EMIRATES INTERNATIONAL UNIVERSITY
FACULTY OF ENGINEERING AND INFORMATION TECHNOLOGY
OIL AND GAS ENGINEERING DEPARTMENT

RE-EVALUATION OF THE PETROPHYSICAL PROPERTIES OF THE MAIN HYDROCARBON PRODUCING RESERVOIRS IN BLOCK 5 IN SABATAYN BASIN AND BLOCK 32 IN MASILAH BASIN

A PROJECT SUBMITTED IN PARTIAL FULFILLMENT
OF THE REQUIREMENTS FOR THE DEGREE
OF BACHELOR OF SCIENCE
IN OIL AND GAS ENGINEERING

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DECLARATION

We hereby declare that this Bachelor's Project is the result of our own work, except for quotations and summaries which have been duly acknowledged.

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APPROVAL

This is to certify that the project titled **Re-evaluation of the Petrophysical Properties of the main hydrocarbon producing reservoirs in block 5 in Sabatayn basin and block 32 in Masilah basin** has been read and approved for meeting part of the requirements and regulations governing the award of the Bachelor of Engineering (Oil and Gas) degree of Emirates International University, Sana'a, Yemen.

Project Supervisor: **Prof. Mohammed Al-Tayeb**

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ABSTRACT

Petrophysical properties is very important parameters for its impact on evaluation and development any hydrocarbon reservoir. According to that, this project studied two of the main hydrocarbons producing reservoirs which are in Tasoure field in Block 32 at Masila basin and AlNaser field in Block 5 at Sabatayn basin. this study focused on analyzing and determine the main petrophysical properties such as shale volume, porosity, resistivity, and water saturation. Petrophysical re-interpretation had done using Techlog software and available standards logs in Tasoure-26s well and in Al-Naser-1 well.

Re-zonation process had done in Tasoure-26s well formations depending on the logs reading for many tools. After applying the cutoff values, the hydrocarbon saturation in the mine reservoir was improve 2.5 percentage and net pay thickness and reduction in effective porosity compared to DNO Yemen Company analysis.

As a result, re-zoning process was done for the main reservoir using GR log where thin shale layers missed in operator interpretation were delineated separately. 11 clean zones and 12 shaly zones were identified. After applying the cutoff values many formations show acceptable property which make them perfect productive formations. It is noticed that the reduction in net pay thickness compared to JHOC analysis is due to the re-zoning process.

The revaluation for the petrophysical properties in the two wells showed variation from the operating companies results and this variation was due to the re-zonation process for the two wells formations and change of the tops of the layers in Tasoure-26s and Al-Naser -01 wells also due to variation on a, m, and n values in Archie’s equation.

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API	American Petroleum Institute
BHA	Bottom Hole Assembly
CALI	Caliper
CCL	Casing Collar Locater
CEC	Cation Exchange Capacity
CMR	Combinable Magnetic Resonance
DST	Drill Stem Test
E&P	Exploration and Production
EOPP	Early Oil Production Phase
FOL	First Oil Level
FWLS	Free Water Levels
FWS	Full Waveform Sonic
GOC	Gas Oil Contact
GR	Gamma Ray
GR_{clean} or GR_{min}	Gamma Ray Reading in Clean Sand
GR_{SH} or GR_{max}	Gamma Ray Reading in Shale Formation
GST	Gamma Ray Spectroscopy Tool
GWC	Gas Water Contact
HI	Hydrogen Index
ID	Inner Diameter
IPL	Integrated Porosity Lithology
JHOC	Jannah Hunt Oil Company
K	Formation Permeability
LLD	Laterolog Deep
LLS	Laterolog Shallow
LTPP	Long-Term Production Phase
LWD	Logging While Drilling
M	Cementation Factor
M	Mobility
MD	Measured Depth
MSFL	Micro Spherical Focused Log
MWD	Measurement While Drilling
N	Saturation Exponent
N/G	Net to Gross Ratio
NMR	Nuclear Magnetic Resonance
NPHI	Compensated Neutron Porosity
NW-SE	North West-South East
OBM	Oil Based Mud
$Ø_{eff}$	Effective Porosity
$Ø_{total}$	Total Porosity

OWC	Oil Water Contact
PC	Capillary Pressure
PEF	Photoelectric Effect
PPM	Part Per Million
PVT	Pressure/Volume/Temperature
RHOB	Bulk Density
RMF*	Resistivity of Mud Filtrate
ROP	Rate of Penetration
R_T*	Resistivity of True Zone
R_W*	Formation Water Resistivity
SCAL	Special Core Analysis
SP	Spontaneous Potential
S_W*	Water Saturation
SWCS*	Sidewall Cores
TD	Total Depth
TDT	Thermal Decay Tool
TVD	True Vertical Depth
V_{sh}*	Volume of Shale
PB	Bulk Density
PF	Fluid Density
PG	Gas Density
PM	Matrix Density
ΔT	Interval Travel Time

CHAPTER ONE

1. INTRODUCTION

1.1. Overview

The Petrophysicists or petrophysical engineer practices the science of petrophysics as a member of the reservoir management team. The Petrophysicists provides answers on products needed and used by team members, as well as physical and chemical insights needed by other teammates.

The reservoir and fluid characteristics to be determined are Thickness (bed boundaries), Lithology (rock type), Porosity, Fluid saturations and pressures, Fluid identification and characterization, Permeability (absolute) and Fractional flow (oil, gas, water)

It’s important to understanding the petrophysical properties for The fields produced for hydrocarbons whether they are oil, gas or mixed, which require continuous evaluation and development because It's represented the backbone of the Yemeni economy. In order to determine the size of the oil wealth of the Yemeni Republic, it is necessary to ensure the correct and logical study of the rocks of these fields, considered the main center of the economy of Yemen. Therefore, the petrophysical properties must be known precisely because the petrophysical characteristics are dependent on the evaluation and development of the reservoir.

1.2. Aims and Objectives

1.2.1. Aims:

The main purpose of this study is to Re-evaluate petrophysical properties for two of the main hydrocarbons producing reservoirs in Block 32 and at Masila basin, and Block 5 at Sabatayn basin.

1.2.2. Objectives

- Reviewing previous researches conducted on the study area.
- Determining geological and stratigraphical setting in the study area.
- Correcting and analyzing the available geophysical data in order to explain the reservoir petrophysics, and evaluating the study area by Using computer software **TECHLOG 2015.3**.
- Analyze of the, petrophysical parameters (matrix, effective porosity, permeability, water saturation, hydrocarbon saturation)

- Compare the results of petrophysical analysis between the wells.
- Compare the results of petrophysical analysis of this study with petrophysical properties that don by the company.

1.3. Significant of The Research

Determination of the petrophysical properties is very critical in exploitation and development of petroleum fields. The uncertainty is faced while all petrophysical properties interpretations. This project will be focusing on re-evaluation for the petrophysical properties to make sure about the previous interpretations that had done by the operator's company. As well as, this project will show the differences between the main productive basins in Yemen to find out the real economic values of the petroleum fields in Yemen.

1.4. Scope of Study

Block 32 at Masila basin and Block 5 at Sabatayn basin.

Table 1-1 Wells of Interest Information

Well. N	Block	Field	Latitude/ Northing	Longitude/ Easting
Tasour26s	32	Tasoure	15 51' 19.553" N	49 6' 43.647" E
Al-Nasr 01	5	Al Nasr	15.244674" N	45.829948" E

1.4.1. Geology of YEMEN

Yemen is geographically located at the southwestern part of the Arabian Peninsula, situated between latitudes (12° 40" - 18° 50" N) and longitudes (42° 50" - 53° 00" E). **Fig.1-1**. It encompasses an area approximately of 536,870 square Km. Yemen is bounded on the west by the Red Sea and the south by the Gulf of Aden, which opens to the east into the Arabian Sea. East of Yemen lies Oman and north of Yemen lies Saudi Arabia. The main areas of oil production in the Middle East and Yemen is one of the countries producing oil, which is located in the Sabatayn and Masila Basin. Masila Basin and Sabatayn Basin, It's of The Thirteen Basins in Yemen, The Masila Basin lies in eastern Yemen, it is part of an extensive system of basins which trend across southern Arabia and the Horn of Africa It trends NW-SE and it is bounded by Mukalla high and Ras Fartaq arch. There are and blocks 14,10,9,32,43,47,53,51 in Masila basin. The Sabatayn Basin Lies in Central Yemen And the Second Big Oil Discovery in Yemen

Was In 1984 In Alif Field, Block (18) Marib, In Sabatayn Basin, By Hunt Oil Company. It Is Part Of An Extensive System Of Basins Which Trend Across Southern Arabia and The Horn Of Africa And It Trends NW-SE And It Is Bounded By Mahfied Out Crops And Mukalla High and Sediments Thickness Increasing From NW To SE And These Basin Can Be Subdivided Into Several Link Grabens And Half Grabens, Filled With Carbonate And Terrigenous Sediments. There in blocks 18,5, S1,4, S2 in Sabatayn basin the discovery of commercial amounts of oil in the eastern and mid areas of Yemen, the number of international oil companies working in oil exploration and production increased rapidly.

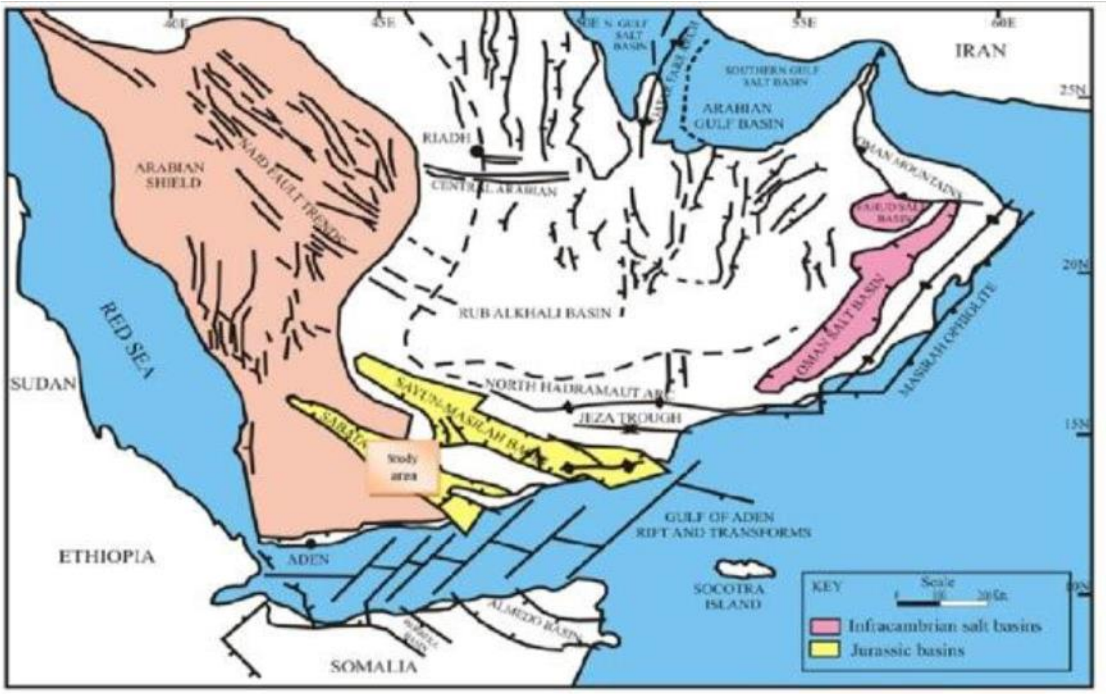

Figure 1-1 Regional tectonic trend of the Arabian craton showing the prominent NW-SE Najd trend.

1.4.2. Geological Setting of YEMEN

Yemen, situate at the southwestern part of the Arabian sub-content, it is geographically and geologically transitional in nature between Arabia and Africa plates. It occurs close to the Tertiary triple junction between the Red Sea, Gulf of Aden and East African rift systems (***Fig.1-1***). Rifting started in Yemen from Late Jurassic to Cretaceous. It is a part of the Arabian Plate and its tectonic and geological architecture is directly related to the tectonic evolution of the Arabian plate. The Arabian plate and its early geologic history were fanned as part of the northern passive margin of the supercontinent

Gondwana. Tectonic stresses associated with Gondwana break up and separated of Indian/Madagascar from Afro-Arabia, and the rejuvenated movement along the old NW-SE Najd fracture system of Arabia during Late Jurassic time. These stresses initiated a series of rift basins across Yemen and caused the breaking up of the pre-rift Jurassic carbonate platform into alternating basins and intervening uplifts. Sabatayn basin rifting is propagated southeastwards from Marib to Shabwa and then to the Hajar sector. It is the only one of the Mesozoic rift basins at Yemen, known to contain extensive evaporates throughout its sectors. The unstable margin of Sabatayn basin was the site of rapid facies changes, local disconformities and periods of emergence and dolomitization along the WNW and NNW striking boundary fault systems. The development of the Sabatayn basin can be subdivided into:

1. Pre- rifting phase (Permian - Oxfordian / Kimmerdgian),
2. Syn-rifting phase (Kimmerdgian - Tithonian) and
3. Post-rifting stage (Early Cretaceous).

Yemen has very large concession areas distributed between its middle and eastern parts. In addition, offshore areas are of a big volume located in Aden Gulf, the Red Sea and Suqatra Island.

On close scrutiny of the Yemeni Concession map, it is possible to infer the following:

- The total number of Concession blocks are 105 as show in **Fig. 1-3**.
- There are 13 producing blocks operated by 11 oil companies as show in **Table. 1-2**.
- 26 blocks are at the exploratory phases operated by 14 oil companies.
- There are 66 open blocks.

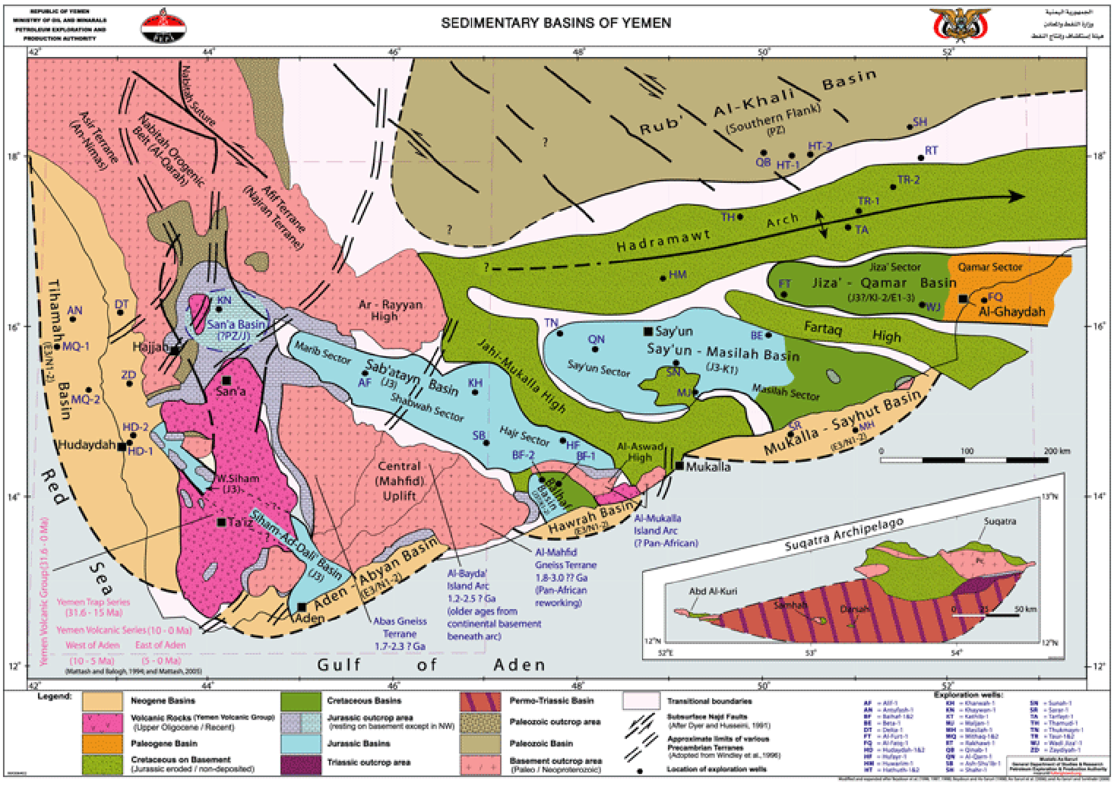

Figure 1-2 Basins of Yemen

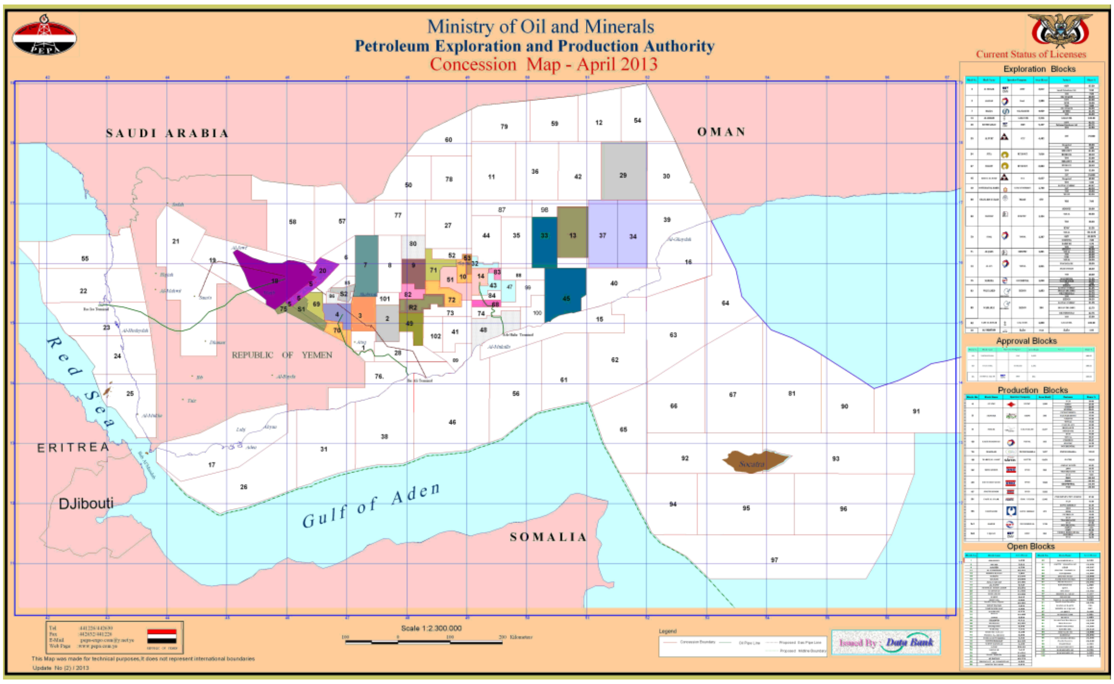

Figure 1-3 Concession Map of Yemen

The oil producing blocks in Yemen until the end of 2012 reached (13) blocks from a total of (105) blocks according to the recent oil concession map. All producing blocks are producing from only two main sedimentary basins was Masila basin and Sabatayn basin, while 12 sedimentary basins present in Yemen. The current average Daily production reached about 274,266 BOPD, whereas the oil in place of the productive blocks reaches (11.948) billion BBL. Production of (2.702 billion barrels took place by the end of Feb, 2010, whereas the gas in place in Yemen reaches about (18.215) trillion CF.

Table 1-2 The Main Blocks and Companies

Block Name	Governorate	Operator	Partners	Area (Km^2)	Start Year
Marib (18)	Marib	Safer E&P Operation Co.	SAFER	8,479	1986
Masila (14)	Hadhramaut	Petromasila	PETROMASILA	1,257	1993
East Shabwah (10)	Hadhramaut	Total E&P Yemen	TOTAL COMECO KUFPEC OCCIDENTAL	964	1997
Jannah (5)	Shabwah	Jannah Hunt	KUFPEC EXXONMOBIL JANNAH HUNT NEWCO TOTAL YICOM	280	1996
East SAAR (53)	Hadhramaut	Dove Energy	DOVE ENERGY DNO MOE PETROLIN YCO	474	2001
Hwarim (32)	Hadhramaut	DNO	ANSAN WIKFS DNO TRANSGLOBE YCO	592	2000
Damis (S1)	Shabwah	Occidental	TRANSGLOBE YCO OCCIDENTA AGENT	1,156	2004
East AL-HAJR (51)	Hadhramaut	Canadian Nexen Yemen Ltd	CDN NEXEN PET YEMEN YCO	2,004	2004
South HWARIM (43)	Hadhramaut	DNO	DNO KUWAIT ENERGY YCO	1,622	2005
Malim (9)	Hadhramaut	CAIVALLY	CALALLEY RELIANCE 5 HOOD OIL YCO	2,227	2006
W. Ayad (4)	Shabwah	KNOC	YCO KNOC YICOM	1,998	1987
Al-Uqlah (S2)	Shabwah	ONV	OMV YEMEN RESOURCES SINOPEC YCO	904	2006

1.5. Sabatayn basin

Sabatayn basin is a part of an extensive west-northwest oriented, petroliferous rift system straddling Southern Arabia and the Horn of Africa. Sabatayn basin is a west-northwest east-southeast trending late Jurassic rift system, which lies in Southeastern Yemen. Sabatayn basin is one of the most important basins in Yemen. This importance came out not just from its variation in geological structure, and numbers of the blocks that it divided to, but also from its important contribution to the volume of oil and gas production which has an extremely high economic value to the country. (**Fig. 1-3**).

The general geological structures of this basin include semi-vertical faults from NW to SE trend parallel approximately to Red sea and vertical to Gulf of Aden. Faults systems analysis in the Sabatayn basin show that the direction of the failed arm, which led to the creation of the Sabatayn basin have been formed around 160M years ago, was dictated by large-scale NW- SE and NE-SW shear faults that began a billion years earlier, during the Precambrian. The NE-SW lines of weakness in the earth's crust are termed the Najd fault zones and can be seen crossing Arabian and African plates. When Gondwana split apart, the crust in Yemen responded by stretching, fracturing and block faulting along one of these ancient fault zones. At this time, Yemen and Somalia were connected and, for this reason, there is no evidence of rifting in the present-day Gulf of Aden. The exploration drilling has revealed that, each of the sub-basins defined by geophysical data (gravity, magnetic and seismic) was filled by various types and sequences of sediments, resulting in different reservoir types. The Marib sub basin is a complex mixture of interfingering sandstones, evaporates and shales with the sandstone reservoirs being dominant. In contrast, the Ayad sub-basin is dominated by carbonate reservoir zones. Sabatayn basin includes sediments from Middle Jurassic to Cretaceous sequences above the basement (**Fig. 1-4**). The Upper Jurassic section at Sabatayn basin reflects post Pangea breakup and the creation of basins the clastic rocks of Sabatayn Formation (Tithonian) are regarded as petroleum reservoir of Sabatayn basin, these rocks are as following: formed by rifting. **Fig. 1-1**

Table 1-1 Sabatayn Basin Hydrocarbon System

Age	Rock Unit	Rock Unit	Type of rocks	Description
Upper Tithonian	Sabatayn Formation	Safer Member	Evaporates	Cap Rocks
Lower-Upper Tithonian		Alif Member	Sandstone (with Some Shale)	Reservoir
Lower-Middle Tithonian		Seen Member	Sandstone (with Some Shale)	Reservoir
Lower Tithonian		Yah Member	Sandstone	Reservoir
Lower Tithonian-Upper Kimmeridgian	Madbi Formation	Lam – Meem Members	Shale	Source Rock

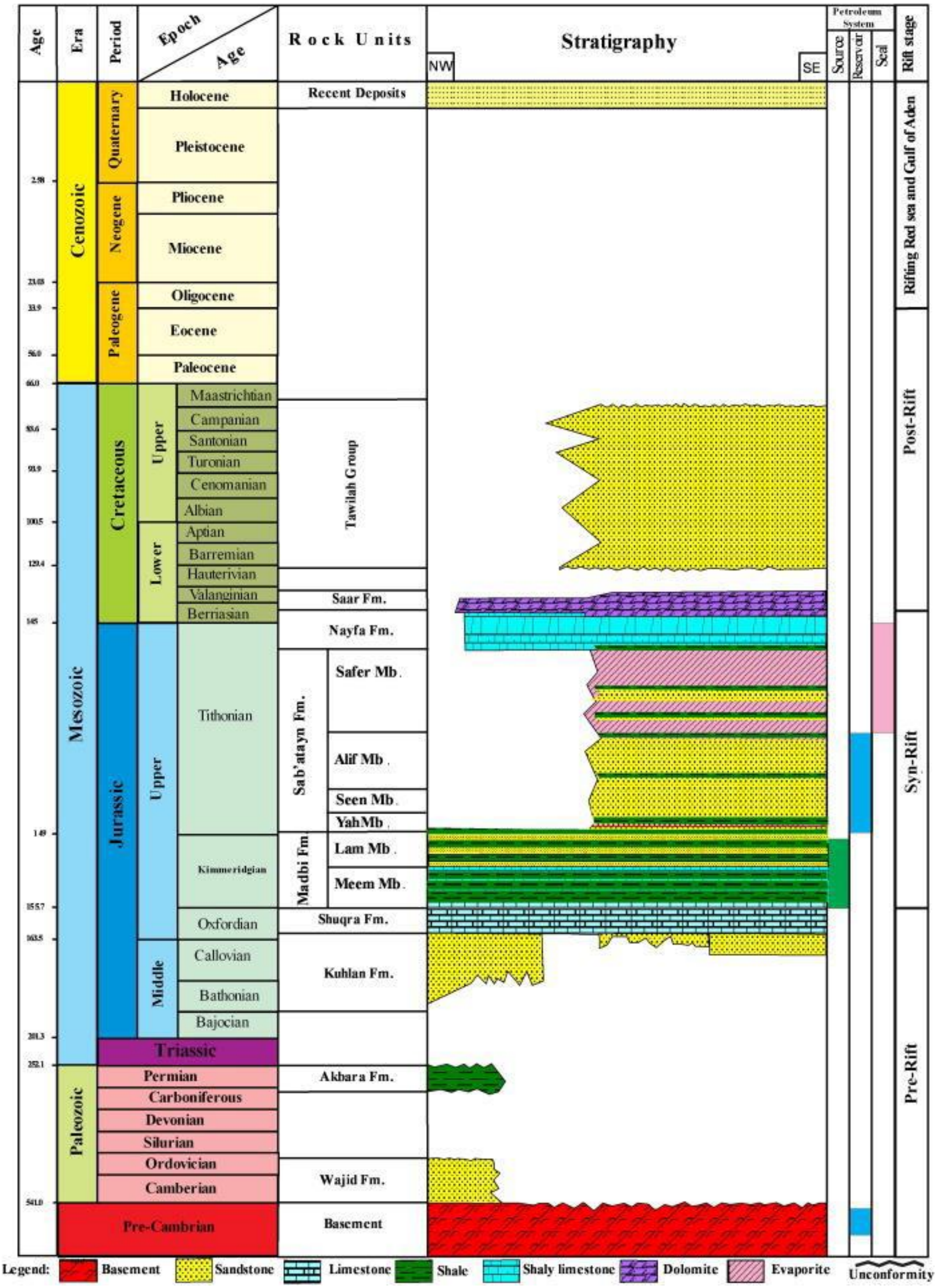

Figure 1-4 Lithostratigraphy of the Sabatayn basin

1.5.1. Stratigraphy of Sabatayn Basin

Basement: it consists mostly of highly metamorphosed rocks ranged in age from Archean to Early Proterozoic and slightly metamorphosed Upper Proterozoic to Lower Cambrian complexes. The sedimentary sequence of Sabatayn basin composed of different rocks ranged in age from Middle Jurassic to Cretaceous **[1]** (***Figure 1.4***):

The sedimentary sequence of this basin which overlying the basement rock include the following rock units from base to top:

Kuhlan Formation (Bathonian to Kimmeridgian): it represents the basal Jurassic rock unit it is composed of sandstone with minor amounts of conglomerate, shale and limestone.

Shuqra Formation (Oxfordian to Kimmeridgian): this Formation had been deposited in a broad shallow shelf environment. It is predominantly a platform carbonate with local reefal build-up and divided into two members **Saba** and **Arwa** Members.

Saba Member The basal part of this member is often sandy due to reworking of the Kuhlan Formation. It is overlain by limestone composed of wackestone and packstone containing interbeds of mudstone.

Arwa Member conformably overlies Saba Member. It is composed of argillaceous limestone and deep-water lime mudstone, the limestone composed of locally minor packstone, wackestone and grainstone in combination with black shale.

Madbi Formation (Kimmeridgian to Tithonian): It is divided also into the Meem and Lam Members.

Meem Member consists of various facies including shallow to relatively deep marine carbonate, shallow marine sandstone, turbidite and organically rich mudstone. It is conformably overlain Arwa Member.

Lam Member is similar in the lithology to the Meem Member; however, it is dominating in sandstone, which interpreted to be turbidite and generally occur as thin beds intercalating the mudstone.

Sabatayn Formation (Tithonian): It is divided into four members Yah, Seen, Alif and Safer Members from base to top.

Yah Member (Early Tithonian): fluvial-deltaic sandstone, mudstone and evaporate are the main component [1].

Seen Member (Early-Middle Tithonian): Interbedded sandstones and shales/mudstones [2]. It is the second evaporate-clastic sequence.

Alif Member (Middle-Late Tithonian): Mainly sandstone with subordinate interbedded shales/mudstone, local anhydrites and dolomitic limestone’s [2]. **Deposited in environments ranged from braided stream, delta front to deeper water turbidity**. It is occurred in Marib-Al-Jawf-Shabwa rift system and forms the most productive reservoir unit **[1].**

Safer Member (Late Tithonian) represents evaporitic condition in the Marib-Al Jawf-Shabwa rift system and consists mainly of halite including minor amount of anhydrite, dolomite and clastics.

Naifa Formation (Tithonian-Berriasian): it consists of argillaceous limestone and calcareous mudstone with minor sandstone deposited in shallow marine environment. It conformably overlies Safer Member and unconformably the Madbi Formation in where the Sabatayn Formation is absent.

Tawilah Group: (Barremian-Campanian): it consists of the following formations from base to top: Saar, Qishn, Harshiat, Fartaq, Mukalla and Sharwayn Formations.

Saar Formation: consists mainly of limestone and mudstone with minor sandstone deposited in open marine environments.

Qishn Formation is divided into four members, Clastic and Carbonate members. **Harshiat Formation**: consists mainly of sandstone deposited in different environments from alluvial to fluvial-deltaic to shallow marine. These clastics interdigitate with carbonate sequence described as the **Fartaq Formation**. **Mukalla Formation:** consists mainly of alluvial fan, fluvial-deltaic and shallow marine sandstone and mudstone with shallow marine carbonate named the Lusb Member.

Sharwayn Formation: it represents the marine transgression in the Cretaceous. This consists mainly of shallow marine carbonate with minor deeper carbonate.

1.5.2. Block 5

located in (Marib-Shabwa) basin, with area of (280) **Km²**, Block (5) operated by **Jannah Hunt Oil Company**.

The main reservoirs in the block are (Alif Sand) and (Seen Sand).

1.5.2.1. Al Naser Field

20 wells were drilled in Al-Nasr field of which 6 wells are used for water injection. One exploratory well was drilled in Aser field and completed as an oil producer. Four wells were drilled in Jannah field, of which one well was plugged and abandoned.

As show in **Fig. 1-5**

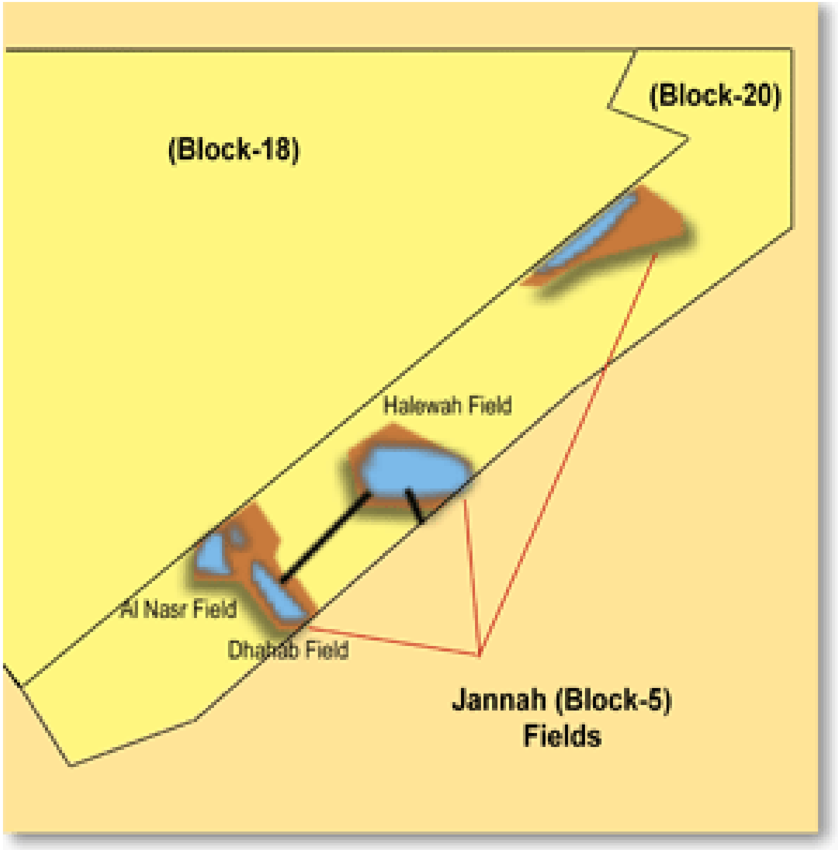

Figure 1-5 Fields In (Block 5)

1.6. Masila basin

The Masila Basin lies in eastern Yemen, it is part of an extensive system of basins which trend across southern Arabia and the Horn of Africa.

- It trends NW-SE and it is bounded by Mukalla high and Ras Fartaq arch
- Sediments thickness increasing from NW to SE.
- The depth of basement of Masila basin ranged between 1-4 Km.
- The basin can be subdivided into several link grabens and half grabens, filled with carbonate and terrigenous sediments.

- The filling of the basin includes Pre Cambrian reconstruction, Mesozoic (Jurassic and Cretaceous) and Cenozoic sediments.

1.6.1. Geological Setting of Masila Basin

Masila rift basin is bounded on the west and south by the Mukalla-Jahi; to the east by the Mukalla-Sayut rift basin and to the north by Ras Fartaq High and partially interrupted to the north-west by North Hadramout Arch **Fig. 1-2** , The Masila rift basin is a few hundred kilometers wide and several hundred kilometers long and is having northwest-southeast orientation.

Masila rift basin was formed during the Upper Jurassic (Kimmeridgian),when the Africa-Arabian Plate separated from the Indian-Madagascar Plate and continued in this area into the Berriasian.

1.6.2. Stratigraphy of Masila Basin

The Masila basin, based on data from Geophysical and Geological carried out by Oil Companies, and Exploration wells drilled in the basin, the basin filled with carbonate and terrigenous sediments the filling of the basin includes Paleozoic, Mesozoic and Cenozoic sediments show in **Fig. 1-6**.

Hlan Formation

Bathonian or possibly older to Kimmeridigian. Predominantly a continental sandstone sequence with thin conglomerates Deposition of the Kuhlan Formation was controlled by Pre-Jurassic topography.

Shuqra Formation

Callovian Kimmeridgian Consists of shallow marine limestone and dolomites.

Madbi Formation

Kimmeridgian - "lower" Tithonian Comprises limestones and calcareous mudstones.

Naifa Formation

upper Tithonian – Berriasian Consists mainly of shallow water Limestone and mudstone.

Saar Formation

Lower Valanginian. Consist of Limestone, locally intercalation with sandstone (shallow marine carbonates).

Qishn Formation

(Barremian- Aptian). The Qishn Formation, is divided into:

Clastic member is generally sandstones and mudstones with minor carbonates (fluvio-deltaic and shallow marine).

Shale member consist of shale.

Carbonate Member comprises. Shallow marine carbonates and mudstones

The sediments are initially of the reactivation.

Tawilah Group

Albian- Maastrichtian. Represents a sequence of alluvial fan to fluvio-deltaic clastics with minor shallow marine carbonate transgressive events. The group is divided into three formations as follow:

Harshiyat Formation:

Comprises sandstones, alluvial fan to fluvio-deltaic and shallow marine. Two carbonate sequences defined as members of the Harshiyat Formation Rays and Sufla Members.

Fartaq Formation:

Dominantly consist shallow marine carbonates.

Mukalla Formation:

(Turonian - Maastrichtian). Similar to the underlying Harshiyat Formation. It comprises mainly alluvial fan, fluvio-deltaic and shallow marine sandstones and mudstones with thin coal, Towards the east of the area appears a shallow marine carbonate unit, the Lusb Member.

Sharwayn Formation

Maastrichtian. It comprises mainly shallow marine carbonates with subordinate deeper water carbonates. Shallow marine and fluvio-deltaic clastics were deposited in the western area.

Hadhramaut Group

Umm Er Radhuma

Formation Upper Paleocene- Lower Eocene, comprises shallow marine carbonates with rare shallow marine mudstones and sandstones, at the base consist of shale.

Jeza Formation

Lower Eocene Represents a sequence of near shore and shallow marine carbonates, locally (at the top of the formation) anhydrite.

Rus Formation

Middle Eocene Consist of anhydrite, interbedded limestone and dolomites More open marine conditions or storm events in eastern Yemen –Qamar bay.

Shihr Group

Oligocene - Recent It is predominantly shallow marine clastics with rare limestones.

1.6.3. Block 32

Located in Masila- Sya'un basin, Block (32) is operated by DNO- Norwegian Company. The main reservoirs in the block are (Qishn Clastic), and expected to be produce from the fracture basement rocks in the future.

1.6.3.1. Tasour Field

The Tasour area presents unique exploration/development challenges that have been met over the past 10 years by successful trial and error. Seismic acquisition has now reached the point where very good quality 2D data can be expected with careful field procedures. The Tasour field continues to grow in size with each additional well and is now approximated at 21 MMBO recoverable (38 MMBO in place). Several new prospects have been delineated with the current evolved methodology. Resolution of the fault shadow issue has significantly enhanced the pool size. Earlier interpretation as a faulted anticlinal structure has been replaced with a more typical rotated fault block interpretation without significant rollover into the fault.

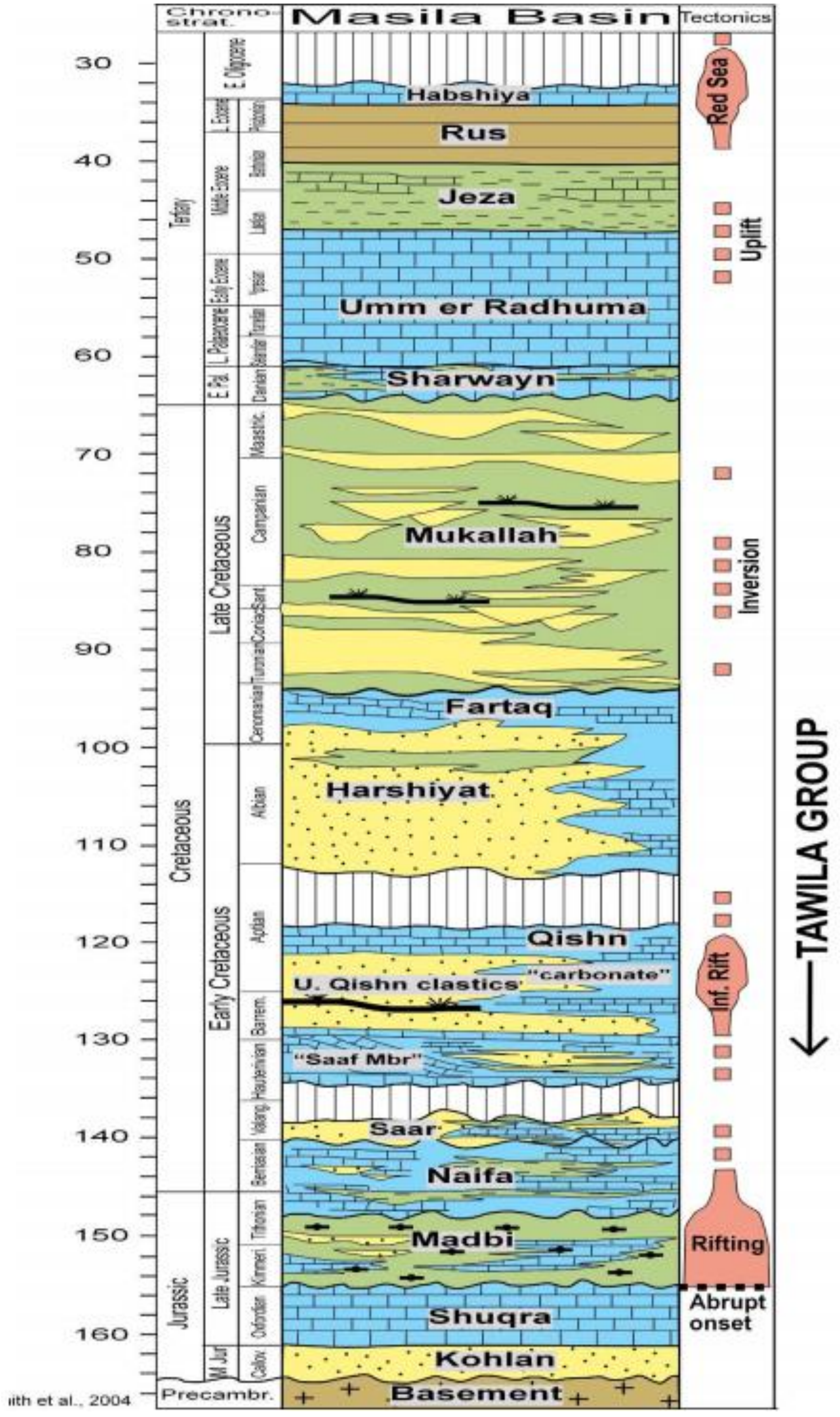

Figure 1-6 Masila Basin's Lithostratigraphy

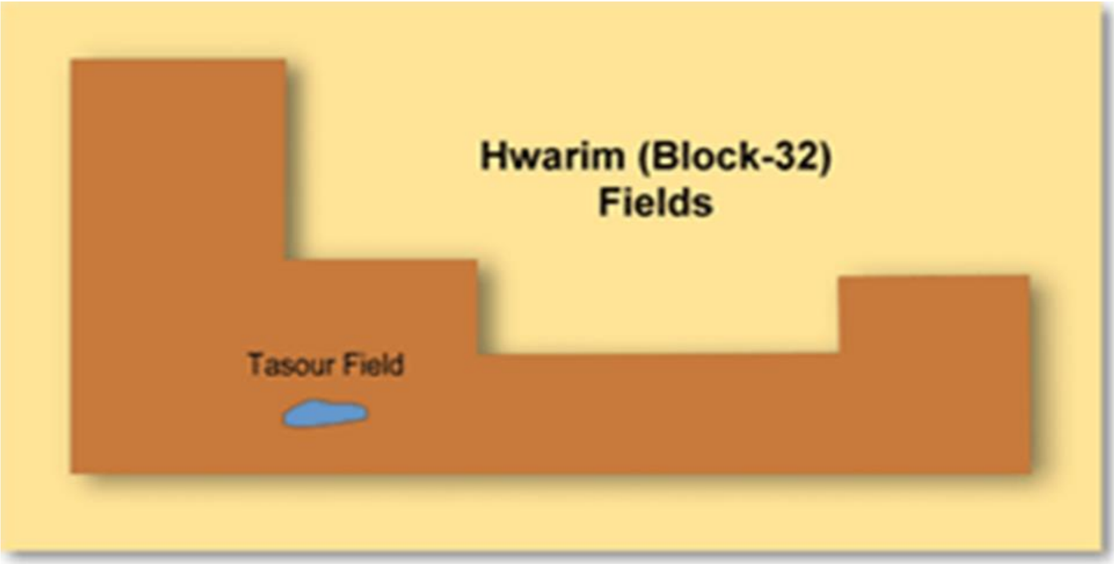

Figure 1-7 Fields In (Block 32)

CHAPTER TWO

2. LITERATURE REVIEW

2.1. Introduction

The Literature review is one of the main phases in performing any research, as it usually highlights the main gaps in the previous studies, which may need to be filled. It helps also to understand the necessary direction to follow to develop the study.

2.2. Formation Evaluation Overview:

Formation evaluation is the process of using borehole measurements to evaluate the characteristics of subsurface formations. It applies to many areas of engineering where various rock properties are needed.

Formation evaluation represents the expenditure of a considerable sum of money each year. In each individual well, the evaluation cost may range up to 20 % of the total well cost. A wide variety of in-situ measurements are available for evaluating formations in an individual well. These measurements may be grouped into four categories:

- Drilling Operation Logs (Mud Logs): cuttings analysis, mud analysis, and drilling data collection and analysis
- Core Analysis: qualitative measurements (visual lithology, presence of shows. etc.) and quantitative measurements (porosity, permeability, formation factors...etc.)
- Wireline Well Logs: electrical (spontaneous potential, SP non-focused current resistivity, focused current resistivity, induction). Acoustic (transit time, Full-wave train, borehole tele-viewer), and radioactive (gamma ray, neutron, density, neutron lifetime, spectral)
- Productivity Tests: formation tester, drill stem tests, and production tests.

2.2.1. The Importance of Formation Evaluation

Formation Evaluation is one of the most important process in oil and gas industry. This process is usually required to:

1. To locate the potential zones and determine its lithology

2. Evaluate hydrocarbons reservoirs and predict oil recovery.

3. Perform measurement of in situ formation fluid pressure and acquisition of formation fluid samples.

4. Provide the reservoir engineers with the formation's geological and physical parameters necessary for the construction of a fluid-flow model of the reservoir.

5. Generally, in petroleum exploration and development, formation evaluation is used to determine the ability of formations to produce petroleum.

All mentioned above can be done using data from different sources such as drilled cuttings, well logs, cores, and test results.

The field of geology that is of most importance to the oil industry and can help evaluate the subsurface formation is sedimentology. It entails a precise and detailed study of the composition, texture and structure of the rocks, the color of the constituents, and identification of any traces of animal and plant organisms. This enables the geologist to perform the following:

a) To identify the physical, chemical and biological conditions prevalent at the time of deposition.
b) To describe the transformations that the sedimentary series has undergone since deposition. He must also consider the organization of the different strata into series, and their possible deformation by faulting, folding, and so on. The geologist depends on rock samples for this basic information. On the surface, these are cut from rock outcrops. Their point of origin is obviously precisely known, and in principle a sample of any desired size can be taken, or repeated. Sampling from the subsurface is rather more problematic. Rock samples are obtained as cores or cuttings.

Cores obtained while drilling (using a core-barrel), by virtue of their size and continuous nature, permit a thorough geological analysis over a chosen interval. Unfortunately, for economic and technical reasons, this form of coring is not common practice, and is restricted to certain drilling conditions and types of formation.

"Sidewall-cores", extracted with a core-gun, sample-taker or core-cutter from the wall of the hole after drilling, present fewer practical difficulties. They are smaller samples, and, being taken at discrete depths, they do not provide continuous information.

However, they frequently replace drill coring, and are invaluable in zones of lost-circulation.

Cuttings (the fragments of rock flushed to surface during drilling) are the principle source of subsurface sampling. Unfortunately, reconstruction of a lithological sequence in terms of thickness and composition, from cuttings that have undergone mixing, leaching, and general contamination, during their transportation by the drilling-mud to the surface, cannot always be performed with confidence. Where mud circulation is lost, analysis of

whole sections of formation is precluded by the total absence of cuttings. In addition, the smallness of this kind of rock sample does not allow all the desired tests to be performed.

Because of these limitations, it is quite possible that the subsurface geologist may find himself with insufficient good quality, representative samples, or with none at all. Consequently, he is unable to answer with any confidence the questions fundamental to oil exploration:

a) Has a potential reservoir structure been located?
b) If so, is it hydrocarbon-bearing?
c) Can we infer the presence of a nearby reservoir?

An alternative, and very effective, approach to this problem is to take in situ measurements, by running well logs. In this way, parameters related to porosity, lithology, hydrocarbons, and other rock properties of interest to the geologist, can be obtained. The first well log, a measurement of electrical resistivity, devised by Marcel and Conrad Schlumberger, was run in September 1927 in Pechelbronn (France). They called this, with great foresight, “electrical coring”. Since then scientific and technological advances have led to the development of a vast range of highly sophisticated measuring techniques and equipment, supported by powerful interpretation procedures.

Well log measurements have firmly established applications in the evaluation of the porosities and saturations of reservoir rocks, and for depth correlations.

More recently, however, there has been an increasing appreciation of the value of log data as a source of more general geological information. Geologists have realized, in fact, that well logs can be to the subsurface rock what the eyes and geological instruments are to the surface outcrop. Through logging this study measures a number of physical parameters related to both the geological and petrophysical properties of the strata that have been penetrated; properties which are conventionally studied in the laboratory from rock-samples. In addition, logs tell us about the fluids in the pores of the reservoir rocks.

Log data constitute, therefore, a “signature” of the rock; the physical characteristics they represent are the consequences of physical, chemical and biological (particularly geographical and climatic...) conditions prevalent during deposition; and its evolution

during the course of geological history. Log interpretation should be aimed towards the same objectives as those of conventional laboratory core-analyses. Obviously, this is only feasible if there exist well-defined relationships between what is measured by logs, and rock parameters of interest to the geologist and reservoir engineer.

The descriptions of the various logging techniques will show that such relationships do indeed exist, and that the study may assume:

a) A significant change in any geological characteristic will generally manifest itself through at least one physical parameter which can be detected by one or more logs.
b) Any change in log response indicates a change in at least one geological parameter.

2.3. Well Logging Overview

Well logging plays a central role in the successful development of a hydrocarbon reservoir. Its measurements occupy a position of central importance in the life of a well, between two milestones: the surface seismic survey, which has influenced the decision for the well location, and the production testing. The traditional role of wireline logging has been limited to participation primarily in two general domains: FORMATION EVALUATION and completion evaluation.[1]

The goals of formation evaluation can be summarized by a statement of four questions of primary interest in the production of hydrocarbons:

- Are there any hydrocarbons, and if so, are they oil or gas?
- First, it is necessary to identify or infer the presence of hydrocarbons in formations traversed by the wellbore.
- Where are the hydrocarbons?
- The depth of formations which contain accumulations of hydrocarbons must be identified.
- How much hydrocarbon is contained in the formation?
- An initial approach is to quantify the fractional volume available for hydrocarbon in the formation. This quantity, porosity, is of utmost importance. A second aspect is to quantify the hydrocarbon fraction of the fluids within the rock matrix. The third concerns the areal extent of the bed, or geological body, which contains the hydrocarbon. This last item falls largely beyond the range of traditional well logging.
- How producible are the hydrocarbons?
- In fact, all the questions really come down to just this one practical concern. Unfortunately, it is the most difficult to answer from inferred formation properties. The most important input is a determination of permeability. Many empirical methods are used to extract this parameter from log measurements with varying degrees of success. Another key factor is oil viscosity, often loosely referred to by its weight, as in heavy or light oil.

Formation evaluation is essentially performed on a well-by-well basis. A number of measurement devices and interpretation techniques have been developed. They provide, principally, values of porosity and hydrocarbon saturation, as a function of depth, using the knowledge of local geology and fluid properties that is accumulated as a reservoir is developed. Because of the wide variety of subsurface geological formations, many different logging tools are needed to give the best possible combination of measurements for the rock type anticipated. Despite the availability of this rather large number of devices, each providing complementary information, the final answers derived are mainly three: the location of oil-bearing and gas-bearing formations, an estimate of their producibility, and an assessment of the quantity of hydrocarbon in place in the reservoir.

2.4. Formation Evaluation Data Sources

Data needed for formation evaluation has many sources such as:

2.4.1. Measurement While Drilling (MWD)

Some Measurements are required to be recorded while drilling is ongoing. This is called measurement while drilling (MWD). Tools are run as an integral part of the drill string. When real-time information is required for operational reasons, such as steering a well (e.g., a horizontal trajectory-to record inclination and azimuth) in a particular formation, and to pick formation tops, coring points, and/or casing setting depths (GR, Resistivity).

Although many measurements are taken while drilling, the term MWD is more commonly used to refer to measurements taken down-hole with an electromechanical device located in the bottom-hole assembly (BHA). Normally, the capability of sending the acquired

information to the surface while drilling continues is included in the broad definition of MWD. Telemetry methods had difficulty in coping with the large volumes of down-hole data, so the definition of MWD was again broadened to include data that was stored in tool memory and recovered when the tool was returned to the surface. All MWD systems typically have three major subcomponents of varying configurations: a power system, a directional sensor, and a telemetry system.

2.4.2. Logging While Drilling (LWD)

Logging While Drilling or LWD is the general term we use to describe the systems and techniques for gathering down-hole data while drilling a well. A more specific definition is the acquisition of petrophysical data. Generally, LWD offers the same measurements as wireline, with some differences in quality, resolution and/or coverage.

Traditionally, Petrophysicists were concerned only with wireline logging, that is, the data acquired by running tools on a cable from a winch after the hole had been drilled. However, advances in drilling/logging technology have allowed the acquisition of log data via tools placed in the actual drilling assembly. These tools may transmit data to the surface on a real-time basis or store the data in a down-hole memory from which it may be downloaded when the assembly is brought back to the surface.

LWD tools present a complication for drilling, as well as additional expense. However, their use may be justified when:

- Real-time information is required for operational reasons, such as steering a well (e.g., a horizontal trajectory) in a particular formation or picking of formation tops, coring points, and/or casing setting depths.
- Acquiring data prior to the hole washing out or invasion occurring
- Safeguarding information if there is a risk of losing the hole
- The trajectory is such as to make wireline acquisition difficult (e.g., in horizontal wells).
- LWD data may be stored down-hole in the tools memory and retrieved when the tool is brought to the surface and /or transmitted as pulses in the mud column in real time while drilling.
- In a typical operation, both modes will be used, with the memory data superseding the pulsed data once the tool is retrieved. However, factors that might limit the ability to fully use both sets of data are:
- Drilling mode: Data may be pulsed only if the drill-string is having mud pumped through it.
- Battery life: Depending on the tools in the string, tools may work in memory mode only between 40 and 90 hours.
- Memory size: Most LWD tools have a memory size limited to a few megabytes. Once the memory is full, the data will start to be overwritten. Depending on how many parameters are being recorded, the memory may become full within 20–120 hours.
- Tool failure: It is not uncommon for a fault to develop in the tool such that the pulse data and /or memory data are not transmissible/ recordable.

Some of the data recorded may be usable only if the tool string is rotating while drilling, which may not always be the case if a steerable mud motor is being used. In these situations, the Petrophysicists may need to request drilling to reacquire data over particular intervals while in reaming/rotating mode. This may also be required if the rate of penetration (ROP) has been so high as to affect the accuracy of statistically based tools (e.g., density/neutron) or the sampling interval for tools working on a fixed time sampling increment. Another important consideration with LWD tools is how close to the bit they may be placed in the drilling string. While the Petrophysicists will obviously want the tools as close to the bit as possible, there may be limitations placed by drilling, whose ability to steer the well and achieve a high ROP is influenced by the placement of the LWD tool string. LWD data that may typically be acquired include the following:

- GR: natural gamma ray emission from the formation
- Density: formation density as measured by gamma ray Compton scattering via a radioactive source and gamma ray detectors. This may also include a photoelectric effect (Pe) measurement.
- Neutron porosity: formation porosity derived from the hydrogen index (HI) as measured by the gamma rays emitted when injected thermal or epithermal neutrons from a source in the string are captured in the formation
- Sonic: the transit time of compressional sound waves in the formation
- Resistivity: the formation resistivity for multiple depths of investigation as measured by an induction-type wave resistivity tool.

Some contractors offer LWD-GR, -density, and -neutron as separate up/down or left/right curves, separating the contributions from different quadrants in the borehole. These data may be extremely useful in steering horizontal wells, where it is important to determine the proximity of neighboring formation boundaries before they are actually penetrated. Resistivity data may also be processed to produce a borehole resistivity image, useful for establishing the stratigraphic or sedimentary dip and/or presence of fractures/vugs. Other types of tool that are currently in development for LWD mode include nuclear magnetic resonance (NMR), formation pressure, and shear sonic.

2.4.3. Open-Hole Logging

Open hole logging devices are used to characterize subsurface formations. Common formation attributes that may be characterized include:

- Storage capacity of the formation, which normally includes porosity and fluid saturations,
- Fluid properties, which include density, gas to oil ratio, API gravity, water resistivity and salinity, temperature, and pressure.

- Geological setting, which may include structural or stratigraphic dip, facies characteristics, and reservoir heterogeneities.

The basic open hole wireline logging devices can be divided into four general groups, as shown in **Table 2-1**. The correlation and lithology devices are used primarily to correlate between wells and to discriminate reservoir from non-reservoir rocks. The resistivity devices are used to determine formation resistivity at varying distances from the wellbore, which is used for correlation and the determination of water saturation. The lithology and

porosity devices are used to determine both lithology and porosity. A variety of auxiliary tools is used to make special logging measurements.

Table 2-1 Basic open hole tools

Type	Device
Correlation and lithology	Spontaneous potential
	Gamma ray
	Photoelectric effect
Resistivity	Induction
	Laterolog
	Micro resistivity
Porosity and Lithology	Density
	Compensated Neutron
	Sonic
	Photoelectric effect
Auxiliary	Caliper
	Formation Tester
	Dimeter
	Borehole Televiewer

2.4.3.1. Correlation and Lithology

Correlation devices are used to identify common formations between wells and their lateral extension and to distinguish potential reservoir rocks from non-reservoir rocks. These devices make use of three different physical phenomena: spontaneous potential, gamma rays, and photoelectric effect.

Spontaneous Potential

Spontaneous potential (SP) is a natural voltage or electrical potential that arises due to differences in the ionic activities (relative saltiness) of the drilling mud and the formation waters. This potential can be used to correlate formations between wells, to indicate permeability, and to estimate formation water resistivity. No SP occurs when oil-based mud is used in the borehole. Hydrocarbons and shaliness in the formation suppress the SP. The magnitude of the SP decreases as the resistivity of the mud filtrate and formation waters approach a common resistivity. The direction of SP deflection reverses as the ratio of the resistivity of the mud filtrate (Rmf) to that of the formation water (Rw) reaches 1.0 or more. If there is no contrast in the mud filtrate and formation water salinities, there is no measurable SP.

Gamma Ray

Gamma rays' tools measure the natural radioactivity of the formation. This radioactivity is emitted primarily from potassium in the structure of clay minerals, radioactive salts in the formation waters, radioactive salts bound to the charged surfaces of clay minerals, potassium associated with feldspars, and radioactive minerals associated with igneous rocks and rock fragments. The gamma ray response is used for correlation of formations between wells and for estimating volume shale and/or volume clay minerals.

An advanced version of the gamma ray tool, called the spectral gamma ray, breaks down or segments the detected gamma rays by their different energies using spectral analysis techniques. These segments correspond to the radioactive families of potassium, uranium, and thorium. Uranium frequently occurs as a precipitated salt deposited in a formation from waters having flown through that formation. When this occurs, the uranium counts disguise radioactivity due to mineralogy. The use of the spectral tool allows the removal of gamma ray counts caused by uranium, typically permitting more accurate use of the remaining gamma rays for determining lithology, volume shale, or volume clay. In some local areas, ratios of potassium to thorium have been successfully used to determine some clay types. However, this clay typing has not proven particularly universal and should be attempted with much caution.

Photoelectric Effect

The photoelectric effect, or Pe, measures a formation's ability to absorb gamma rays. The absorptive abilities of formations vary with lithology. The photoelectric absorption is recorded as a supplementary measurement to the formation density measurement, using common detectors and radioactive sources. Since this measurement is part of the density measurement, the tool is a pad contact tool and is subject to borehole wall rugosity. The measurement is not valid in muds weighted with barite. The recording can be used both for correlation of formations between wells and for determining lithology.

The photoelectric effect is used for lithology determination. Knowledge of lithology significantly improves the accuracy of interpretation of all the porosity measurements.

Table 2-2 Correlation Devices Resolution and Applications

Tool	Vertical Resolution	Radius of Investigation	Applications	Limitations
Spontaneous potential (SP)	6–10 ft.	N/A	Well-to-well correlation, estimate *R*w, and indicate permeability	Does not work in oil-based mud and *R*mf and *R*w must contrast
Gamma ray	2 ft.	12 in	Well-to-well correlation and estimate $\mathbf{V_{sh}}$	Sensitive to hole size changes
Spectral gamma ray	3 ft.	16 in	Well-to-well correlation and estimate *V*sh	Sensitive to hole size changes
photoelectrical effect (Pe)	2 in	2 in	Identify lithology and well-to-well correlation	Does not work in barite mud, is a pad device, and uses a radioactive source

2.4.3.2. Resistivity

Resistivity tools are primarily used for correlation and to determine the volume of the pore space saturated with water. Resistivity tools can be divided into three tools types: induction, laterolog, and microresistivity tools.

Induction

Induction tools use electromagnetic coils to establish magnetic fields that excite current flow in the formation, which in turn excites secondary magnetic fields and current flow in receiver coils in the tool. This principle of exciting magnetic fields allows induction tools to measure resistivity without the requirement of a direct electrical connection to the formation. This feature permits the tool to be used in nonconductive muds (OBM). Different transmitter and receiver arrays allow focusing of the measurement for different vertical resolution and depths of investigation.

Laterologs

The laterolog device measures the voltage and current magnitudes associated with a series of current electrodes mounted on the surface of the logging sonde, such tools operate in salty mud and measure the resistivity of uninvaded zone. These measurements require direct electrical contact with the formation, which is normally provided by the drilling mud.

This characteristic does not allow this measurement to be made in oil-based muds. The focusing of the laterolog measurement is accomplished through the placement of the electrodes. Generally, laterologs exhibit very good vertical resolution. Because the measured currents must pass through the drilling mud and the flushed zone to enter the unaltered formation, laterolog measurements are usually unfavorably influenced by nonconductive mud and mud filtrate.

The deep laterolog measurement current is returned to the earth's surface to ensure deep investigation and to minimize the influence of resistive beds. However, the surface return can give rise to anomalously high resistivity readings for tens of feet below massive, extensive, highly resistive beds. This phenomenon is known as the Groningen effect.

Microresistivity

Microresistivity devices are used to estimate the resistivity of the flushed zone immediately adjacent to the borehole. The devices are of the pad contact type to ensure that the investigation is very shallow and to minimize the influence of changing hole sizes and tool position within the borehole. This shallow investigation can result in mudcake being a significant influence. Hole size and mudcake corrections are commonly required. Like laterologs, these devices require a direct electrical contact with the formation. For this reason, microresistivity devices cannot be used in oil-based muds. Formation resistivity is typically profiled with three resistivity measurements of different depths of investigation to characterize the influence of the invading mud filtrate upon apparent formation resistivity. This characterization permits the influence of the flushed zone to be separated from the reading of the deep device for a more accurate determination of the true formation resistivity (Rt).

2.4.3.3. Porosity

Each of the porosity tools density, compensated neutron, sonic, and photoelectrical effect can be used to estimate porosity when lithology and fluid properties are known. **Table 2-3**. shows the resolution and applications of porosity devices.

Density

The density tool measures the apparent density of the formation using a radioactive source that bombards the formation with high energy gamma rays and then measures the number of lower energy gamma rays returning to the detectors. The detectors and source are mounted in a pad that is forced against the borehole wall. The measurement attempts to correct automatically for the effects of mudcake and minor hole rugosity. The measurement is sensitive to significant borehole wall rugosity and pad standoff, which cause the tool to read too low of a density.

Compensated neutron

Compensated neutron devices measure the hydrogen index of the formation using a radioactive neutron source that bombards the formation with fast-moving neutrons. Neutrons collide with atoms of the formation, transferring their energy through these collisions. The most efficient transfer of energy occurs with hydrogen atoms because the mass of hydrogen is approximately the same as the mass of a neutron. Two detectors count the number of deenergized (thermal) neutrons returning from the formation. The ratio of the detector count rates is primarily related to the hydrogen index or the apparent water-filled porosity.

The source and detectors are mounted in a mandrel that, ideally, is pressed against the borehole to minimize the influence of the high apparent porosity of the borehole. This measurement is very sensitive to tool standoff, hole size, temperature, and salinity. Environmental corrections are highly recommended before attempting to interpret results. Gas has a very low hydrogen index compared to water, which causes the tool to report abnormally low porosities in gas-bearing formations. When used in conjunction with density measurements, gas-bearing intervals are often easy to identify.

Table 2-3 The Resolution and Applications of Porosity Devices.

Limitations	Applications	Radius of Investigation	Vertical Resolution	Tool
Compensated density	18 in.	8 in.	Estimate porosity	Pad contact device
Compensated neutron	2 ft.	10 in.	Estimate porosity and identify presence of gas	Needs environmental corrections; sensitive to standoff from wall
Porosity Lithology)	1 ft.	--	Estimate porosity and identify presence of gas, thin bed evaluation, shalt sand evaluation	Needs environmental corrections; sensitive to standoff from wall
Sonic	2 ft.	Typically, 6 in.	Measure compressional velocity and estimate porosity	Sensitive to compressibility
FWS (monopole)	4 ft.	Typically, 6 in.	Measure compressional and shear velocities and estimate porosity	Cannot measure shear velocity when shear velocity > mud velocity
Dipole sonic	4 ft.	Typically, 12 in	Measure shear velocity	—
CMR* (Combinable Magnetic Resonance)	6 in.	1 in.	Porosity, pore size distribution, permeability	Minimum 6.5 in. wellbore
Photoelectrical effect (Pe)	2 in.	2 in.	Identify lithology and correlation	Does not work in barite mud and pad contact tool

Sonic

Sonic devices measure the velocity of various acoustic waves, most notably compressional, shear, and Stoneley waves. The velocity of the waves is a function of the elastic properties and the density of the formation. Logs normally present the inverse of velocity, called the interval transit time or delta t (Δt).

Two versions of the compressional sonic device are available: the compensated sonic and the full waveform sonic (FWS). The full waveform sonic contains an array of receivers that are used to determine both compressional and shear velocities. Sonics are available in a variety of transmitter-to-receiver spacing's from 3 to 12 ft. or more. The longer spacing's are capable of investigating deeper into the formation. Both the conventional sonic and the full waveform sonic devices are used to measure compressional velocity. Shear velocities are used to determine mechanical properties of the formations and to determine Poisson's ratio for use in interpreting seismic data. Shear velocities can be determined from the FWS (monopole), the dipole sonic, or the quadrupole sonic. The monopole sonic is not able to measure shear velocities when the shear velocity of the formation is slower than the compressional velocity of the mud. Mud interval transit times are typically in the 190 μsec/ft. range. When this condition is not met, no shear energy is refracted toward the receivers, making shear velocity measurements impossible. The dipole overcomes this limitation by directly exciting shear flexural energy in the formation regardless of the mud velocities.

2.4.3.4. FORMATION TESTING

Formation Testing is a means of obtaining information concerning the liquid type and pressure in an open-hole formation. There are three methods for formation testing which include:

- Wireline Testing,
- Drill stem test (DST) and
- Production Test.

Wireline Testing

Wireline Testing provides reservoir pressure measurement, reservoir fluid samples, an indication to fluid mobility and information on reservoir continuity. Essentially, a wire-line tester consists of a sampling chamber or chambers of several gallons' capacity. These chambers are connected to an opening in a pad that is forced against the wall of the hole to affect a seal. Firing a shaped charge or hydraulically forcing a tube from the center of the pad establishes communication between the chamber and the formation.

The tool is run on an electrical logging cable and the valves, which open and close the sample chamber, are controlled from the surface. The pressure behavior during sampling, as well as a final pressure buildup, is recorded.

When the chamber is filled, the fluid sample valve is closed and the fluid sample is sealed in at maximum pressure. The pad and back up shoe are then retreated and the tool is brought to the surface where the sample is removed for detailed study.

Throughout the entire test, electrical circuits permit a complete recording at the surface of the progress of the whole operation. The data recorded include mechanical action, sample shots, pressure buildup, formation shut-in pressure, and finally hydrostatic mud pressure.

Drill stem test (DST)

A drill stem test (DST) is a procedure for isolating and testing the surrounding geological formation through the drill stem. The test is a measurement of pressure behavior at the drill stem and is a valuable way to obtain important sampling information on the formation fluid and to establish the probability of commercial production. Data obtained from DST can be summarized as gathering Fluid Samples, Measure Reservoir Pressure, determine Formation Properties, including Permeability, Skin Factor, and Radius of Investigation. Gathering Hydrodynamic Information such as Barriers, Permeability changes, and Fluid Contacts, Estimation for the Productivity, including Flow Rate, and Depletion of the reservoir pressure can be obtained.

Production Test

Production tests are run to obtain an indication of well productivity. Some production tests are performed in open hole (such as drill stem tests) and can be used in making completion decisions. Others (such as single-point, multipoint, and swab tests) are performed after the well is completed and generally involve routine measurements of oil, gas, and/or water production under normal producing conditions. The test results can be used to determine reservoir properties, to assess the degree of damage or stimulation, to identify production and reservoir problems, or to satisfy the reporting requirements of regulatory bodies. Production tests can also be performed when more conventional well tests (such as pressure drawdown and buildup tests) are impractical due to time constraints, well conditions, or extremely low well productivity.

2.4.4. Cased Hole Logging

When a hole has been cased and a completion string run to produce the well, certain additional types of logging tools may be used for monitoring purposes. These include:

- Thermal decay tool (TDT): This neutron tool works on the same principle as the neutron porosity tool, which is, measuring gamma ray counts when thermal neutrons are captured by the formation. However, instead of measuring the HI, they are specifically designed to measure the neutron capture cross-section, which principally depends on the amount of chlorine present at formation brine. Therefore, if the formation water salinity is accurately known, together with the porosity, Sw may be determined. The tool is particularly useful when run in time-lapse mode to monitor changes in saturation, since many unknowns arising from the borehole and formation properties may be eliminated.

- Gamma ray spectroscopy tool (GST): This tool works on the same principal as the density tool, except that by measuring the contributions arising in various energy windows of the gamma rays arriving at the detectors, the relative proportions of various elements may be determined. In particular, by measuring the relative amounts of carbon and oxygen a (salinity independent), measurement of Sw may be made.
- Production logging Tool: This tool, which operates using a spinner, does not measure any properties of the formation but is capable of determining the flow contributions from various intervals in the formation.
- Cement bond log: This tool is run to evaluate the quality of the cement bond between the casing and the formation. It may also be run in a circumferential mode, where the quality around the borehole is imaged. The quality of the cement bond may affect the quality of other production logging tools, such as TDT or GST.
- Casing collar locator (CCL): This tool is run in order to identify the positions of casing collars and perforated intervals in a well. It produces a trace that gives a "pip" where changes occur in the thickness of the steel.

2.4.5. Mud Logging

Since its commercial introduction in 1939, the mud logging unit has become a hub for monitoring formation responses to the drilling process. Initially, the mud logger's mandate was to record the depth and describe the lithology of formations encountered by the drill bit then determine whether those formations contained hydrocarbons. However, the scope of mud logging has expanded as additional sensors brought more data into the logging unit such as gas chromatographs, weight-on-bit and mud pit level indicators. Basic mud logging services now typically track drilling rates, lithology, visual hydrocarbon indicators, total combustible gas in mud and individual hydrocarbon compounds in the gas along with numerous drilling parameters. The mud logger monitors and evaluates a broad range of surface indicators to compile a concise record of subsurface geology, hydrocarbons encountered and significant drilling events. These days, the term surface logging is sometimes used to encompass a range of enhanced mud logging services that incorporate advanced sensor and computing technology to provide monitoring for wellbore stability and early kick detection.

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 down-hole sensors. The term mud logging is thought, by some, to be outdated and not sufficiently descriptive. Because of the relatively broad range of services performed by the geologists, engineers, and technicians traditionally called mud loggers, the term "surface logging" is sometimes used, and the personnel performing the services may be called surface-logging specialists.

The practice of mud logging relies heavily on the mud circulation system. High-pressure mud pumps draw mud or drilling fluid, from surface tanks and direct it down-hole through the drill-pipe (**Fig. 2-1**). The mud exits the drill- string through nozzles in the bit. As a bit drills through the subsurface, the rock it grinds along with water, oil or gas in the formation is carried back up the hole by the drilling fluid. Upon reaching the surface, the fluid exits through a flow-line above the blowout preventer and is deposited over a vibrating mesh screen at the shale shaker, which separates formation cuttings from the liquid mud. The liquid portion of the drilling fluid falls through the screens to the mud pits, ready to be pumped back into the well; the rock cuttings on the shaker screen provide the basis for determining down-hole lithology.

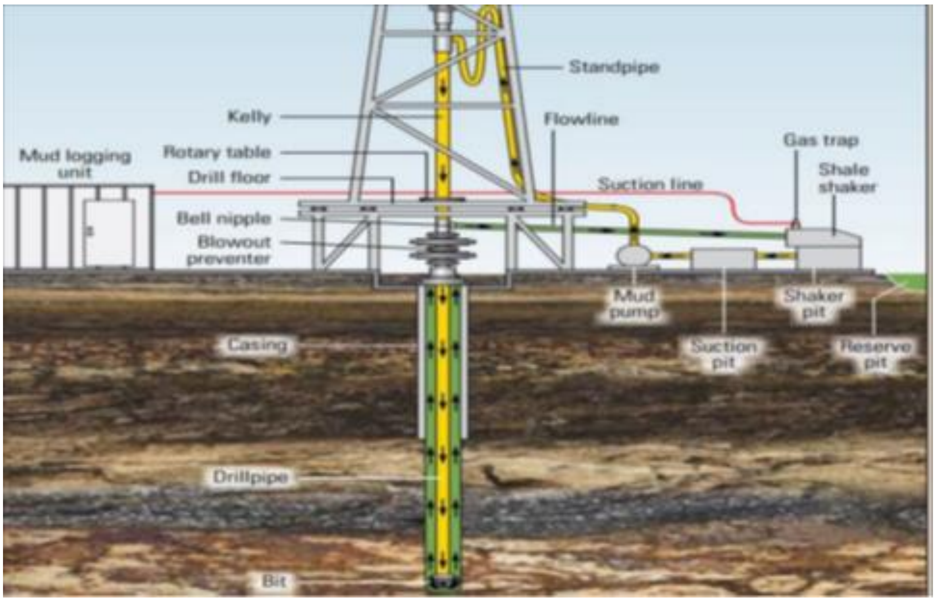

Figure 2-1 The Mud Circulation System

2.4.5.1. OBJECTIVES OF MUD LOGGING

There are several broad objectives targeted by mud logging: identify potentially productive hydrocarbon-bearing formations, identify marker or creatable geological formations, and provide data to the driller that enables safe and economically optimized operations. The actions performed to accomplish these objectives include the following:

- Collecting drill cuttings.
- Describing the cuttings (type of minerals present).
- Interpreting the described cuttings (lithology).
- Estimating properties such as porosity and permeability of the drilled formation.
- Maintaining and monitoring drilling-related and safety-related sensing equipment.
- Estimating the pore pressure of the drilled formation.
- Collecting, monitoring, and evaluating hydrocarbons released from the drilled formations.
- Assessing qualitatively the producibility of hydrocarbon-bearing formations.
- Maintaining a record of drilling parameters.

2.4.6. Conventional and Sidewall Coring

Rock cores provide essential data for the exploration, evaluation and production of oil and gas reservoirs. Physical rock samples allow geoscientists to examine firsthand the depositional sequences penetrated by a bit and offer direct evidence of the presence, distribution and deliverability of hydrocarbons. Cores provide ground truth for calibration of well logs and can reveal variations in reservoir properties that might be undetectable through down-hole logging measurements alone. Operators are better able to characterize pore systems in the rock and model reservoir behavior to optimize production based on the analysis of core porosity, permeability, fluid saturation, grain density, lithology and texture. These analyses are carried out in core laboratories around the world. Cores can be cut and collected by different techniques such as conventional and sidewall coring.

2.4.6.1. Conventional Coring

Conventional cores, also known as whole cores are continuous sections of rock extracted from the formation in a process similar to conventional drilling. The two operations differ chiefly in the type of bit used: Instead of a conventional drill bit, coring uses a hollow bit and core barrel in the bottom-hole assembly (BHA).

During conventional coring operations, the operator first drills the well down to a zone of interest using a conventional drill bit and drill-string. A well-site geologist closely monitors drilling progress to decide when to begin coring operations. The timing of this decision is critical because if the coring begins too soon, the operator will waste rig time obtaining unneeded core above the zone of interest; if coring begins too late, the drill will have already penetrated the zone and possibly miss the most crucial section of the formation.

Correlations with offset well logs usually provide the first indication that the drill bit is nearing the coring point. By charting the formation type, drilling rate and amount of gas extracted from the mud during drilling, the geologist can create a mud log that may be compared with logs from offset wells. Some zones have been cored simply on the basis of a drilling break an increase in drilling rate, which is often accompanied by an increase in gas or evidence of oil in the formation cuttings. Modern logging-while drilling technology, how- ever, can deliver resistivity-at-the-bit measurements in real time to help operators determine when the bit is approaching the zone of interest.

Once the geologist gives the order to begin coring, the driller pulls the drill bit out of the hole, and the drilling crew exchanges the drilling BHA for a coring bit and core barrel. The hollow coring bit grinds away the rock, leaving a cylindrical core of rock at its center. This core is retained inside the core barrel, which is mounted just above the bit. The core barrel consists of an inner and outer barrel and a core catcher. These barrels are attached to a swivel that enables the inner barrel to remain stationary while the outer barrel rotates with the coring bit. Drilling fluid can circulate between the inner and outer barrels. The catcher keeps the core from slipping out through the hollow bit when the coring BHA is retrieved to the surface. Cores typically range in diameter from 4.45 to 13.34cm (1.75 to 5.25 in.) and are usually cut in 9m (30ft) increments, corresponding to the length of the core barrel or its liner, which in turn, is consistent with the length of standard drill pipe.

When the core barrel is full, the drilling crew pulls the drill-string to the surface and retrieves the core barrels. A core recovery specialist lays the barrel liner on the pipe rack. The liner, with core inside, is then scribed with depth markings and orientation lines. The metal liner is usually cut into segments and sealed at each end for shipping to a core analysis laboratory.

Conventional coring operations often provide the best rock samples for testing, analyzing and evaluating reservoirs. However, the time required to cut and recover whole cores can impact drilling efficiency. Depending on coring objectives and cost limitations, some E&P ventures may deem conventional coring nonessential. In such cases, the operator may turn to an alternate method for sampling downhole formations, such as sidewall coring which is done after drilling is finished and logging is completed.

Figure 2-2 Conventional Coring

2.4.6.2. Sidewall Coring

Sidewall cores (SWCs), plugs of rock taken from the wellbore wall, may offer a cost-effective alternative to conventional cores. The SWCs are usually acquired by wireline tools, and a single wireline descent can recover SWCs from multiple zones of interest.

After the driller reaches a casing point or drills to total depth (TD), the drill pipe is pulled out of the hole and the well is logged before casing is set. Sidewall cores typically are obtained after logs have been run, usually near the conclusion of an open-hole wireline logging job. This gives geologists time to pick core depths after consulting the logs to identify zones that Merit sampling. Wireline gamma ray or spontaneous potential logs are used to correlate between open hole log depths and core depths. Sidewall coring devices are controlled from the surface logging unit and can extract samples from the side of a wellbore at up to 90 selected depths.

The same operation of sidewall coring can be conducted using Rotary sidewall coring tool **Fig. 2.3** or Percussion sidewall coring gun **Fig. 2.4.**

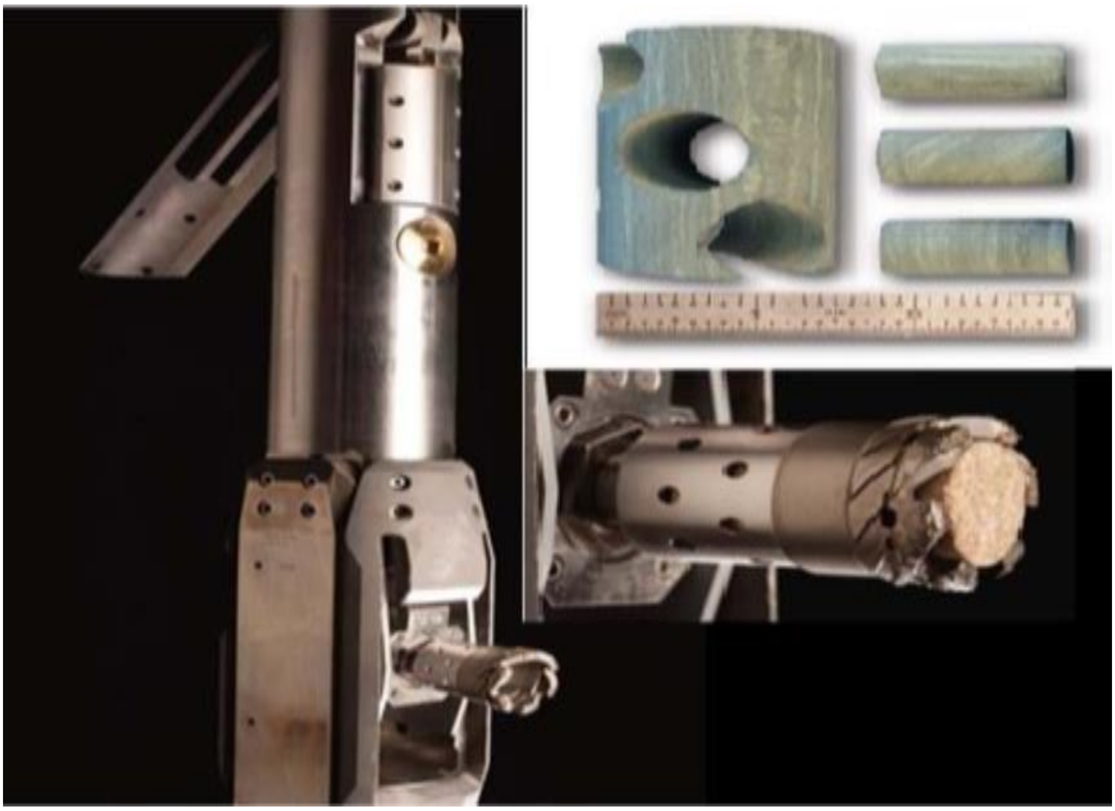

Figure 2-3 Rotary Sidewall coring tool

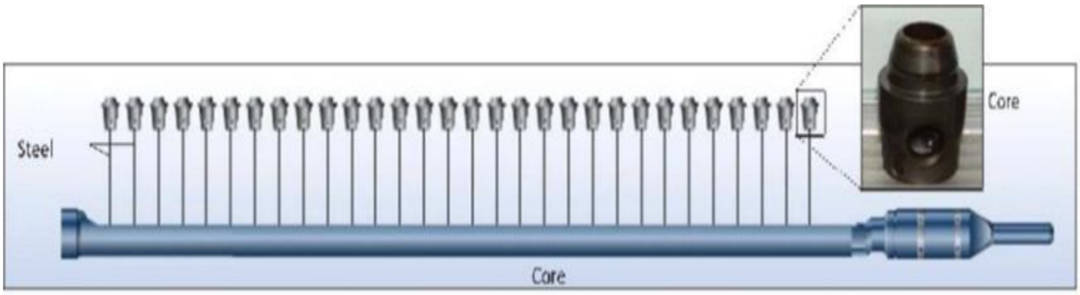

Figure 2-4 Percussion sidewall coring gun.

Petrophysicists use SWCs to validate log responses and obtain empirical petrophysical and geophysical properties. Sidewall cores also offer an alternative means for Petrophysicists to acquire core data should conventional coring operations fail. However, because of their small size relative to conventional cores, SWCs taken from a heterogeneous formation may not have properties that are representative of the formation at a reservoir scale. The rock from which the SWC is taken may also lack crucial features that geologists need to analyze the reservoir, especially in laminated sand-shale sequences, organic shales and fractured reservoirs.

2.4.6.3. Limitations of Core Measurements

- A core is a section of rock cut usually over only a subset of the reservoir in a particular part of a field. There is no a prior reason why it should be representative of the reservoir as a whole. In particular, a core cut in the water leg, where digenetic processes may be occurring, is not necessarily representative of the oil or gas legs in a reservoir.
- The coring and recovery process subject the rock to stress and temperature changes that may profoundly affect the rock structure.
- The plugging, cleaning, and drying process may completely change the wettability of the plugs, making them unrepresentative of down-hole conditions.
- Resistivity measurements performed on plugs at ambient temperature, using air as the non-wetting fluid, may be wholly unrepresentative of reservoir conditions. Apart from the fact that the brine has a totally different resistivity at ambient temperatures, there may be other factors affecting how easily the non-wetting phase may mingle with the wetting phase. In fact, where experiments have been performed to measure m and n under truly in-situ conditions, it was found that the values differed completely from those measured under ambient conditions.

- When measurements are made on a selection of, say, 10 SCAL plugs, it will typically be found that the m, n, and Pc behavior of all 10 will be completely different. These are usually then averaged to obtain a representative behavior for the reservoir. However, because of the variability, if a new set of 10 plugs is averaged, the result will be completely different. This calls into question the validity of any average drawn from 10 plugs that are taken to represent thousands of acre-feet of reservoir.
- Overall, it is better to use core-derived values than nothing at all, and a lot of valuable information about the reservoir can be gained from core inspection. However, no core-derived average should be treated as being completely reliable, and there will be many cases in which it has to be disregarded in favor of a common sense approach to all the other sources of information.

2.5. Quicklook Log Interpretation

Once the section TD (total depth) of the hole has been reached, the petrophysicist will be expected to make an interpretation of the open-hole logs that have been acquired. Before starting the log interpretation, the petrophysicist should have:

- All the relevant daily drilling reports, including the latest deviation data from the well, last casing depth, and mud data
- All the latest mud-log information, including cuttings description, shows, gas reading, and ROP (rate of penetration)
- Logs and interpretations on hand from nearby wells and regional wells penetrating the same formations, in particular where regional or field-wide values of m, n, R_w, ρ_g and fluid contacts are available.

2.5.1. Basic Quality Control

Once the log arrives, the Petrophysicists needs to ensure the quality of the log data and should perform the following regimen:

1. Check that the logger’s TD and last casing shoe depths roughly match those from the last daily drilling report.
2. Check that the derrick floor elevation and ground level (or seabed) positions are correct.

3. Check that the log curves are on depth with each other. The tension curve can be used to identify possible zones where the tool-string has become temporarily stuck, which will put the curves off depth and result in “flat lining.”
4. Check that the caliper is reading correctly inside the casing (find out the casing ID) and that it is reading the borehole size in non-permeable zones that are not washed out.
5. Check the density borehole correction curve. It should not generally exceed 0.02 g/cc, except in clearly washed out sections (>18 in.), for which the density curve is likely to be unusable.
6. Inspect the resistivity curves. If oil-based mud (OBM) is being used, the shallow curves will usually read higher than the deep curves (except in highly gas or oil saturated zones). Likewise, with water-based mud (WBM) the shallow curves will read less than the deep curves, providing Rmf<Rw, or in hydrocarbon-bearing zones. In theory, the curves should overlie each other in non-permeable zones such as shales. However, in practice this is often not the case, due to either anisotropy or shoulder bed effects.
7. Check the sonic log by observing the transit time in the casing, which should read 57ms/ft.
8. Look out for any cycling-type behavior on any of the curves, such as a wave pattern. This may be due to corkscrewing while drilling, causing an irregular borehole shape. However, it is necessary to eliminate any possible tool malfunction.
9. Check that the presentation scales on the log print are consistent with other wells or generally accepted industry norms. These are generally:
    - GR: 0–50 API
    - Caliper: 8–18”
    - Resistivity: 0.2–2000 ohm.m on log scale
    - Density: 1.95–2.95 g/cc (solid line)
    - Neutron: -0.15 ±0.45 (porosity fraction) (dashed line)
    - Sonic: 140–40 ms/ft.2.6.1.

2.5.2. Identifying the Reservoir

In this part, it will be assumed that one is dealing with clastic reservoirs. The most reliable indicator of reservoir rock will be from the behavior of the density/neutron logs, with the density moving to the left (lower density) and touching or crossing the neutron curve. In clastic reservoirs in nearly all cases, this will correspond to a fall in the gamma ray (GR) log. In a few reservoirs, the GR is not a reliable indicator of sand, due to the presence in sands of radioactive minerals. Shales can be clearly identified as zones where the density lies to the right of the neutron, typically by 6 or more neutron porosity units.[1]

The greater the crossover between the density and neutron logs, the better the quality of the reservoir. However, gas zones will exhibit a greater crossover for a given porosity than oil or water zones. Because both the neutron and density logs are statistical measurements (i.e., they rely on random arrivals of gamma rays in detectors), they will “wiggle” even in completely homogeneous formations. Therefore, it is dangerous to make a hard rule that the density curve must cross the neutron curve for the formation to be designated as net sand. For most reservoirs, the following approach is safer: **Fig. 2-5**

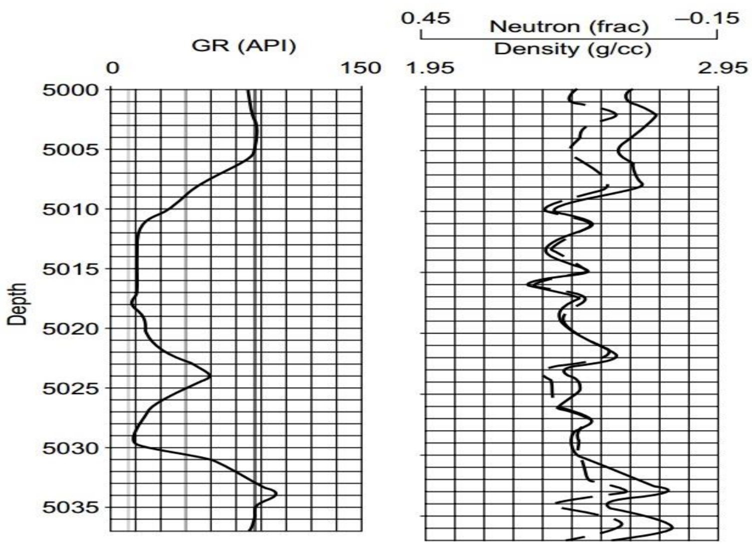

Figure 2-5 Identifying Net Reservoir

- Determine an average GR reading in clean sands ($GR_{clean\ sand}$ or GR_{min}) which is the minimum value and a value for shales (GR_{sh}) which is the maximum value.
- Define the shale volume as

2-1

By comparing V_{sh} with the density/neutron response, determine a value of V_{sh} to use as a cutoff.

2.5.3. Identifying the Fluid Type and Contacts

Because the porosity calculation will depend on the formation fluid type, it is good at this stage to at least have a working assumption regarding the fluids. If regional information is available regarding the positions of any gas/oil contact (GOC) or oil/water contact (OWC), then convert these subsea depths into measured depths in the current well and mark them on the logs. If the formation pressures have already been measured (this is usually never the case), then any information on possible free water levels (FWLs) or GOCs can also be marked on the log.

Start by comparing the density and deepest reading resistivity log for any evidence of hydrocarbons. In the classic response, the resistivity and density (and also GR) will be seen to "tramline" (i.e., follow each other to the left or right) in water sands and to "Mae West" (i.e., be a mirror image of each other) in hydrocarbon sands. However, some hydrocarbon/water zones will not exhibit such behavior, the reasons being:

- When the formation-water salinity is very high, the resistivity may also drop in clean sands.
- In shaly sand zones having a high proportion of conductive dispersed shales, the resistivity may also fail to rise in reservoir zones.
- If the sands are thinly laminated between shales, the deep resistivity may not be able to "resolve" the sands, and the resistivity may remain low.
- If the well has been drilled with very heavy overbalance, invasion may be such as to completely mask the hydrocarbon response.
- When the formation water is very fresh (high Rw), the resistivity may Mae West even in water-bearing zones.

When either of the first two situations arises, it is very important to look at the absolute value of the deep resistivity, rather than at only the behavior compared with the density. As long as a known water sand has been penetrated in the well (or a neighboring well), one should already have a good idea of what the resistivity ought to be for a water-bearing sand. If the resistivity is higher than this value, whatever the shape of the curve, then hydrocarbons should be suspected.

Obviously, any mud-log data (gas shows, fluorescence) should be examined in the event that it is not clear whether or not the formation is hydrocarbon bearing. However, the mud log can certainly not be relied on to always pick up hydrocarbons, particularly where the sands are thin and the overbalance is high. Moreover, some minor gas peaks may be observed even in sands that are water bearing. **Fig. 2-6**

As stated earlier, gas zones will exhibit a greater density/neutron crossover than oil zones. In a very clean porous sand, any GOC can be identified on the log relatively easily. However, in general, GOCs will be identified correctly in only about 50% of cases. Secondary gas caps appearing in depleted reservoirs will usually never be picked up in this way. Formation-pressure plots represent a much more reliable way to identify GOCs, but these will generally be useful only in virgin reservoirs. Various cross-plots have been proposed in the past involving the GR, density, neutron, and sonic logs as a way to identify gas zones, but it has never found these to be reliable. In a depleted reservoir where gas has started to come out of solution in an oil zone and not had a chance to equilibrate (i.e., form a discrete gas cap), the gas may exist in the form of football-sized pockets surrounded by oil. In such a situation, the basic logs will never give a definitive answer.

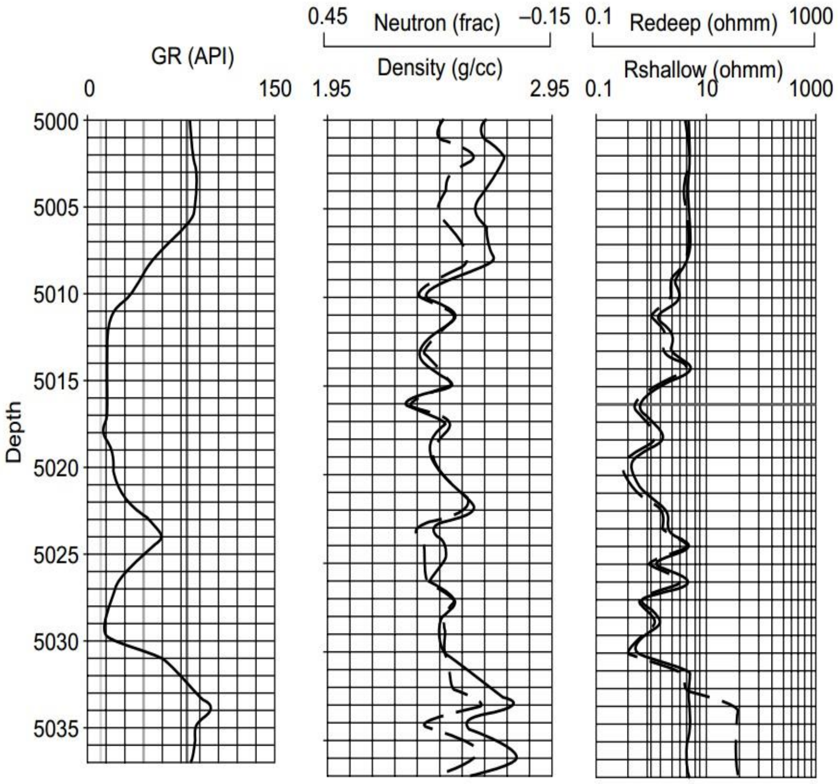

Figure 2-6 Identifying Net Pay

2.5.4. Calculating the Porosity

Porosity should be calculated from the density log using the equation:

$$\emptyset = (\boldsymbol{\rho_m} - \boldsymbol{\rho_B}) / (\boldsymbol{\rho_m} - \boldsymbol{\rho_f}) \qquad 2\text{-}2$$

Where:

ρ_m = matrix density (in g/cc) and ρ_f = fluid density (in g/cc).

The density tool actually works by injecting gamma rays into the formation that are then scattered by electrons in the formation, a process known as Compton scattering. These gamma rays are then detected by two detectors. Since the tool actually measures electron density, there is a slight miscalibration due to the variation in electron density between different minerals. The correction is typically small (typically 1% or less), so is no major cause for concern. Assuming that the density porosities will at some stage be calibrated against core data, this correction can be ignored, at least for quick look purposes.

For sandstones, ρ_m typically lies between 2.65 and 2.67 g/cc. Where regional core data are available, the value can be taken from the average measured on conventional core plugs. Fluid density, ρ_f, depends on the mud type, formation fluid properties, and extent of invasion seen by the density log. **Table 2-4** gives some typical values that may be used.

As to the appropriateness of the values being used, the following tests may be applied:

- Where regional information is available, the average zonal porosities may be compared with offset wells.
- In most cases, there should be no jump in porosity observed across a contact. An exception may occur across an OWC where diagenetic effects are known to be occurring.
- In no cases in sandstones would one expect porosities to exceed about 36%.

Note that the porosity calculated from the density log is a total porosity value; that is, water bound to clays or held in clay porosity is included.

Table 2-4 Selection of fluid density for porosity calculated from density tool

Formation Fluid	OBM	Heavy Mud System	Light Mud System
Gas, clear gas effect on logs	0.4	0.6	0.5
Gas, no clear gas effect on logs	0.55	0.7	0.6
Light Oil	0.6	0.8	0.7
Heavy Oil	0.7	0.9	0.8
Low-Salinity Water	0.85	1.05	1.0
High- Salinity Water	0.9	1.1	1.05

This has the advantage, therefore, of being directly comparable to porosities measured on core plugs, since these have had all clay-bound and free water removed.

Having calculated the porosity, it is important to check for any zones where washouts have resulted in erroneously high-density values and thus unrealistically high porosities. In some cases, it is sufficient to just apply a cutoff to the data whereby porosities above a certain value are capped at a value. This recognizes the fact that zones often wash out because they are soft and have a high porosity. However, in some cases it is necessary to manually edit the density log using one's best estimate of what the density should be. Note that in water-bearing sections a good estimate of porosity, $\emptyset$, may be made using true resistivity (Rt) and Archie's equation, which is:

$$\mathbf{R_t = R_w * \emptyset^{-m} * S_w{}^{-n}} \qquad \textbf{2-3}$$

or

$$\mathbf{S_w = \left[\left(R_t/R_w\right) * \emptyset^m\right]^{\left(-1/n\right)}} \qquad \textbf{2-4}$$

Where

R_w = formation water resistivity (measured in ohm.m)

m = the cementation, or porosity, exponent

S_w = water saturation

n = saturation exponent.

Alternatively, sometimes a correlation can be made between the GR and density in non–washed-out zones and applied.

It generally favors always working in a total porosity system. The term effective porosity is also used, although often different people take it to mean different things. Probably the best definition is that it is the total porosity minus the clay-bound water and water held as porosity within the clays. It may therefore be defined as:

$$\boldsymbol{\emptyset_{eff} = \emptyset_{total} * (1 - C * V_{sh})} \qquad \textbf{2-5}$$

where C is a factor that will depend on the shale porosity and CEC (cation exchange capacity). It may be determined from calculating the total porosity in pure shales (V_{sh} = 1) and setting $\emptyset_{eff}$ to zero. However, we have doubts about the correctness of assuming that properties of the shales in non- reservoir zones can be applied to dispersed shales within sands in the reservoir. In general, we do not recommend calculating $\emptyset_{eff}$ at all as part of any quicklook evaluation. At this point we would like to make it clear that we never favor making use of the neutron/density cross plot log for calculating porosity in sandstones. The reasons for this are as follows:

- Both the neutron and density logs are statistical devices and vary randomly within certain limits determined by the logging speed, detector physics, source strength, and borehole effects. The error introduced when two such random devices are compared is much higher than when one such device is used on its own.
- The neutron is severely influenced by the amount of chlorine atoms in the formation, occurring either in the formation water or in the clay minerals. This means that the neutron porosity is only very loosely related to the true porosity (as observed when it is compared with the density log in sand/shale sequences!).
- The neutron is also affected in an unpredictable way by gas (unlike the density, for which a correction can be made using the appropriate rho_f).
- It has never had much faith in the overlays presented on standard neutron/density cross plots by the contractors. In practice, when real data are plotted, the overlays typically predict all kinds of minerals, from dolomite to limestone, to be present when in fact one is dealing with a clay/quartz combination.

2.5.5. Calculating Hydrocarbon Saturation

In most quicklook evaluations of clastic reservoirs, it is sufficient to use Archie's equation (see above) to calculate saturations, using the deepest reading resistivity tool directly as Rt. In the absence of any regional core values, it is recommended using m = n = 2.

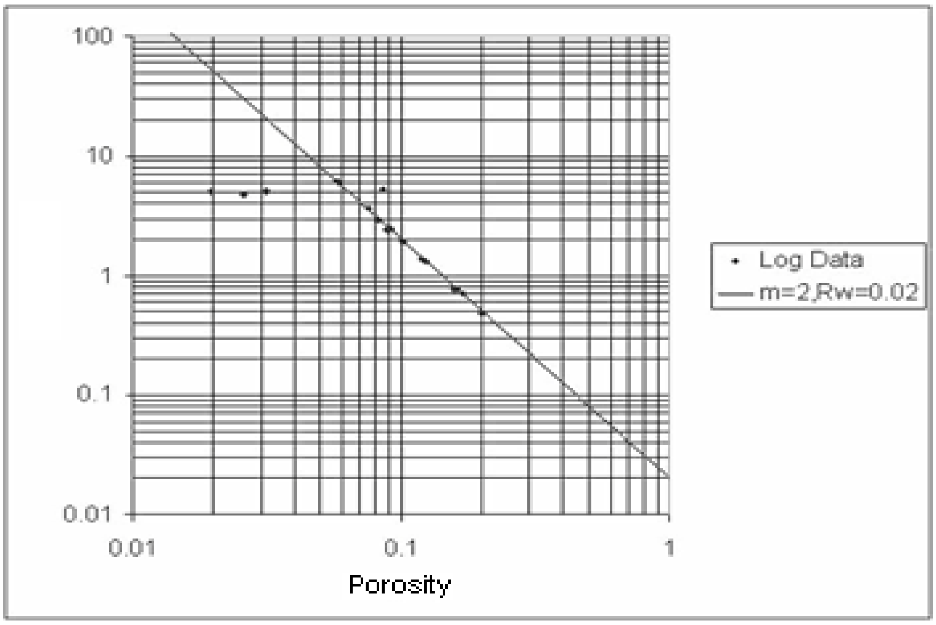

Figure 2-7 Pickett Plot

If m and n are predefined, then clearly the key parameter that must be determined is R_w. By far the preferred method of determining the best R_w to use in a particular well evaluation is a Pickett plot over a known water bearing section of the formation (**Fig. 2-7**). By plotting Log (R_t) vs. log (Ø), m may be determined from the gradient of the line drawn through the points, and R_w may be read from the intercept of the line with the R_t axis.

Note that if m is fixed, the line can be moved only up and down. At this point, if the slope of the data is clearly at odds with the assumed m value, it would be recommending changing m, provided that it still lies within a reasonable range (1.5–2.5).

Some information regarding R_w may also be available from regional data and produced water samples in neighboring wells. Note that this will usually be in the form of a salinity expressed as NaCl concentration in ppm or mg/l. This has to be converted to a R_w value using the contractor's chart book and knowledge of the formation temperature.

Where no clear water legs have been logged in the well, there is no alternative but to use regional data, although the Pickett plot may yield a different value than that expected from regional information. Reasons for this may be one of the following:

- The porosities calculated in the well are incorrect.
- The zone may not in fact be 100% water bearing as assumed.
- The value of m needs to be adjusted.
- The regional value is not applicable in this well.

Reasons why the regional value may not apply are:

- The salinity may be different in this well.
- The chart books assume that the conductivity of the brine is caused only by the presence of NaCl. If other chlorides are present (e.g., MgCl), the R_w calculated from the chart book will be wrong.
- The samples from which the salinity has been measured in other wells may be contaminated or affected by salt dropout when the samples were recovered at surface.
- If shale effects are predominant, the conductivity arising from clay- bound water may have a different salinity from that produced in a well. Typically, clay-bound water will be fresher than free water.
- The water zone may have originally been oil bearing but became flushed by injection water of a different salinity (this is common off- shore, where seawater is often used for injection).

In theory, the spontaneous potential (SP) curve may be used in some instances to derive a measurement of R_w.

2.5.6. Presenting the Results

Having calculated the $\emptyset$, and S_w curves, it is usually required to provide averages over various formation zones. This should be done as follows. First of all, determine over which depths the results should be broken up. Apart from the formation boundaries as agreed upon with the geologist, further subdivision should be made for any possible changes in fluid type or zones where the data are of particularly poor quality, or at any points where there is marked change in log character.

Note that the average porosity is given by:

$$(\emptyset)\ \textbf{Average}=\sum {}^{\emptyset,i}/_{h} \qquad \textbf{2-6}$$

where **h** is the net thickness

The average value of S_w is given by

$$(S_w)\ \textbf{Average}=\sum {}^{\emptyset_i\ *\ S_{wi}}/_{\sum \emptyset_i} \qquad \textbf{2-7}$$

Where a permeability transform is available, the average permeability over each major sand body should also be presented.

2.5.7. Pressure/Sampling

In most cases, there will be a requirement to run the pressure/sampling tool to acquire pretests and possibly downhole samples. While these data are also used by the reservoir engineer and production technologist, they can be extremely valuable to the petrophysicist in determining the fluids present in the formation. Pretests can provide the following information:

- The depths of any FWLs or GOC in the well
- The in-situ fluid densities of the gas, oil, and water legs
- The absolute value of the aquifer pressure and formation pressure
- A qualitative indication of mobility and permeability
- The bottom hole pressure and temperature in the wellbore

Additionally, acquiring downhole samples can provide the following information:

- Pressure/volume/temperature (PVT) properties of the oil and gas in the reservoir
- Formation-water salinity
- Additional mobility/permeability information

In the conventional mode of operation, a probe is mechanically forced into the borehole wall and chambers opened in the tool into which the formation flows. Pretest chambers are small chambers of a few cubic centimeters that can be reemptied before the next pretest station. For downhole sampling, larger chambers are used, typically 23/4 or 6 gallons. Since the first fluid entering the tool is typically contaminated by mud filtrate, normal practice is to make a segregated sample; that is, fill one chamber, seal it, and then fill a second chamber (hopefully uncontaminated). Once the chambers are retrieved at surface, they may be either drained on the well- site or kept sealed for transferring to a PVT laboratory.

Optional extra modes in which the tools can typically be used include the following:

1. As an arrangement of packers in order to isolate a few meters of the borehole wall, thereby providing a greater flow area
2. As a pump, out sub while sampling in order to vent the produced fluids into the wellbore until it is hoped that the flow is uncontaminated by mud filtrate
3. To monitor the fluid properties (resistive, capacitant, optical) while pumping out to determine whether oil, water, or gas is entering the chamber
4. As dual packer assemblies run to create a "mini-interference test" that can be used to assess the vertical communication between different intervals.

Pretests and sampling are often not successful. Moreover, the fact that the tool is stationary in the hole for long periods means that there is a higher than usual chance of getting the tool stuck in the hole. One of these problems can occur:

- Seal failure. The rubber pad surrounding the probe, which provides a seal between the mud pressure and the formation pressure, may fail, resulting in a rapid pressure buildup to the mud pressure.
- Supercharging. Tight sections of the formation may retain some of the pressure they encounter during the drilling pressure (which is higher than the static mud pressure). The pretest pressure is measured as a pressure that is anomalously high.
- Dry test. If the formation is very tight, there may be a very slow buildup of pressure in the pretest chambers, and it is not operationally feasible to attempt to wait until equilibrium is reached.
- Anomalous gradients. If sands are isolated even over geological time scales, then they may lie on different pressure trends, not sharing a common aquifer of FWL. In addition, if any depletion has occurred in the reservoir or the reservoir is not in a true equilibrium state (for instance, due to a slowly leaking seal or fault), then gradients may not be meaningful.

At this point it will probably be helpful if the distinction is explained among FWL, FOL (free oil level), OWC, GWC (gas/water contact), and GOC and how they are related in pressure measurements (**Fig. 2-8**).

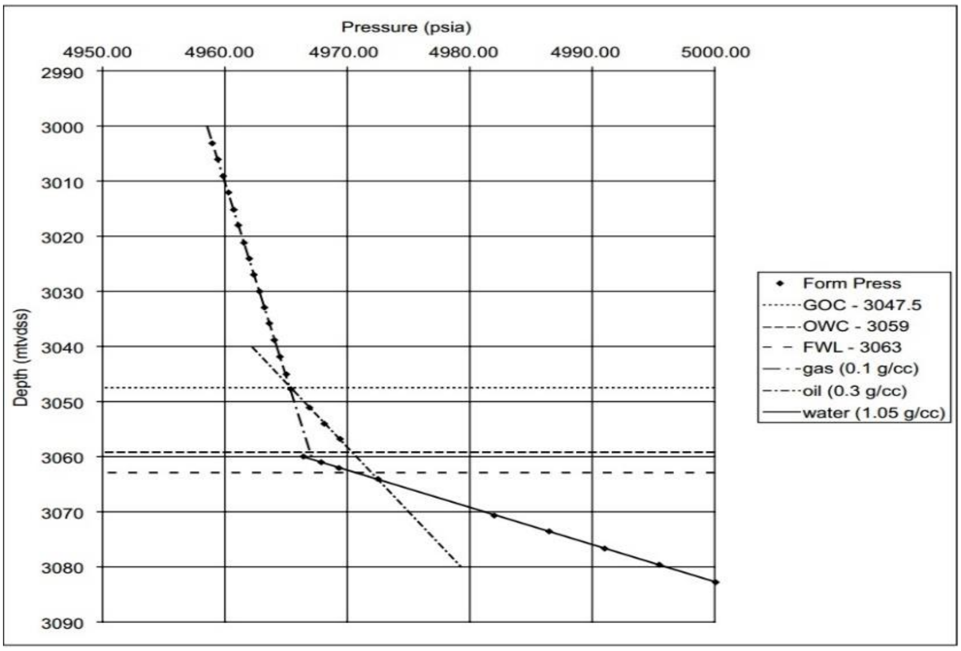

Figure 2-8 Example of Formation Pressure Plot

The FWL is the point at which the capillary pressure, Pc, in the reservoir is zero and below which depth no hydrocarbons will be found within that pressure system. Often the FWL may be related to the spill point of the structure, particularly where there is an abundant supply of hydrocarbons in the system. On a formation pressure/depth plot, the intersection between the points of the oil and the water (or gas and water) will fall at the FWL.

Above the FWL, Pc is available to allow the drainage of water by hydrocarbons. However, particularly in low permeability rocks, a certain entry pressure is required before the value of Sw can fall below unity. Once this pressure is reached, hydrocarbons will be found in the rock and one can be said to be above the OWC or GWC. Note that between the FWL and the OWC/GWC, pressure points will continue to fall on a waterline.

For an oil/gas reservoir, the pressure will rise above the OWC on a trend corresponding to an oil gradient (but intersecting the waterline at the FWL). At the GOC, technically one would expect some kind of similar FWL/OWC effect to occur with an FOL. However, the situation is not the same as at the OWC, because one is dealing with three phases (gas/oil/water) and not two, as before. Hence, it is common practice to treat the GOC as being the same as the intersection point of the gas and oil pressure lines. This may be technically incorrect, but it can only say that it has never caused any problems.

For a gas-only reservoir, the pressure will rise above the GWC on a trend corresponding to a gas gradient (but intersecting the waterline at the FWL).

Note that the above considerations have nothing to do with the "transition zone" that relates to the interval between the OWC or GWC and the point at which hydrocarbon values start to approach "irreducible" values.

In poor quality rocks, the effect of entry height can be appreciable (up to tens of meters). It may have the effect of causing the OWC/GWC to vary in depth across the field if the reservoir quality is changing.

2.5.8. PERMEABILITY DETERMINATION

During a typical pretest, the pressure gauge will show a behavior as shown in **Fig. 2-9**.

The behavior of the pressure buildup, analogous to a production-test buildup, may be used to estimate the properties of the formation.

The mobility (M) of the formation is defined by:

$$\mathbf{M = {}^{k}/_{\mu}} \qquad \textbf{2-8}$$

Where: k= permeability of formation, in md, μ =viscosity of fluid entering chamber, in centipoises (cp).

It may be shown theoretically that the mobility of the formation is related to the drawdown pressure, drawdown time, and flow rate. From analysis of the buildup, the contractor will normally give a mobility estimate. For conversion of the mobility to permeability, the viscosity needs to be known. In most cases the pretest chamber will be filled with mud filtrate, either water or oil based. **Table 2-6** gives some values.

While pretests are very useful in that they can prove that some permeability is present if a good buildup is obtained, it should be remembered that they represent only a point measurement. Typically moving the probe up or down by a few centimeters may result in a completely different measurement of mobility. The lack of a good buildup may be purely the result of bad luck in the positioning of the probe. Moreover, the results may not give an accurate idea of the average permeability of a zone.

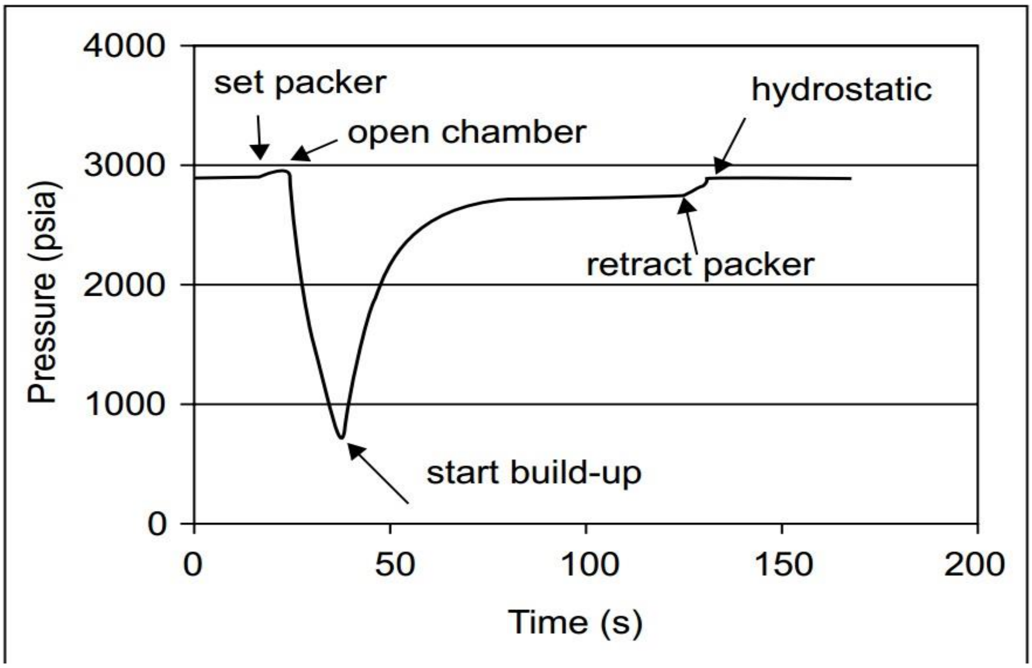

Figure 2-9 Pressure Measurements During a Pretest

Table 2-5 Typical viscosities of borehole fluids

Fluid	Viscosity (cp)
Water	0.3
Diesel	2–3
Oil	3–10
Gas	0.015

In general, pretests should be used to verify that a zone has some permeability, but the other methods used (e.g., permeability as derived from a poroperm relationship) are to determine an average permeability to be used in dynamic models. A pretest permeability being lower than that derived from a poroperm relationship may be a result of formation damage occurring while drilling. This may also be observed when the zone is tested for production.

Petrophysicists should always try to obtain the actual field print from the contractor when doing field studies, with a view to assessing permeability and fluid contacts. Reasons for this are as follows:

- Older generation tools report pressures from a strain gauge, which measures psi per gauge (psig) rather than the absolute psi (psia) reported from quartz gauges. If the values are entered incorrectly into a database, there will be a shift equivalent to atmospheric pressure (14.7 psi).
- When databases are created for fields (e.g., a shared Excel™ spreadsheet), sometimes not all the field data are entered, such as zones reported as "tight." Knowledge of tight zones is crucial if zones are being considered for recompletion based on log-derived permeability estimates.
- When zones are reported as being tight or of limited drawdown, it may be possible in some cases to make an estimate of formation pressure by extrapolating the buildup pressures.
- The contractors will typically report a measured depth for the pretest, as well as a true vertical depth (TVD), with reference to the derrick floor. It is important to check that the pressures used are being referenced properly to the best estimate of TVD relative to the datum (usually mean sea level). After the pressure tool is run, there will typically be a gyro survey run once the final casing is set, and this should be used to convert all measured depths in the well to TVD relative to the datum.

CHAPTER THREE

3. METHODOLOGY

3.1. Introduction

Wireline log is one of the most useful and important tools available to a petroleum geologist. Besides their traditional use in exploration to correlate zones and to assist with structure and isopach mapping, logs help define physical rock characteristics such as lithology, porosity, pore geometry, and water saturation etc.

Logging data is used to identify productive zones, to determine depth and thickness of zones, to distinguish between oil, gas, or water in reservoir, and to estimate hydrocarbon reserves. Also, geologic maps developed from log interpretation help with determining face's relationships and drilling locations.

3.2. Type of Data

For the purposes of the present study, two drilled boreholes have been selected from **Tasoure** and **Al Naser** Oil Fields. To fulfill the main objective, two wells scattered over the selected basins. These wells are **Tasoure -26s** and **Al-Naser-1**. The data available wireline log in **LAS** format. The collected data have been supplied by the Yemen Oil Investments Company and Data Bank Development Project.

3.3. Analysis Approach

Analysis approach for the available data is Descriptive, Qualitative and Quantitative approach. ***Techlog 2015.3*** will be used for re-evaluation of petrophysical properties for the available well logs for "**Tasoure-26s** and **Al Naser-01**.

3.3.1. TECHLOG 2015.3

Techlog is a Schlumberger owned Windows based software platform intended to aggregate all the wellbore information. It allows the user to interpret any log and core data. It addresses the need for a single platform able to support all the wellbore data and interpretation integration workflows, reducing the need for a multitude of highly specialized tools. By bringing the whole workflow into a single platform risk and uncertainty can be assessed throughout the life of the wellbore.

With the Techlog Quanti module, you can perform log quality control and precomputations of fluid properties followed by a full petrophysical analysis. This workflow can be saved and reused for future work, incorporating Monte Carlo for uncertainty analysis.

Using the module for interactive log interpretation, it is possible to

- Design your own petrophysical workflow
- Save and quickly reapply workflows to new data
- Easily transfer workflows to other projects
- Resample on-the-fly, allowing variables from different datasets to be input to a workflow
- Add your own scripts to further extend your workflows.
- Log quality control

Multiwell control of petrophysical parameters can be achieved by setting defaults for well, dataset, and zone combinations. With graphical and tabular, multiwell and multizone parameter management, users have control at all times. Plots are dynamically linked to parameter tables, allowing graphical selection of equation parameter values. Using the cascade function, parameter values can be edited and effects monitored on subsequent results.

Petrophysical computations

A comprehensive list of petrophysical computations (lithology, porosity, saturation, productivity, etc.) is available in the Quanti module. Parameter defaults can be defined at project, well, and zone levels and hierarchical parameter management facilitates scenario comparison. Users may insert scripts into the Quanti workflows for instant multiwell, multizone applications. Monte Carlo uncertainty modeling can also be performed.

Workflow design

Quanti workflows enable users to

- Apply cutoffs to determine reservoir and pay quality rock
- Calculate sums and averages over discriminated intervals
- Create report quality tables by zone or by layer
- Investigate sensitivities to the choice of cutoffs and uncertainties in results.

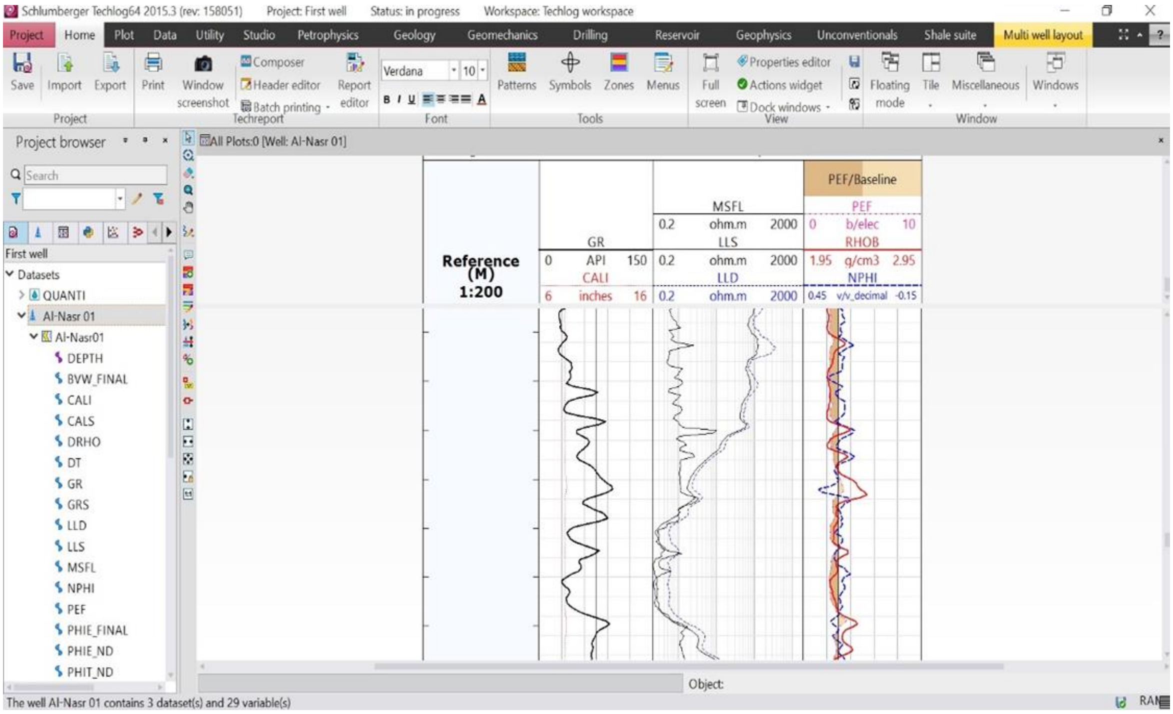

Figure 3-1 Techlog Interface

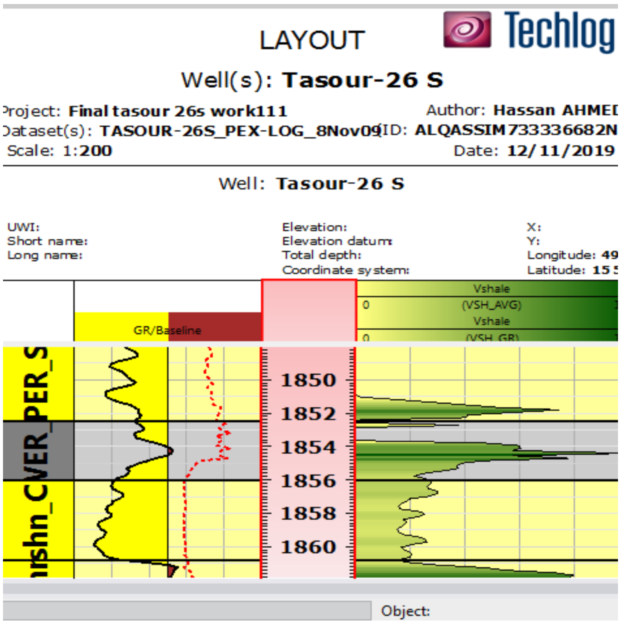

Figure 3-2 Techlog calcul V_{sh} from Al—Naser_1

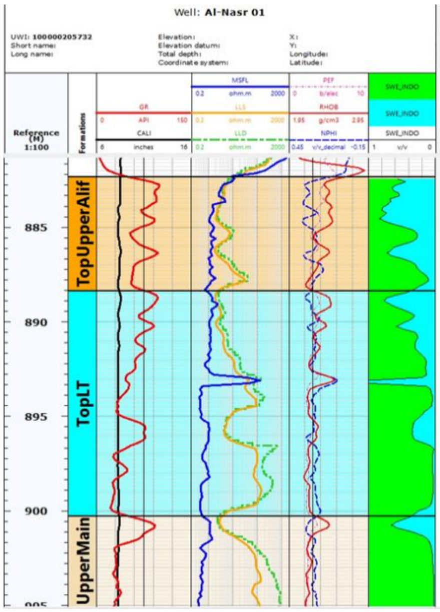

Figure 3-3 Water Saturation-Al-Naser_1

3.3.2. Permeability calculation

The permeability in this study had determined by using Schlumberger chart as show in **Fig. 3-4**.

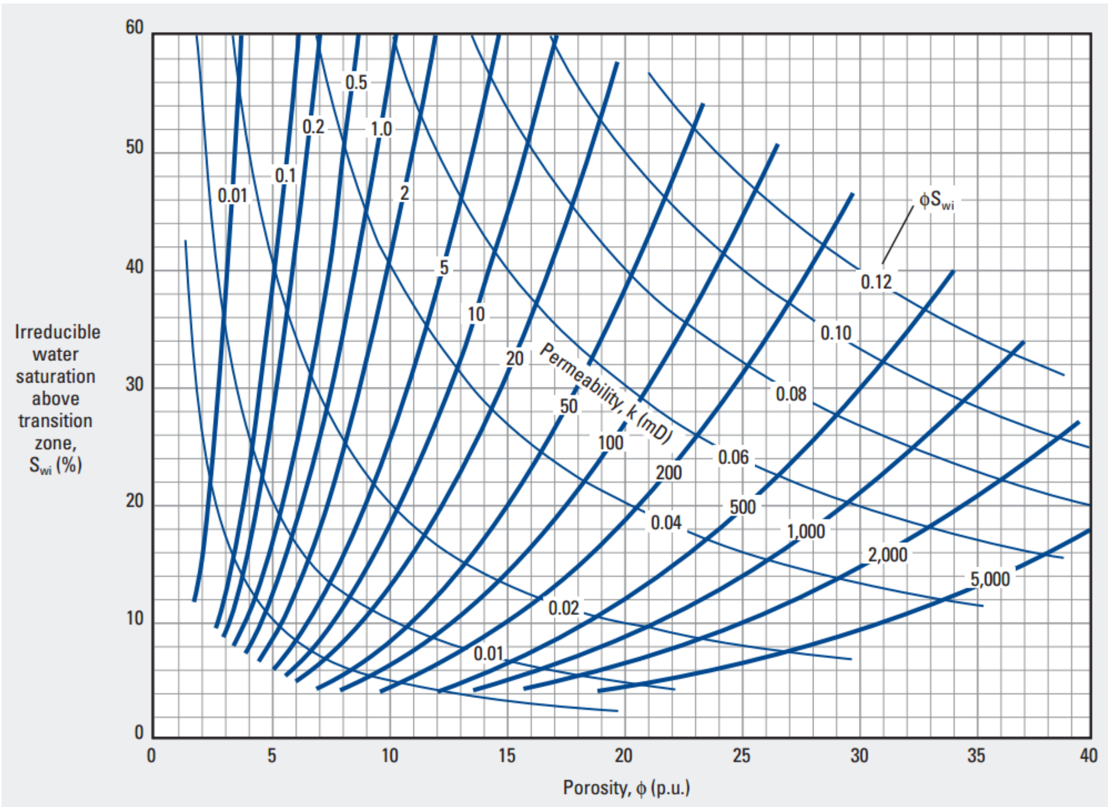

Figure 3-4 Permeability from Porosity and Water Saturation.

CHAPTER FOUR

4. PETROPHYSICAL INTERPERTATION

As mentioned earlier in this research, evaluation of reservoir rocks properties has its special importance in oil and gas industry to understand, evaluating, developing, manage and producing any fields. After the drilling operation reached the target, logging tools must run downhole to measure different properties from the target (the reservoir). Many types of logs had been recorded in Tasoure -26s and AL-Nasre-01 wells to obtain the data required by the company and needed to evaluate the reservoir.

This chapter will discuss the interpretations of petrophysical properties from the electrical wire line logs and compare the results the present work with the results of the petrophysical properties interpretation that had done by the company.

Re-evaluation for the logs either will confirm the previous evaluation for the petrophysical properties or it will give different results that will suggest a change of the reserve calculations

In these study petrophysical properties interpretations well be done by ***Techlog 2015.3***.

4.1. Tasour Field-Block 32 Well Logs

4.1.1. Petrophysical Interpretations of Tasour – 26s Well

The side tracked wellbore was kicked off on 31st of October, 2009 and reached TD at 1901 m (1696 m TVD) on 6th of November, the well encountered a partially upswept reservoir section with good oil saturations.

Tasour- 26s penetrated the **S1A** in a crestal position close to the main boundary fault.

There are different well logging tools that were used in **Tasour-26s** well which include **Caliper (HCAL)**, **Compressional Slowness (DL)**, **Gamma ray (GR)**, **Array Resistivity (RLA5 & RLA3)**, **Micro Resistivity (RXOZ)**, **Compensated Neutron (NPHI)** and **Density (RHOZ)**.

GR log was used to determine the shale volume “$\mathbf{V_{sh}}$”. The Neutron, density and Compressional Slowness logs were used together to determine the total and effective porosity “$\emptyset_{effe}$”. The deep Array Resistivity RLA5 was used to determine the formation true resistivity "R_t". The combination uses of the V_{sh}, $Ø_{effe}$ and R_t were done for determination of water saturation S_w.

According to **DNO YEMEN AS COMPANY** petrophysical report the following cutoff values for volume of shale (V_{sh}), Effective porosity ($Ø_{effe}$) and Water saturation (S_w) has been taken in account in our analysis (**Table. 4-1**):

Table 4-1 Cutoff Values Tasour- 26s Well

V_{sh} %	$Ø_{effe}$ %	S_w %
33	**10**	**70**

DNO Yemen AS analysis for **Tasour-26S** well logs show that there are **5** different layers which are: **Qishn Carbonate BRS**, **Upper Qishn Clastic S1A**, **Upper Qishn Clastic S1B**, **Upper Qishn Clastic S1C**, **Upper Qishn Clastic S2** as show in **Fig. 4-1**.

DNO YEMEM AS company log shows that the target Reservoir **S1A** starts from the depth of **1821 m** and ending at **1840 m**, the formations **S1B** and **S1C** starts from **1840 m** to **1856 m** and from **1856 m** to 1862 m respectively.

Depending on GR, Resistivity Tool, HCAL, and RHOZ, new zonation process had been done for the original zonation that had done by DNO company interpretations which is different from them. **Table. 4-2** and **Fig. 4-2** shows the new zones and depth with theirs new names.

Table 4-2 New Zonation for The Reservoir Tasour-26S well

DNO Interpretations			New Interpretations		
Original Zone	Depth (M)		New Zone	New Depth (M)	
	Top	Bottom		Top	Bottom
Qishn Carbonate Brs	1778	1821	Qishn Carbonate Brs	1778	1821
Upper Qishn Clastic S1A	1821	1840	Uppers1A	1821	1823
			LOWRS1A	1823	1839
Upper Qishn Clastic S1B	1840	1456	Uppers1b	1839	1852.5
			LOWRS1B SUORCE	1852.5	1856
Upper Qishn Clastic S1C	1856	1862	Upper Qishn Clastic S1C	1856	1860.8
Upper Qishn Clastic S2	1862	1901	Upper Qishn Clastic S2	1860.8	1901

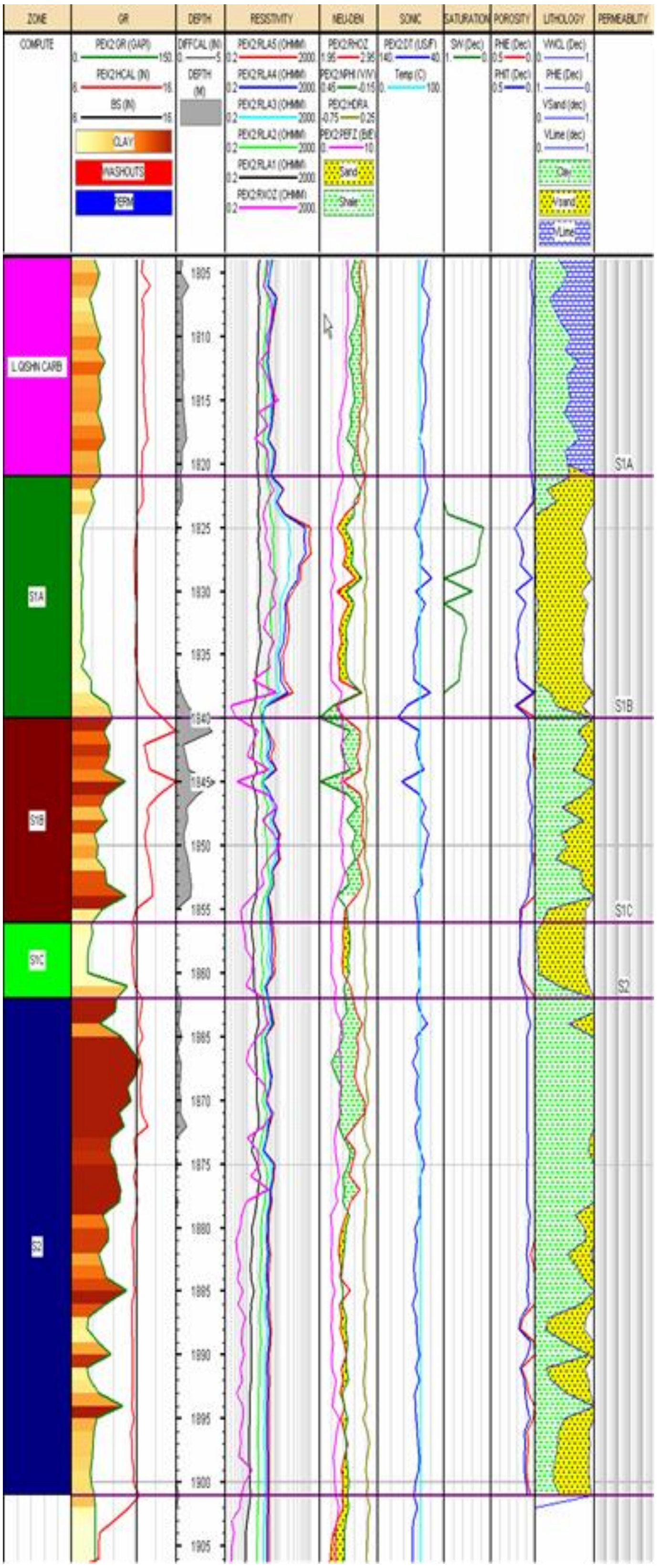

Figure 4-2 Tasour-26S Company Log

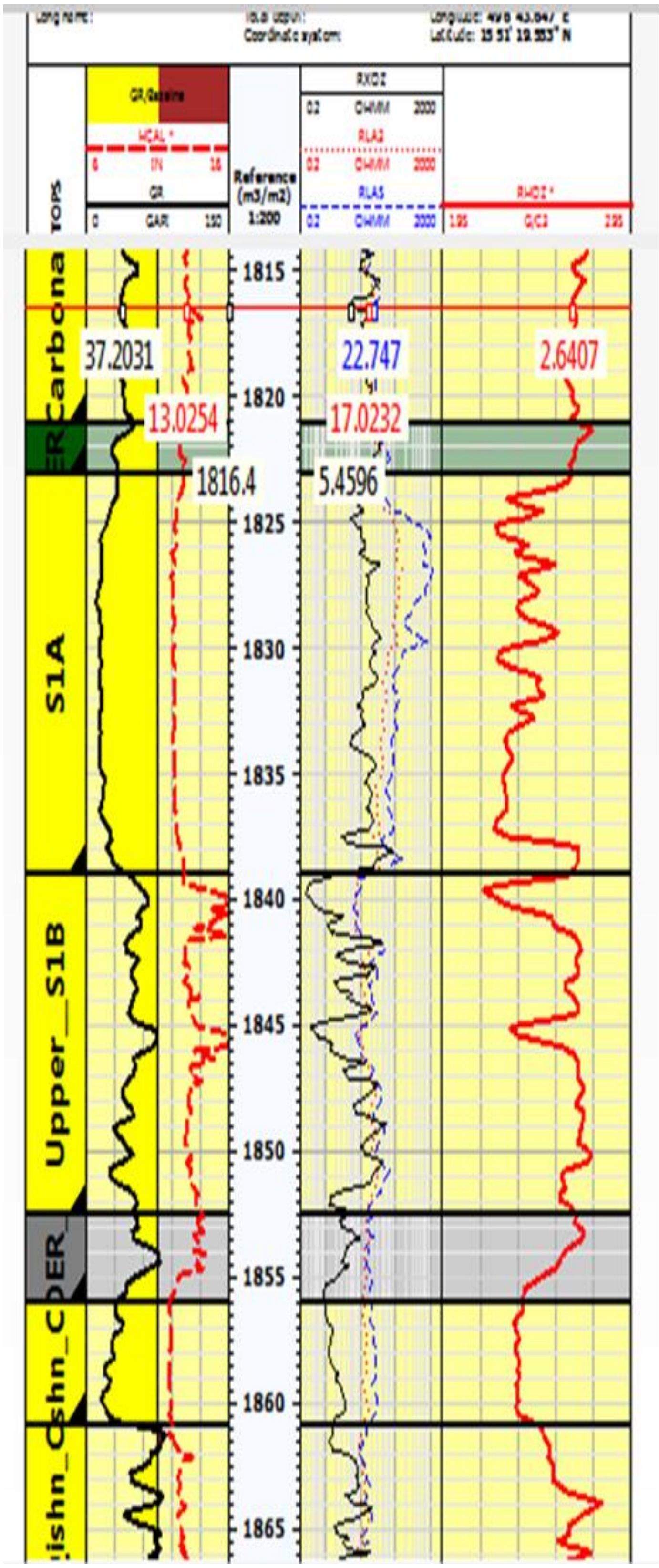

Figure 4-1 Tasour-26S New zonation Log

4.1.1.1. Shale Volume Calculation V_{sh}:

In this study the calculation of shale volume had done for each layer individually. The minimum and maximum GR used for calculation for the layers show in **Table. 4-3**.

Table 4-3 GR Values for Every Layer

Zones Name	GR	
	Minimum	Maximum
LOWRS1A	10.8	35
UpperS1B	25	77.5
LOWRS1B SUORCE	40	79
Upper Qishn Clastic_S1C	17	39
Upper Qishn Clastic S2	23	98.5

4.1.2. "Upper S1A/ LOWR S1A" Formation (Upper Qishn Clastic S1A)

Upper Qishn Clastic S1A" has divided into two layers: **Upper S1A** and **Lower S1A**.

4.1.2.1. Upper S1A

Is started from **1821m** to **1823 m**, And the thickness of this layer is 2 m. The reason for the exclusion of the layers is that it was considered within the layer of (Qishn Carbonate) depending on reading tools (GR, Resistivity Tool, HCAL, and RHOZ) from reading these devices it is clear that this layer follows Qishn Carbonate as show in fig 4.3. The GR curve show this layer is not clean sand, and to match the curve reading same with Qishn Carbonate reading, HCAL clearly show a very identical reading with Qishn Carbonate, and also the beginning of the Lower S1A layer at 1823, we note that the curve got a deviation and decrease in his initial value, RESISTIVITY LOG the reading device is very clear that this layer is carbonate, and that to converge readers micro resistivity, RAL3, and RAL5, It is also very similar with reading device in a carbonate layer, RHOZ it clearly shows a high reading in this layer as it was high value end of Qishn Carbonate layer, and also continued high value in the Upper S1A layer, and at the end of Upper S1A layer, and in beginning of Lower S1A at 1823 it shows that the RHOZ curve is deviates and decrease it is value to read clean sand layer.

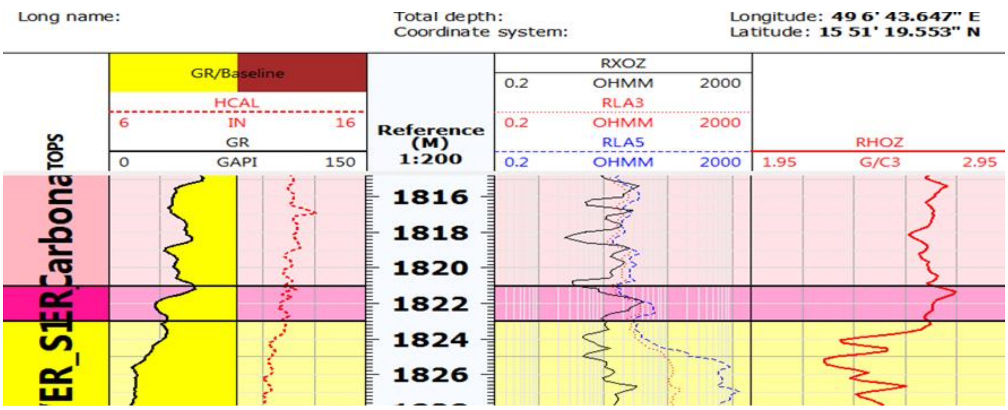

Figure 4-3 “Upper S1A” Formation Log Tasour-26S

4.1.2.2. LOWR S1A

LOWRS1A” formation located in Top depth 1823 m to bottom1839 m. This zone considered as clean sand formation in our study we excluded 1m of the end of lower S1A, that is depending on the (GR, Resistivity, HCAL, and RHOZ), the readings shows that it is shale layer follow upper S1B as show in **Fig. 4-4**.

It has total gross thickness of 16 m. Net pay thickness of this formation considered as 10.97 m. reading tools of resistivity shows the saturation of oil in terms of the difference between reading in micro, RA1and RA15.

“LOWRS1A” formation has 4.4 % shale volume “Vsh” and total effective porosity “$\emptyset_{effe}$” of 19.7 %. The saturation of water “Sw” of this formation is about 19.6 %. In our study oil saturation improved to 20%.

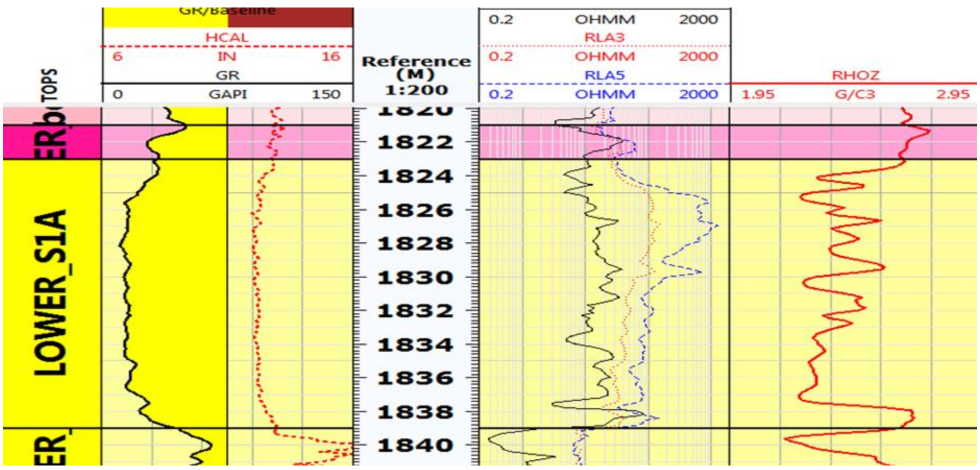

Figure 4-4 “LOWER S1A” Formation Log Tasour-26S

4.1.3. “Upper S1B / Lower S1B” Formation (Upper Qishn Clastic S1B)

4.1.3.1. Upper S1B

Upper S1B formation located in depth of 1839 m to 1852.5 m. This zone considered as shaly sand formation. The total gross thickness of 12.758m. porosity, water saturation, Net pay and shale volume of this formation not available because of exceed cut off value.

4.1.3.2. Lower S1B

Lower S1B started from 1852.5m and ends at 1856, from GR curve this is shale formation, RHOZ it is reading indicates that this formation is saturated with residual hydrocarbon so as to have high density value, HCAL indicate this from ason was saturated with hydrocarbon which show there is not washout in this formation as we see in the shale formation above it in UPPER S1B as show in **Fig.4-5.**

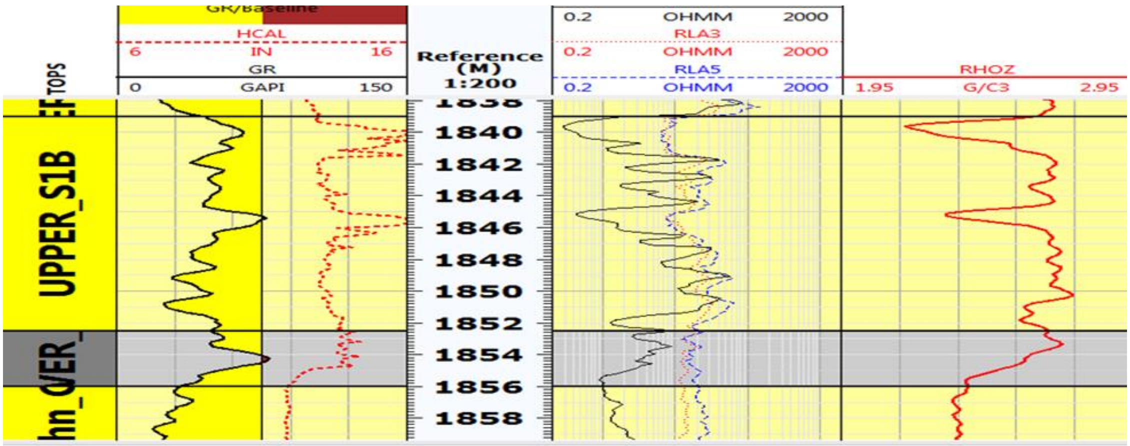

Figure 4-5 “Upper S1B and Lower S1B” Formation Log Tasour-26S

4.1.4. Upper Qishn Clastic S1C Formation

Upper Qishn Clastic S1C is started from 1856m and ends at 1860.8m, it is sand formation mixed with small amount of on the top shale, in our study we excluded 1.2m from the bottom of this original layer because it is shale layer and this 1.2m part has been follow the below layer S2 as shown in the reading of GR curve as show in fig 4.5 the value of S1C Net Pay 1.219m, Shale Volume Vsh(net) 8.7%, Total Effective Porosity (net) 17.8%, Water Saturation Sw(net) 48.9%.

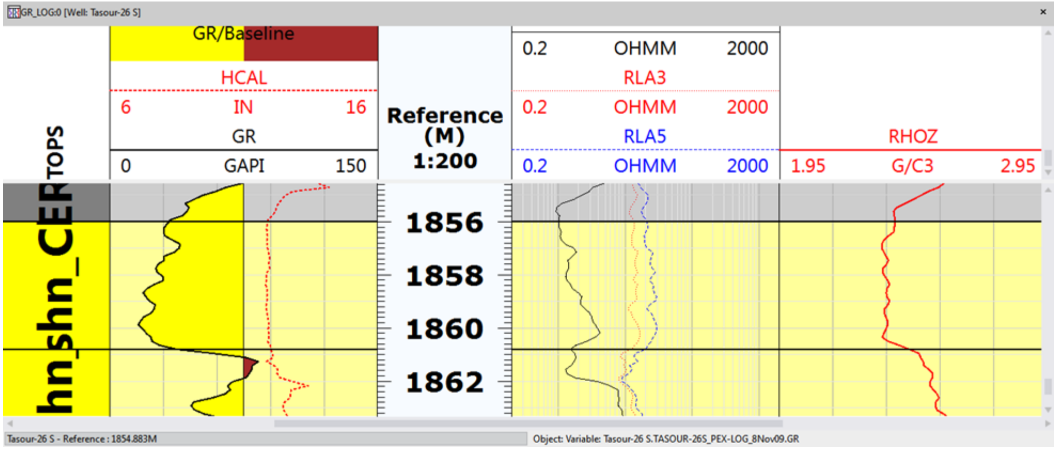

Figure 4-6 “Upper Qishn Clastic S1C” Formation Log Tasour-26S

4.1.5. Upper Qishn Clastic S2 Formation

Upper Qishn Clastic S2 is started from 1860.8m and ends at 1901m, it is sand formation mixed with small amount of on the top shale, in our study we supplied 1.2m from the top of the original layer because it is shale layer as shown in the reading of GR curve show in **Fig. 4-7** the value of Net Pay 7m, Gross 39.19m, Shale Volume Vsh(net) 7.2%, Total Effective Porosity (net) 21.1%, Water Saturation Sw(net) 53.8%

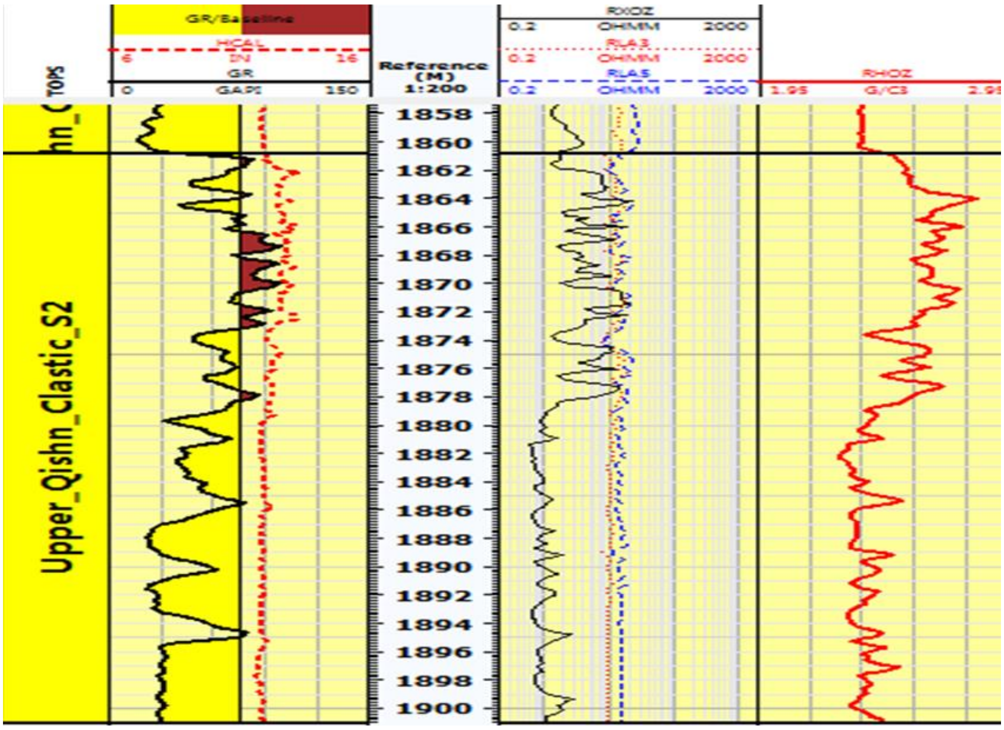

Figure 4-7 “Upper Qishn Clastic S2” Formation Log Tasour-26S

The Petrophysical properties for the new zones show in **Table. 4-4** and the Petrophysical properties that had done by DNO YEMEN company show in **Table. 4-5**.

Table 4-4 Petrophysical properties for the new zones

Zone name	Net pay (m)	Gross (m)	N/G	V_{sh} %	$Ø_{effe}$ %	Sw %	K(md)
Lower S1A	10.97	14.87	74 %	4 %	20%	20 %	190
Upper S1B	0	12.7	0	**#N/A**	**#N/A**	**#N/A**	
Lower S1B	0	4.32	5%	32 %	13 %	**#N/A**	
S1C	1.219	4.8	25 %	9 %	18 %	49 %	19
S2	7.04	39.19	18 %	7 %	21 %	54 %	33
Average	**19.229**	**75.88**	**-**	**13 %**	**18 %**	**41 %**	**80.66**

***#N/A: Absent because of exceeding the cut off value**

Table 4-5 DNO YEMEN Company Petrophysical properties Interpretations

Zone name	NET (PAY)	$Ø_{effe}$ %	S_w %
S1A	10.4	22 %	40 %
S1B	0	11 %	**#N/A**
S1C	1.2	18 %	51 %
Average	11.6	17 %	46 %

***#N/A: Absent because of exceeding the cut off value**

4.2. Al-Naser Field – Block 5 Well Log

4.2.1. Petrophysical Interpretations of Al-Naser 01 Well

As mentioned earlier in this research, many types of logs had been recorded in Al-Nasr wells to obtain the data required by the company and needed to evaluate the reservoir. This part will discuss the interpretations of petrophysical properties from the logs and compare the results with the results of interpretation that had been done by the company. According to **JANNAH HUNT OIL COMPANY** (**JHOC**) petrophysical report the following cutoff values for volume of shale (V_{sh}), Effective porosity ($Ø_{effe}$) and Water saturation (S_w) has been taken in account in our analysis:

Table 4-6 Cutoff Values

V_{sh}, %	$Ø_{effe}$, %	S_w, %
30	**12**	**55**

Table 4-7 Minimum and Maximum Values of GR

Zone	Top (m)	Bottom (m)	GR matrix	GR shale
TopUpperAlif_1	885.0088	885.9201	53.33	67.28
TopUpperAlif_2	886.7964	888.35	55.09	70.8
TopLT_1	890.582	900.25	22.49	77.79
UpperMainSand_1	901.3429	918.64	19.02	65.82
LowerMainSand	920.42	939.5844	22.06	87.7
Marker5a_1	942.3534	946.82	30.47	79.22
TopLowerAlif_1	947.9968	949.6442	65.91	72.73
Mk6	950.62	954.83	41.97	84.65
Mk7	954.83	959.7191	29.92	78.67
Mk8	961.15	966.59	22.94	56.3
Mk9	968.36	986.2667	23.11	77.33

There are different well logging tools that were used in **Al-Nasr 01** Such as well which include Caliper (**CALI**), Sonic (**DL**), Gamma ray (**GR**), Laterolog (**LLD & LLS**), Microresistivity (**MSFL**), Compensated Neutron (**NPHI**), Photoelectric effect (**PEF**), and Density (**RHOB**).

We notice that Laterolog has been used for resistivity measurements which indicates that Salty water base mud was used. **GR** log was used to determine the shale volume "**Vsh**". The Neutron, density and sonic logs were used together to determine the total and effective porosity "$Ø_{effe}$". The deep laterolog **LLD** was used to determine the formation true resistivity "**Rt**". The combination uses of the **Vsh,** $\boldsymbol{\emptyset_{effe}}$ and **Rt** were done for determination of water saturation **Sw.**

Al-Nasr 01 is a vertical well which located at 589126 x and 1685558 y and it was drilled to the total depth of 1910m. As all wells in Sabatayn Basin generally and block-5 specifically.

Practically, Safer formation is the upper boundary "**cap rock**" for the petroleum system. Safer formation is a huge salty dome.

JHOC analysis for Al-Nasr 01 well logs show that there are 13 different layers which are: **UpperAlif, TopLT, UpperMain, MainShale, LowerMain, Marker5a, TopLowerAlif, Mk6, Mk7, Mk8, Mk9, Mk10 and Yah.**

According to **GR** our interpretation makes new zonation process which is different from the original that had been done by **JHOC**. The following table (**Table. 4-8**) shows the new zones with theirs new names.

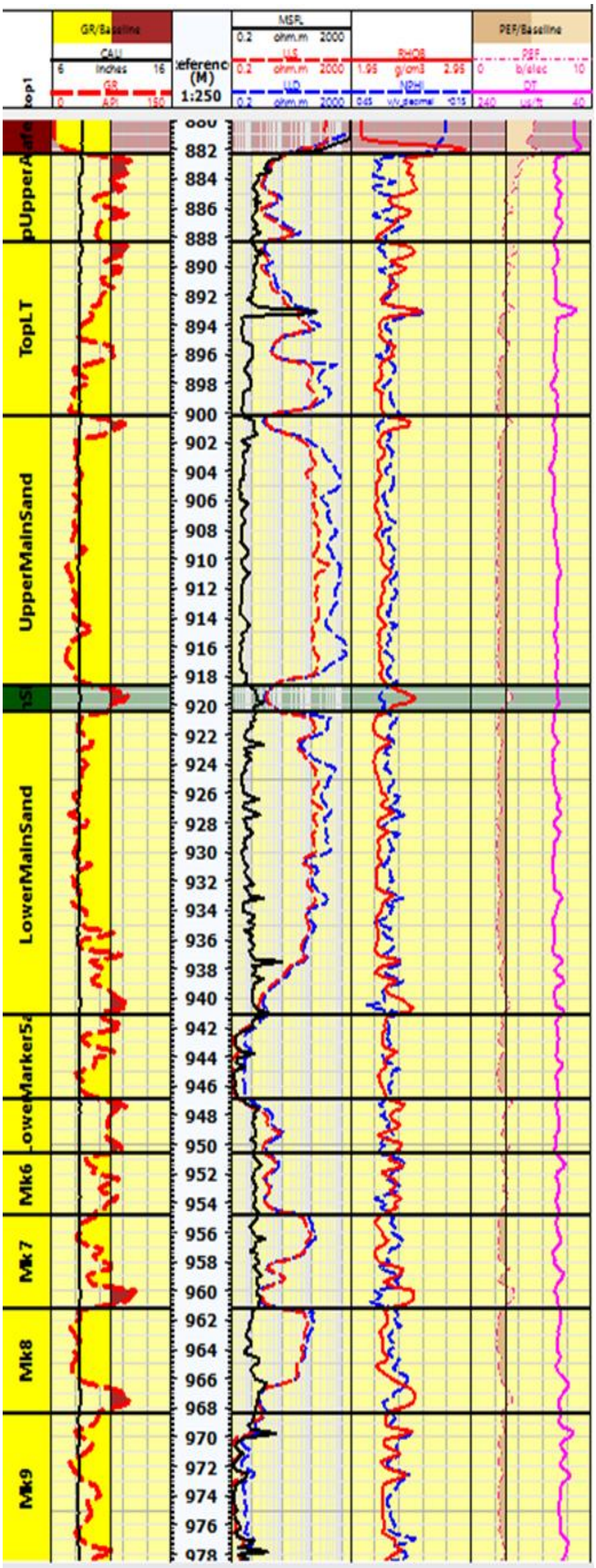

Figure 4-8 Al-Naser 01 Company Log

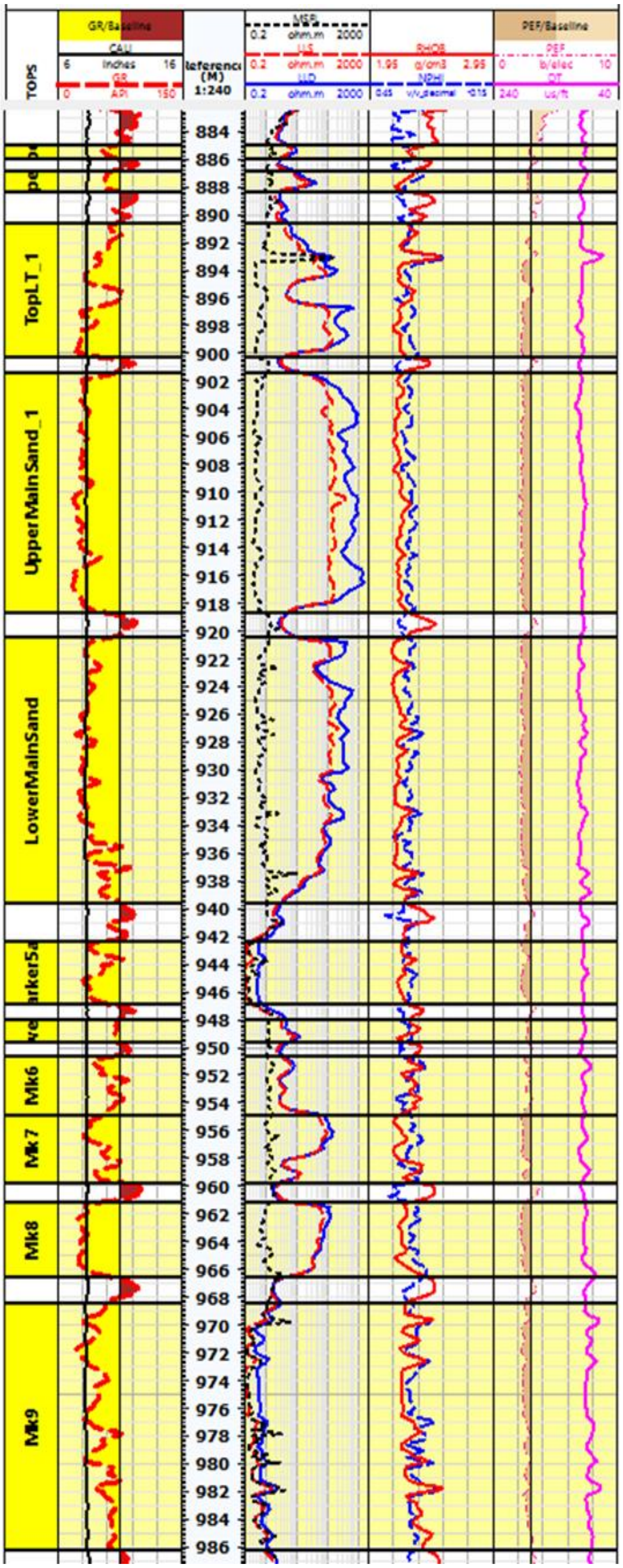

Figure 4-9 Al-Naser 01 New Zonation Log

Table 4-8 The New Zones with Theirs New Names

Original Zone	Depth (M)		New Zone	Depth(M)	
	Top	Bottom		Top	Bottom
TopUpperAlif	882.34	888.35	SH1_TopUpperAlif	882.34	885.02
			TopUpperAlif_1	885.02	885.88
			SH2_TopUpperAlif	885.88	886.78
			TopUpperAlif_2	886.78	888.35
TOPLT	888.35	900.25	SH1_TopLT	888.35	890.50
			TOPLT_1	890.50	900.25
UpperMainSand	900.25	918.64	SH1_UpperMainSand	900.25	901.34
			UpperMainSand_1	901.34	918.64
SH1_MainShale	918.64	920.42	SH1_MainShale	918.64	920.42
LowerMainSand	920.42	941.15	LowerMainSand	920.42	939.60
			SH1_LowerMainSand	939.60	941.15
Marker5a	941.15	946.82	SH1_Marker5a	941.15	942.35
			Marker5a_1	942.35	946.82
TopLowerAlif	946.82	950.62	SH1_TopLowerAlif	946.82	948.00
			TopLowerAlif_1	948.00	949.64
			SH2_TopLowerAlif	949.64	950.62
Mk6	950.62	954.83	Mk6	950.62	954.83
Mk7	954.83	961.15	Mk7	954.83	959.70
			SH1_MK7	959.70	961.15
Mk8	961.15	968.36	Mk8	961.15	966.6
			SH1_MK8	966.6	968.36
Mk9	968.36	987.25	Mk9	968.36	986.25
			SH1_MK9	986.25	987.52

According to the previous analysis for this well “which had been done by **JHOC**”, it shows that the last two layers “**MK10 and Yah**” considered as an aquifer so our analysis doesn’t cover them.

4.2.1.1. TopUpperAlif

This layer located at depth of **882.34 m -888.35 m** and had divided into four layers as shown in **Table. 4-8**.

TopUpperAlif_1

Layer **TopUpperAlif_1** which located at the depth of **885.009 m - 885.92 m.** The total gross thickness of **0.911 m**. Net pay thickness of this formation considered as **0.3 m.** TopUpperAlif_1 formation has **4 %** average shale volume “V_{sh}” and total effective porosity “$\emptyset_{effe}$” of **24 %**. The saturation of water “S_w” of this formation is about **16 %.**

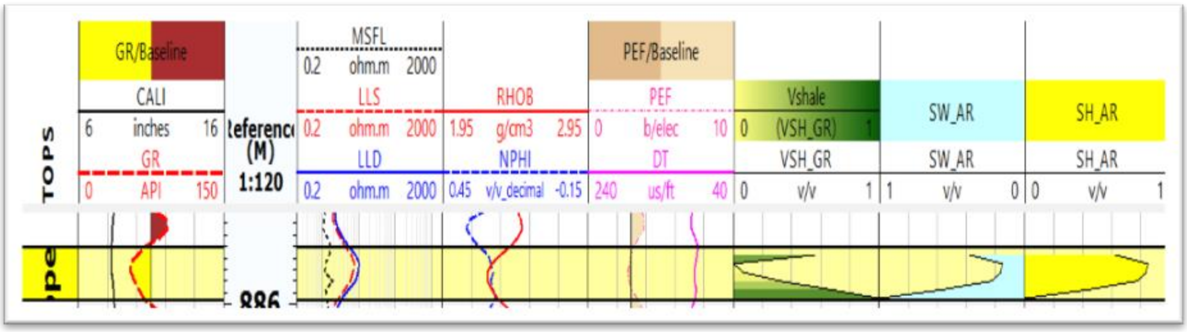

Figure 4-10 TopUpperAlif_1 Formation Log

TopUpperAlif_2

Layer **TopUpperAlif_2** which located at the depth of **886.79 m - 888.35 m.** The total gross thickness of **1.56 m**. Net pay thickness of this formation considered as **1.2 m.** TopUpperAlif_1 formation has **14 %** average shale volume "$\mathbf{V_{sh}}$" and total effective porosity "$\mathbf{Ø_{effe}}$" of **23 %**. The saturation of water "$\mathbf{S_w}$" of this formation is about **13 %.**

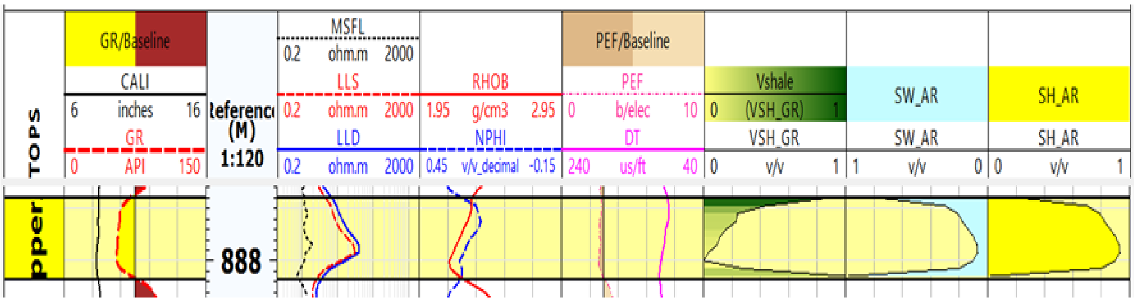

Figure 4-11 TopUpperAlif_1 Formation Log

4.2.1.2. TOPLT

This layer is located in the depth of **888.35m - 900.25m** which had divided into two layers as shown in **Table. 4-8**.

TOPLT_1

Layer **TOPLT_1** which located at the depth of **890.58m - 900.25 m.**

The total gross thickness of **9.67 m**. Net pay thickness of this formation considered as **3.85 m.** TOPLT_1 formation has **14 %** average shale volume "$\mathbf{V_{sh}}$" and total effective porosity "$\mathbf{Ø_{effe}}$" of **24 %**. The saturation of water "$\mathbf{S_w}$" of this formation is about **6 %.**

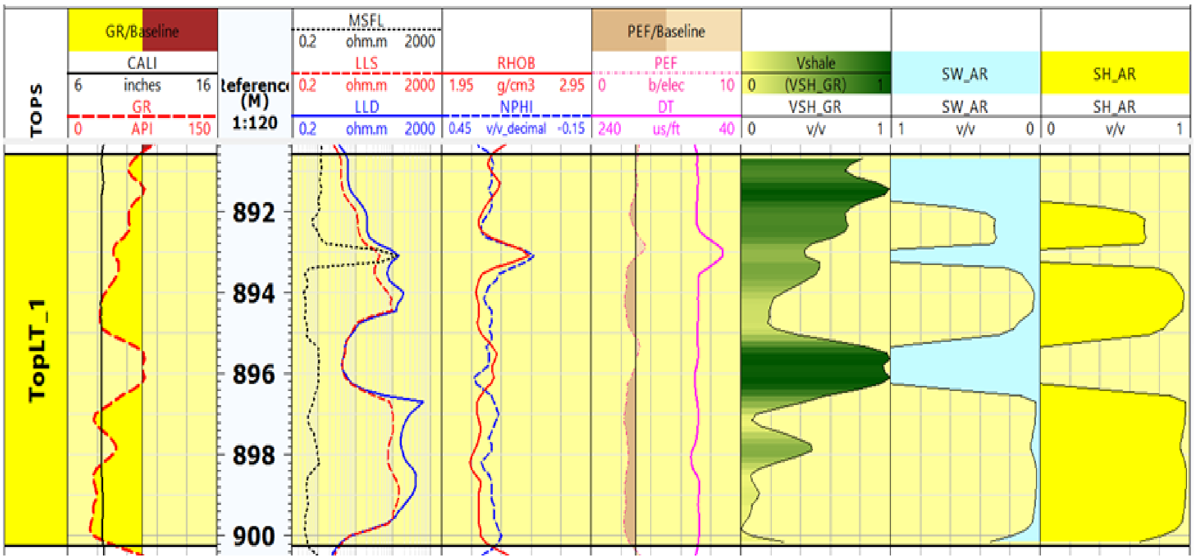

Figure 4-12 TOPLT_1 Formation Log

4.2.1.3. UpperMainSand

This layer is located at a depth of **900.25m - 918.64m** and had divided into two layers as shown in **Table. 4-8**.

UpperMainSand_1

Layer UpperMainSand_1 which located at the depth of **901.34 m - 918.64 m**.

The total gross thickness of **17.3 m**. Net pay thickness of this formation considered as **13.2 m**. UpperMainSand_1 formation has **18 %** average shale volume “**Vsh**” and total effective porosity “$\mathbf{\emptyset_{effe}}$” of **23 %**. The saturation of water “**Sw**” of this formation is about **3 %**.

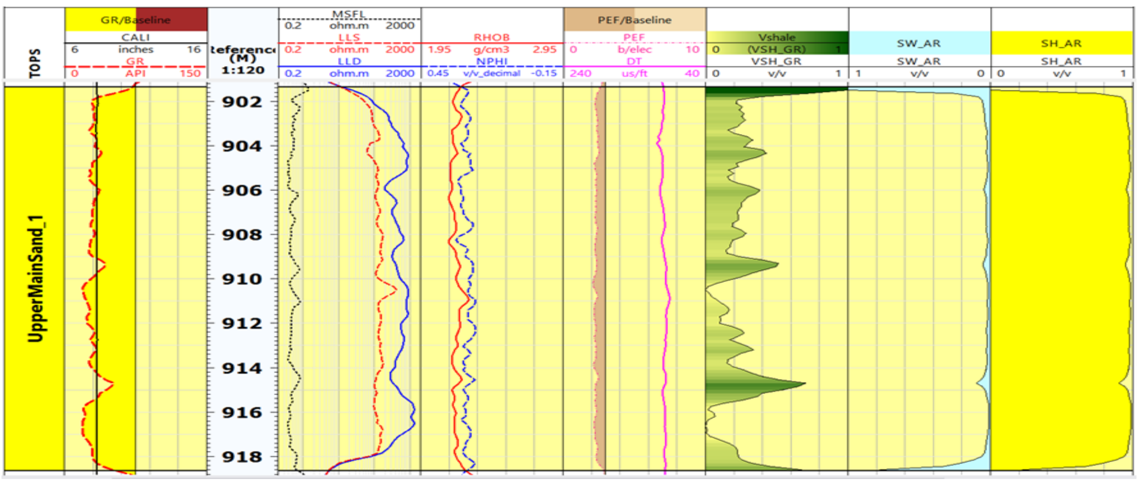

Figure 4-13 UpperMainSand_1 Formation Log

4.2.1.4. LowerMainSand

This layer had divided into two layers which located at a depth of **920.42m - 941.15m** as shown in **Table. 4-8.**

LowerMainSand-1

Layer **LowerMainSand_1** which located at the depth of **920.42 m - 939.60 m**.

The total gross thickness of **19.16 m**. Net pay thickness of this formation considered as **12.60 m**. **LowerMainSand_1** Formation has **17 %** average shale volume "**Vsh**" and total effective porosity "**$\emptyset_{effe}$**" of **23 %**. The saturation of water "**Sw**" of this formation is about **4 %**.

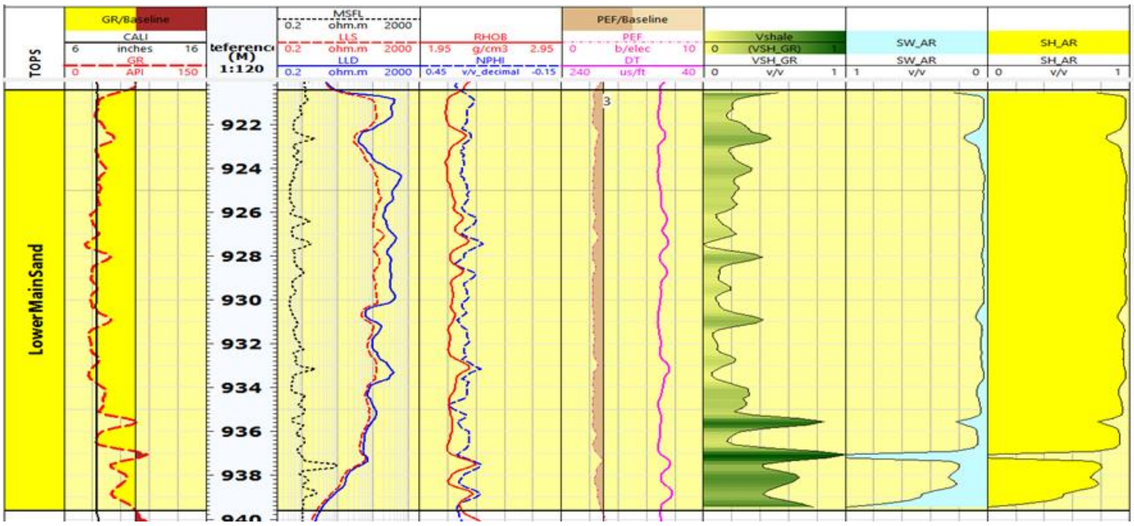

Figure 4-14 LowerMainSand_1 Formation Log

4.2.1.5. Marker5a

This layer is located at a depth of **941.15m - 946.82m** and it divided into two layers as shown in **Table. 4-8.**

According to the cutoff values" **Table 4-6**", this formation considered as non-productive formation.

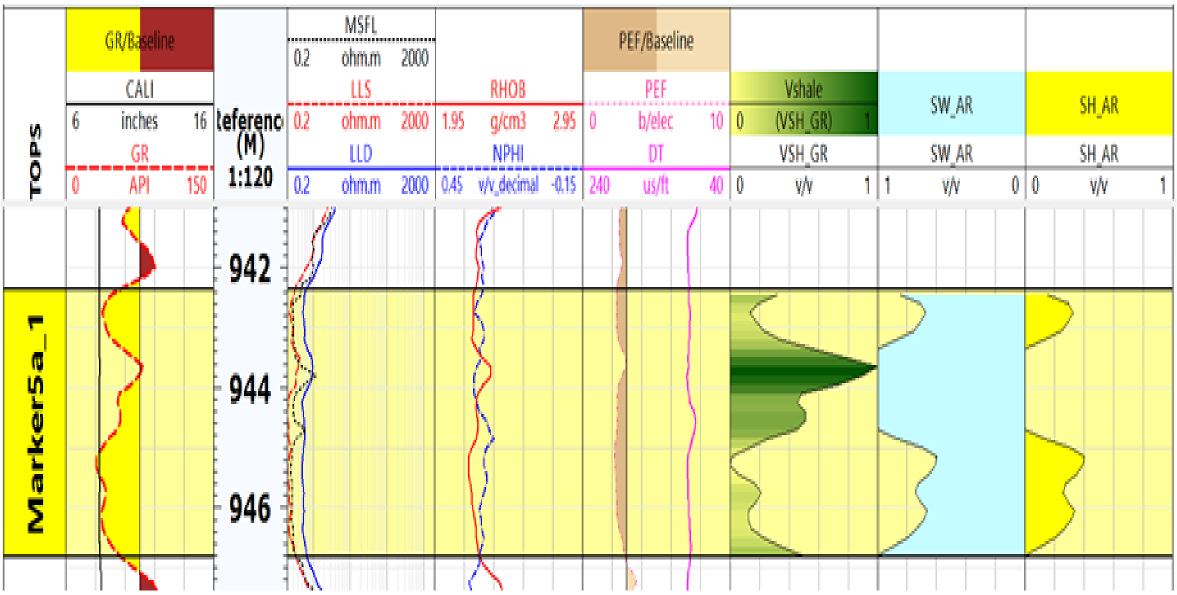

Figure 4-15 Marker5a Formation Log

4.2.1.6. TopLowerAlif

This layer is located at a depth of **946.82 m - 950.62 m** and it divided into three layers as shown in **Table. 4-8**.

TopLowerAlif_1

Layer **TopLowerAlif_1** which located at the depth of **920.42 m - 939.60 m**.

The total gross thickness of **1.64 m**. Net pay thickness of this formation considered as **0.294 m**. **TopLowerAlif_1** Formation has **8 %** average shale volume "**Vsh**" and total effective porosity "$\boldsymbol{\emptyset_{effe}}$" of **26 %**. The saturation of water "**Sw**" of this formation is about **16 %**.

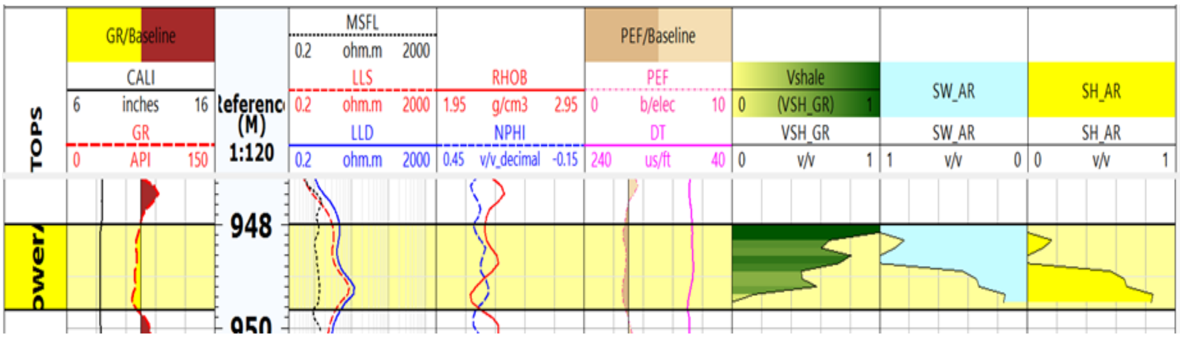

Figure 4-16 TopLowerAlif_1 Formation Log

4.2.1.7. Mk6

This layer is located at the depth of **950.62 m - 954.83 m**.

The total gross thickness of **4.21 m**. Net pay thickness of this formation considered as **1.28 m**. **MK6** Formation has **16 %** average shale volume “$\mathbf{V_{sh}}$” and total effective porosity “$\mathbf{Ø_{effe}}$” of **18 %**. The saturation of water “$\mathbf{S_w}$” of this formation is about **25 %**.

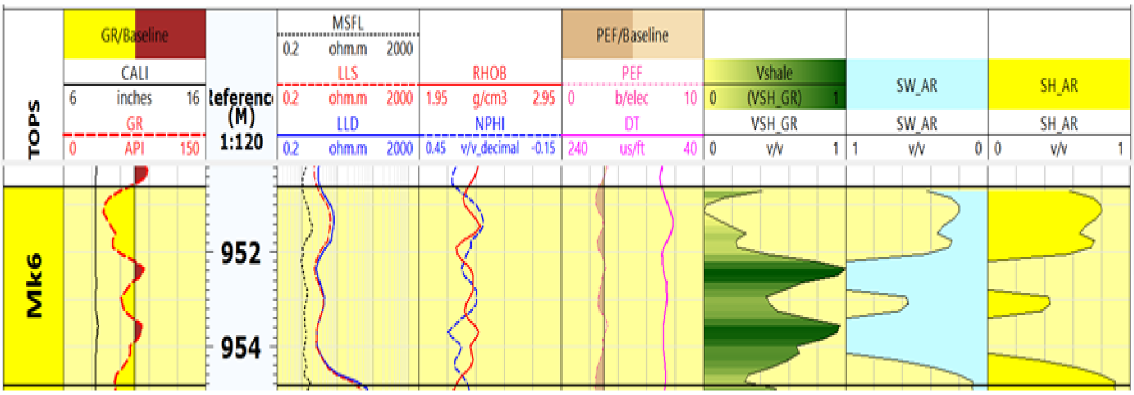

Figure 4-17 MK6 Formation Log

4.2.1.8. Mk7

This layer is located at the depth of **954.83 m - 961.15 m** and had divided into two layers as shown in **Table. 4-8**.

MK7_1

Layer **MK7_1** which located at the depth of **954.83 m - 959.71 m**.

The total gross thickness of **4.88 m**. Net pay thickness of this formation considered as **1.72 m**. **MK7_1** Formation has **15 %** average shale volume “$\mathbf{V_{sh}}$” and total effective porosity “$\mathbf{Ø_{effe}}$” of **22 %**. The saturation of water “$\mathbf{S_w}$” of this formation is about **5 %.**

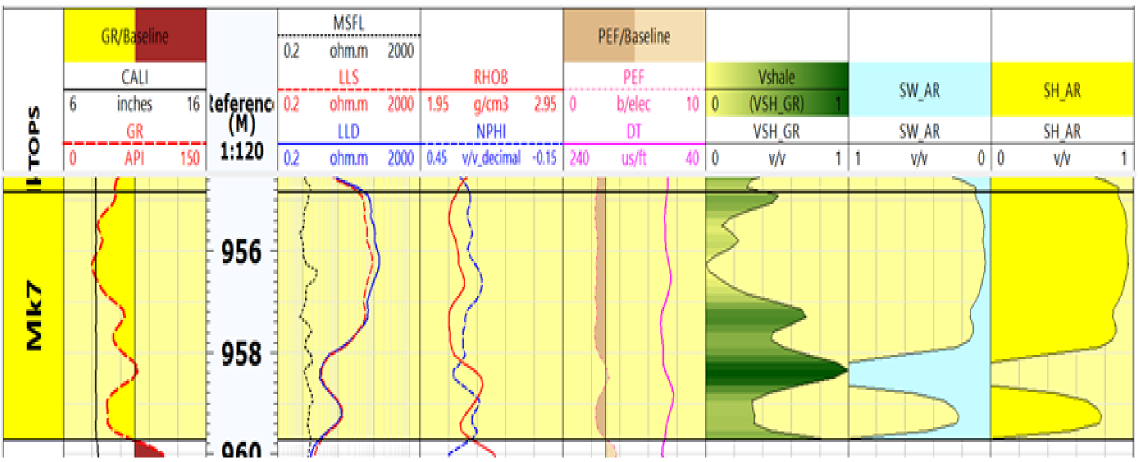

Figure 4-18 MK7_1 Formation Log

4.2.1.9. Mk8

This layer is located at the depth of **961.15 m - 968.36 m** and had divided into two layers as shown in **Table. 4-8**.

MK8_1

Layer **MK8_1** which located at the depth of **961.15 m – 966.6 m**.

The total gross thickness of **5.44 m**. Net pay thickness of this formation considered as **3.6 m**. **MK8_1** Formation has **16 %** average shale volume “$\mathbf{V_{sh}}$” and total effective porosity “$\mathbf{\emptyset_{effe}}$” of **22 %**. The saturation of water “$\mathbf{S_w}$” of this formation is about **7 %.**

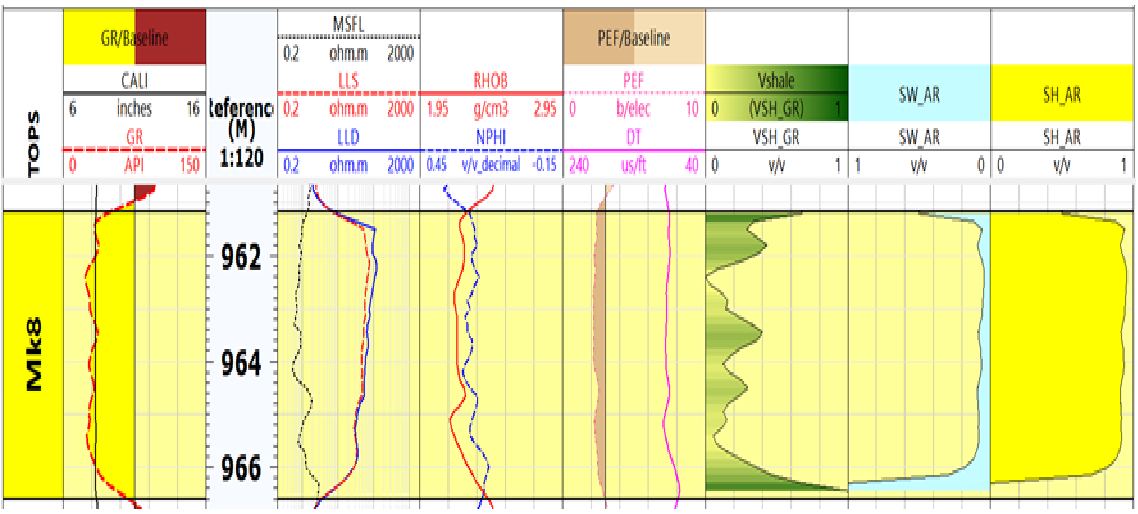

Figure 4-19 MK8_1 Formation Log

4.2.1.10. MK9

This layer is located at the depth of **968.36 m - 987.25 m** and had divided into two layers as shown in **Table. 4-8**

According to the cutoff values” **Table 4-6**”, this formation considered as non-productive formation.

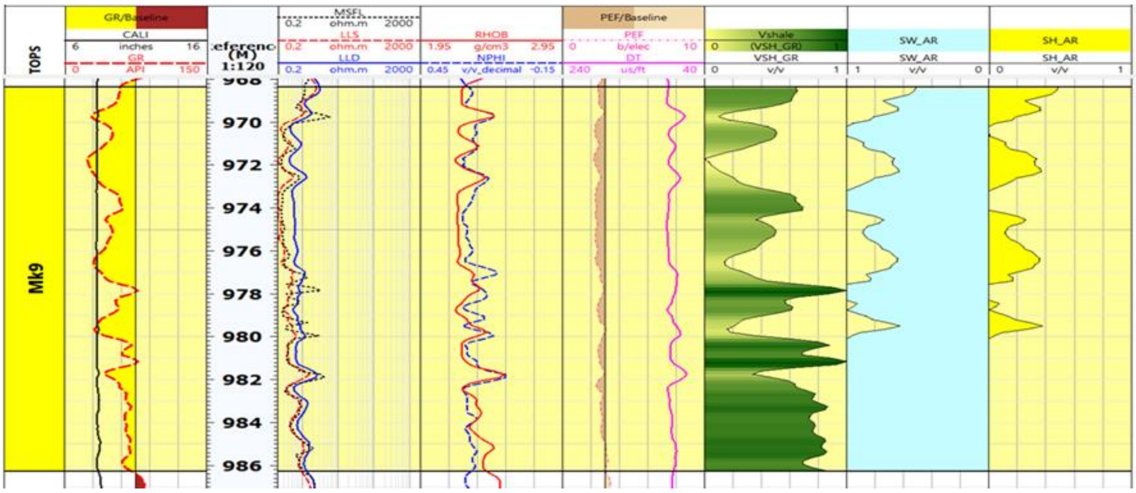

Figure 4-20 MK9 Formation Log

Table 4-9 Summary of Petrophysical Parameters for Al-Nasr 01 Well

Zones	Top (m)	Bottom (m)	Gross (m)	Net (m)	N/G %	V_{sh} %	$Ø_{effe}$ %	Sw %	K (md)
TopUpperAlif_1	885.009	885.92	0.911	0.3	0.329	4 %	24 %	16 %	700
TopUpperAlif_2	886.796	888.35	1.554	1.2	0.772	14 %	23 %	13 %	900
TopLT_1	890.582	900.25	9.668	3.85	0.398	14 %	24 %	6 %	5000
UpperMainSand_1	901.343	918.64	17.297	13.2	0.763	18 %	23 %	3 %	5450
LowerMainSand	920.42	939.584	19.164	12.599	0.657	17 %	23 %	4 %	5300
Marker5a_1	942.353	946.82	4.467	-	-	-	-	-	-
TopLowerAlif_1	947.997	949.644	1.647	0.294	0.179	8 %	26 %	16 %	990
Mk6	950.62	954.83	4.21	1.28	0.304	16 %	18 %	25 %	80
Mk7	954.83	959.719	4.889	1.72	0.352	15 %	22 %	5 %	5100
Mk8	961.15	966.59	5.44	3.6	0.662	16 %	22 %	7 %	2100
Mk9	968.36	986.267	17.907	-	-	-	-	-	-
Average	**-**	**-**	**87.154**	**38.043**	**49 %**	**14 %**	**23 %**	**10 %**	**2846.667**

Table 4-10 JHOC Petrophysical Parameters for Al-Nasr 01 Well

Well Name	Net (m)	$Ø_{effe}$ %	S_w %
Al-Nasr 01	**55.33**	**21.8 %**	**7.1**

CHAPTER Five

5. CONCLUSION, RECOMMENDATIONS, AND LIMITATIONS

5.1. Introduction

In This project the interpretation of reservoir rock properties for Tasour oil Field-Block 32 at Masila basin and Al-Nasr oil Field-Block 5 at Sabatayn basin by applying the analysis for two wells (Tasour 26s and Al-Nasr-01) was conducted in chapter 4.

The analysis done for two wells which described in chapter 5.

5.2. Conclusion

5.2.1. Formation Evaluation Results for Tasour 26S Well – Block 32:

Re-zonation process for the formations had done for each layer separately in order to obtain more accurate results.

The target reservoir "Upper_Qishn_Clastic_S1A" had divided into two layers (**UPPER S1A**, **LOWER S1A**). After Re-zonation process, **UPPER S1A** formation did not considered as a reservoir. **LOWER S1A** has shale volume of 4 %, effective porosity of 20%, water saturation 20 %, gross thickness of 10.97 m, and Net pay thickness of 10.8m.

According to these results and comparing with DNO Company results, the hydrocarbon saturation improved by 2.5%.

The Upper_Qishn_Clastic_S1B had divided into two layers (**UPPER S1B**, **LOWER S1B**). According to the cutoff values, UPPER S1B, LOWER S1B formations considered as non-productive formations.

The Upper_Qishn_Clastic_S1C with the new depth, has considered as clean sand with, shale volume of 8.7%, effective porosity of 17.8% and water saturation of 48.9%, Gross thickness of 4.8m, and Net pay thickness of 1.219m.

According to the cutoff values, Upper_Qishn_Clastic_S2 formations considered as non-productive formations.

5.2.2. Formation Evaluation Results for Al-Naser-01 well – Block 5:

After applying the cutoff values for Al-Naser-1 well has average water saturation Sw of 10 %, average total porosity of 23% and net pay thickness of 38 m. Water saturation value and the porosity indicate good clean sand reservoir. The reduction in net pay thickness compared to JHOC analysis is due to the re-zoning process. Marker 5a_1 and Mk 9 formation properties exceed the cutoff value. TopUpperAlif_1, TopUpperAlif_2, TopLT_1, UpperMain_1, LowerMain_1, TopLowerAlif_1, Mk6', Mk7' and Mk8' formations show acceptable properties and meet the cutoff values which make them perfect to production.

5.3. Recommendations

- Re-zonation process should be done for Tasoure 26s and Al-Naser wells.

5.4. Limitations

- Limited time and Difficulties while gathering the data led to Limit the project objectives.

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