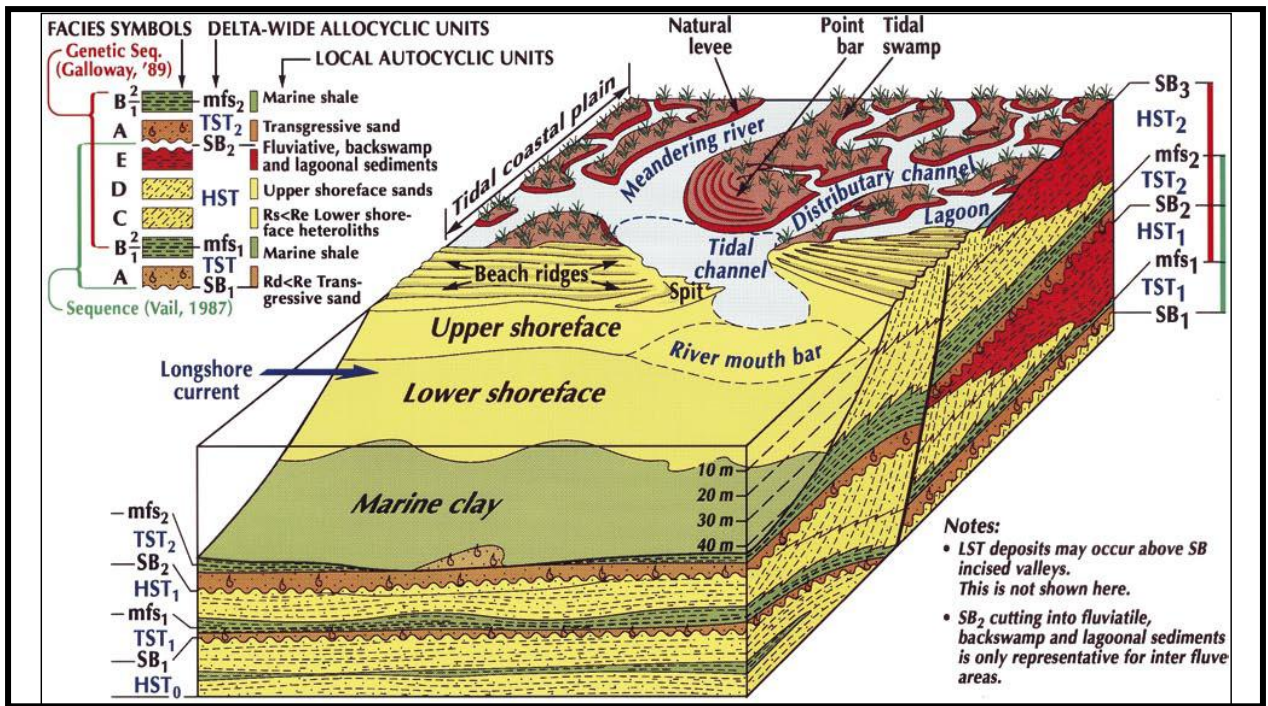


Fig 4.31 Geomorphology, cyclic sedimentation and an active fault in the Tertiary Niger Delta coastal zone (Modifie after Weber, 1971; Reijers, 2011)

In shoreline systems adjacent to active deltas, the geometry and internal anatomy of sandstone bodies are controlled by interplay of tidal and wave processes. Clastic, non-deltaic shorelines with a tidal range of 0–2 m (microtidal) tend to be wave-dominated. Resulting sand bodies are elongate barrier (beach) islands and strand plain. A tidal range of 2–4 m (mesotidal) tends to produce short (“drum stick”) barrier islands with extensive tidal flats and ebb tidal deltas. A tidal range of 4–6 m (macrotidal) tends to produce estuarine linear tidal sand ridges that are perpendicular to shoreline with associated extensive tidal flats (Boggs, 2009)..

Barrier islands illustrate the spatial variability in facies that affect reservoir properties. Sands in the beach or foreshore are very well sorted, lack interstratified clay, and exhibit excellent reservoir properties where not cemented. Tidal inlet and flood tidal delta deposits comprise another important grouping of reservoir quality rocks, particularly because they are most often preserved in the rock record (Boggs, 2006).

In general, barrier islands have the best reservoir quality rocks at the top of the sequence. Reservoir quality drops off as one moves either seaward down the foreshore and shoreface into muds of the marine shelf or landward into the lagoons. High reservoir quality is also developed within the tidal inlet sandstones. Two major trends in directional permeability are suggested by (1) the shore-parallel nature of foreshore and shoreface sandstones and (2) shore-perpendicular tidal inlet and delta sandstones. In coastlines dominated by tidal processes, extensive interbedded mud and sand “flats” occur in the intertidal area of the coast and sand bars in estuarine channels in the subtidal area. The reservoir quality of tidal flat environments varies as a function of sand to mud ratio of the deposits. Reservoir quality of estuarine channel deposits also varies as a function of sand to mud ratio and degree of bioturbation (Gaynor & Scheihing 1988).

A total of nine reservoir sands were delineated and zoned. However, at appropriate evaluation these reservoirs were grouped into three major sand units namely D_2000, E_3100 and F1000 reservoir respectively. The reservoir zones are considered to be homogenous, although clay pockets may exist at various intervals as identified in the core photos.

Identifying and evaluating a reservoir zone is based on the ability of the petrophysicist to make good use of all available data in interpreting various reservoir parameters (Eshimokhai and Akhirevbulu, 2012). To illustrate the application of logging techniques and to establish the hydrocarbon potential of the study area, formation evaluation of the three reservoir zones was conducted.

Analysis of the estimated petrophysical properties revealed that these reservoirs are composed of high quality sands owing to their high effective porosity and net reservoir thickness values (Table 4.8). The estimated average permeability values for these reservoirs are 16.92mD for D2000 sand, 47.80mD for E3100 sand and 28.05mD for F_1000 sand. These reservoirs are qualitatively described as having moderate permeabilities following the scheme propounded by Rider (2002) (Table 4.8).

Correlation analysis was performed to determine whether the petrophysical attributes (water saturation and porosity) are interdependent. Generally, the effective porosity decreases with depth in all the wells with low correlation coefficient. The observed reduction in depth would likely be attributed to the effect of compaction resulting from overburden pressure. Water saturation generally increases with depth. This implies that reservoirs in “Azoh” field occur in shallow depth hence the unavailability of reservoirs as we go deeper into the subsurface. Efforts made to delineate trends for water saturation and effective porosity was marginally efficient.

Table 4.8 porosity and permeability values for reservoirs qualitative description (After Rider, 2002)

Qualitative Evaluation of Porosity	
<i>Percentage Porosity (%)</i>	<i>Qualitative Description</i>
0 - 5	Negligible
5 - 10	Poor
15 - 20	Good
20 – 30	Very Good
> 30	Excellent
Qualitative Evaluation of Permeability	
<i>Average K_ Value (md)</i>	<i>Qualitative Description</i>
< 10.5	Poor to fair
15 – 50	Moderate
50 – 250	Good
250 – 1000	Very Good
> 1000	Excellent

From crossplot results, a reduction in water saturation with increased effective porosity was observed in all the wells. Correlation analysis for these two petrophysical properties revealed that a strong interdependence of the two parameters in Azoh-001. However, the correlation coefficient was extremely low for Azoh-002 and Azoh-003 wells which suggest that no relationship exists between the two petrophysical attributes.

Porosity is often related to permeability, this is particularly evident in clastics but often less predictable in carbonates. Porosity-permeability (poroperm) crossplots for the three wells show that the reservoirs are clean sandstones with little or no clay content. This is further supported by the low average volume of shale values computed for the reservoirs. Low volume of shale value indicated low clay content and higher permeability, and high neutron density porosity indicated high permeability. Also, the correlation coefficient values obtained show a fairly strong linear relationship between the two variables in all the reservoirs. This reveals that the reservoirs are permeable and have porosities of some form that are in communication.

Formation evaluation of the three reservoir sands indicates that the D2000 and F1000 reservoirs contain oil in appreciable quantity, while E3100 reservoir contains a large volume of gas. Volumetric estimations of the hydrocarbon content in each of the reservoirs have been given in Table 4.6. The low water saturation content values recorded in the reservoir suggests that hydrocarbon production from these sand units will be water free.

CHAPTER FIVE

CONCLUSION AND RECOMMENDATION

5.2 Conclusion

The evaluation of the three reservoir sand bodies encountered by the three wells (Azoh-001, Azoh-002 and Azoh-003) used in this study was made possible by the careful integration of well log responses, sidewall core information and mud log data. The study examined the vertical sequence of lithologies of the sand bodies, trend of data, and log interpretation.

A detailed petrophysical properties estimation of the wells revealed that:

1. The reservoirs are sand units whose quality was found to be strongly influenced by facies and depositional environment.
2. In reservoirs where porosities are high, permeabilities are equally high and vice versa.
3. These high values of porosities and permeabilities are attributed to the grain size and sorting of the sediments.
4. Porosity and permeability increased with increasing reservoir quality.
5. Estimated average water saturation values for the reservoirs range from 3-14% for D_2000 sand, 2-14% for E_3100 and 1-21% for F_1000 respectively; while the average hydrocarbon saturation values range from 86-97% for D_2000 sand, 86-98% for E_3100 and 79-99% for F_1000 sand respectively.
6. The D_2000 and F_1000 reservoir sands both contain oil while E_3100 reservoir sand contains gas.
7. Average permeability for these reservoirs range from 13.34-19.21mD for D_2000 sand, 24.04-67.22mD for E_3100 and 10.81-47.50mD for F_1000 suggesting moderate permeabilities for hydrocarbon extraction.

Based on the analysis of the identified lithofacies in the wells, the sediments were inferred to be deposited or formed in a tidally influenced progradational shoreline or fluvio-marine

environment. The sands are interlaminated with clays towards the base and become progressively clay free sand upward. They show funnel shaped log signatures that are serrated at the bottom which can be attributed to sedimentation rate exceeding rate of subsidence. The reservoirs have very good porosities and moderate permeabilities with average porosity coupled with relatively low irreducible water saturation. The porosity and effective porosity values across the reservoirs have very close similarities. The net to gross ratio is also relatively very high. These are direct indications that the reservoirs has very good interconnected pore spaces and is symptomatic of the locally high permeability values as against the 1 – 2 Darcies of the Niger Delta permeability range. It has good hydrocarbon saturation and therefore huge prospect for hydrocarbon production. The low irreducible water saturation would account for a low water saturation cut-off to be employed when considering production well siting. The reservoirs also show a good range in sand thickness from clean sand to slightly shaly sand indicating progressively finer grains as you go further basinward indicating direction of lithologic dip.

Decisions on economic production of hydrocarbons from the wells should not be based solely on electrical log responses and core analysis, but should also consider evidence obtained from other techniques used in reservoir characterization.

5.2 Recommendation

I recommend that, for further studies with regards to this field there should be an integration of thin-section of well cores data, this will provide a reliable result for porosity and permeability interpretation, thereby, improve the mapping of reservoirs sand tops with high level of certainty.

Integrated studies involving several sciences and engineering discipline should be conducted for quantum recovering of the hydrocarbon trapped within the reservoir sands.

A detailed structural modeling of the study area is also recommended since this can provide additional information and precise information on how to place wells or make perforations.

High resolution biostratigraphic method is also recommended to delineate the biofacies for depositional environment interpretation

5.3 Contribution to Knowledge

The volumetric reserve estimate for the reservoir sands shows that D2000 reservoir contains 2.9 billion barrels of oil, E3100 reservoir contains 3.1 Trillion cubic feet of gas, while F1000 reservoir contain 2.4 billion barrels of oil respectively. The reservoirs have very good porosities and moderate permeabilities with average porosity coupled with relatively low irreducible water saturation. Furthermore, the porosity and effective porosity values across the reservoirs have very close similarities

By this, this research has shown that hydrocarbon recovery in mature producing fields onshore Niger Delta can be optimized through advanced and careful evaluation of the petrophysical parameters estimated from well logs, mud logs and core data.

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