RESERVOIR CHARACTERISATION OF THE WND FIELD IN THE NIGER DELTA BASIN, NIGERIA: BACKGROUND STUDY TO SIMULATION

A thesis Submitted for the degree of Master of Science

By

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Abstract

The WND field located in the north-west proximal offshore of the Niger delta basin was discovered in 1988 and started production in 1995 with most of its oil production coming from the D-01 reservoir. The focus of this project is on the description of the D-01 reservoir and quantification of the hydrocarbon reserves and the role that the description has on understanding the reservoir performance.

The integration of petrophysical data, seismic and production data has made it possible to delineate the D-01 reservoir and allowed for a better understanding of the architecture and sedimentary parameters that influence reservoir properties to optimize recovery of the hydrocarbon reserves.

The aims of this research among others is to describe the reservoir, determine the oil- water contact in the reservoir, delineate the boundaries and extent of the reservoir in the field, as well as to estimate the oil reserves. Database for this project include mudlog, core, digital log curves, seismic and production data. The reservoir has been described and characterised, and this project yielded six lithostratigraphic facies associations, a depositional model, correlation cross sections through every well in the field, 2-D structure contour maps of the top and base horizons of the reservoir in time and depth, isopach and net-isopach maps, and a 3-D geologic model of the D-01 reservoir that honours all the available data for this project.

The D-01 reservoir characterisation provides the geologic framework that can be used for reservoir management purposes in the WND field. Petrophysical analysis shows that the sands in this reservoir generally occur as blocky sandstone successions with minor upward fining, having moderate to high porosity and permeability, and low water saturation.

Core data analysis and log interpretations have led to the identification of six lithostratigraphic facies associations for the sediments in this reservoir. It was discovered that the reservoir is made up of barrier bar sandstones (characterised by a coarsening upwards of grain size) and prodelta marine shales (exhibiting fining upward log trend) deposited in a prograding wave dominated middle-lower shoreface to prodelta environment. The marine shales deposited in the low energy environment hardly have any porosity and permeability, while the sandstones deposited in the higher energy environment are mostly found in the upper part of the sequence intercalated with very thin shale beds, and they turned out to be the best reservoir facies. Well-to-well correlation shows that the sands have good lateral continuity and the shale interbeds are not extensive laterally to act as vertical permeability barrier.

The delineation and mapping of the extent of the D-01 reservoir in the WND field was done from seismic interpretations made. 2-D and 3-D grids were constructed from which structure contour maps for the top and bottom of the reservoir were constructed. Isopach maps were also constructed for the gross reservoir thickness and net thickness defined by the oil-water contact. Interpretations from these contours show that the D-01 sands tend to develop more in the middle part of the field, this area is a good development target.

Results of petrophysical analysis and seismic interpretations were integrated with available production data to construct a 3-D geological model that honours all the available data for this project. Recoverable estimates carried out compared with the available production shows that there is still 52,332,620 barrels of oil left in the reservoir to be recovered.

Declaration

The material presented in this thesis is the result of research carried out between October, 1997 and September, 1998 in the Department of Geology and Applied Geology, University of Glasgow, under the supervision of Dr. Gary Couples.

This thesis is based on my own independent research and any published or unpublished material used by me has been given full acknowledgement in the text.

Gloria Okome

September, 1998

Supervisor's certification:

I certify that Gloria Okome has undertaken the bulk of the work involved in this thesis. Specifically, background geology, data collation and analysis, and computer modelling. I have assisted with advice and help of a general, technical, conceptual nature, as would be expected in the course of normal M. Sc. Supervision. Gloria Okome has written the thesis her self, and is responsible for its content.

G.D. Couples

Dedication

I dedicate this thesis to my family for their love, support and believe in me throughout this work

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Chevron Nigeria limited provided all the data used in this project. I would particularly like to thank Mr E.U Adokpaye, Biodun Alimi, Sunkanmi Iyiola who were always there to answer my many questions concerning the data used for this research.

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Chapter One **Introduction**

1.1 Context of Reservoir Characterisation in this study

This thesis represents one year MSc. project using data set provided by Chevron Nigeria limited. The project was undertaken to provide broad training in a variety of interpretation techniques applicable to a range of reservoirs. It was funded by Landmark Graphics Nigeria limited.

After an accumulation of petroleum is discovered, and even long after discovery, when it has started producing, it is essential to characterise the reservoir in order to calculate the reserves and determine the most effective way of recovering as much of the petroleum as possible from the reservoir (Lake *et al.*, 1991; Worthington, 1993; Lucia and Fogg, 1991; Haldersen and Damsleth, 1993).

Reservoir characterisation in the context of this study is the detailed knowledge of the architecture and sedimentary parameters that influence reservoir properties. It involves the quantification, integration, reduction and analysis of geological, petrophysical and seismic data to optimise recovery of hydrocarbon reserves, (Tinker and Mruk, 1995).

1.2 Aims of this Study

The primary goals of this study are:

1. To describe the D-01 reservoir of the WND field in north western offshore of the Niger delta basin.
2. To find out if the D-01 sand is actually separated into two anticlinal lobes.
3. To determine the oil-water contact.
4. To determine the extent of the field in order to optimise recovery of oil reserves.
5. To quantify the significant oil remaining for additional recovery beyond what is being produced at present.

1.3 Objectives

The objective of the WND field geologic reservoir characterisation project is to describe the producing D-01 reservoir sand of the Agbada formation in terms of its rock geometry and properties, in a format that could be evaluated using wireline logs, seismic and production data to map the reservoir facies distribution in both 2-D and 3-D. These reservoir descriptions can then be integrated into operation projects, reservoir management strategies and for simulation studies.

1.4 Project Components and Database

- **Core analysis**

Sedimentological and stratigraphical analysis of 124.4 ft of five already-described cores from well WND-02 was carried out to examine the distribution of lithology in the D-01 reservoir, and to understand better the stratigraphy and environment of deposition of the D-01 reservoir interval for the whole field. The result of the core analysis was used to interpret mud-log and wire-line logs for the three other wells.

- **Correlation**

Correlation using wireline log data available for wells in the WND field was done in the strike and dip directions, that is from NW to SE and from NE to SW. The aim of doing correlation is to define the lithologic units, the vertical distribution of the reservoir facies and the depositional cycles in the field of study. Cross sections were made using GMAplus software to illustrate the stratigraphic framework of the reservoir and to show the areal distribution of the reservoir facies.

- **Wire-line log analysis**

Wire-line log data avilable for this study was for wells WND-01, WND-02 and WND-03. The wire-line logs available include gamma-ray, caliper, resistivity (medium and deep), sonic, porosity and bulk density. These were examined digitally using the GMAplus software to interpret the lithology of the sediments, the depositional system, and to determine the petrophysical characteristics of the D-01 sand. Such characteristics include the pore system, permeability, water saturation and the general reservoir geometry. Results from these studies were then used to define the lithofacies and depositional environments.

- **Seismic analysis**

Seismic data available for this study include raw checkshot data, seismic shot point map of the field, and seismic lines. PROMAX software was used to make hard copy prints of selected seismic lines for use in the 2-D manual seismic interpretations (twelve in-lines and sixteen cross-lines on the whole were interpreted). The check shot data was used to do time/depth conversions. The seismic lines were interpreted manually and the identified horizons of interest were digitised and imported into the EARTHVISION software from which two-way time and depth structure contour maps of the top and base D-01 reservoir were constructed.

- **Three Dimensional Integration and Geologic Modelling**

Three-dimensional reconstruction of the body geometries was performed using EARTHVISION, in order to determine the size and shape of the D-01 reservoir in the WND field in an accurate way as well as to estimate the reserves in this reservoir. All the core, log and seismic data were integrated to give a 3-D geologic model in EARTHVISION. This model mimics the geometries of the prograding and aggrading sandstones of the D-01 reservoir across the WND-field. This 3-D model was also used to examine the reservoir distribution, connectivity, and for volumetric calculations.

1.5 Study Area

1.5.1 Introduction of the WND Field

The WND field covers an area of about 10 km^2, and is located in the Northwest proximal offshore of the Niger Delta basin, Nigeria, where water depth is up to 200m (figure 1.1). The WND-field produces from the Agbada formation, which is the main prolific oil productive formation in the Niger Delta basin (Dickey, *et. al.*, 1987; Oboh, 1993; Beka and Oti, 1995). The study area has a present production rate of 20,000 barrels of oil per day from the D-01 reservoir. The thickness of the D-01 reservoir sand interval varies from 100-250 ft across the field, with an average porosity of 29% and average water saturation of 26%.

1.5.2 History and Reservoir Management of the WND-field

The proximal offshore WND field was discovered in 1988. The first well WND-01 which is a straight well, was drilled the same year to a total depth of 9727 ft. Three more wells WND-02, WND-03 and WND-04, were drilled in the next six years and a fifth well WND-05 is being proposed for drilling. WND-02 which is also a straight well was spudded in November, 1991, WND-03 and WND-04 are deviated wells spudded in August, 1994 and December, 1994 respectively. Both were drilled deviated from the surface locations of wells 2 and 1 respectively. There were no data available for WND-04 for this study. The main producing reservoir in this field is the D-01 sand, with WND-02 being the first to be completed in August 1994. Production was predominantly from this well in the early years of the field and it was driven by the inherent energy. The main recovery mechanism used for this field is the water injection mechanism.

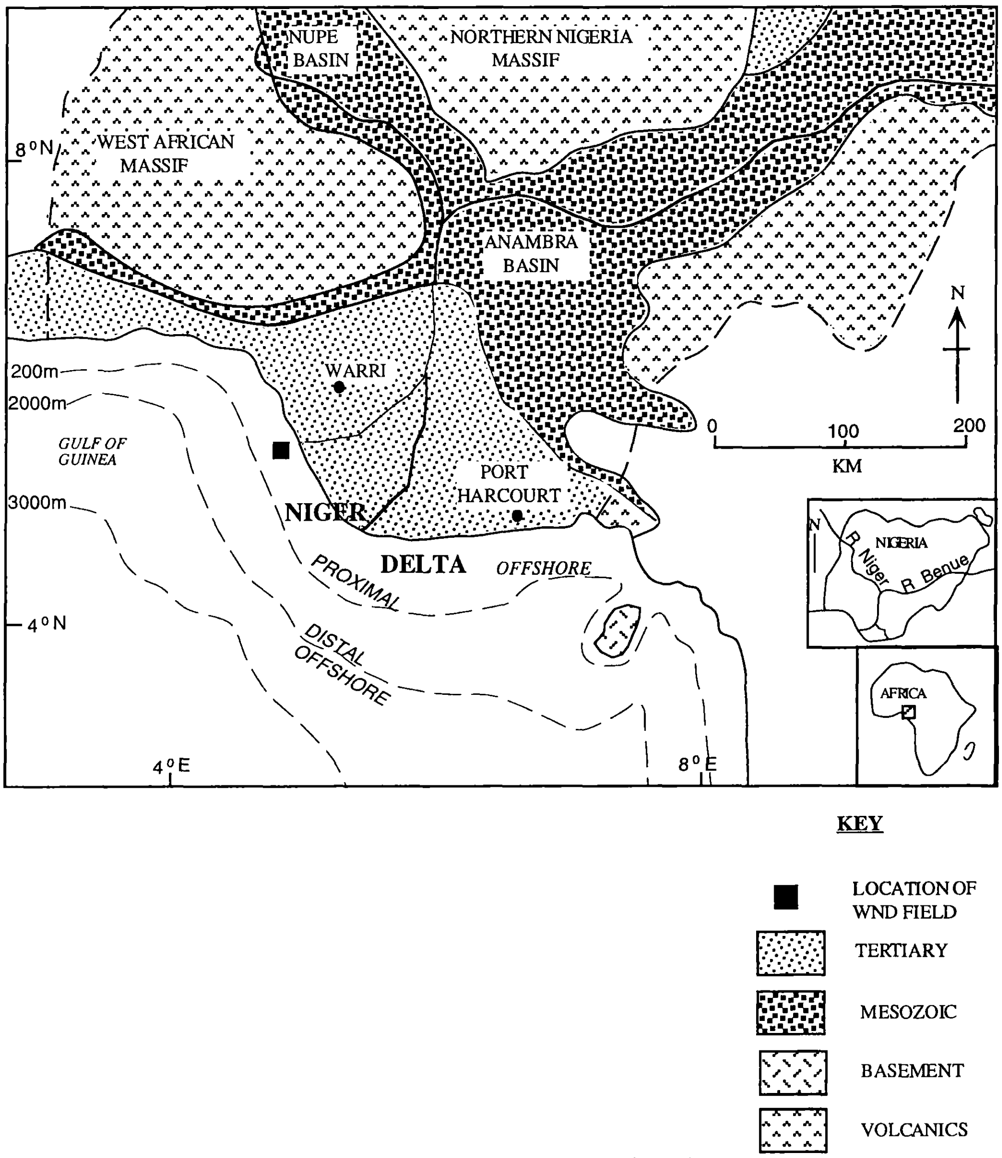

Figure 1.1 Sketch map of southern Nigeria showing the location of the WND field in the Niger Delta and bathymetric contours indicating approximate limits of the proximal and distal offshore (modified from Beka and Oti, 1995).

Chapter Two **Regional Geology and Stratigraphic Setting of the Niger Delta Basin**

The aim of this chapter is to briefly review the literature on the regional geology and stratigraphy of the Niger delta basin, in which the study area is located, as well as previous work done on describing the D-01 reservoir.

2.1 Regional Geology

The origin of the Niger Delta basin is associated with the evolution of a triple junction during the separation of the south American plate from the African plate in the late Jurassic times (Short and Stauble, 1967; Burke *et al.,* 1972; Whiteman, 1982). The Tertiary Niger Delta forms a sedimentary wedge situated at the point where the Benue Trough abuts the South Atlantic Ocean. The Niger Delta occupies 6400 $km^2$of the sedimentary basin of southern Nigeria, of this, the offshore portion (in which the study area is located), as far out as the lower continental slope, exceeds 30,000 sq miles (Lambert-Aikhionbare and Shaw, 1982).

2.2 Stratigraphy

The stratigraphy of the Niger Delta is highly complex due to the presence of numerous multi-cycles and facies changes as well as syn-sedimentary deformations. After the transgression of the Paleocene, anoxic sediments were deposited in a prograding delta, resulting in a sequence of diachronous lithologic units from bottom to top. The wave dominated Niger Delta (Doust, 1990) can be divided into six depobelts separated by major syn-sedimentary fault zones. These depobelts can be thought of as transient basinal areas succeeding one another in space and time as the delta progrades southwards (Evamy *et al.*, 1978; Ekweozor and Daukoru, 1984 and 1994; Akanni, 1994; Stacher, 1995). The scope of the present study will be limited to the offshore depobelt. The deltaic sequence of the Niger delta consists of a clastic sedimentary wedge of approximately 12km thickness covering an areal extent of about 140,00 km^2 (Knox and Omatsola, 1989). The sedimentary succession comprises marine, fluvio-marine, littoral and deltaic plain environments (Weber, 1971; Weber and Daukoru, 1975).

The Niger Delta is made up of three lithostratigraphic units (figure 2.1) (Weber and Daukoru, 1975; Evamy *et al.*, 1978; Weber, 1986; Amajor and Agbaire, 1989), namely:

(i) The Akata Formation

The basal Akata formation consists of about 6000 m of continuous, mobile, over-pressured (Schlumberger, 1985; Owolabi *et al.*, 1990), and under-compacted marine shales (Knox and Omatsola, 1989), with silty and sandy intercalations towards the top laid down in front of the advancing delta. The Akata shales that have been deposited from Paleocene to Recent are the main source rock of the Niger Delta (Weber and Daukoru, 1975), although there have been controversies regarding this. Workers such as Lambert-Aikhionbare and Shaw (1982) and Egbomah and Lambert-Aikhionbare (1980) think the shale beds of the Agbada formation are also source rocks.

(ii) The Agbada Formation

The delta front paralic megafacies of the Agbada formation overlies the Akata shales. The Agbada formaion consists of approximately 4500 m of alternating sandstone and shale beds which is as a result of differential subsidence, variation in sediment supply and shifts in depositional lobes of the delta (Oboh, 1993). The upper part of the Agbada formation is generally sandier than the lower part; this depicts a seaward advance of the delta. The age of this formation varies from Eocene in the north to Recent in the south; that is at the present delta surface (Lambert-Aikhionbare and Shaw, 1982; Beka and Oti, 1995).

The main reservoir of the Niger Delta hydrocarbons is the interbedded sandstones in the paralic Agbada formation with structural and stratigraphic trapping mechanisms (Dickey *et. al.,* 1987; Oboh, 1993; Beka and Oti, 1995). Here the hydrocarbons are trapped at the crest of rollover anticlines in syn-sedimentary growth faults generated with the deposition of the sediments. The shales of this formation act as cap-rocks or seals, and prevent the upward migration of the hydrocarbons.

The sandstones of the Agbada formation are poorly cemented coarse to fine grained quartz arenites. The environment of deposition of the Agbada sequence is from the transition between the lower deltaic plain to marine sediments of the continental shelf fronting the delta.

iii) The Benin Formation

The continental Benin formation overlies the Agbada, and is the upper deltaic plain megafacies. It consists mainly of about 2000 m of massive fluviatile, continental sandstones and gravels, commonly with some conglomerates and occasionally with a few shale and lignite intercalations that are more abundant towards the base. The Benin formation is non-marine; it is deposited in a fluvial and coastal environment. Its age is from Oligocene in the north to Recent in the modern Niger delta (Lambert-Aikhionbare and Shaw, 1982; Beka and Oti, 1995).

2.3 Offshore Niger Delta

Offshore Niger Delta is broadly classified into:

(i) Proximal offshore: where this study area is located.

(ii) Distal offshore (deep offshore).

The highly prolific proximal offshore, which is a mature exploration and production belt, stretches beyond the coast to a bathymetric depth of about 200m. The study area, WND-field falls within the proximal offshore (figure 1.1).

2.4 Geologic and Structural Setting of the WND-field in the Niger Delta

The WND-field is positioned at the north-western proximal offshore of the Niger Delta basin. It is a continuation of the NW to SE trending early Miocene - late Oligocene structural trend of the Northwest Niger Delta. The area is characterised by erosional channel systems, which are often shale filled and constitute stratigraphic traps.

The D-01 sands of the Agbada formation of this field, on which this study is focused is thought to be a closed system bounded by growth faults and channels in the NW and SE parts of the field. It is also thought to be made up of two anticlinal lobes (Chevron, unpublished work). Part of this study is to determine if it is really of two lobes or is a continuous structure. The D-01 can be generally said to be clean, fairly blocky sands, which have good porosity and permeability, and low water saturation (S_w). These characteristics make it a good reservoir.

2.5 Paleo-environment and depositional history of the Niger Delta

The deposition of sediments and progradation in the Niger delta have generally been sustained by rapid sediment supply by the River Niger and its tributaries, despite the fluctuations in sea-level during the Tertiary and Quaternary (Vail *et al.*, 1977; Haq et al., 1988). However the sea level fluctuations resulted in a cyclical deposition in the Niger Delta (Weber, 1971).

The Niger Delta is a wave-dominated shoreline (Doust, 1990) and has three main types of deposits: -

1) Prograding or regressive barrier island deposits.
2) Transgressive or re-worked barrier island systems.
3) Barrier inlet deposits.

Generally, the depositional environment for the reservoir sandstones in the Niger Delta (Agbada formation) is from transitional to marine paralic environment. The Agbada formation is said to be heterogenous because it contains a mixture of barrier bar and channel sands with occasional deep-water turbidites in transitional sequences into the Agbada formation. The heterogenous Agbada formation consists of a series of sedimentary offlap rhythms, usually five, and are 17-100m thick (Ekweozor and Daukoru, 1984). It starts with a basal on-lap transgressive, marine sand, followed by four offlap sequences viz marine shales, laminated barrier foot sands, barrier bar sands and distributary/tidal channel and backswamps/lagoonal deposits.

The D-01 reservoir sediments were deposited in a prograding and wave dominated environment (as inferred from the knowledge of the geology and stratigraphy of the Niger Delta Agbada formation). The trapping mechanism here is growth fault controlled.

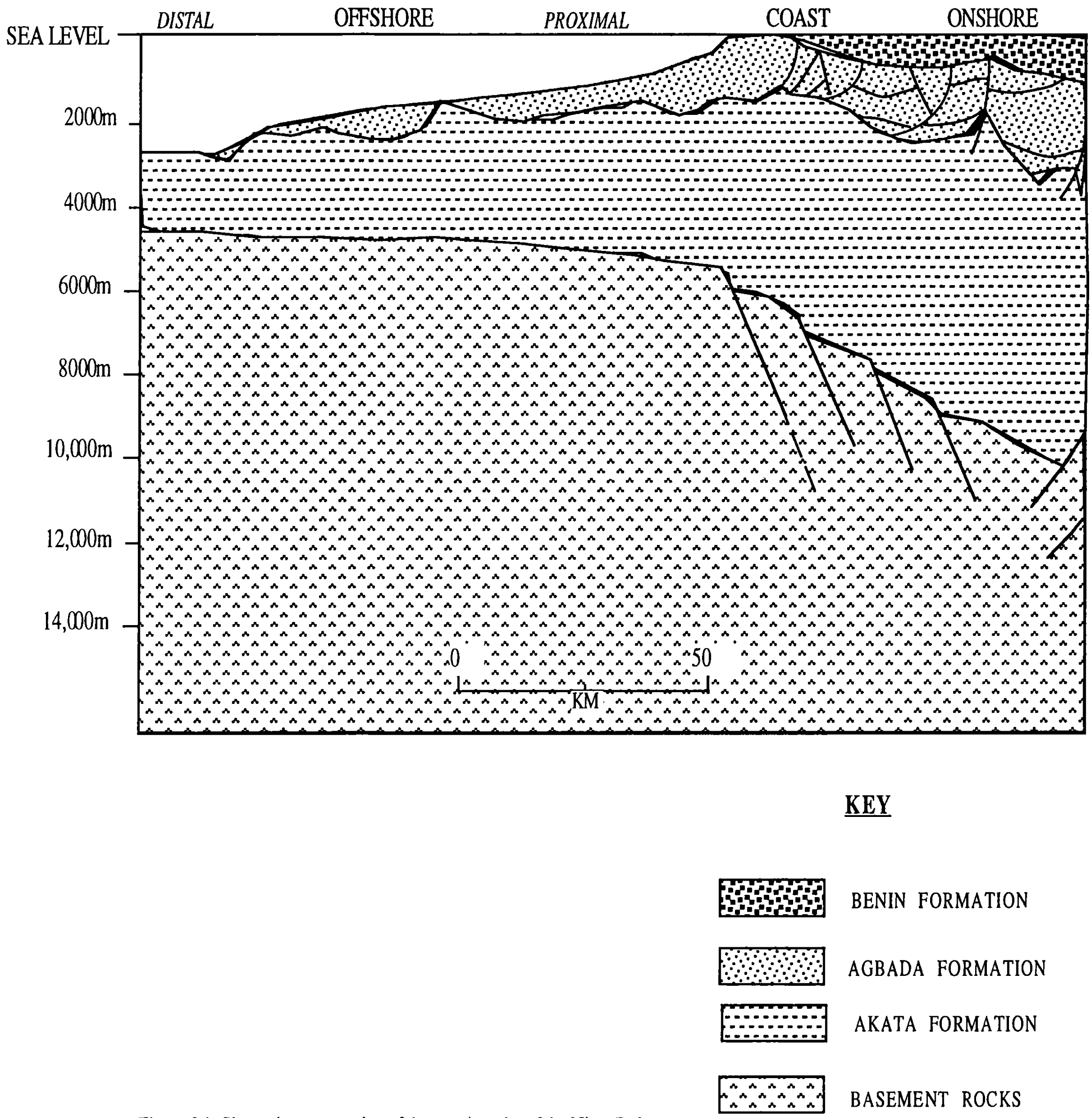

Figure 2.1 Shematic cross section of the stratigraphy of the Niger Delta showing from coastal onshore to distal offshore (adapted from Whiteman, 1982).

Chapter Three **Petrophysics**

3.0 Lithofacies Determination Methodology

Petrophysical evaluation done in this study is fundamental to the definition, description and interpretation of lithofacies and their depositional environments and also for the development of a facies model.

The D-01 reservoir sand facies identification was based on the detailed description and analysis of five cores taken from well WND-02. These cores together with mudlog data available for WND-02 were used to define core reservoir facies for WND –02, which serves as a model to tie petrophysical information to the non-cored wells in this field. The core reservoir facies were then tied to the wireline logs and used to develop wireline reservoir facies in WND-02 based on log curve responses and the associated core reservoir facies descriptions. Finally, the wireline reservoir facies interpretation for well WND-02 was applied to similar curve signatures in the non-cored wells to arrive at definite facies associations for the WND field.

3.1 Mud Log Analysis

Analysis of the mud log data available is as follows:
WND-01:
The shales found at the top portion of the D-01 reservoir in this well are glauconitic, carbonaceous and silty/sandy.
Sandstone in this well is generally very fine to fine grained and well sorted, shows fluorescence and cut. Sand-2 in this well is fine to medium grained, well sorted, no fluorescence or cut. Shale at base portion of reservoir is hard and platy, and slightly silty/sandy.

WND-02:
Sandstone in this well is generally fine to medium grained, fairly to poorly sorted.

WND-03:
Shale at top parts of reservoir is carbonaceous and silty.
Sandstone in this well is generally fine to medium grained and moderately sorted.
Shale found at the bottom portion of the reservoir is also carbonaceous.

3.2 Core Analysis

Core analysis is fundamental to the interpretation of lithology, determination of porosity distribution in the reservoir; evaluating the formation porosity-permeability relationship, and interpreting depositional environments and the development of a facies model. Five cores were taken from well WND-02 at different depth intervals corresponding to the depths given in mud log as listed below. Depth values are measured depths.

Core #1: 6030.0 - 6051.80 ft (21.80 ft)

Core #2: 6060.0 - 6069.30 ft (9.30ft)

Core #3: 6078.0 - 6086.65 ft (8.65ft)

Core #4: 6087.0 - 6141.30 ft (58.30ft)

Core #5: 6147.0 - 6188.70 ft (41.70ft)

From the analysis of the description of the cores and available mud log data, six litho-stratigraphic facies associations were identified, based on the sedimentological characteristics of the sediments and their genetic relationships. Core analysis in this study also involved using the defined facies associations to interpret the environment of deposition of the sediments with regards to the stratigraphy and how the energy regime and relative sea level changes affected the sediment deposition (Middleton, 1978). The depositional modelling of the D-01 reservoir using core data analysis serves as a means of extrapolating petrophyisical information to the non-cored wells.

3.2.1 Core Facies Identification and Environment of Depositon

The methodology used for facies classification and interpretation in this study was by integrating results of core description in WND-02 (described by COPI Stratigraphic Sciences) with log motifs and petrophysical properties of WND-02. The facies were then extrapolated to the other non-cored wells in this field. Lithofacies identified were given different designators to differentiate them as listed below:

1. SBSM - Siderite Banded Striped Mudstone.
2. IMWS - Interbedded Siderite Banded Mudstone and Wave-rippled Sandstone.
3. HSSM - Hummocky, Cross-Stratified Sandstone and Sideritic Mudchips.
4. IBWS - Interbedded, Bioturbated and Wave-rippled Sandstone.
5. IWSM - Interbedded Wave-Rippled Sandstone and Mudstone.
6. MBFS - Muddy, Bioturbated, Fine Grained Sandstone.

Figure 3.1 is a facies model constructed for the D-01 reservoir, alongside with the core porosity plot showing porosity for the facies associations at different depth intervals. The model is a description of the essential compositional, textural and biological aspects of the deposits. It also serves as a summary of the essential elements of the depositional system.

Facies 1 *Siderite Banded Striped Mudstone (SBSM).*

This facies is made up of black/brown mudstone with regularly spaced alternation of sideritic beds and non-sideritic beds, giving it a characteristic striped appearance (figure 3.1). The sideritic beds are 1-2cm thick, while the non-sideritic beds are generally 2-4cm thick. This facies also contains very thin lamina (10%) of fine grain sand/siltstone. Bioturbation in this facies is very low, with rare occurrence of the trace fossil *planolites*. Facies one is made up of high-density shale with little or no sand interbed, thickness is usually less than 10 ft thick.

Facies 1 is interpreted to be sediment of slow deposition under open marine shelf or prodelta conditions (Oboh, 1993); with occasional current and wave action agitating and reworking the bottom resulting in the deposition of the thin, very fine grained sandstone beds as isolated storm deposits in marine shales. In such an environment, the most active and main processes of sediment modification are burrowing by organisms as evidenced from the bioturbation present. The mudstone was probably deposited from suspension in the prodelta with low energy, reducing conditions and occasional effects of storms. The reducing condition is inferred from the low to rare bioturbation and low diversity and abundance of trace fossils.

The striped appearance of the mudstone is interpreted to be due to the seasonal laying down of the sediments when there are changes in the water chemistry, with the siderite beds resulting from the exposure of the sediments to variable reducing conditions near the sediment-water interface. It could also be due to seasonal, rhythmic deposition from iron silica solutions and the oxidation of the iron rich sediments at the time of deposition. This marine shale facies has no reservoir quality.

Facies 2 *Interbedded Siderite Banded Mudstone and Wave Rippled Sandstone (IMWS)*

Facies 2 consists of facies 1 striped mudstone interbedded with 20-25% wave-rippled, very fine grain sandstone beds (figure 3.1). Soft sediment deformation is present in the

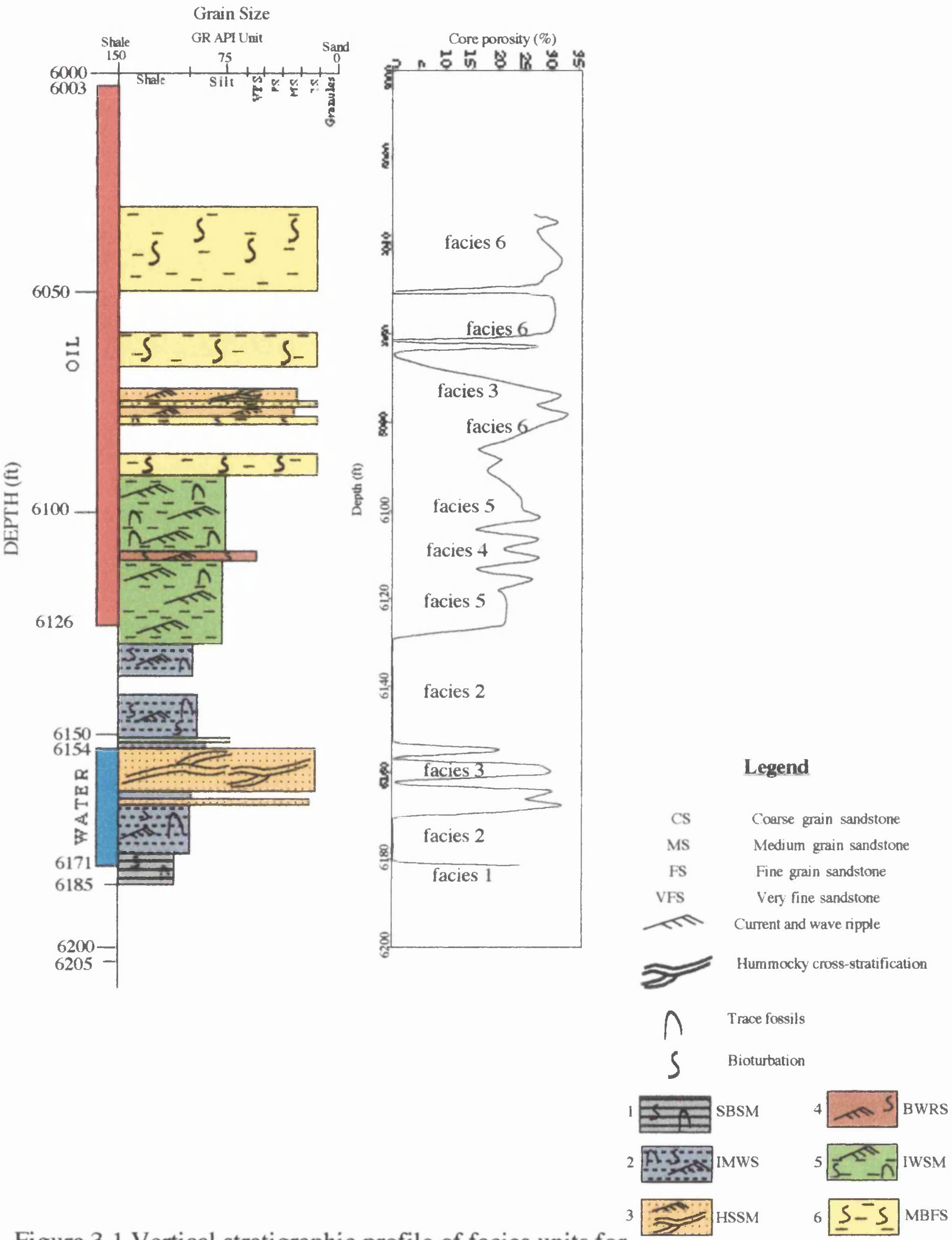

Figure 3.1 Vertical stratigraphic profile of facies units for D-01 reservoir in WND-02, with gaps shown between cores. It also serve as facies model for D-01 reservoir in the un-cored wells

sandstone beds indicating loading. Bioturbation in this facies is low and *planolites* is present.

Facies 2 is interpreted to have been deposited in a littoral, shallow marine shelf environment as evident from the presence of *planolites* which are usually present in littoral sands (Geitelink, 1973). The condition in this environment is such that sea level was sometimes below fair weather wave base but above the storm wave base, allowing the deposition of the very fine grain sandstone beds. The soft sediment deformation present in this facies could have been caused by storm waves which deposited the sandstone beds in the marine shales (Allen, 1995). Likewise, the ripples in the sandstone beds are most likely current ripples being associated with the storm events that deposited the sandstone beds.

Facies 3 Hummocky Cross-Stratified Sandstone and Sideritic Mud Chips (HSSM)

Facies 3 consist of fine grain hummocky cross-stratified sandstone beds, which are also flat-laminated in some bed intervals. This facies also contains 15-20% organic laminae of plant materials, and also thin intervals of sideritic mud chips thought to be erosional lags at the base of the depositional event. Slight soft sediment deformation is also observed to be present in some intervals of this facies. Wave ripples are very rare in this facies association. Porosity and permeability measurements show that the reservoir quality is good with porosity ranging from 21 to 34% and vertical and horizontal permeability values ranging from 86 - 2000 mD and 87 - 2010 mD respectively.

Facies 3 is interpreted as being deposited in the transition from lower to middle shoreface environments (MacEachern and Pemberton, 1992), as inferred from the hummocky cross-stratification of the sandstone beds. The hummocky cross-stratification is thought generally to be formed by storm wave activities, it could also be due to gravity driven sedimentation. Hummocky cross stratification forms just above the storm-wave base, below the fair weather wave base (Walker, 1984; Prothero and Schwab, 1996). The presence of numerous sideritic mud chips/shale clasts indicates that they are erosional lags at the base of depositional events associated with the storm events due to their high erosive energy (Leckie, 1988; Smith and Ainsworth, 1989; DeCelles & Cavazza, 1992; Mclane, 1995).

Facies 4 Interbedded, Bioturbated and Wave Rippled Sandstone (IBWS)

This facies is made up of fine to medium grained wave rippled sandstone that is bioturbated, and 15-20% mud/organic lamina. Trace fossils present include *planolites*, *chondrites* and *paleophycus*. Porosity values for this facies average 27% and horizontal permeability values range from 39 - 112mD.

Facies 4 is interpreted to be of a moderate to low energy wave dominated shallow water environment, which allowed wave ripples to be formed as well as allowing for bioturbation to take place. A lower shoreface environment is envisaged (Mclane, 1995; MacEachern, *et al.*, 1998). This is supported by the presence of *planolites, chondrites* and *paleophycus* trace fossils, which are all shallow water/shoreface trace fossils. Also the presence of 15-20% organics and mud infers a coastal origin.

Facies 5 Interbedded Wave-Rippled Sandstone and Mudstone (IWSM)

Facies 5 consist of fine grained wave rippled sandstone interbedded with mudstone beds (see figure 3.1). It is similar to facies 2 association but has higher sand content, about 50-60% sand. Some depth intervals belonging to this facies have the sandstone being more wave-rippled throughout. Bioturbation is low to moderate in this facies, with the mudstone beds being less sideritic than facies 2 mudstone beds. Porosity and permeability measurements show that porosity ranges from 15-26%, vertical and horizontal permeability ranges from 18 -255mD and 20-107mD respectively.

Facies 5 is interpreted to be a moderate to low energy lower shoreface environment deposit, as indicated by the low bioturbation of the sediments and wave ripples thought to be formed by storm events, while the mudstone beds were deposited from suspension between storm events. The presence of siderite in the mudstone beds infers an oxidizing environment.

Facies 6 Muddy Bioturbated fine Grained Sandstone (MBFS)

This facies consist of muddy, moderate to well bioturbated fine grained sandstone (see figure 3.1). Mud percentage ranges from 15-35% with some intervals having up to 65% mud (in which case it could be called a sandy mudstone). Vague wave ripples and organics are also present in some places in this facies. Sand beds belonging to this facies association have some intervals that are unconsolidated, very porous and permeable. Trace fossils present in this facies include *Teichichnus and planolite*. Porosity values for this facies range from 26 -31%, and vertical and horizontal permeabilities range from 39 - 1730mD and 130-335mD respectively. The sandstoones are generally clean as shown from the GR log response. Log motifs are generally blocky/and mildly serrated indicative of thin shale interbeds. Resistivity and porosity log responses are indicative of a very good reservoir quality. These units appear to be laterally extensive.

Facies 6 is interpreted to be a low energy, lower shoreface deposit (MacEachern et al., 1998) as inferred from the heavy bioturbation intensity and the vague presence of wave ripples which is thought to have been destroyed by the extensive bioturbation of the sediments. The mud is thought to be deposited from suspension while the sand was deposited by storm events. Facies 6 has the best reservoir quality and greater part of the interval net hydrocarbon thickness falls within this facies. It is also very extensive laterally, and wireline log correlation from well to well supports this.

Note

Poor recovery of cores made it difficult to achieve an accurate depth shift for some of the cores, cores #1 and #2 for instance were mostly rubble. Therefore an approximate depth conversion to match the core and well logs was made.

3.3 Well Log Lithology Interpretation and Identification of Litho-facies units from Wireline logs.

The wireline log measurements available for this study are as listed in table 3.1. The methodologies adopted for the wire-line log lithology and depositional environment interpretation in this study is as defined by Serra and Sulpice, (1975) and Selley, (1978, 1997). Figure 3.2 is an example of gamma ray log curve trends used as a basis for interpreting lithology and identifying the depositional environments of sandstones. Lithology and fluid boundaries interpretation is done in this study using the log motif of several primary curves such as gamma ray, resistivity, sonic, bulk density and neutron porosity logs. The interpretation done is in collaboration with the results of core analysis done.

Data for the true vertical depth values for the deviated well WND-03 is not available for this study. Since three out of the four wells in the field are being studied here, with two out of these being straight wells, measured depth values are used for all lithology and reservoir fluid interpretations in this study for uniformity.

3.3.1 WND-02 Lithologies

WND-02 is a straight well. Wireline logs run include gamma ray, caliper, medium and deep resistivity, bulk density and neutron porosity logs (figure 3.3). Lithology interpretation from mud log and core data analysis shows that the D-01 reservoir interval in well WND-02 is a fine - medium grained, moderate - well sorted sand with intercalations of dark grey blocky / platy silty - very sandy carbonaceous shale beds. Several facies were identified based on lithology, textural changes and grain size distribution inferred from the trends of the different log curves.

From analysis of the shape of the GR log trend calibrated with the other log trends, the D-01 reservoir sands in this well can be divided into two parts separated by a marine shale interval, the parts are here referred to as R-1 and R-2 intervals, respectively (figure 3.3) R-1 the upper part is oil bearing, while R-2, the lower part of the reservoir, is water bearing. The total D-01 reservoir in this well is 211 ft thick in this well (depth 5994.10-6205.00). Gamma-ray log shape is used here to infer grain size. The upper part of the reservoir in this well, R-1 is from 6129.00-5994.00 ft, while R-2 the lower part is from 6205.00-6152.00 ft, with a sandy shale interval in between from depth 6152.00 to 6129.00 ft. Interpretation is started from base of the reservoir.

R–2 interval

The base of R-2 starts with silty-shale interval, which passes gradually into a medium-coarse grained sandstone (6205-6192 ft). A sharp contact on top of this leads to mudstone, with thin sand/siltstone inter-beds being deposited from depth 6192-6171. There is another almost sharp /gradual contact on top of this leading to the deposition of medium/coarse grain sandstone which passes into clean sands forming an almost horizontal contact with the shale deposited on top of it. This extends for the next 14 feet (6171-6155 ft). This almost horizontal top forms a sharp contact indicating change of environment into marine pro-delta environment due to regression, and this results in the deposition of shale beds on top of it (depth 6152.00-6129.00).

R-1 interval

The R-1 interval is generally made up of at least two stacks of coarsening upward sequences of sands, and it extends from 6129.00 ft to 5994.00 ft. The base of R-1 starts with a unit that gradually coarsens upwards into fine-medium grain sands with interbeds of sandy shale beds, (6129-6113 ft). Next comes the deposition of a thin bed of medium grained sandstone (6113-6105 ft), this gradually passes on to finer grained sands made up of inter-beds of siltstone and sandy shale. This unit is thought to be deposited due to erosion (may be a channel with shale fills) in to the R-1 sand; and has a sharp contact with the blocky sands on top of it. This sharp contact is interpreted to be an erosional surface.

The succession of R-1 in this well is capped with a finning upward sequence of sedimentation thought to be of lagoonal origin due to the presence of carbonaceous shales and organics, as well as some glauconite (information obtained from mud-log data). This lagoonal deposit is from depth 6010.00 - 5994.00 ft.

- **Porosity Interpretation from logs in WND-02**

(i) From neutron porosity log:
Porosity for the D-01 reservoir sands in well WND-02 as observed from neutron porosity log has average value of 0.30 for the oil bearing sandy parts. Neutron porosity values tend to be highest in shale intervals due to water bound in the clay minerals.

(ii) From bulk density log:
Porosity from the density log was calculated in this study using the formula below (Dresser Atlas, 1974 and 1975; Doveton, 1986 and 1994). (See figure 3.15).

Density porosity = (matrix density – bulk density) / (matrix density – fluid density).

Where:

Matrix density = 2.65 (mean average of grain density, quartz in this case)
Bulk density = value from formation density log
Fluid density = average density of the pore fluid (0.80 and 1 gm/cc for oil and water respectively.
Density porosity in oil zone:

Upper R-1 interval, average bulk density = 2.1
Porosity = (2.65-2.1) / (2.65-0.80)
= 0.3
Lower R-1 interval, average bulk density = 2.2
Porosity = (2.65-2.2) / (2.65-0.80)
= 0.24

Water zone:
Upper R-2 interval, average bulk density = 2.13

Porosity = 0.52/1.65 = 0.32

Lower R-2 interval, average bulk density = 2.19

Porosity = 0.46/1.65 = 0.28

Bulk density at LKO = 2.38, porosity = 0.15

Porosity Therefore average porosity for WND-02 = 0.26

- **Reservoir Fluid Interpretation**

The depth interval 6003.00-6126.00 ft is interpreted to be oil bearing as indicated by the high resistivity log values with curve deflecting to the right, While depth interval 6154.00 to 6216.00 ft is interpreted to be water bearing (figure 3.3).

HKO	=	6003.00 ft (5923 Subsea)
LKO	=	6126.00 ft (6046 Subsea)
HKW	=	6154.00 ft (6074 Subsea)
LKW	=	6171.00ft (6061 Subsea)
Net oil	=	123.00 ft (6003 to 6126 ft)
Net water	=	17.00 ft (6154 to 6171 ft)

- **Depositional Environment Interpretation for WND-02**

The lithology and vertical grain size distribution within the reservoir, such as fining or coarsening upward sequences is used to identify and delineate the litho-facies and their environment of deposition.

Sediments at depth 6205.00 - 6190.00 ft tend to coarsen upwards with marine shale at the base of this succession, passing up to coarse sands. The next succession of sediments at depth interval 6190-6146 ft displays the same GR coarsening upwards curve shape and so is interpreted to have the same depositional history as the preceding succession. The base of this succession is characterised by a straight, constant deflection of high gamma ray curve to the right indicating high gamma values. These deposits are therefore interpreted to be prodelta and shallow marine shales deposited in a low energy, reduced environment. This corresponds to core facies SBSM and IMWS (facies1 and 2). The upper part, which is coarse grained is interpreted to be middle to lower shoreface sandstone.

These two successions of sediments make up the R-2 interval of the D-01 reservoir and can be said to be marine prodelta shales with thin coarse grained middle shoreface sands deposited in it by storm activities. The shale interval that divides the reservoir into two was deposited next by transgression and is interpreted as marine prodelta shales.

The R-1 interval is basically a coarsening upward, funnel-shaped sequence, with a serrated, fining upwards deposit characterised by a bell-shape gamma-ray curve trend, due to local transgression or erosion towards the base. R-1 is interpreted to be barrier bar sands (Davies, 1977; Tizzard and Lerbekmo, 1975; Selley, 1978 and 1997) of middle–lower shoreface origin eroded into by a channel, which later became shale filled.

Finally a fining upwards regressive shoreline deposit characterised by a serrated bell-shaped GR log shape caps the D-01 reservoir in this well at depth interval 6010.00-5994.00ft. These sediments are interpreted to be of lagoon origin, formed behind the barrier bar.

3.3.1.1 Calibration of WND-02 Core Facies with the well log Profile

The aim of doing this calibration is to create a model that is used to tie petrophysical evaluations to the other non-cored wells in this field. Although it has been difficult to accurately depth tie the cores to the well logs, approximate matches were made with depth shift of plus or minus 1-5 ft, as indicated in the core descriptions. The cores taken from well WND-02 started at depth 6030ft with core #1 and ended with core #5 at depth 6188.6 ft, whereas the D-01 reservoir in this well as defined from well logs extend from 5994.00 ft to 6205.00ft. This implies that the cores taken from this well do not span the whole depth interval of the D-01 reservoir sands in this well. Generally, the cores from WND-02 tie very well with the log for this well.

Stratigraphic Calibration:

Calibration is done here starting from the base of the core and log. The bottom of core #5 at depth 6158 ft can be matched with the wire-line log for WND-02 at this depth also (figure 3.3), a summary of all the identified facies characteristics on log curves are as shown on table 3.2.

R-2 Interval

The middle to upper part of this sand interval is in core #5, the base of which starts at depth 6185.00 ft with facies 1 (SBSM) marine prodelta mudstones. At depth 6177.00 ft this unit gradually passes on to facies 2 shallow marine shelf interbedded siderite banded mudstone and wave rippled sandstone (IMWS). Next comes facies 3 middle/lower HSSM making a sharp/abrupt contact with the preceding shallow shelf, shoreface mudstone IMWS at 6170.00 ft, this indicate a change of environment from marine shelf to shoreface environment.

A 1 foot thick bed of facies 2 lower shelf mudstone was deposited next, but this was immediately overlain by the HSSM facies association again from depth 6167.00-6157.00ft. Correlating this interval with the other wells shows this unit to be composed of amalgamated beds with mud clasts erosive surfaces within it. The deposition of coarse grain HSSM facies sandstone in the midst of mudstone is an indication of storm activities. Most likely sediments eroded from upper/middle shoreface during storms being deposited on top of open marine shales, forming hummocky cross stratification, and the shales settle out of suspension during fair weather to drape the hummocky cross stratified sandstones again (McLane, 1995).

A thin bed of facies 6 sediments (2 ft thick) was deposited again but was quickly overlain sharply by a thin unit of facies 5, IWSM at depth 6155.00. This is indicated on the log by the low GR values suddenly changing to high GR values, inferring coarse grain sandstone suddenly passing on to shales; resulting in an almost horizontal GR log motif at the top of this unit, indicating change in sea-level and sequence boundary. Facies 1, prodelta mudstones were laid down again from depth 6155.00-6143.00 ft, which is the top of core #5. The horizontal/sharp boundary at the top of the middle shoreface indicates a fall in relative sea level, resulting in a regressive surface, with shallow shelf sediments being deposited on top of middle shoreface sediments.

Depth interval 6153.00-6133.00 is a transgressive succession with an abrupt lower contact forming a hiatal or maximum flooding surface, and marks the boundary between the transgressive and regressive phase of the sequence (Frazier, 1974; Vail et al., 1987).

R -1 Interval

R-1 begins at depth 6133.00 ft. There is a 4 ft gap between core #5 and #4, but correlating this interval with the log shows that it is most likely a mixture of facies 1 and 2 sediments. The base of core #4 begins at depth 6139.00 ft with a thick unit of facies 2 shallow marine shelf IMWS sediments. Overlying this unit with a gradual contact is a more sandy version of facies 5 lower shoreface IWSM sediments. This indicates a transition from shallow marine shelf to lower shoreface environment. This facies 5 unit extends from depth 6129.00 - 6112.00 ft, becoming even more sandy towards the top, with the sand percentage

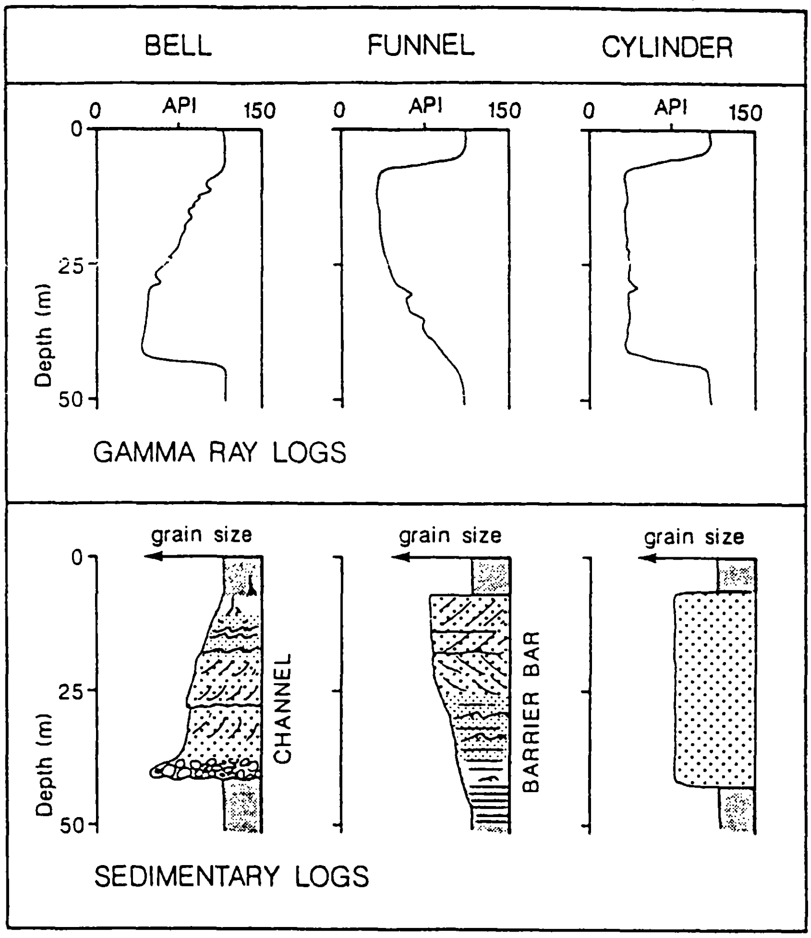

Figure 3.2 The three principal gamma-ray log shapes and their corresponding sedimentary interpretation used for log interpretations in this project (After Serra and Sulpice, 1975)

WELL NAME	LOGGING CURVES	CORE
WND -01	GR - CALI - ILD - DT - NPHI - RHOB	No
WND-02	GR - CALI - ILD - ILM - CNL - RHOB	Yes
WND-03	GR - CALI - ILD - ILM - DT - NPHI - RHOB	No

Table 3.1 Wireline log curves for the three wells available for this project

FACIES number and designator	GR (API)	GR LOG MOTIF	RESISTIVITY LOG	NEUTRON POROSITY LOG	DENSITY LOG	SONIC LOG
1 SBSM	85 - 105	Shaley,, Interbedded	Low (<5 ohm-m)	mod - high (0.33 - 0.42 %)	mod - high (2.30 - 2.40 gm/cc)	low (90 - 85 ms/ft)
2 IMWS	85 - 100	shaley, Interbedded	Low (<5 ohm-m)	mod - high (0.33 - 0.40 %)	mod - log (2.30 - 2.40 gm/cc)	low (95 - 85 ms/ft)
3 HSSM	40 - 60	blocky, funnel	low (<5 ohm-m)	low - mod (<0.30 %)	low (<2.2 gm/cc)	high (>130 ms/ft)
4 BWRS	65 - 75	blocky - serrate	high (5 - 15 ohm-m)	low - mod (<0.30 %)	mod (2.20 - 2.25 gm/cc)	mod (105 - 110 ms/ft)
5 IWSM	70 - 95	serrated, interbedded, erratic	high (5-15 ohm-m)	low -mod (0.27 - 0.30 %)	mod (2.20 - 2.30 gm/cc)	mod - low (100 - 120 ms/ft)
6 MBFS	45 - 65	Blocky, interbedded	high (>15 ohm-m)	mod - low (0.27 - 0.30 %)	low <2.20 gm/cc)	high (>140 ms/ft)

Table 3.2. Summary of the log characteristics of all the facies identified in the D-01 reservoir interval.

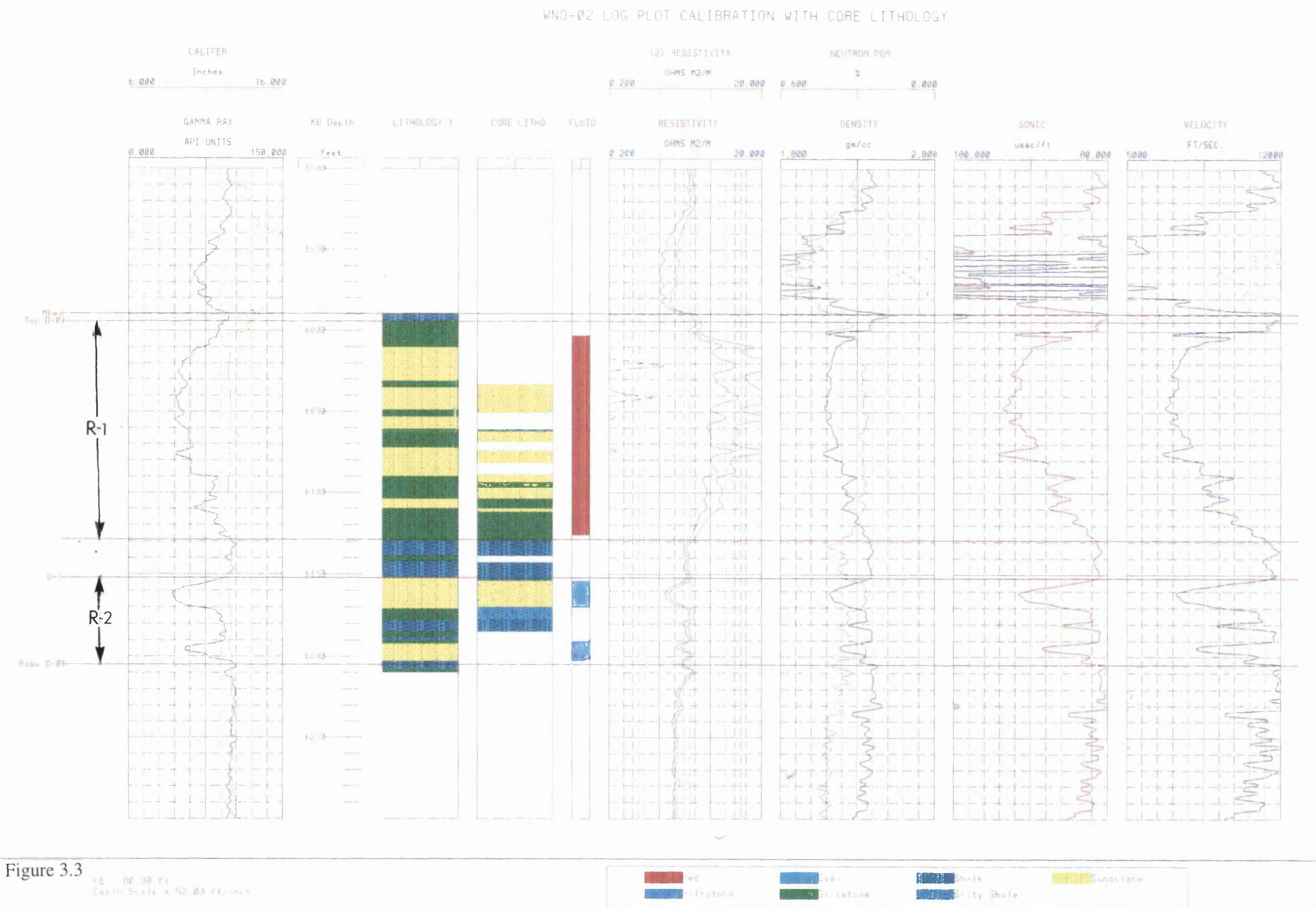

Figure 3.3

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Panel 1 of 1
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increasing from 40% at the base to 70% near the top. Bioturbation is also slightly higher towards the top of this unit, which supports a lower shoreface environment.

A thin, 2ft thick bed of facies 4, IBWS sediment was laid on top of the facies 5 unit at depth 6112.00-6110.00 ft. This unit was then sharply overlain again by facies 5 lower shoreface sediments from 6110.00 - 6104.00 ft. At depth 6104.00 this unit graded into a unit made up of a mixture of facies 5 and 6 sediments, and extend to 6098.00 ft, this indicate a sort of gradational transition from facies 5 to 6 sediments. This transition zone continues into more wave-rippled sediments of facies 5 association, with increase in mud content also, 35%-45% mud.

The gamma ray curve trend of WND-02 from depth 6110.00-6090.00 shows a fining upwards sequence, which is a transgressive succession made up of facies 5 sediments and a transition from facies 5 to 6 sediments. The sharp boundary at the top suggests a hiatus/non-depositional surface or erosional surface. The more wave-rippled facies 5 unit grades into facies 6 MBFS, which extends to the top of core #4 at depth 6089.00ft.

A 7ft gap (6089.00-6082.00 ft) is between cores #4 and #3, but correlation of this interval with GR log of WND-02 shows that it is possibly the same facies 6 sandstone that are present here as indicated from the low GR values. The base of core #3 commences at 6082.00 ft with facies 4 lower shoreface IBWS that extends for just 2ft, and is sharply overlain at 6080.00 ft 2 ft of more sandy facies 3 middle shoreface sandstone, (6080.00-6078.00 ft).

There is another 5ft gap (6073.00 - 6069.00 ft) between cores #3 and #2. Core #2 is 8 ft thick, (6069.00 - 6061.00 ft) and the whole core is made up of facies 6 lower shoreface sandstone, with the topmost 1ft being very muddy; (up to 65% mud). This top 1ft interval can also be called a sandy mudstone.

A 10ft gap (6061.00-6051.00 ft) is between cores #2 and #1. Core #1 is 18 ft thick (depth 6051.00-6033.00 ft), and is made up entirely of facies 6 lower shoreface MBFS, which gets very muddy towards the top. This succession gets even muddier at depth 6037.00-6033.00 ft, which is the top of this unit. The base of this facies 6 unit at this interval is very porous, permeable and well bioturbated throughout. The top of core #1 is part of the top portion of R-1 and the D-01 reservoir in the WND-02 well.

Note.

Core #2 and #1 as indicated on the core descriptions are mostly rubble, but approximate depth match of the cores with the log depth seem to match well.

3.3.1.2 Log lithostratigraphic interpretations for depth intervals not cored

Base of Core #5 down to base D-01 reservoir:

The base of R-2 which also coincides with the base of the D-01 reservoir in the WND-02 well begins at depth 6205.00 ft, with facies 1 marine shelf mudstones which is sharply overlain by a thin bed of facies 5 lower shoreface IWSM at depth 6200.00 ft. This then grades into facies 6 MBFS from depth 6199.00-6191.00 ft, also of the lower shoreface environment. This unit is sharply overlain again by facies 1 mudstone from 6191.00-6188.00 ft, showing a change of environment of deposition from shoreface to shallow marine environment, and regression of the sea. This facies 1 mudstone gradually passes on to a facies 2, shallow marine shelf IMWS deposit from depth 6188.00-6185.00 ft.

Top of core #1 to top D-01 reservoir.

The top of core #1 ends at 6033.00 ft, and a unit made up of facies 5 IWSM is laid on top of it from 6033.00-6030.00 ft. This grade into facies 6 lower shoreface MBFS from depth 6030.00 to 6019.00 ft. This unit gradually passes onto facies 5 IWSM again from 6019.00-6010.00 ft. This then is overlain almost sharply by facies 2 IMWS from 6010.00-5994.00 ft, which grades into facies 1 SBSM deposits capping the D-01 reservoir in this well.

3.3.2 WND-01 Lithologies

WND-01 is a straight well. Wireline logs run for this well include gamma-ray, caliper, deep resistivity, sonic, bulk density, compensated neutron porosity logs (figure 3.4). The D-01 reservoir sand in well WND-01 is at depth interval 6080 - 6280 ft. The reservoir sands as observed from the GR log motif and confirmed with the density and neutron logs are generally fine to medium grained sands, very silty with intercalations of sandy shale beds. This interpretation ties with mudlog data and core analysis results of very fine to fine grained sandstone with intercalations of dark grey to brown shale beds, sideritic in some parts.

The D-01 reservoir is 203 ft thick in this well (6077.00-6280.00 ft). The GR log motif trend for this well correlates well with that of WND-02 being used as a model in this study. The reservoir can also be divided into two parts, R-1 and R-2. Sand interval R-1 extends

from depth 6212.00-6077.00 ft, while R-2 is from depth interval 6280.00 to 6233.00 ft separated by a silty to shaly interval from 6234.00 to 6212.00 ft.
Interpretation is done from base of Reservoir.

R -2 interval

This interval starts at the bottom at 6280.00ft with a thin sandy shale bed, this gradually passes on to medium/coarse grain sandstone extending up to 6192.00 ft. This medium to coarse grain succession of sand suddenly becomes silty a little bit above the base (from depth 6270-6248 ft), and it tends to coarsen up again, but with a serrated gamma-ray log motif, indicating inter-bedding of sand and silty shale. At depth 6248 there is a sudden increase in grain size, resulting in an almost horizontal top contact. This commences the deposition of a layer of coarse grain/clean sand, which extends from 6248-6234 ft. There is another sharp/abrupt change in grain size at the top of this succession with an almost horizontal GR curve trend forming a sharp contact, which can be interpreted as being due to change in environment of deposition into marine pro-delta shales. This sharp contact commences the deposition of the silty shale interval (depth 6234 - 6212 ft) which separates R-2 from R-1.

R –1 interval

R-1 starts at depth 6208 ft with the silty shale interval gradually coarsing up with the top of the succession having the maximum sand percentage. This then tended to fine up giving a bell shaped, fining upward sequence (depth 6208 - 6203). This interval is thin compared to the same sediments in WND-02. This unit is thought to be deposited due to erosion (may be a channel with shale fills) in to the R-1 sand; and has a sharp contact with the blocky sands on top of it. This sharp contact is interpreted to be an erosional surface. A sudden change in grain size resulting in an almost horizontal GR curve trend commences the deposition of very coarse grain blocky succession of sandstones, from depth interval 6203-6080. Within this sandstone interval are several thin inter-beds shale beds. At depth 6101 ft the sandstone started fining upwards, giving a thin silty-shale interval, which corresponds to the lagoonal deposits of WND-02. These sediments tend to gradually coarse upwards into medium grain sands, top of which is at depth 6080 the top of the reservoir; unlike what is present in well-02 and well-03 where the sediment fines upwards to the top of the reservoir.

- **Porosity Interpretation from Logs in WND-01**

(i) From neutron porosity log:

Generally, porosity for the D-01 sand reservoir in well WND-01 as observed from the neutron porosity log values range from 0.25-0.30. The neutron porosity curve values tend to be high in the shale beds, due to water bound in the shale / clay minerals (neutron porosity measures hydrogen content). Porosity in reservoir intervals containing oil is about 0.23. Neutron porosity curve tends to cross density curve at points where there are changes in lithology from sand to shale or shale to sand.

(ii) From bulk density log: (figure 3.15)

Density porosity = (matrix density – bulk density) / (matrix density – fluid density).

Density porosity in oil zone:

average bulk density = 2.17
Porosity = (2.65-2.17) / (2.65-0.80)
= 0.26
water zone in R-1 interval, average bulk density = 2.21
Porosity = (2.65-2.21) / (2.65-0.80)
= 0.27

Water zone:
Upper R-2 interval, average bulk density = 2.15
Porosity = 0.5/1.65 = 0.30
Lower R-2 interval, average bulk density = 2.23
Porosity = 0.42/1.65 = 0.26

Bulk density at OWC = 2.23, porosity = 0.23

Therefore average porosity for WND-01 = 0.26

(iii) From Sonic Log:

Sonic log curve values for WND-01 are relatively low/moderate throughout (on a scale of 80-180) 95 for sandy parts to 112 for shaley parts. This shows less travel time for the sand portions, confirming a generally moderate porosity for this well. But sonic values tend to be high where there is a washout in the sand beds as indicated by high caliper readings.

- **Reservoir Fluid Interpretation**

The hydrocarbon-bearing interval in well WND-01 is from 6080-6142 ft (6006-6068 Subsea). The hydrocarbon here is oil as seen from the high resistivity curve deflection to the right and confirmed with the density and neutron curves tracking closely. There is no gas in this reservoir as observed from the density/neutron logs. The lower part of the reservoir at depth interval 6146.5-6211 ft in this well contains water as indicated by the low resistivity curve values with deflection to the left.

Net oil = 62.00 ft (6080 to 6142 ft)
Net water = 61.00 ft (6142 to 6203 ft)
OWC is at 6142 00ft (6068 Subsea)

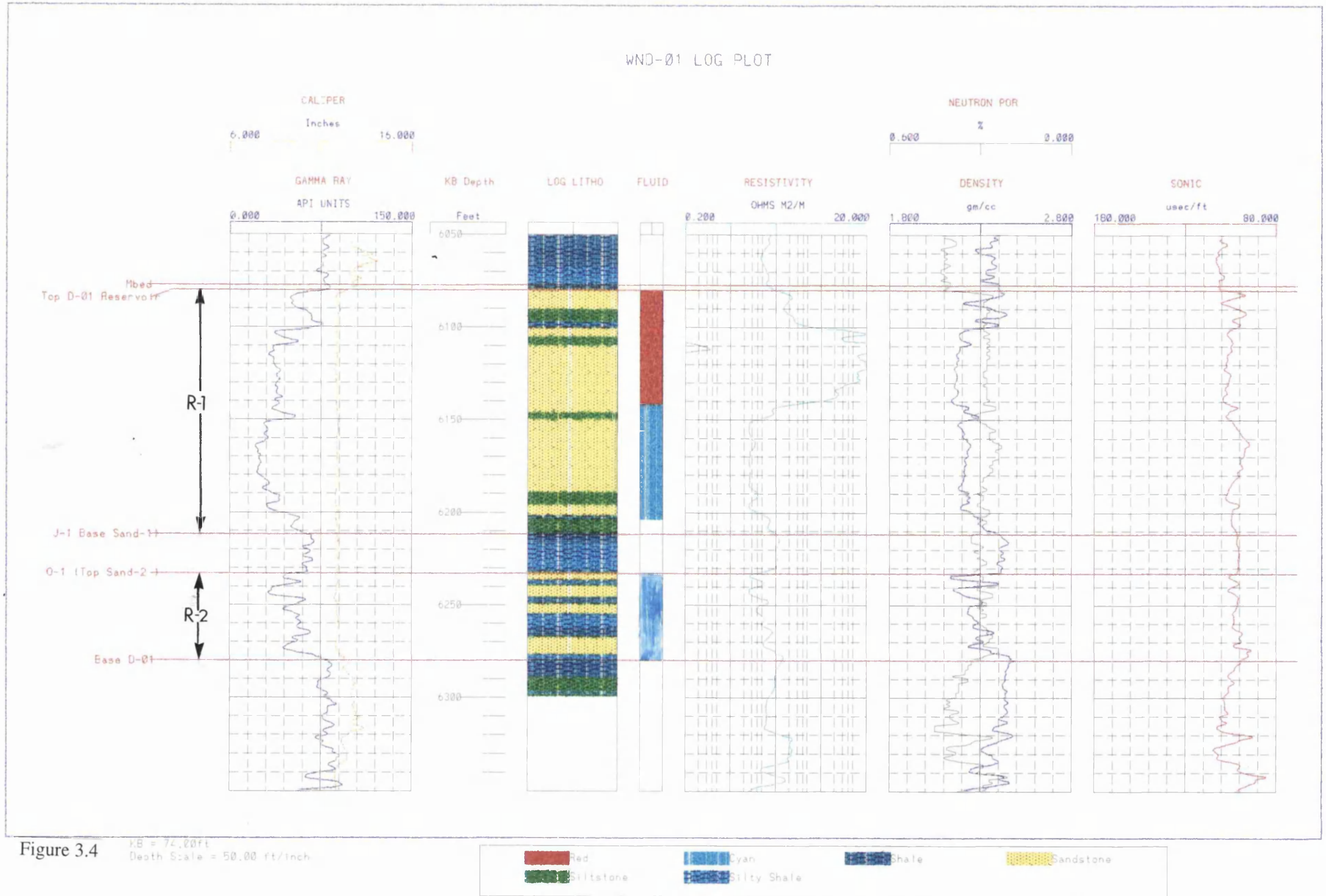
The oil-water contact (OWC) for WND was determined from the log using the point with minimum porosity and maximum water saturation in the oil zone.

- **Depositional Environment Interpretation for WND-01**

The lithology and vertical grain size distribution within the reservoir, such as fining or coarsening upward sequence is used to identify and delineate the litho-facies and their environment of deposition.

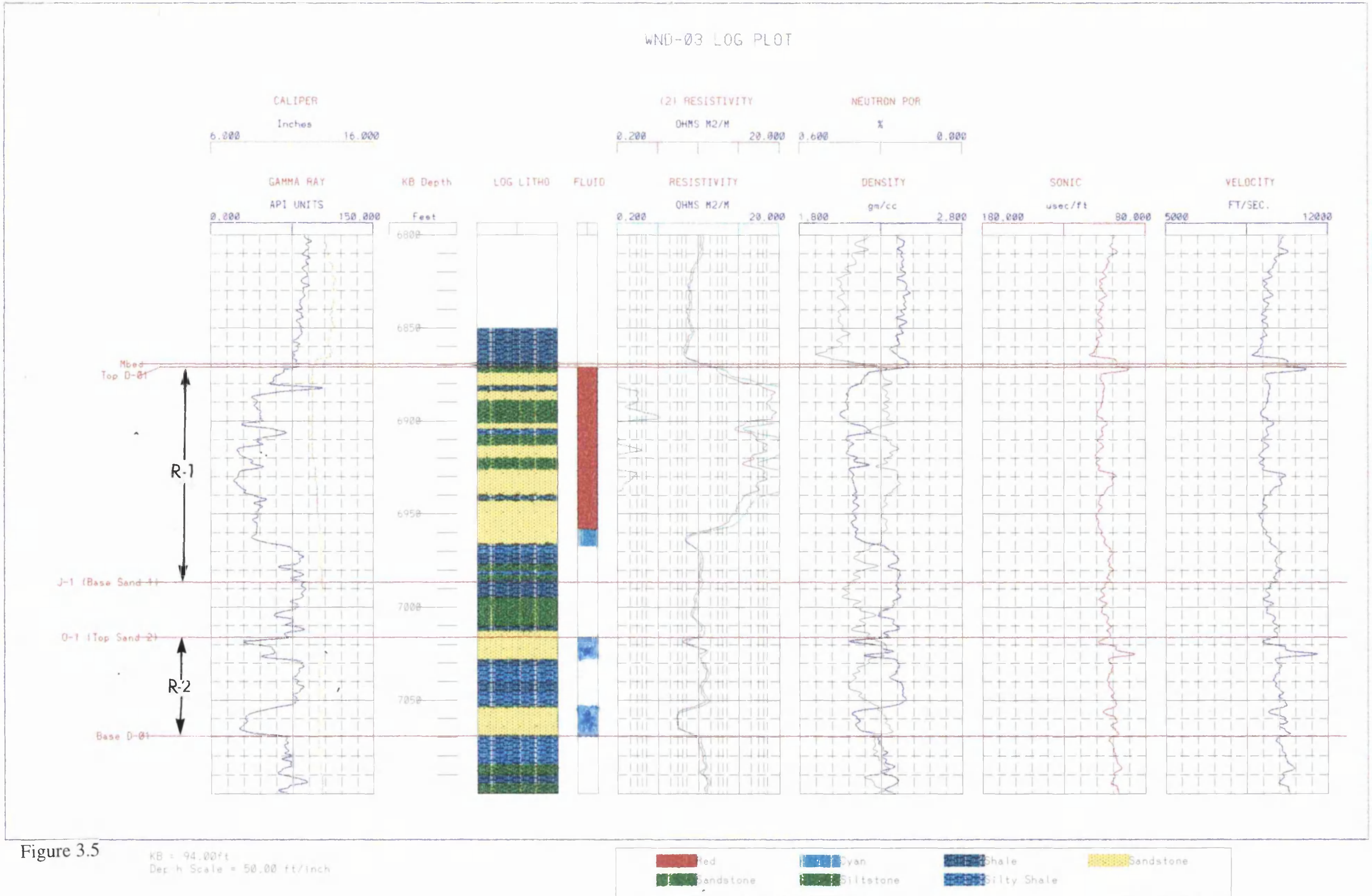
The basal part of the D-01 reservoir in WND-01 with high gamma ray values is interpreted to be marine shales. It corresponds to facies 1 and 2. This is overlain by a regressive sedimentation of deposits displaying a serrated gamma ray curve trend of fining and coarsening upward lithofacies sequence. The serrated curve reflects inter-bedding of sandstone and shale transition typical of a fluctuating sea level; and is interpreted as middle shoreface sediments deposited in the midst of prodelta shales as a result of storm activities. The coarse grain sandstones in this sequence correspond to facies 3 HSSM, while the shale are facies 1 and 2 prodelta and shallow marine shale. This sequence makes a sharp upper contact with the next unit above it, reflecting abrupt lithological and textural changes indicating an abrupt change in the depositional environment caused by regression. This begins the next succession of sediments, which is the shale interval separating R-1 from R-2, and is interpreted as being deposited during transgression of the sea; corresponds to facies 1 and 2 marine shales.

The above shaley succession gradually passes into a blocky, coarsening upwards, regressive sequence displaying a gentle sloping; funnel-shape, gamma-ray curve trend. It reflects a gradual vertical transition from shale/silt to sandstone, with an upward increase in sand grain size indicative of a gradual change in the energy level of the depositional



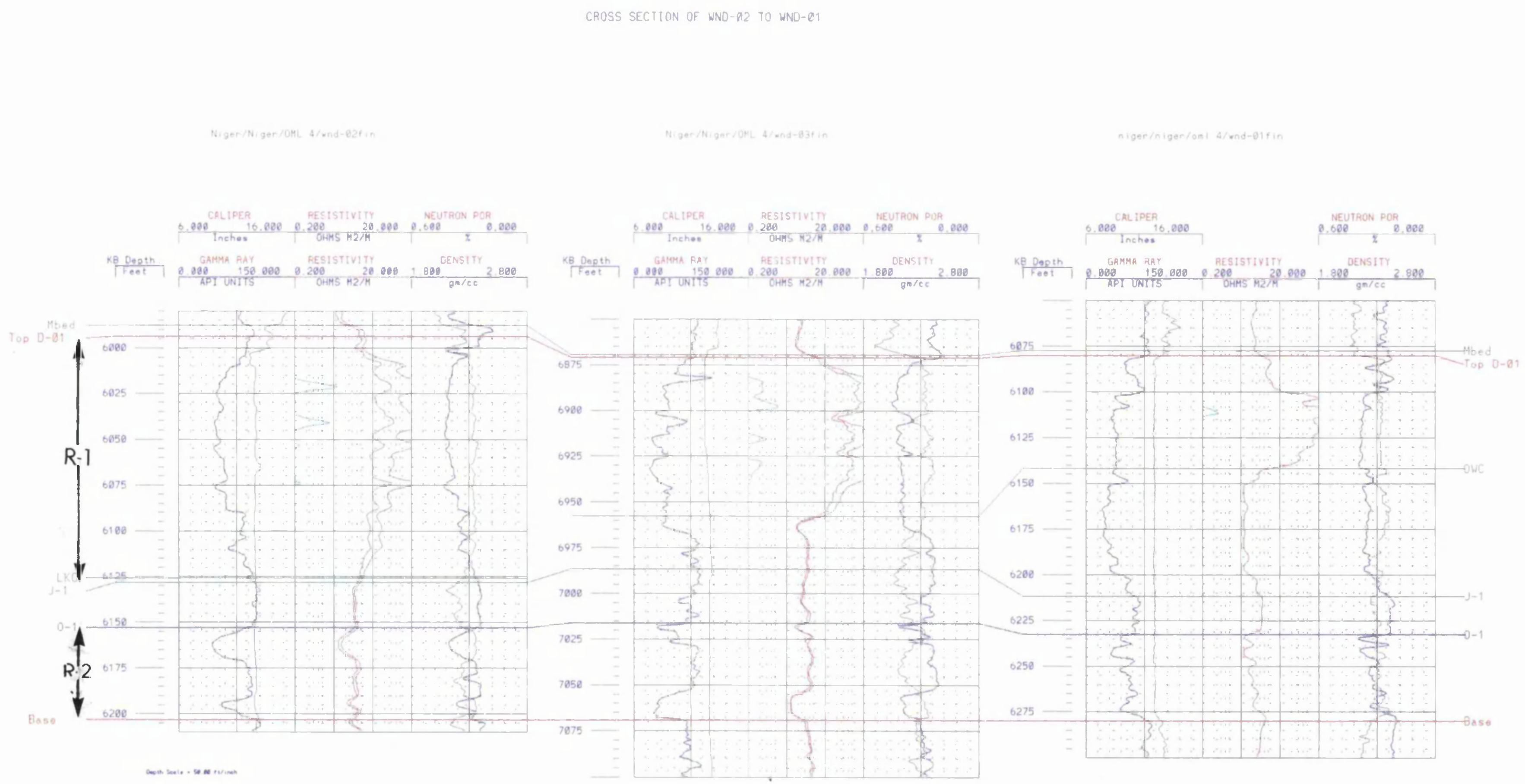
WND-01 LOG PLOT
CALIPER
Inches
6.000
16.000
GAMMA RAY
API UNITS
0.000
150.000
KB Depth
Feet
6050
6100
6150
6200
6250
6300
LOG LITHO
FLUID
RESISTIVITY
OHMS M2/M
0.200
20.000
NEUTRON POR
%
0.600
0.000
DENSITY
gm/cc
1.800
2.800
SONIC
usec/ft
180.000
80.000
Mbed
Top D-01 Reservoir
J-1 Base Sand-1
O-1 (Top Sand-2)
Base D-01
R-1
R-2
KB = 74.00ft
Depth Scale = 50.00 ft/inch
Red
Cyan
Shale
Sandstone
Siltstone
Silty Shale

Figure 3.4



WND-03 LOG PLOT
CALIPER
Inches
6.000
16.000
GAMMA RAY
API UNITS
0.000
150.000
KB Depth
Feet
6800
6850
6900
6950
7000
7050
LOG LITHO
FLUID
(2) RESISTIVITY
OHMS M2/M
0.200
20.000
RESISTIVITY
OHMS M2/M
0.200
20.000
NEUTRON POR
%
0.600
0.000
DENSITY
gm/cc
1.800
2.800
SONIC
usec/ft
180.000
80.000
VELOCITY
FT/SEC.
5000
12000
Mbed
Top D-01
J-1 (Base Sand 1)
O-1 (Top Sand 2)
Base D-01
R-1
R-2
KB = 94.00ft
Depth Scale = 50.00 ft/inch
Red
Cyan
Shale
Sandstone
Sandstone
Siltstone
Silty Shale

Figure 3.5



CROSS SECTION OF WND-02 TO WND-01
Niger/Niger/OML 4/wnd-02fin
Niger/Niger/OML 4/wnd-03fin
niger/niger/oml 4/wnd-01fin
CALIPER
RESISTIVITY
NEUTRON POR
GAMMA RAY
DENSITY
KB Depth
Feet
Inches
API UNITS
OHMS M2/M
gm/cc
Mbed
Top D-01
LKO
J-1
O-1
Base
OWC
R-1
R-2
Filename: SCSrecent3.cgm
Date: 98-09-01 14:38
Panel 1 of 1
Rotate=0

Figure 3.6

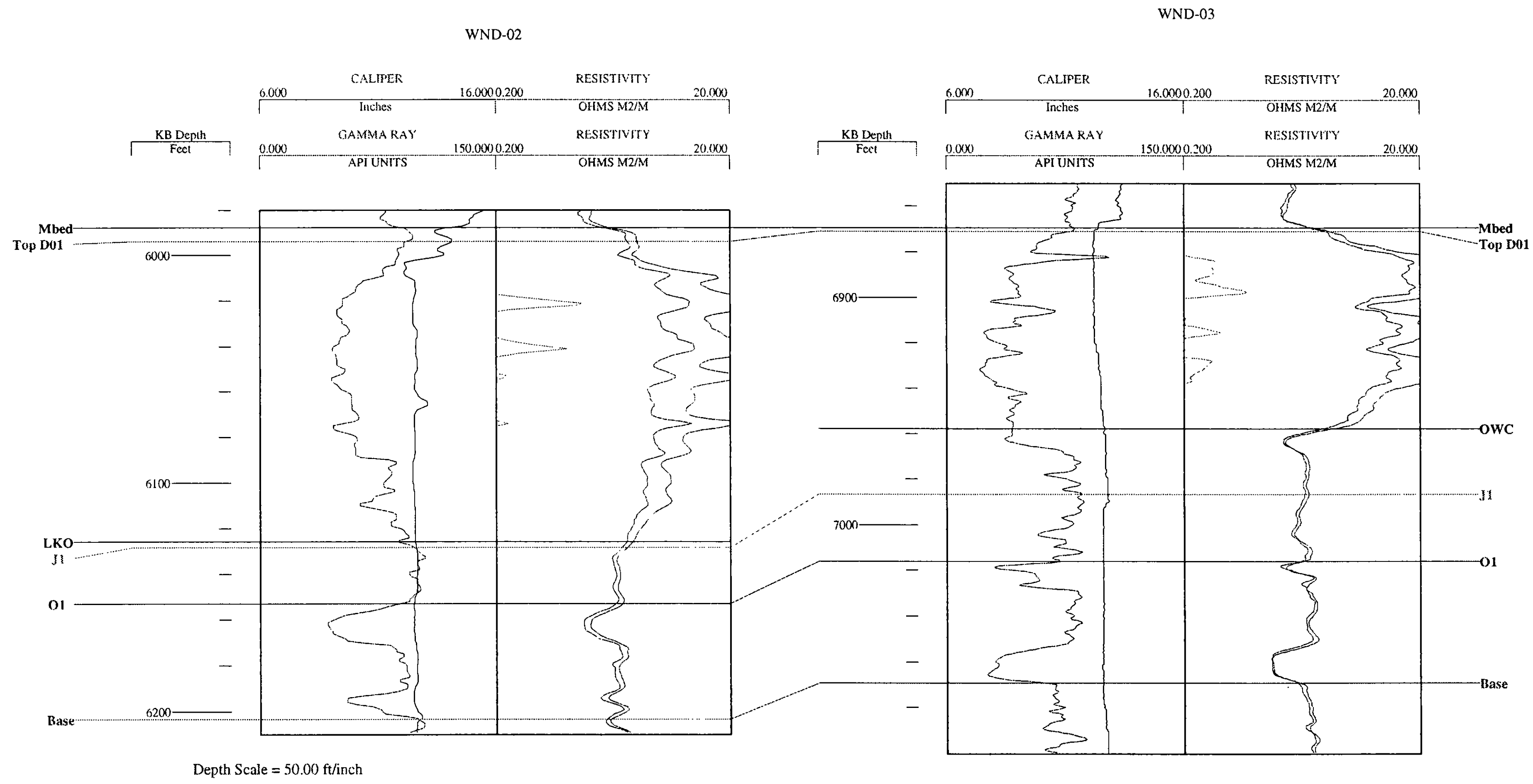


Figure 3.7 Correlation in the dip direction (NW-SE) of WND0-2 to WND-03

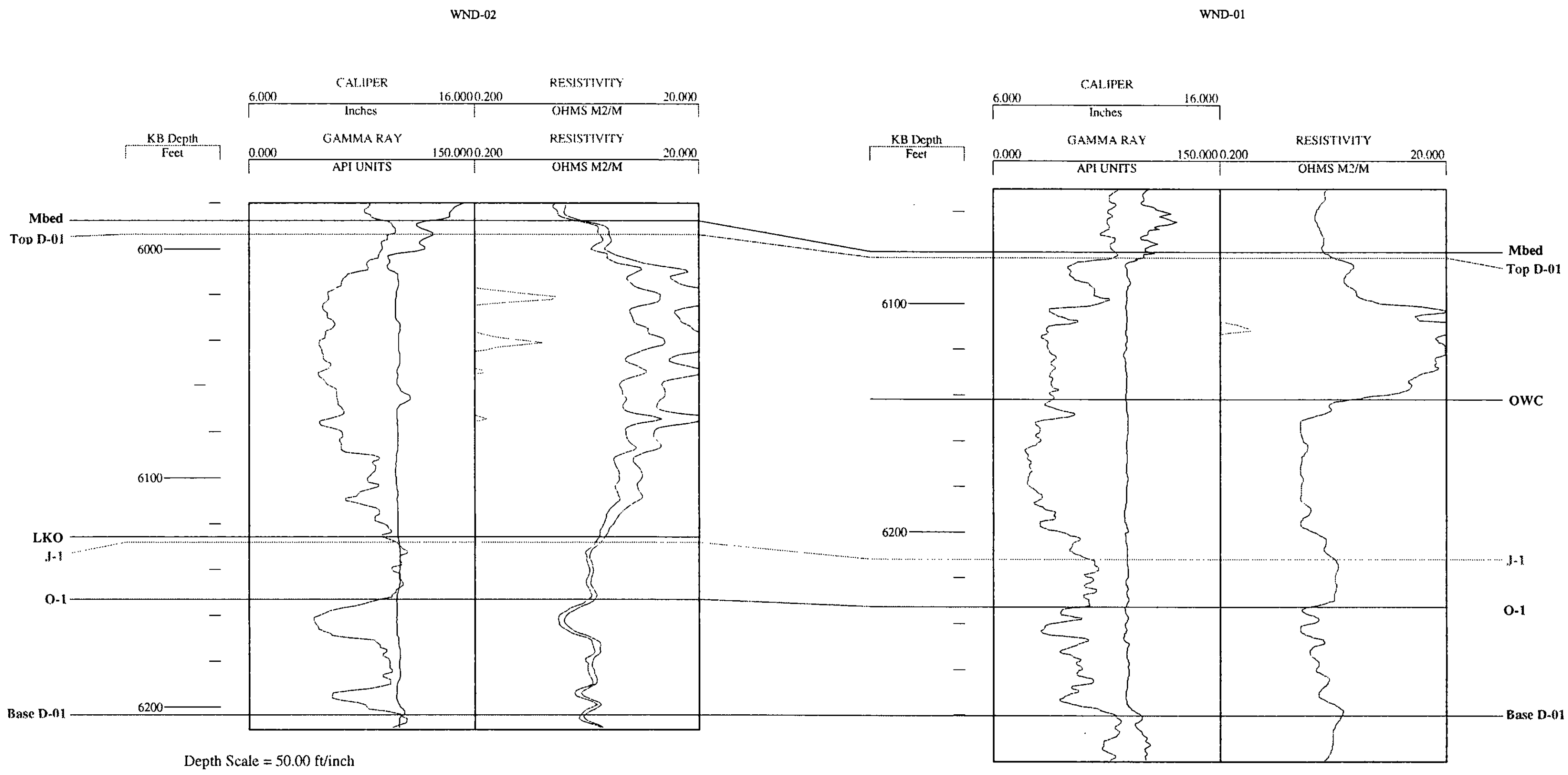


Figure 3.8 Correlation in strike direction (NE-SW) of WND-02 to WND-01

environment. This deposit is interpreted as barrier bar sandstones (Davies, 1977; Tizzard and Lerbekmo, 1975; Selley, 1978 and 1997) of middle to lower shoreface environment. It corresponds to mostly facies 6 sandstone depth interval 6210-6205 corresponds to facies 4 sandstone. Finally, another coarsening upward sequence caps the D-01 reservoir in well WND-01, it is interpreted as a barrier bar deposit also.

3.3.3 WND-03 Lithologies

WND-03 is a deviated well from WND-02. The wire-line logs run for well-03 include gamma-ray, medium and deep resistivity, sonic, bulk density and compensated neutron porosity logs (figure 3.5). There is no downhole survey data to use in correcting measured depth to true depths.

The D-01 reservoir sand in this well is 197 ft thick (6871 to7069 ft). It is also divided into two parts, sand intervals R-1 and R-2 separated here by a thick shale interval from depth 6987.00-7016.00 ft. R –1 extends from 6871.00 to 6987.00 ft, while R –2 is from depth 7016.00-7069.00 ft. Interpretation is from base of the reservoir

R –2 interval

R-2 is a generally coarse to medium grained sand with a thick interval (23 ft thick) of shale interbed. R-2 lies on top of prodelta shales, which makes its base consistent with a basin ward facies shift, causing the deposition of coastal marine strata on shelfal shales (Flint *et al,* 1998).

The base of R-2 starts with a thick and blocky interval of coarse grain sand at depth 7069.00 ft. This sand gets silty towards the top and extends up to 7052.00 ft. Overlying this with a sharp contact at 7052.00 ft is an interval of shale bed, 25.00 ft thick (7052.00 to 7027.00 ft). This sudden change in grain size from coarse grain sand to shale is an indication of a change in the depositional environment from shoreface to open marine environment, inferring a basin-ward movement. Another 12ft thick (7028 - 7016 ft) medium to coarse grain sand interval was deposited next on the preceding marine shales also with a sharp contact. Deposited next on top of R-2 is an interval of fine grained silty sand and sandy shale sedimentation, this is the interval that divides the D-01 reservoir into two block of sands. The fine grained silty sand bed extends from 7016.00 ft to 6996.00 ft, this gradually passes on to the sandy shale bed from 6996.00 to 6986.00 ft, marking the base of R -1.

R -1 interval

This interval is generally made up of blocky coarse grain sands, silty in some places and with thin shale inter-beds. The base of the R-1 sand starts at 6987.00 ft with the sandy shale bed below it grading into fine grained silty sands up to 6975ft. Deposited on top of this is another interval of sandy shale from 6975.00 - 6966.00 ft, this is the sedimentation due to channel erosion or a local transgression. This is overlain sharply by medium to coarse grain stack of blocky sandstone, which becomes serrated towards the top from 6966-6942 ft, indicating some siltiness. This passes on to even more coarse grain/ clean blocky sands, extending from 6942-6913, with a layer of shale inter-bed that is 4 ft thick in it (6926-6921 ft).

A thick block of coarse to medium grained sands was deposited on top of the preceding shale bed from 6903.00- 6883.6 ft, the bottom part of this interval is more coarse grained; it sort of fines upwards to medium grain sands having some silty beds within it. At depth 6884 - 6881 ft the grain size suddenly changes to finer clay sediments which is thought to be open marine shale. The sharp contact at the top and bottom indicates a sudden change in environment of deposition. This shale bed sharply passes on to medium grain sand again which fines up gradually capping the D-01 sands in this well. This finning upward succession of sediment is thought to be of lagoonal origin.

- **Porosity Interpretation from logs in WND-03**

(i) From neutron porosity log: (figure 3.15).

Density porosity = (matrix density – bulk density) / (matrix density – fluid density).

Density porosity in oil zone:

Upper R-1 interval, average bulk density = 2.09

Porosity = (2.65-2.09) / (2.65-0.80)

= 0.30

Lower R-1 interval, average bulk density = 2.14

Porosity = (2.65-2.14) / (2.65-0.80)

= 0.28

Water zone:

in R-1 interval, average bulk density = 2.15

Porosity = 0.30

Upper R-2 interval, average bulk density = 2.11

Porosity = 0.54/1.65 = 0.33

Lower R-2 interval, average bulk density = 2.13

Porosity = 0.52/1.65 = 0.32

Bulk density at OWC = 2.15, porosity = 0.3

Therefore average porosity for WND-01 = 0.31

(iii) From sonic log:

Sonic values are generally low to moderate all through, between 100-110. This indicate a long interval travel time, and hence a porous formation.

- **Reservoir Fluid Interpretation**

Depth interval 6871.00 to 6958.00 ft is interpreted as oil bearing indicated by the high resistivity values with curve deflecting to the right, while depth interval 6958.00 to 6969.00 ft is interpreted to be water bearing as indicated by low resistivity values and deflection of curve to the left.

Net Oil = 87.00 ft (6871.00 to 6958.00 ft).
Net Water = 9.00 ft (6958.00 to 6967.00 ft).
OWC is at 6958.00ft (measured depth)

OWC was determined here from log interpretations by the point with minimum porosity and maximum water saturation.

3.4 Lithostratigraphic Well Correlations

Correlation in the context used in this study is a demonstration of equivalence
Well to well correlation was done for wells WND-01, WND-02 and WND-03 in the WND field and cross sections were constructed to illustrate the facies distribution and to predict the reservoir quality and continuity (Weber et. al., 1995).

The aims of doing correlation of wells in the WND field are:

(i) to define the vertical and lateral distribution of the reservoir.

(ii) for the interpretation of changes in thickness of the reservoir across the field.

(iii) to establish lateral continuity of the litho-facies units across the field.

(iv) to define the formation tops in the D-01 reservoir.

The correlation section passes through all the wells in the field as shown in figure 3.6. Lithostratigraphic well correlations along the strike and dip directions of the field (3.7 and 3.8) shows the wells correlate well across the field.

3.4.1 Distribution of Litho-facies in the D-01 reservoir across the WND Field.

Interpretation of lateral correlations of the lithostatigraphic model of WND-02 with the other non-cored wells revealed that generally, the core depth intervals and in essence the log depth intervals are made up of facies successions from marine shelf to lower and middle shoreface environments. The correlation show that the deposits of the D-01 reservoir as a whole should have great lateral extent of several kilometres in the strike direction and hundred of meters in the dip direction. The middle shoreface, hummocky cross-stratified sandstones may pass into facies IWSM, muddier lower shoreface sandstones over a short distance of a few hundred meters. Facies IWSM sandstones pass laterally into shallow shelf/open marine muddy sediments, hence these facies are prone to increasing mud content basin-ward. Due to the fact that there are few wells in the WND field right now, it is difficult to accurately determine the correlation lengths of the individual facies at present.

3.5 Rock Properties

The rock properties which determine the quality of a reservoir includes porosity, permeability, water saturation, permeability porosity relationship and the net to gross sand ratio. All of these properties as they apply to the D-01 reservoir are discussed below.

3.5.1 Porosity

Porosity was determined from cores as well as qualitatively and quantitatively from well logs. Porosity measurements from cores show values of 0.15 to 0.35; with most of the intervals in the oil zone showing values of 0.2 to 0.33. Porosity calculated from density log gave values ranging from 0.15 to 0.30 in the oil zone (R-1 interval) and 0.26 to 0.33 in the water zone (R-2 interval). The calculated porosity compared with porosity obtained from neutron log and the core porosity, the average porosity for the D-01 reservoir is taken to be approximately 0.3 for this study (See table 3.3 and 3.4 and figures 3.9 and 3.10).

The neutron porosity/density log plot for the three wells show the density log and neutron porosity logs to deflect to the left and right respectively in the sandstone intervals;

indicating a porous formation. The deflection of the density and neutron logs to the right and left respectively indicates shaliness and less porosity.

It is observed that the core and log porosity do not show any clear trend with depth, which suggest that the presence of shale in some intervals and some other factors might have caused this. Montgomery and Morgan (1998) have shown that sandstone reservoirs with this kind of porosity trend might have the total porosity being affected more by cementation, diagenesis or the development of secondary porosity, compared to the effect of compaction.

Generally, as observed in figure 3.9 and 3.10, the core porosity measurements made and well log porosities show that the D -01 reservoir sands generally have good porosity, having moderate to high porosity values (15-35%).

Porosity values for fine grain sands of facies MBFS ranges from 20-35%. In the bioturbated medium - fine grain sandstones of facies IBWS, porosity value is 27% on the average. Porosity values for the interbedded wave-rippled, very fine grained sandstones and mudstone of facies IWSM ranges from 15-25%, which is lesser than what is found in the first two upper intervals. The hummocky cross-stratified fine grained sandstones facies HSSM on the other hand have porosity values ranging from 27-33%, which is very high, but it is water bearing.

3.5.2 Permeability

Permeability analysis here is based on data available for this study. Permeability is generally good in the D-01 sands, with variable ranges of values. From the core permeability measurement result, horizontal permeability could be said to be generally higher than vertical permeability in most of the depth intervals. It is noticed that the vertical permeability is unusually higher than horizontal permeability at some depth intervals in the D-01 sands. (see figures 3.11, 3.12 and 3.13 and table 3.4) due to the presence of shale interbeds. Permeability values for facies 6 MBFS range from 130 - 335 mD for horizontal permeability (K_H) and much higher values for vertical permeability, K_V (900-1730 mD). The K_V/K_H ratio is high here. For sandstones of facies 5, IWSM, K_H values range from 39-112 mD, with extremely variable K_V/K_H ratios. Facies 2 IMWS have permeability values ranging from 20 - 129mD. The K_V/K_H ratio is very low here. The hummocky cross-stratified sandstones of facies 3, HSSM have permeability that is dependent on the grain size. The upper fine grained sand have permeabilities ranging from

532-2010 mD, while the lower very fine grained sands have permeabilities ranging from 104-122 mD. K_V/K_H ratios are again extremely variable.

3.5.3 Water Saturation (S_w)

Water saturation was calculated from the resistivity log (figure 3.15) using Archies equation combined with Humble formula (Rider, 1991; Doveton, 1986 and 1994; Laudon, 1996).

Archie equation:

$$S_w = \{(F^*R_w) / R_t\}^{1/n}$$

Humble formula:

$$F = a/\text{porosity}^m$$

Where :

S_w = formation water saturation

F = formation resistivity factor

Porosity = 0.3

R_w = resistivity of formation water = 0.06

R_t = True formation resistivity (obtained from deep resistivity log)

n =Saturation exponent, (usually 2).

m = cementation factor = 2.15 (widely used for sandstones)

a = constant = 0.62

The Humble equation used for this study is applicable to sandstone and is the best average for sandstones (Rider, 1991; Doveton, 1986 and 1994; Laudon, 1996). R_w of 0.06 used here was obtained from water table (Dresser Atlas, 1974 and 1975).

The calculation of water saturation is as shown below:

$$F = a/\text{porosity}^m$$

$$= 0.62/0.3^{2.15} = 0.62/0.075$$

$$F = 8.3$$

Substituting the value of F in the Archie equation the water saturation was calculated at different depths in the three wells as shown in figure 3.15 and the results are shown in table 3.5. The calculation shows that the average water saturation for the D-01 reservoir is 0.28.

3.5.4 Porosity/Permeability Relationship in the D-01 reservoir

The plot of vertical permeability versus porosity for the D-01 reservoir (figure 3.13) shows the importance of clay content to the reservoir quality. It is observed from this plot that even very low clay content have an overall effect of reducing the permeability of the reservoir, since it is mostly the intervals with shale that show low permeability values. This infer that shales block pore throats and act as barriers to vertical permeability, (Jarrard, 1996). The relationship between porosity and permeability of the D-01 sands is such that permeability is good at depth intervals with good porosity. For this reservoir sands vertical permeability is generally observed to be higher than horizontal permeability, with the KV/KH ratio being variable, ranging from very low values to very high values at some depth intervals. On the average, the permeability versus porosity plot shows that shale or clay free intervals of the D-01 reservoir with porosities equal to or greater than 0.25%, and permeabilities equal to or greater than 150 mD make better reservoir; and would yield better oil recovery.

3.5.5 Net/Gross Ratio Determination

The criteria used for calculating the net sand here are gamma-ray, porosity and neutron – density logs. Porosity in the D-01 reservoir is generally moderate to high and it does not vary very much across the reservoir. Net to gross ratio in the context used in this study refers to the net reservoir as being the whole reservoir interval without the shale intervals or very low-porosity zones, while the gross reservoir is the gross reservoir thickness irrespective of the shale interval or low porosity zones. The net sand includes intervals with gamma-ray values less than 70 API units, neutron porosity less than 0.3 and density values less than 2.3 gm/cc.

Net sand to gross reservoir sand ratio combined with structure maps (from two way time values) is used to make an isopach map to know where the reservoir sand is developing, that is where it is thickest, and to know where the sand is clean. This area is then recommended for further development such as drilling more wells. But if the sand is thickest in an area and not clean then there is no need for further development in such an area.

The net sand value for D-01 reservoir in WND-01 is 139.00 ft, while the gross sand is 203ft. Thus the net: gross ratio is:

$$139/203 \text{ ft} = 0.7.$$

For WND-02, the net sand value for D-01 reservoir is 129.00 ft, while the gross sand value is 211.00 ft. Thus the net: gross ratio is:

$$129/211 = 0.60.$$

WND-03 has net sand value of 123.00 ft, while the gross sand value is 198.00 ft thick. Thus the net: gross ratio is:

$$123/198 = 0.62.$$

From the above, it implies that the D-01 reservoir generally in the WND field, have an average net: gross ratio of 0.64, which can be said to infer good reservoir quality for further development of the field.

3.6 Determination of the Oil-Water Contact (OWC)

The determination of the oil-water contact in the WND field was done from core and log interpretations, and tied with the seismic. The resistivity and gamma-ray logs were the major logs used for the determination of the OWC from the logs. The resistivity log as can be seen in figure 3.4 show a clear cut in fall of resistivity values at measured depth 6142.00 ft (6068.00 subsea), indicating a change in fluid content to water. Porosity and water saturation calculated from logs together with the core porosity were also used to aid the definition of the OWC. As shown in the preceding section on porosity and figure 3.15 and table 3.5, the porosity value is minimum, while the water saturation is maximum at the OWC. The OWC arrived at in WND-01 is used for volumetric calculations in this study because it is a straight well. WND-02 is also a straight well but it has a lowest-known oil contact (LKO), no OWC; while WND-03 is a deviated well and data for it's true vertical depth is not available for this study. There was no log data available for well WND-04. An oil water contact of 6142 ft measured depth (6068 ft, subsea depth) was arrived at. This OWC was used to define the net-sand thickness used to in reserve estimates and to determine the areas likely to contain oil or water.

3.7 Depositional Environment Interpretation for the D-01 reservoir in the WND Field

Generally, the reconstruction of the paleoenvironment and depositional history of siliclastic units involves determining the dorminant sediment dispersal process, and the depositional development of the unit in space and time. These are achieved by integrating the information on the geometry of the unit; vertical and lateral variations in lithology;

sedimentary structures and textures; trace and body fossils; and paleocurrent patterns (Amajor and Agbaire 1989). But this is usually not achieved because in most subsurface sedimentological studies, most of these data are hardly available. In a case where all the above information are not available, environmental prognosis can then be based on sandstone composition (Davies and Ethridge, 1975); grain size characteristics (Visher, 1969); and Spontaneous Potential and gamma-ray log shapes (Pirson, 1970). Data available for depositional environment prognosis in this study include mud log, core descriptions and wire-line logs.

Environmental prognosis in this study is based on sandstone composition (Davies and Ethridge, 1975), grain size characteristics, (Moiola and Weiser, 1968; Visher, 1969), gamma-ray log shapes (Galloway, 1968; Fisher, 1969; Pirson, 1970) and aspects of sandstone composition (glauconite and carbonaceous detritus (Selley, 1978). Observations from core analysis results such as sedimentary structures and trace fossils, integrated with the grain size, textures, gamma ray and resistivity log profiles and mineralogical composition form the basis for the delineation of depositional environments in this study. Figure 3.13 is a depositional model for the D-01 reservoir.

The log motif of the D-01 reservoir shows dominantly blocky sandstone with minor upward fining. The reservoir generally comprises thick units of sandstone alternating with thin shale beds of varying thickness. The sands in this reservoir occur as stacks of coarsening upward sequences built seaward and are intercalated with thin, fining upward shaly zones deposited during transgressions, displaying sharp bases or gradational bases. The vertical succession of sedimentary structures in the deposits is characteristics of a shoreface environment.

The D-01 reservoir across the WND field is basically barrier bar sands separated into two parts by prodelta shale interval (Dickey, 1986). The upper part is oil bearing and is referred to as R-1 and the lower water bearing part is R-2. The sands were most probably cut into by a channel, which later became filled with marine shales deposited as transgressive shoreline deposits in a low energy environment. The channel is identified by the fining upward of the grain size, indicated by the bell-shape gamma ray log motif at such intervals. On the other hand, the barrier bar sands show funnel-shape gamma-ray curve trend.

The basal part of the D-01 sand, R-2 is made up of medium to coarse grain sandstone of eroded from the upper-middle shoreface and deposited below the fair weather base but above the storm wave base, causing the hummocky cross-stratification exhibited by the sandstones here as in facies 3 HSSM. Prodelta marine shales settle out of suspension during fair weather conditions to partially drape the hummocky cross-stratified sandstones (Mclane, 1995).

The upper portion of the D-01 reservoir, R-1 is made up of coarse to medium to fine grain sandstones of lower to middle shoreface, coarsing upwards, with thin marine shelfal or prodelta shale beds that are probably transgressive erosional deposits. This sequence tend to fine upwards in to lagoonal sediments deposited at the back of the barrier sands, capping the D-01 reservoir at the top.

The above information suggests that the D-01 reservoir sand is made up of stacking arrangements of sandstone and shale units displaying coarsening upward and finning upward sequences which are typical of barrier bar and channel deposits.

The general depositional history of the D-01 reservoir sand in WND field can thus be reconstructed from the above observations made. The WND field is littoral being located in a shallow marine (200m deep) environment. It can be said that the D-01 reservoir sand in this field is heterogenous being made up of a mixture of barrier bar and channel sands, and lagoonal deposits. The sediments are middle - lower shoreface and open marine prodelta sedimentary deposits deposited in a wave dominated prograding environment.

Note

The various parameters used for environmental prognosis however are not without limitations. The GR log for instance is affected by excessive caving. The presence of glauconite, mica, Zircon and potassium can give anomalously high gamma ray readings in sandstones so cannot be a perfect shale indicator, (Rider, 1990, Selley, 1997). Also, facies prediction from logs in non cored wells are subjective.

3.8 General Reservoir Characterisation and Formation Evaluation of the D-01 Reservoir

The best quality reservoirs in terms of volume and flow rate are those with inter-granular porosity. A strong relationship exists between litho-facies type and reservoir quality in the WND field. A summary of reservoir interpretation results for the D-01 reservoir interval in 3 of the wells in the WND field are given in table 3.3. The facies defined for a reservoir directly control the reservoir continuity, and the ultimate recovery efficiency as well as the fluid migration path, (Finley and Tyler, 1986).

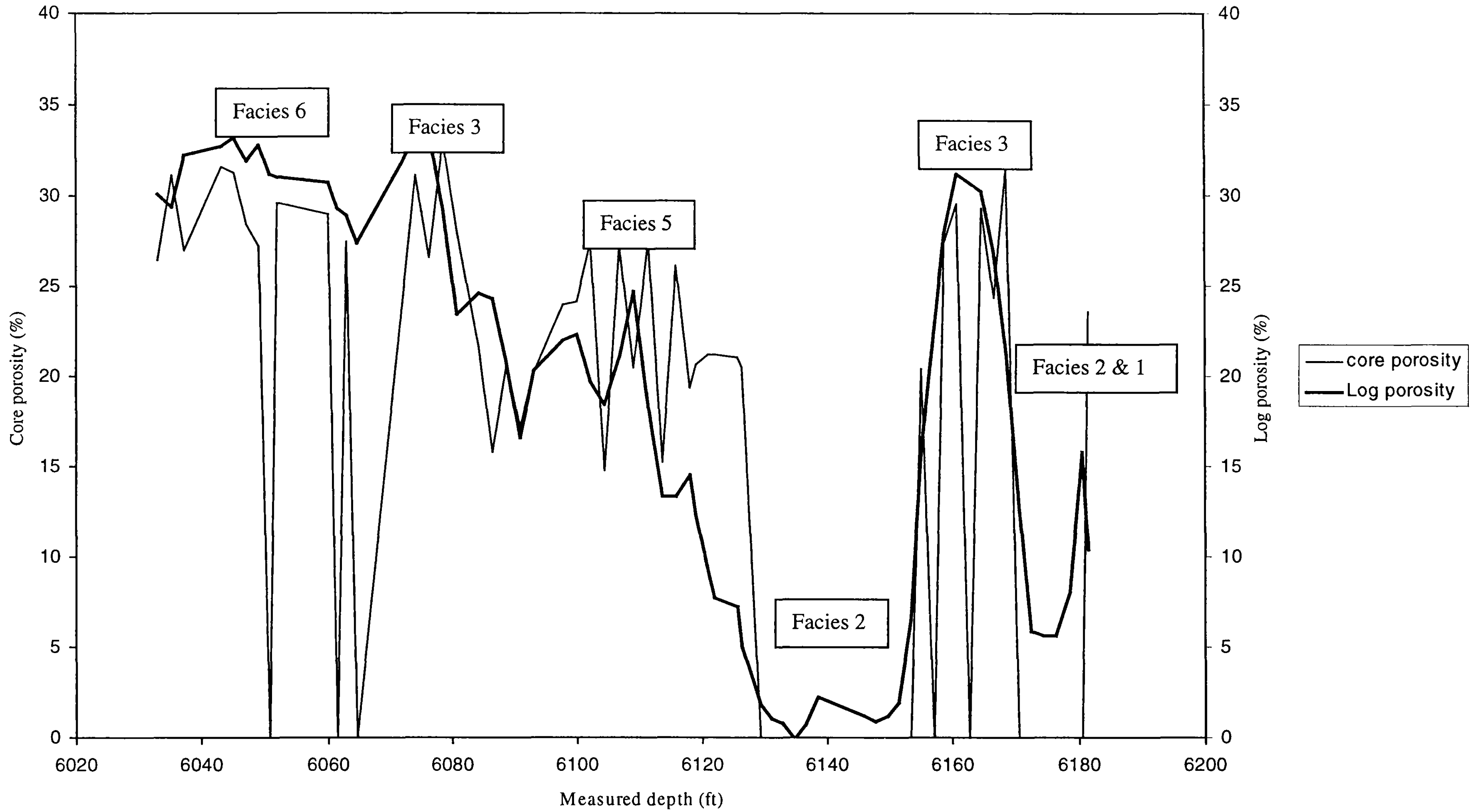
The lateral continuity of the D-01 reservoir as illustrated by the cross sections in figure 3.6 shows that lateral continuity is greatest in the barrier bar sands, while the shale filled channel system is not continuous laterally, and so would not act as a permeability barrier.

Generally, R-1 succession of sediments have a better reservoir quality than R-2.
R-1 consists of massive / blocky sandstone successions with minor shale intervals that seem not to have long lateral extent, so will not be a barrier to vertical and horizontal permeability. Also, the sediment succession in R-1 generally has coarse to medium tofine grained sandstone making it more porous than R-2 sediments succession which are generally medium to very fine grained sandstone with thick shale intervals.

R-1 interval of sediments are of the lower-middle shoreface environments with generally prograding/aggradational geometries, implying that sediment supply and rate of creation of topset accumulation volume are roughly balanced. Facies units therefore stack vertically and the offlap break does not migrate landward or basinward. The average reservoir quality in the upper succession sand, R-1 range from 136 to 334 mD permeability which is better than in the lower succession sand, R-2 with values of 20 - 120 mD.

R -2 interval of sediments have good-fair reservoir properties in the hummocky, cross-stratified sandstone succession with porosity of 21 –34%, but these sandstones as indicated from the resistivity readings are water bearing. On the whole, the top portion of R-1 which is in core #1 and #2 have the best reservoir quality, with average porosity, permeability and water saturation of 0.30, 203 mD and 0.28 respectively.

Generally, as observed from results of analysis of data from mud log, cores and wire-line logs, the D-01 reservoir sandstones can be said to be clean, relatively thick, blocky sands; with good porosity and permeabilty, low water saturation, They are middle - upper shore face sedimentary deposits, deposited in a wave dominated prograding environment.



Figures 3.9 and 3.10 Plot of core and log porosity versus measured depth showing porosity values at different depth in the D-01 reservoir. It is observed that facies 6 and 3 have the highest porosity values.

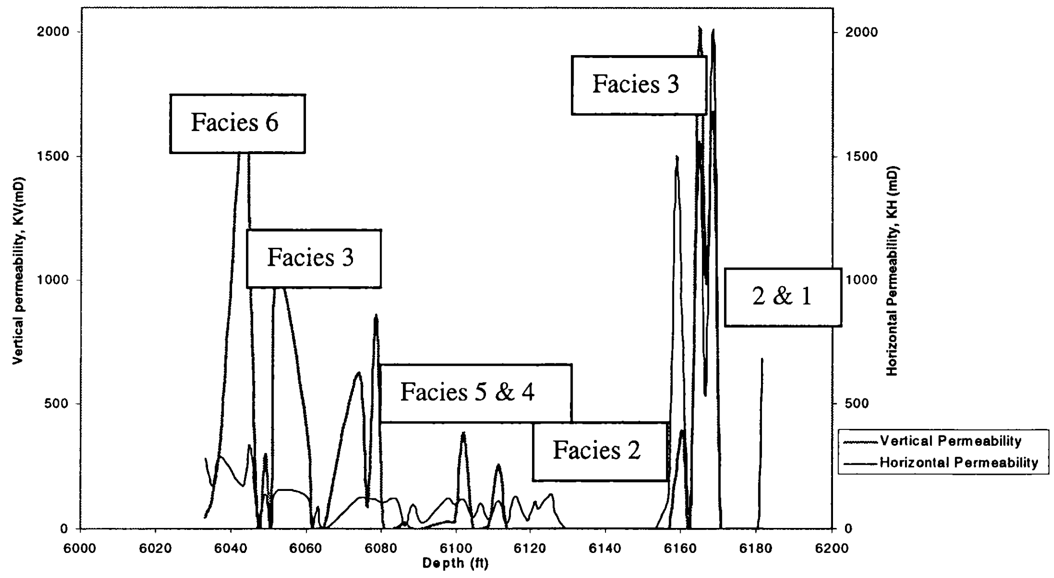


Figure 3.11 Plot showing how vertical and horizontal permeability varies in the D-01 reservoir. Vertical permeability tends to be higher than horizontal permeability in interval with less shale content, such as in the oil bearing interval of the D-01 reservoir, hence K_H:K_V ratio is low for this interval. The water bearing interval and intervals with considerable shale contents have K_H and K_V almost equal, and no permeability in the marine shale intervals.

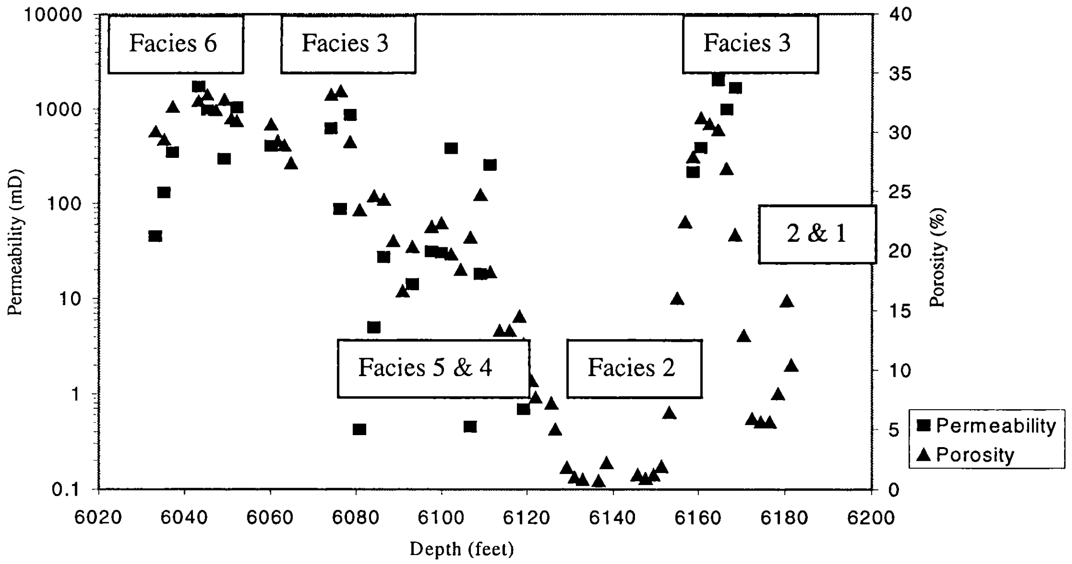


Figure 3.12 Plot showing how porosity and permeability varies with depth in relation to the facies associations defined for the D-01 reservoir in the field of study. The plot shows that facies 6 and facies 3 sandstones have the best reservoir character having the highest porosity and permeability values, while facies 1 and 2 show very poor reservoir quality having very low porosity and permeability values.

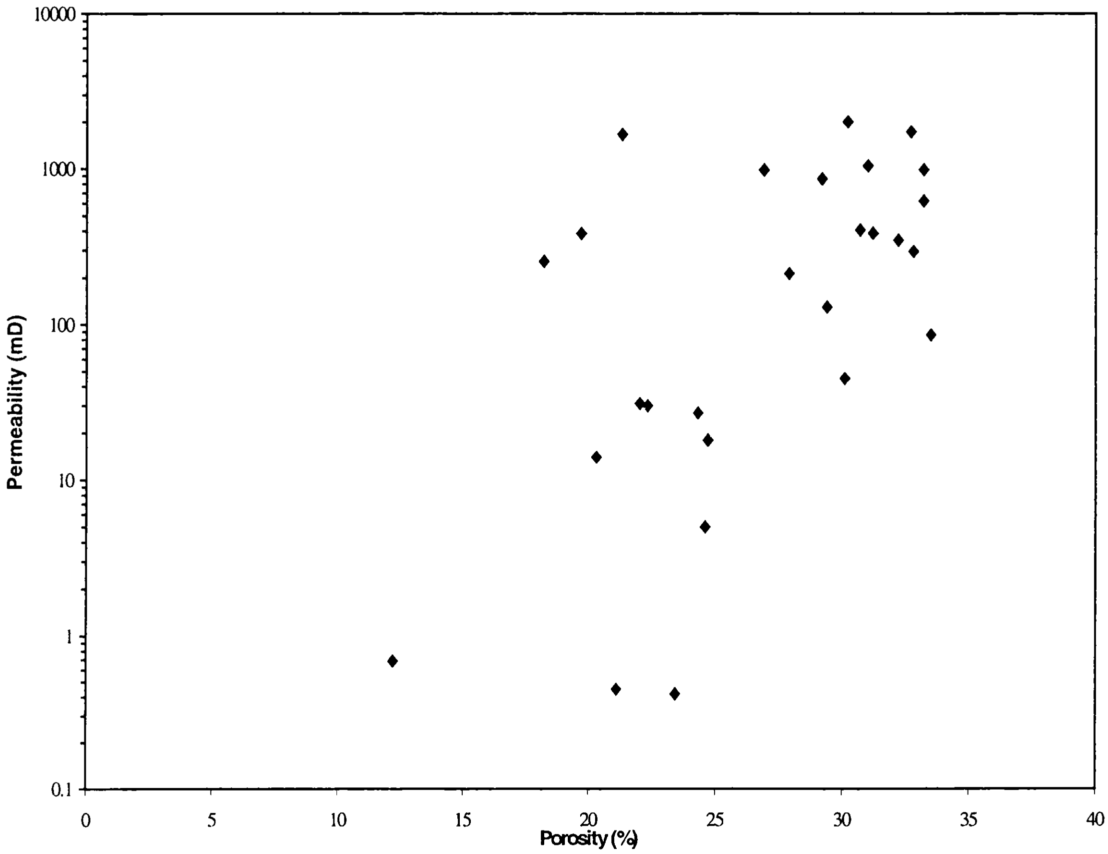


Figure 3.13 Plot of permeability versus porosity. Permeability and porosity in the D-01 reservoir tend to be generally moderate to high, as indicated by the data points clustering towards the top right hand corner of the plot

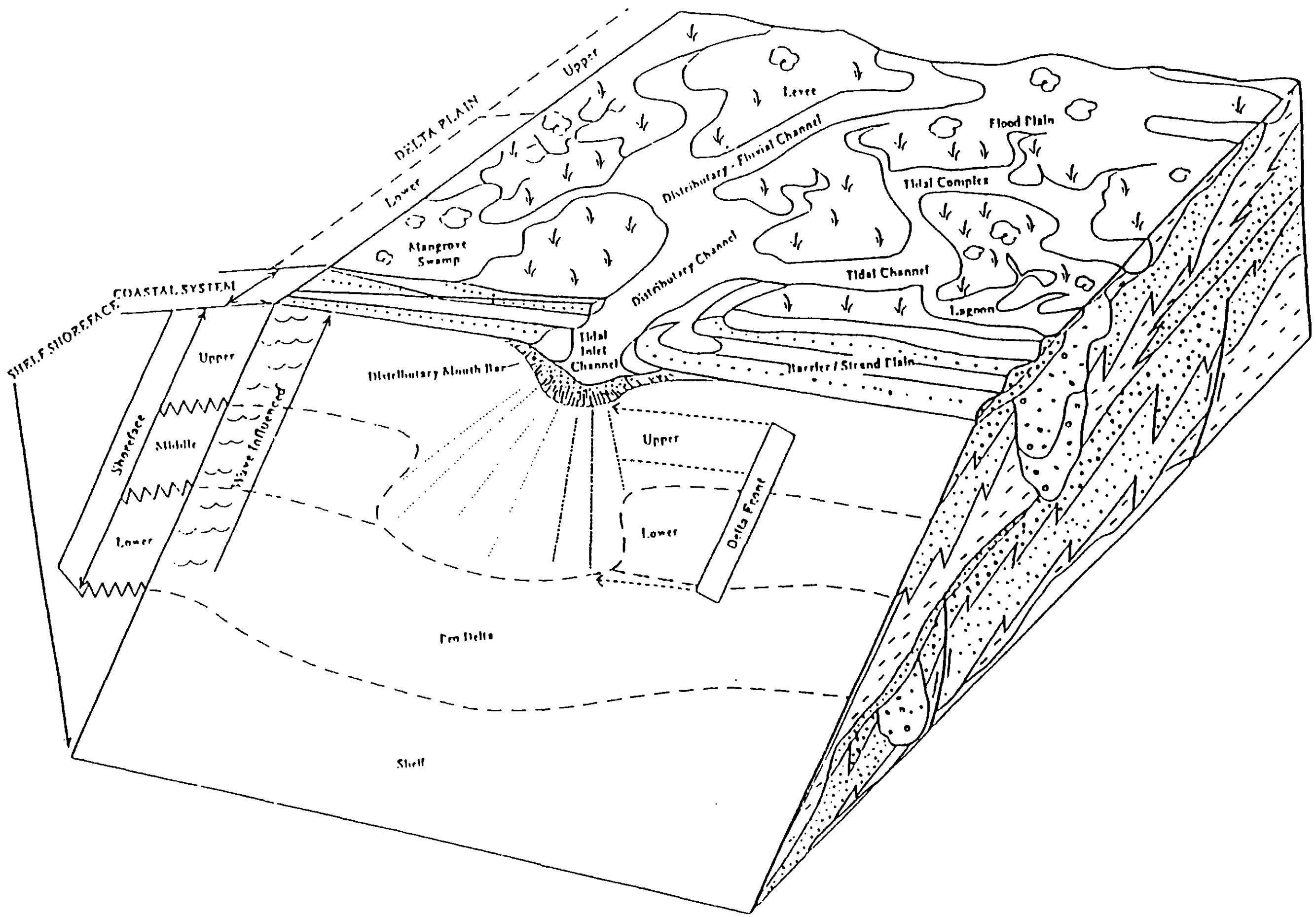


Figure 3.14 Depositional model of a wave dominated delta/strand plain system, composed of shoreface and deltaic facies as indicated in the diagram. Upward coarsening cyclic patterns on the logs are as a result of regression and transgression of the shoreface/delta front deposition. (Modified from Oomkins, 1974)

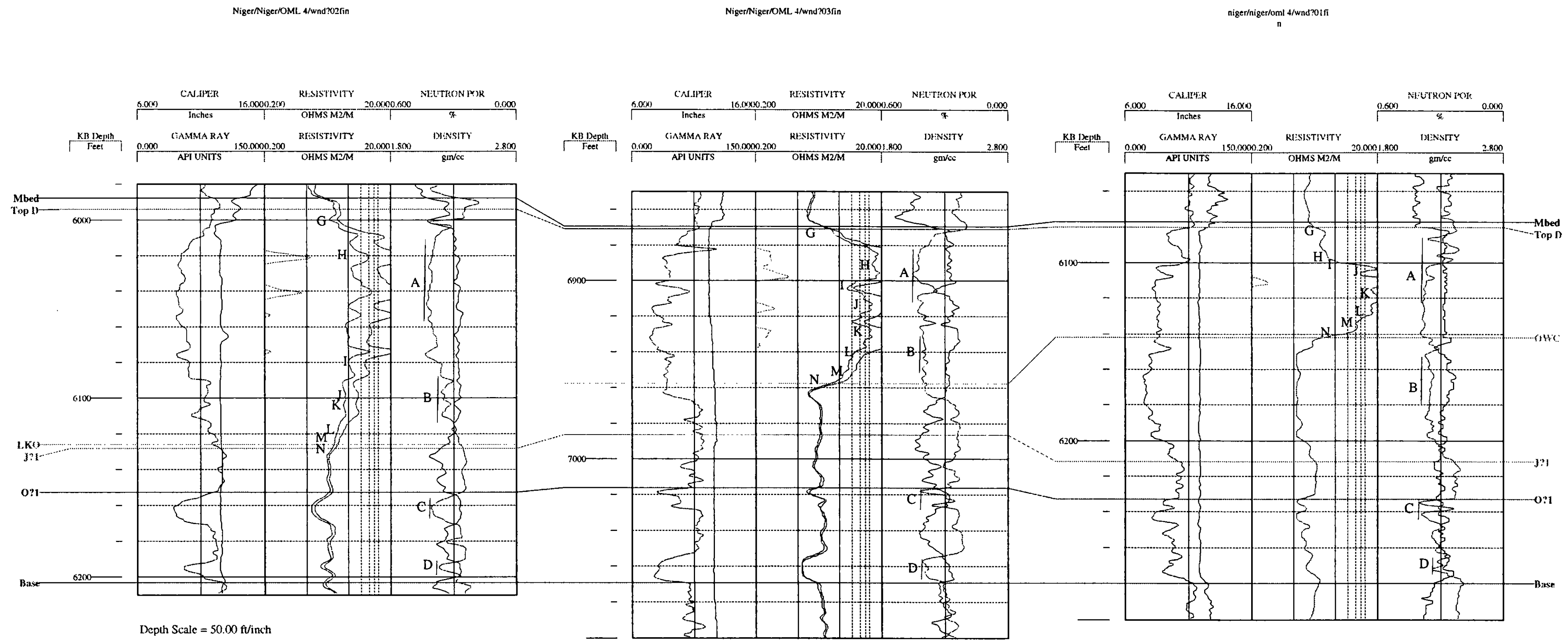


Figure 3.15 Shows the depth intervals for which porosity and water saturation were calculated using bulk density and resistivity logs respectively for the three wells. Porosity was calculated for the three wells at depthe intervals A-D, while water saturation calculations was done at depths G-N.

DEPTH, (ft)	Core Porosity (%)	Log Porosity (%)	Horizontal permeability millidarcies	Vertical Permeability millidarcies	Grain Density (g/cc)	Saturation % pore volume	
						OIL	WATER
6033.123	26.4	30.1	279	45	2.59	57	0.234
6035.123	31.1	29.4	172	130	2.64	32.1	0.216
6037.123	27	32.2	286	349	2.63	38.9	0.326
6043.123	31.6	32.7	171	1730	2.64	43.1	0.239
6045.123	31.3	33.2	334	985	2.63	49.3	0.131
6047.123	28.4	31.9	45.1	0	2.62	39.1	0.169
6049.123	27.2	32.8	136	296	2.63	18	0.356
6050.723	0	31.2	0	0	0	0	0
6052.043	29.6	31	144	1040	2.63	50.7	0.215
6060.042	29	30.7	131	405	2.63	28.6	0.222
6061.595	0	29.3	0	0	0	0	0
6063.147	27.5	28.9	87.3	0	2.64	21.1	0.277
6064.701	0	27.4	0	0	0	0	0
6074.019	31.1	33.2	120	623	2.64	33.4	0.249
6076.268	26.6	33.5	122	86	2.62	56.1	0.228
6078.518	33	29.2	118	860	2.63	46.8	0.37
6080.768	28.1	23.4	104	0.42	2.61	19.4	0.146
6084.143	21.7	24.6	116	5	2.62	32.9	0.304
6086.393	15.8	24.3	12	27	2.6	33.2	0.348
6088.643	20.5	20.8	96.9	0	2.79	43.4	0.324
6090.893	17.2	16.6	25	0.06	2.63	14.2	0.394
6093.142	20.2	20.3	51.4	14	2.63	14.8	0.429
6097.642	24	22	120	31	2.64	24	0.394
6099.892	24.1	22.3	97.6	30	2.64	19.7	0.18
6102.142	27.4	19.7	116	384	2.66	43.5	0.269
6104.395	14.8	18.4	47	0	2.64	10.1	0.53
6106.728	27.2	21.1	102	0.45	2.62	57.8	0.277
6109.061	20.5	24.7	39.1	18	2.64	29.9	0.286
6111.356	27.5	18.2	111	255	2.61	28.4	0.207
6113.642	15.2	13.3	20.2	0.05	2.66	1.8	0.498
6115.928	26.1	13.3	128	0.02	2.65	17.6	0.427
6118.214	19.4	14.5	48.6	0	2.67	0	0
6119.194	20.6	12.2	33.8	0.69	2.62	22	0.197
6121.033	21.2	9.1	107	0.01	2.61	18.5	0.328
6121.952	21.2	7.7	79.1	0	2.62	17.5	0.227
6125.63	21	7.2	136	0.09	2.63	24	0.231
6126.549	20.5	5	67	0	2.66	11.9	0.367
6129.307	0	1.8	0	0	0	0	0
6131.146	0	1	0	0	0	0	0
6132.984	0	0.8	0	0	0	0	0
6134.823	0	-0.1	0	0	0	0	0
6136.662	0	0.7	0	0	0	0	0
6138.5	0	2.2	0	0	0	0	0
6145.855	0	1.2	0	0	0	0	0
6147.694	0	0.9	0	0	0	0	0
6149.533	0	1.2	0	0	0	0	0
6151.372	0	1.9	0	0	0	0	0
6153.21	0	6.4	0	0	0	0	0
6155.049	20.4	16	49.1	0.01	2.65	8.3	0.485
6156.888	0	22.4	151	0	2.64	0	0
6158.727	27.4	27.9	1490	214	2.64	0	0.634
6160.565	29.5	31.2	675	386	2.63	2.8	0.646
6162.513	0	30.7	87	0	2.65	0	0
6164.513	29.3	30.2	1560	2000	2.64	0	0.692
6166.513	24.4	26.9	532	983	2.67	17.9	0.171
6168.513	31.5	21.3	2010	1660	2.65	6.3	0.527
6170.513	0	12.9	0	0	0	0	0
6172.513	0	5.9	0	0	0	0	0
6174.513	0	5.6	0	0	0	0	0
6176.513	0	5.6	0	0	0	0	0
6178.513	0	8	0	0	0	0	0
6180.513	0	15.8	0	0	0	0	0
6181.513	23.6	10.4	685	0	2.62	11.4	0.261

Table 3.4 WND-02 core analysis results

WND-01 KB = 74				WND-02 KB = 80				WND-03 KB = 94		
Depth (ft)		Resistivity log value	Calculated	Depth (ft)		Resistivity log value	Calculated	Depth (ft)	Resistivity log value	Calculated
Measured depth	Subsea	(Rt) ohms m2/m	Sw	Measured depth	Subsea	(Rt) ohms m2/m	Sw	Measured depth	(Rt) ohms m2/m	Sw
6080	6006	2.02	0.50	6000	5920	2.85	0.42	6874	4.70	0.33
6100	6026	5.17	0.30	6020	5940	66.40	0.10	6890	34.00	0.14
6100.5	6026.5	6.32	0.28	6080	6000	8.00	0.25	6903	8.00	0.25
6101	6027	10.50	0.22	6100	6020	6.20	0.28	6915	37.40	0.11
6120	6046	19.30	0.17	6105	6025	5.70	0.30	6930	31.30	0.13
6130	6056	13.40	0.20	6120	6040	0.39	0.40	6940	13.60	0.19
6134	6069	9.00	0.25	6126	6046	2.87	0.42	6950	7.73	0.25
6142	6068	2.81	0.42	6129	6049	2.50	0.45	6958	3.60	0.37
Average water saturation for WND-01 = 0.29				Average water saturation for WND-02 = 0.33				Average water saturation for WND-03 = 0.22		

Table 3.5 Water saturation calculation results for D-01 reservoir

WELL NAME	HOLE TYPE	RTE (Feet)	TD (Feet)	LOCATION (coordinates)		TOP SAND		BASE SAND		GROSS RESERVOIR INTERVAL		NET SAND (Feet)	Net/Gross ratio	FLUID CONTACTS			NET OIL	NET WATER	AVE. POR. oil zone	AVE. SAT. oil zone
				x	y	MD	TVDSS	MD	TVDSS	MD	TVDSS			TYPE	MD	TVDSS				
WND01	Straight	74.00	9727.00	285.345	202.565	6077.00	6003.00	6280.00	6206.00	203.00	203.00	139.00	0.70	OWC	6142.00	6068.00	62.00	61.00	0.260	0.290
WND02	Straight	80.00	6680.00	283.325	202.321	5994.00	5914.00	6205.00	6125.00	211.00	211.00	129.00	0.60	LKO	6126.00	6046.00	123.00		0.260	0.330
														HKW	6154.00	6074.00		17.00		
WND03	Deviated	94.00	7461.00	283.745	202.686	6871.00	5974.00	7069.00	6064.00	198.00	198.00	123.00	0.62	OWC	6958.00	6050.00	13.00	9.00	0.310	0.220

Table 3.3 Spreadsheet showing summary of results of petrophysical analysis for the D-01 reservoir.

WELL NAME	KB (ft)	TOP D-01 RESERVOIR					BASE D-01 RESERVOIR			
		TWT	DEPTH		AVE. VEL.		TWT	DEPTH		AVE. VEL.
		(msec)	MD (ft)	TVDSS (ft)	(ft/sec)		(msec)	MD (ft)	TVDSS (ft)	(ft/sec)
WND-01	74.00	1687.00	6077.00	6003.00	7205.00		1747.00	6280.00	6206.00	7190.00
WND-02	80.00	1680.00	5994.00	5914.00	7136.00		1732.00	6205.0	6125.0	7165.00
WND-03	94.00	1694.00	6871.00	5974.00	7053.00		1743.00	7069.00	6064.00	6958.00

Table 4.1 Results of seismic interpretation showing two way times and corresponding depth for the wells in the WND field at the top and base D-01 reservoir

Chapter Four **Seismic Interpretation**

4.0 Introduction

Seismic interpretation in this study is done to integrate seismic analysis with the petrophysical analysis, and both integrated to form a geological model. Prather *et al.* (1998) have shown that the integration of seismic analysis with well data from cores and logs and
3-D seismic interpretation serves to link seismic response, lithology and depositional environment. The integration of seismic, core and log analysis results provide the key to a complete interpretation, which is important for the development of a geologic model.

4.1 Interpretation Techniques

Selected cross-lines and in-lines across the WND field (figure 4.1) were studied and used for interpretation. The horizons of interest, top and base D-01 reservoir, were identified, and 2-D interpretations were done with the aid of the intergration of generated synthetic seismograms of the wells, well log information from the three wells and checkshot data available for the field of study. The identified top and base D-01 horizons were then picked manually on the seismic sections around the loops formed by the intersections of the in-lines and cross-lines.

Header information containing seismic data parameters were not available, hence the seismic data parameters were estimated from the seismic profiles, synthetic ties and well data. The stratigraphic interval of interest falls between 1650 to 1850 millisecond two way travel time.

4.1.1 Well log to seismic ties

Synthetic seismograms produced from the different wells in the WND field were overlain/spliced in on the seismic sections at points where there are well locations (Badley, 1985). This was used to identify the top and base horizons of the D-01 reservoir interval on the seismic sections. The synthetic seismograms of the wells served as a way of integrating the available well data with the seismic profiles (Varnai, 1998). These ties agree with the check-shot results. The next stage was to manually pick the horizons of interest on the in-lines and cross-lines across the field. The picking was started from lines passing through the well locations because they give a clear geologic picture and show strong reflections where expected (Badley, 1985, Mcquillin et. al., 1984). Finally, the picking of the horizons of interest on the seismic lines was tied together forming closed loops, with the line intersections being consistent.

4.2 Description and Interpretation of Seismic sections

A few data quality issues made interpretation difficult. For instance, the scaling of the hard copy prints of the seismic sections was such that the D-01 reservoir came out very thin, so it was not possible to accurately interpret the internal form/geometry of the reservoir. Also, detail seismic stratigraphic and facies interpretations were not possible on the seismic sections, but an attempt is made here to do these interpretations. For the same reason, it was difficult to map the faults because reflection terminations were almost absent as they came out too gentle with this scale.

Seismic facies interpretation was done in this study based on seismic stratigraphy and sequence stratigraphy framework (Vail et al, 1987). This method used for seismic analysis involves sequence, facies, and attribute analysis (Selley, 1997).

4.2.1 Sequence analysis, facies analysis and attribute analysis.

Sequence analysis involves the definition of the sequence boundary.

Facies analysis is the description and geological interpretation of the seismic reflections, and it includes analysis of the continuity, configuration and amplitude of the reflectors. All of these parameters give an indication of the lithology and environment of deposition of the sediments (Selley, 1997).

Attribute analysis is concerned with the analysis of the wave shape, continuity, amplitude and polarity, all of which may indicate the thickness, nature of the top and bottom of a sand bed, as well as the vertical changes in the rock properties (Selley, 1997).

For the scope of this study, a detail analysis of the above parameters was not done but an attempt was made to interpret the seismic data based on these parameters as follows. Generally, the D-01 reservoir interval comes out as a thin interval, and the reflectors that define the top and bottom of the reservoir are laterally parallel to sub-parallel and continuous, becoming chaotic and hummocky towards the edges at the southeast end of the field.

On a sequence analysis basis (figure 4.2, which is a seismic section of one of the selected cross-lines interpreted) the reflectors defining the top and bottom of the D-01 reservoir can be said to show parallel seismic reflection configuration, characterized by moderate/high amplitude, and show good continuity (Boyd *et. al.*, 1993). The reflection patterns exhibited by the D-01interval in the WND field is interpreted to be prograding sets, exhibiting the typical prograding delta character of parallel and continuos reflectors with gentle discontinuities. The prograding clinoforms recognised are interpreted to represent the progradation of the basin margin slope system into deep water (Selley, 1997).

The reservoir as indicated by the character of the bounding reflectors based on a facies analysis basis (figure 4.3) shows that the environment of deposition of the sediments is from shoreline in the north-west end to shelf environment in the south-east end of the field. Based on attribute analysis, the bounding reflectors can be said to have moderate to high amplitude and continuity.

The high amplitude reflections of the top and base of the D-01 reservoir look quite continuous (figure 4.2 and 4.3), however on closer inspection gentle terminations and discontinuities can be recognised within this interval. These discontinuities are observed at the Northwest, Southeast, Northeast and Southwest ends of the field, and are interpreted to be most likely due to channelling and faulting.

4.3 Mapping Methodology

After the seismic sections were interpreted hand-drawn contour maps of two way time of each horizon, top and base D-01 reservoir were produced. In making the contour map from the picked seismic sections, measurement of two-way time to the picked horizons along each line sections was made. These two-way times were then posted on to the shot-point map of the survey area to produce contour maps of structure in two-way time of both the top and base of D-01 reservoir.

After contouring was completed, it was checked against the original seismic sections, especially in the vicinity of closed highs and in areas of faulting to see if they may be of hydrocarbon significance (Mcquillin et. al., 1984). These hand-drawn contour maps were constructed just to have a feel of the structure of the horizons. The main structure contour map in time for the top and base of the D-01 reservoir (figure 4.4 and 4.5) were constructed from 2-D grid lines constructed for both horizons using EARTHVISION software.

4.3.1 Time to Depth Conversion

Time to depth conversion operations was done on the two-way time 2-D grids for the top and base horizons in the formula processor window in the utilities menu of Earth-vision using the formula:

Depth = two-way time / 2*1000*average velocity
Where:
Two way time = the node at each cell of the 2-D grid lines.
Average velocity = 7120 and 7190 ft/sec for the top and base horizons respectively.
1000 = conversion factor to convert millisecond to seconds.

Average velocities of 7120 and 7190 ft/sec were used for this calculation because the check-shot data available for this study shows that average velocity increases with subsea depth. Depth structure contour maps for the top and base horizon of the D-01 reservoir were constructed from the resultant 2-D grids from the conversion operations (figures 4.6 and 4.7).

4.3.2 Structural boundaries and reservoir extent

Although it was difficult to map the faults on the scale of the seismic sessions available for interpretations, an attempt was made to interpret and map the faults and channels bounding the D-01 reservoir. From this interpretation and mapping process a polygon was constructed, which represents the map of all boundaries and extent of the D-01 reservoir. This polygon was used to limit/clip the 2-D grids constructed for the top and base horizons to define the extent of the reservoir, before they were contoured. The clipping were done by assigning null values to all the data points outside the limiting polygon.

4.3.3 Contour Maps

Contour maps constructed in this study include structural contour maps for the top and base D-01 reservoir in time and depth, (figures 4.4 to 4.7), isopach, net-isopach, reservoir thickness defined by the oil-water contact. The structure maps and contour maps in depth of the top and bottom D-01 reservoir constructed, revealed that the D-01 reservoir occurs in two lobes, at the north-west and south-east portions of the field. The anticlinal lobes can be clearly seen in the 3-D view of the above contour maps in figures 5.2 and 5.3. Production data shows the north-west lobe to be more productive so far. The OWC is always above the bottom of the reservoir across the field. The top of the reservoir is below the OWC in the middle of the map. This shows OWC determined in one well may not be applicable across the field. WND-02 in the NW lobe have shales at depth approximating the OWC and the value for the LKO and HKW bracket the OWC determined in WND-01, therefore this OWC is a reasonable estimate.

4.3.4 Isopach maps and interpretations

Isopach maps are graphic representations of the vertical thickness of the reservoir rock. They can also be referred to as lines joining points of equal thickness (Badley, 1985). Isopach maps were constructed to show the thickness and the net thickness of the D-01 reservoir (figure 4.8 and 4.10). The construction of the isopach map was achieved by subtracting the base horizon 2-D grid from the top horizon 2-D grid, and the resultant 2-D grids was then contoured to get the thickness. The net-isopach map was derived from the isopach by multiplying it with the net to gross ratio.

The isopach map was used to predict the direction of sediment transport, and hence served as a guide to predicting potential reservoir properties (Badley, 1985). From the isopach maps thickly developed sandstone areas can be identified, such as in the middle of the field and that area is recommended for development.

As shown on the isopach map (figure 4.8) at the top structure of the D-01 reservoir sand, outside the contour of the oil-water contact all the sand will contain water. The oil water contact cannot be seen on the base structure of the sand. As seen from the contour map of the thickness defined by the oil-water contact (figure 4.9) which can also be referred to as the net thickness map, the first zero line for the isopach corresponds to the oil-water contact or the down-dip limits of the oil-water contact (Laudon, 1996). All the areas below this line have been assigned zero values. The isopach maps were also used for volumetric reserve estimates because they overlay the structure contour maps and represent the vertical thickness of the rock volume saturated with oil (Laudon, 1996).

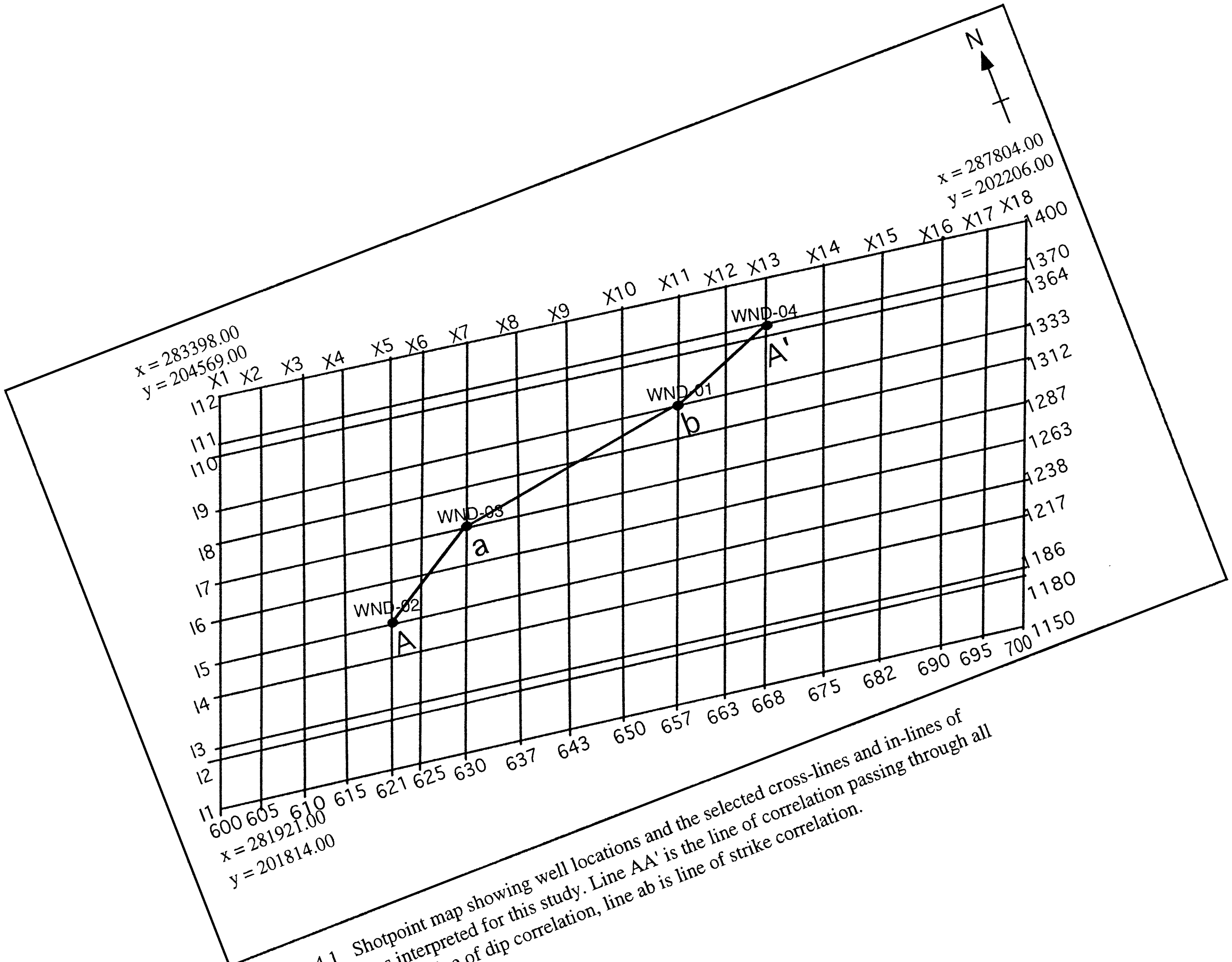


Figure 4.1 Shotpoint map showing well locations and the selected cross-lines and in-lines of seismic sections interpreted for this study. Line AA' is the line of correlation passing through all the wells, line Aa is line of dip correlation, line ab is line of strike correlation.

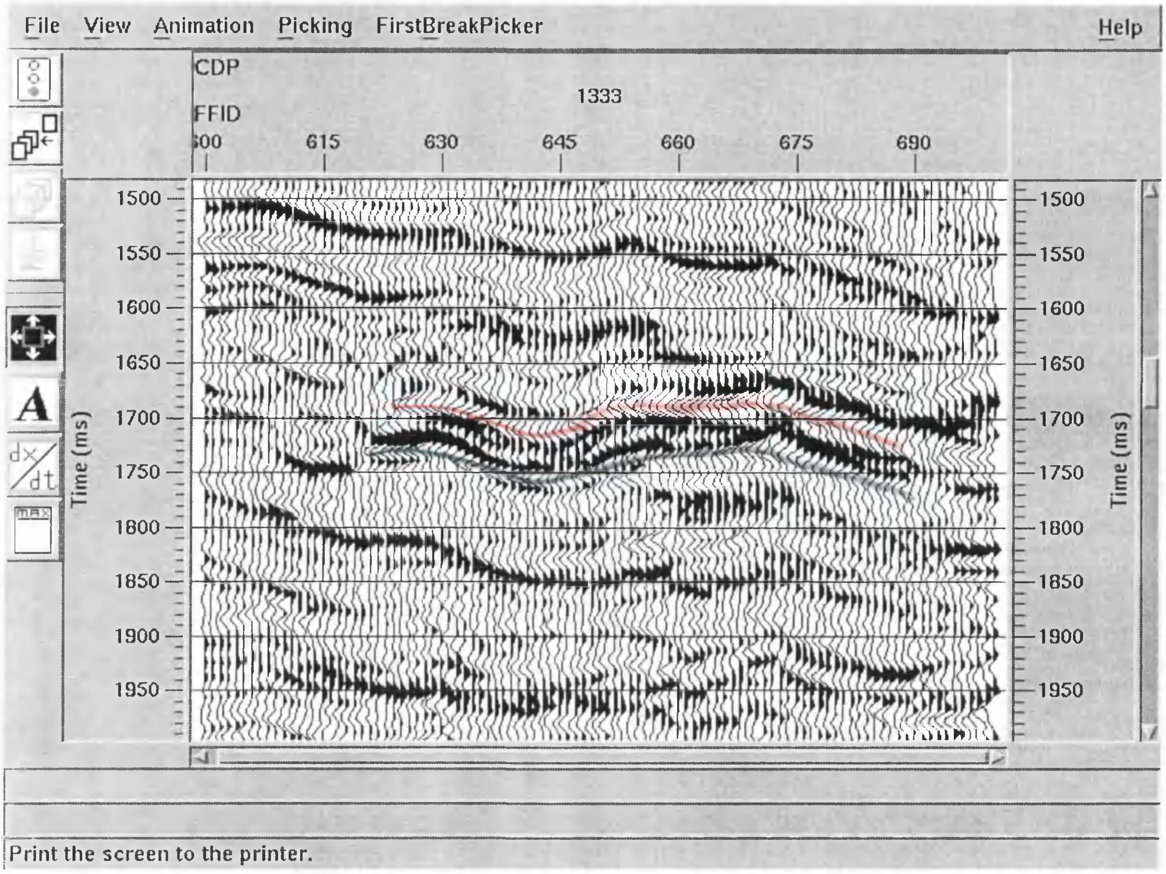


Figure 4.2 Seismic section of one of the selected in-lines interpreted for this project. The top and base horizons of the D-01 reservoir are highlighted in red and green colors respectively.

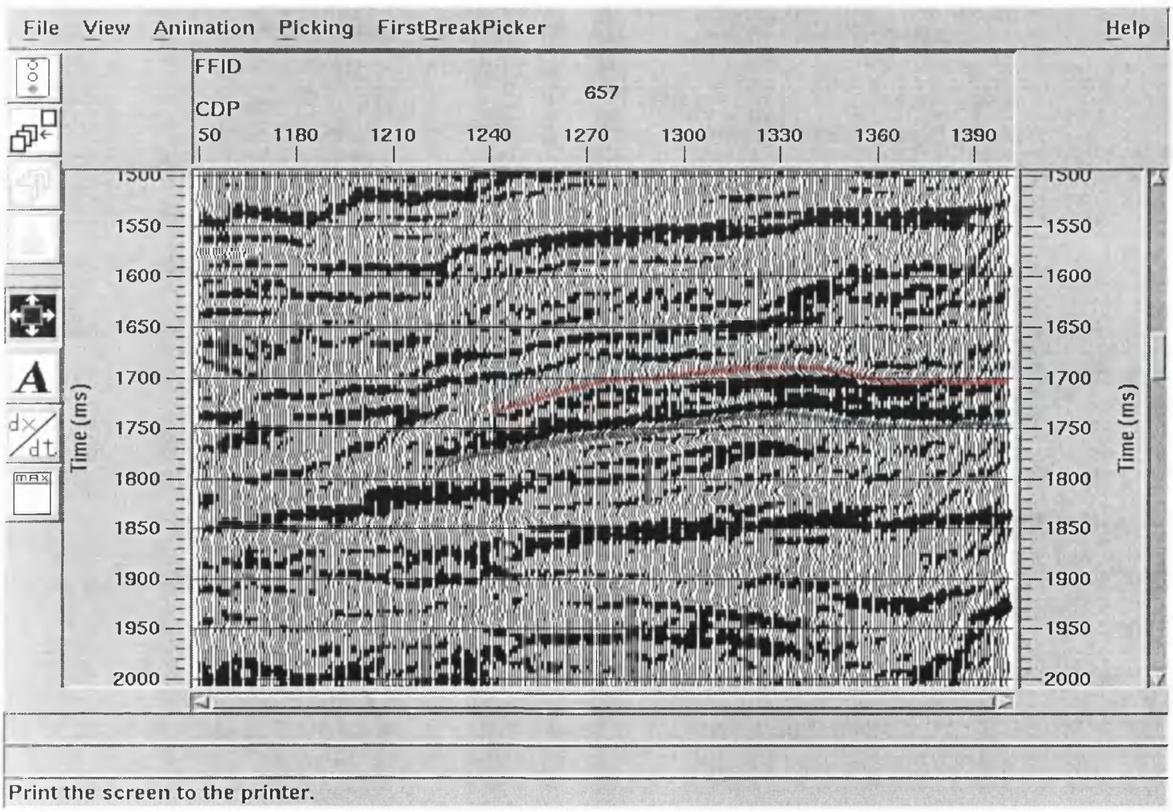


Figure 4.3 Seismic section of one of the selected cross-lines interpreted for this project. The top and base horizons of the D-01 reservoir are highlighted in red and green colors respectively.

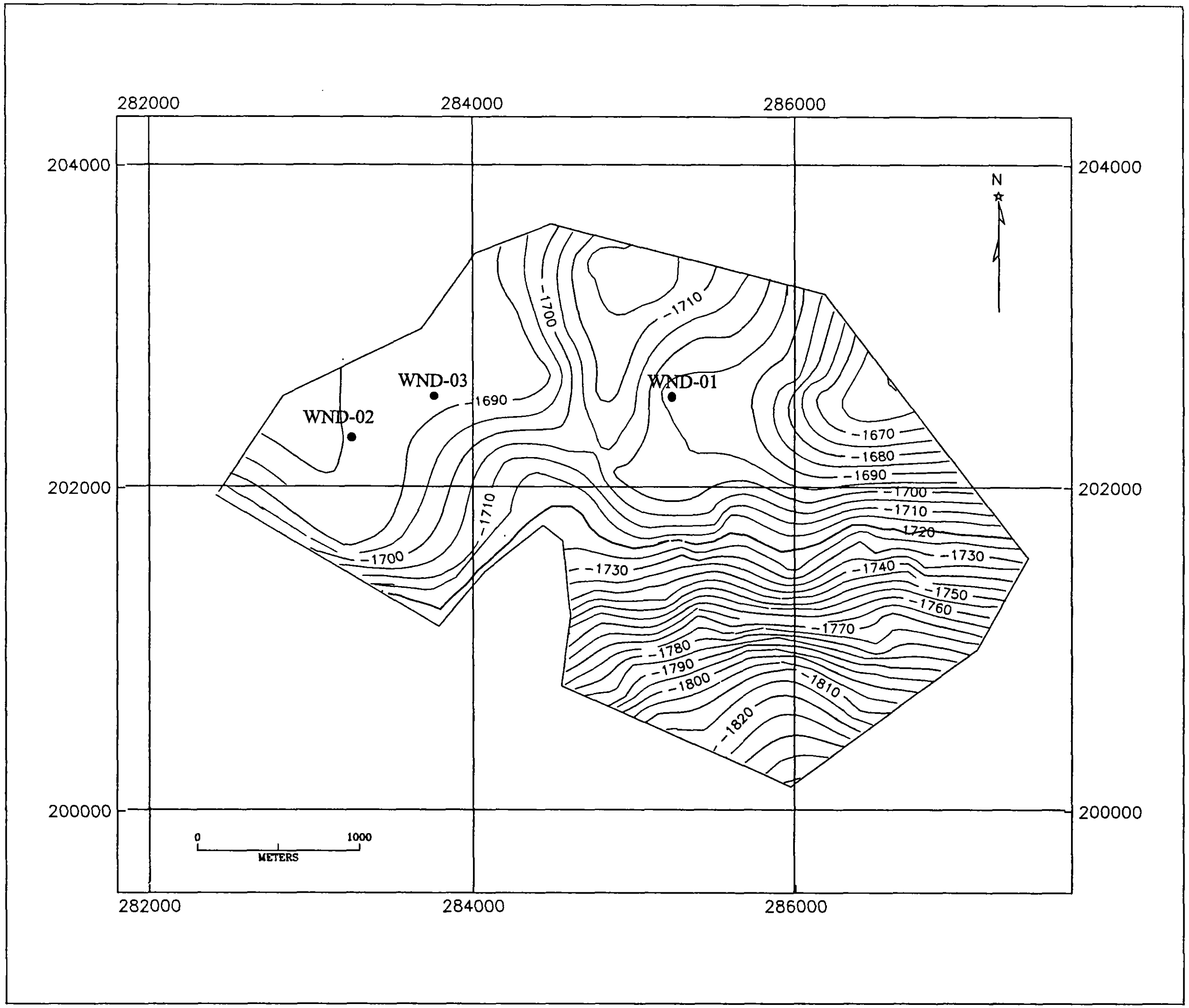


Figure 4.4 Structure contour map in time of top horizon of the D-01 reservoir. Contour interval is 5 msec.

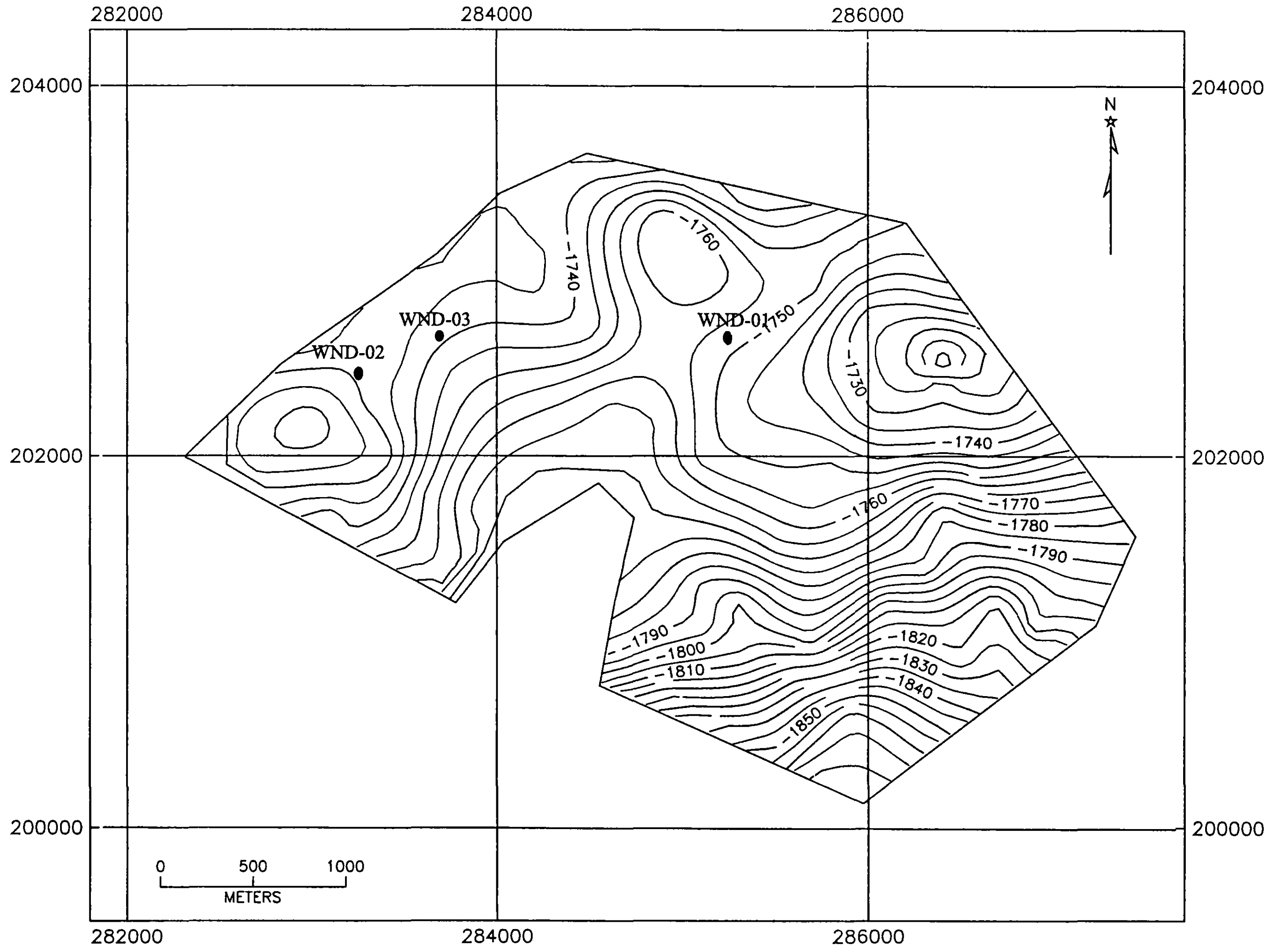


Figure 4.5 Structure contour map in time for base horizon of D-01 reservoir, contour interval is 5 msec.

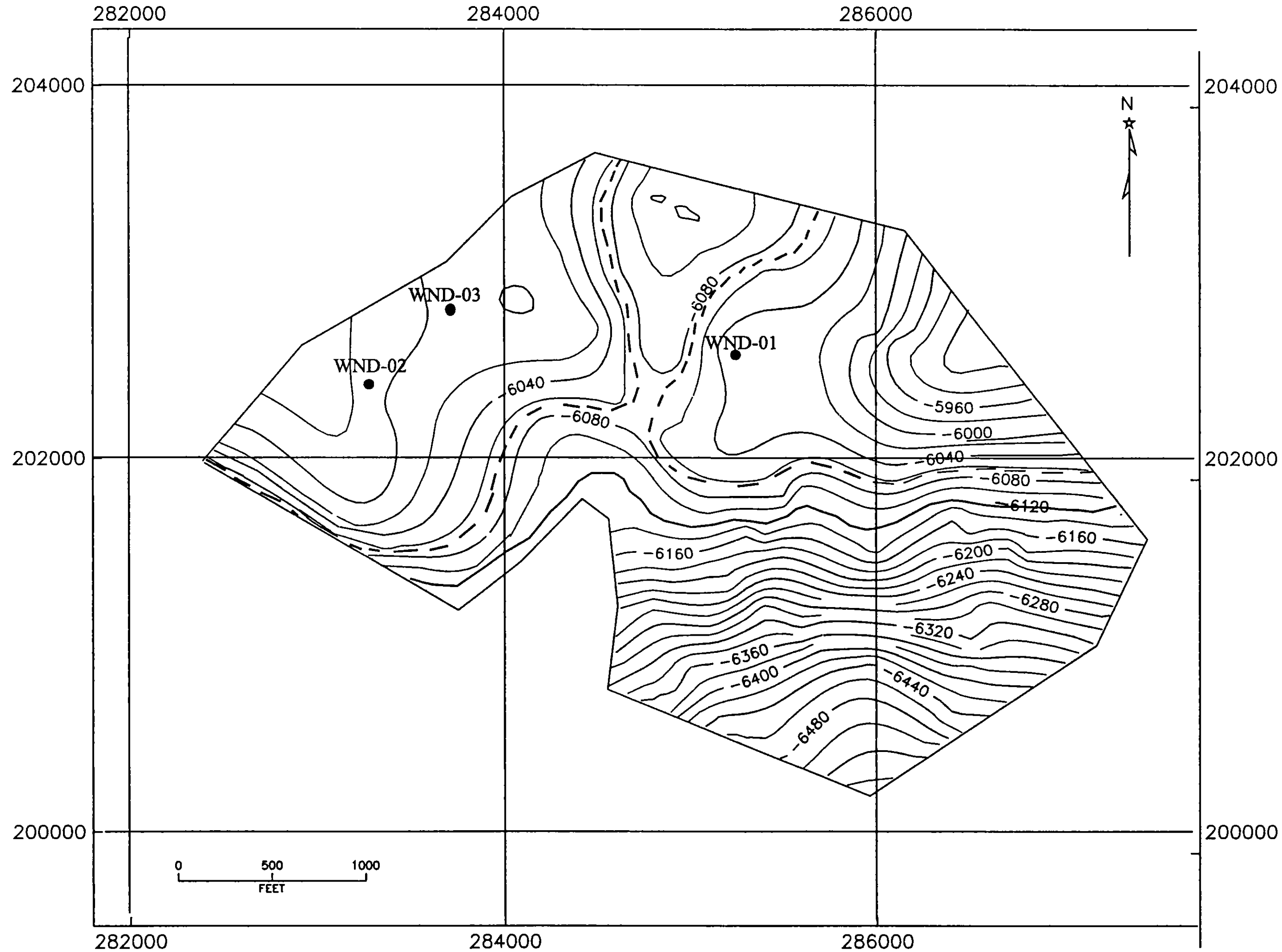


Figure 4.6 Structure map in depth of top horizon of the D-01 reservoir, contour interval is 20 feet. Broken line is the oil-water contact contour line at depth 6068.

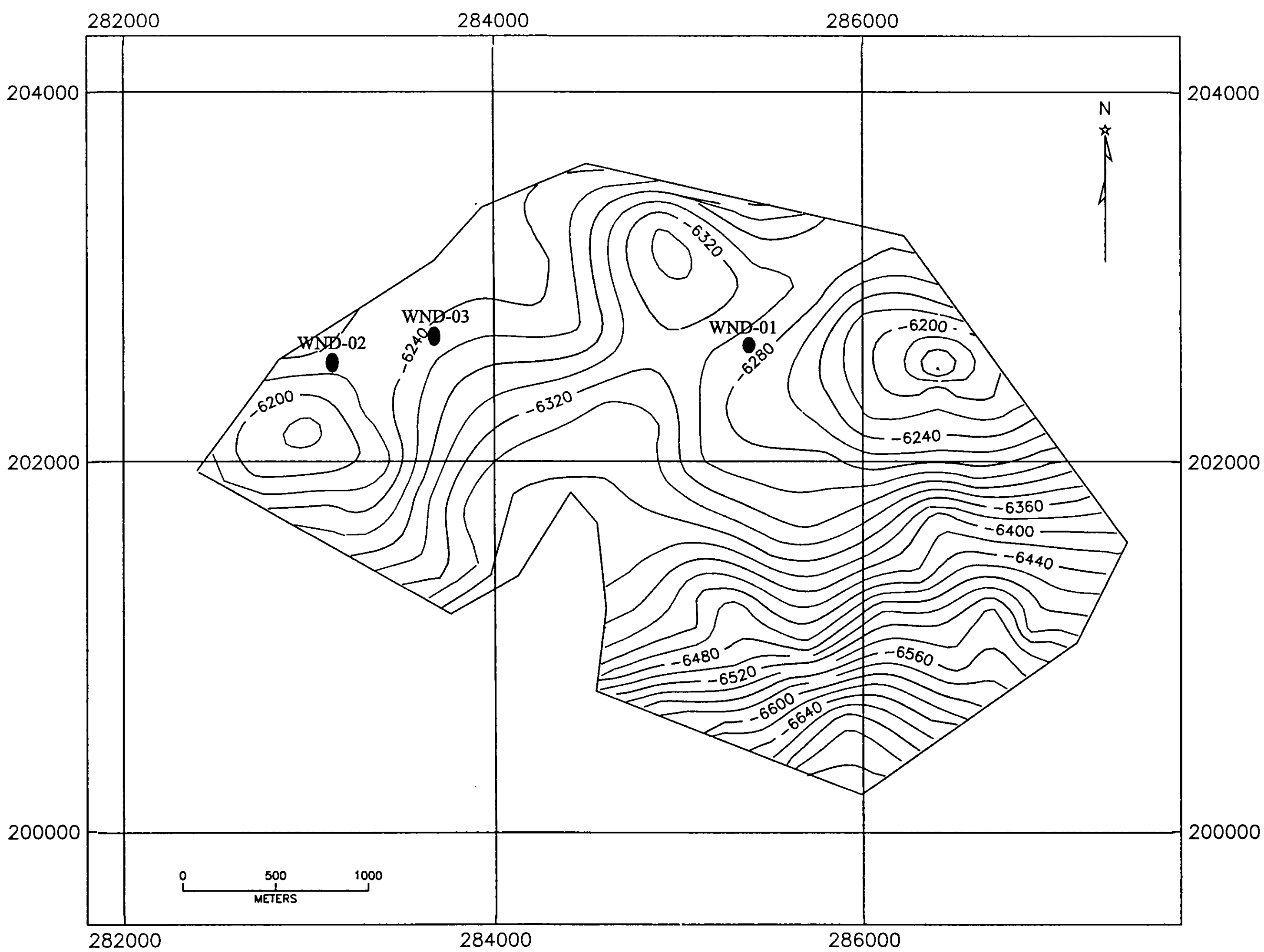


Figure 4.7 Structure contour map in depth of base horizon of the D-01 reservoir, contour interval is 20 feet.

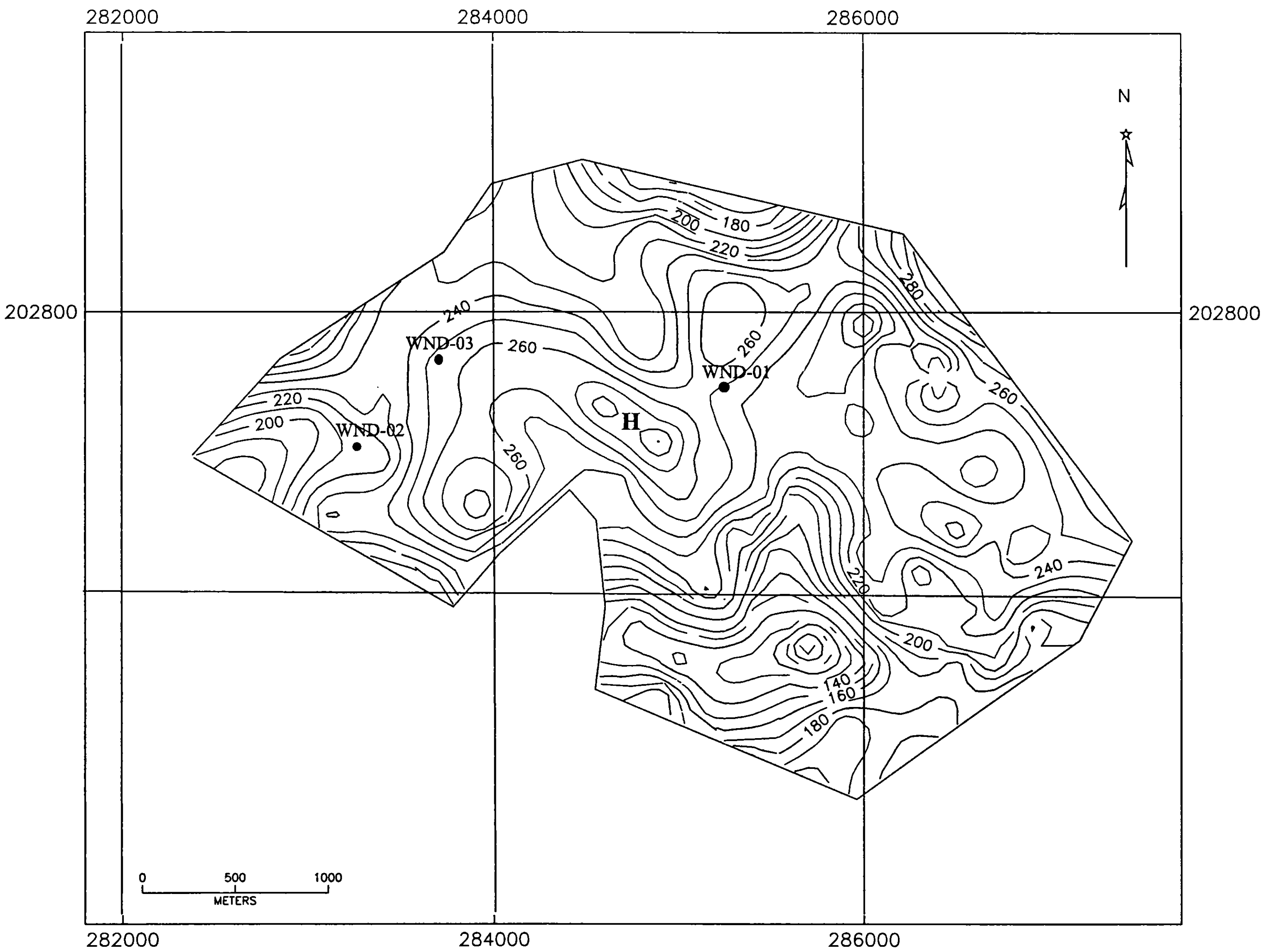


Figure 4.8 Isopach map of the D-01 reservoir, showing the thickness of the gross reservoir sand interval across the field. The sand is developed more around the middle of the field (labelled H) in the south west lobe. Contour interval is 10 feet.

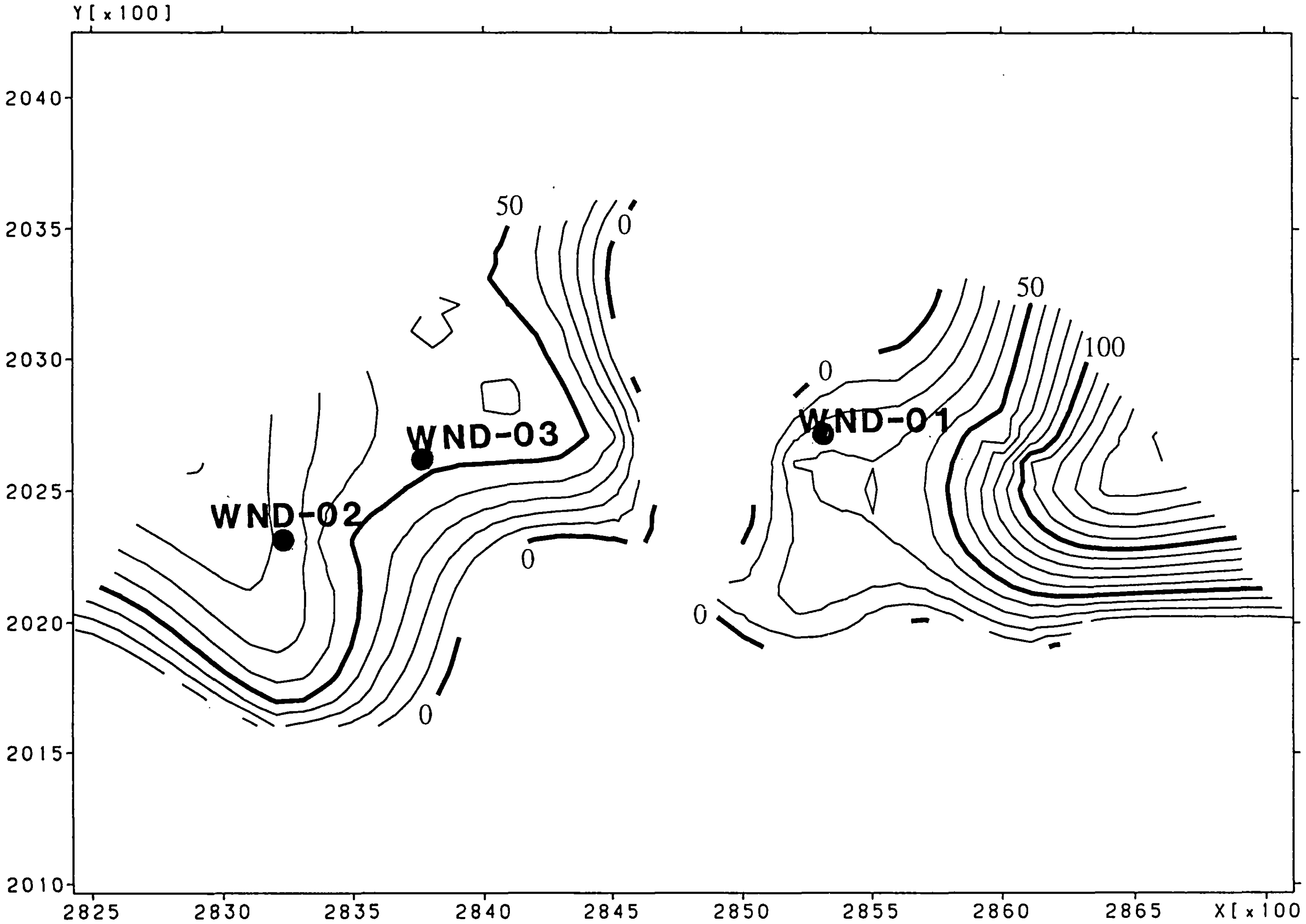


Figure 4.9 Thickness contour map of D-01 reservoir defined by the OWC. The zero contour in broken lines is the OWC contour line. The contour map shows that the reservoir is separated into two lobes, this has the implication that the OWC defined for he east lobe might not apply for the west lobe, also, the reserve estimate might be a bit different if the west lobe OWC is different.

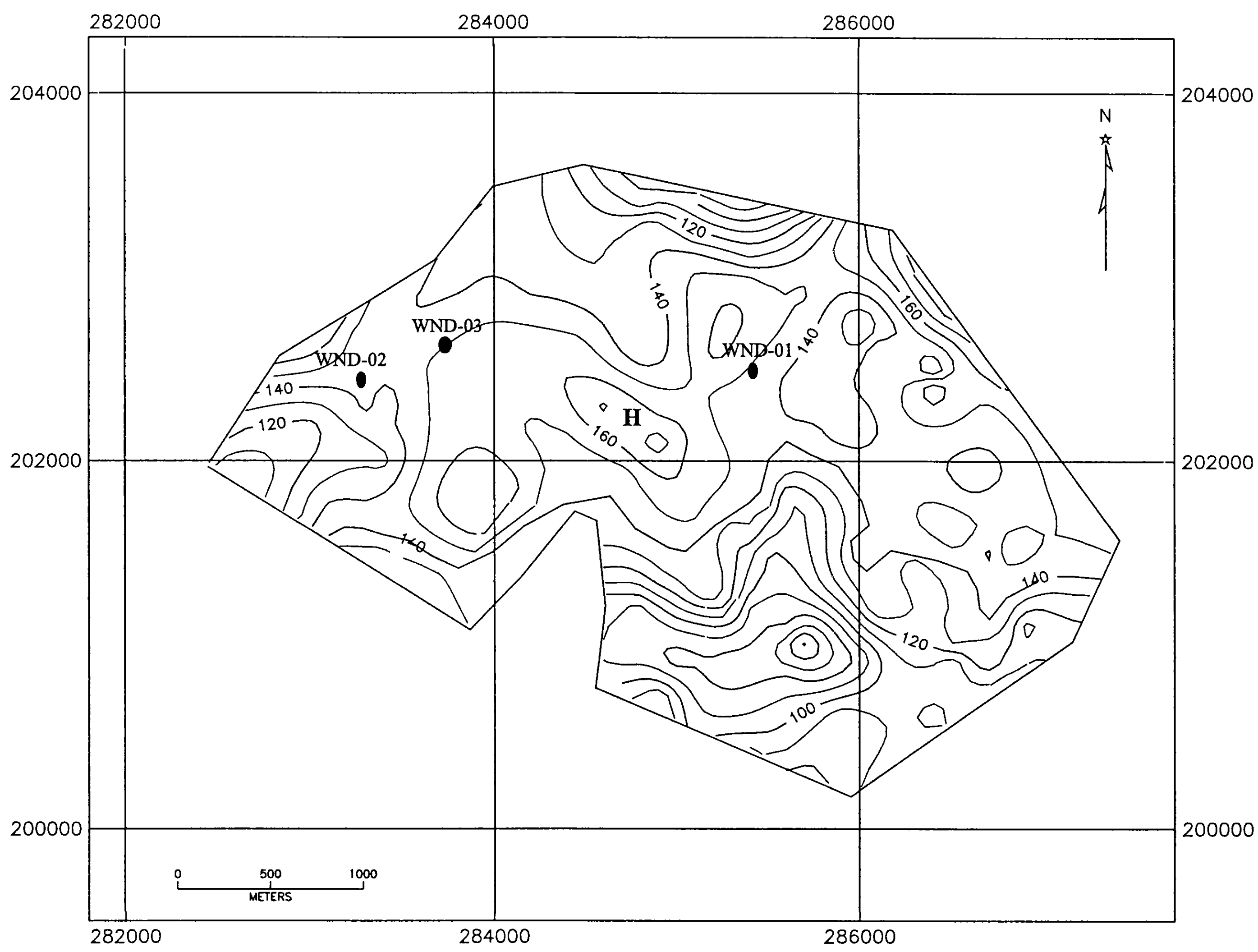


Figure 4.10 Net-isopach map of the D-01 reservoir showing the position of the area with the highest sand thickness labelled H. Contour interval is 10 feet.

Chapter Five **Geologic Reservoir Modelling**

5.0 Introduction

The major goal of reservoir characterisation is to produce a geologic model, which honours all the available data. This model is usually a three dimensional grid of the field, with the values for porosity and oil saturation placed within each cell of the grid (Geehan and Pearce, 1994).

The primary aim of constructing geological reservoir models is to estimate the amount of the recoverable hydrocarbons through the determination of the volume character and distribution of the reservoir rocks (Alexander, 1993). In order to achieve this, features of the reservoir such as the facies architecture and geometry, porosity and permeability, which will affect the production, are identified and quantified, and these have already been done in the previous chapters of this thesis.

In this final stage of this study, techniques designed to extrapolate rock lithofacies type and properties (such as porosity, water saturation and average velocity) into three-dimension, away from the well bores were utilised, and a geological model was produced which honours all the data available for the study.

The D-01 reservoir here is modelled by applying the deterministic approach, using geology, and not probabilistically, using statistics, such as the stochastic method (Weber and Van Guens, 1990; Laudon, 1996). The D-01 reservoir was modelled as two and three-dimension grid cells, with specified size and number. The two and three dimension reservoir grid cell model is filled from top to bottom with several general input data (Moss, 1990), such as:

1. Reservoir model dimension
2. Distribution of the thickness and net thickness of the reservoir
3. Average porosity and water saturation, across the field.
4. Results of calculating the volume of connecting sands

5.1 Methodology of reservoir modelling

EARTH-VISION software was used for all the 2-D and 3-D grids constructed in this study. The limited two-dimensional grids which were constructed earlier for both the top and base horizons of the D-01 reservoir in depth were the multiplied by 0.3048 to convert the depth (z) values from feet to meters. This was done to assist in volumetric calculations since the horizontal grid is metric. From these grids isopach (thickness) and net-isopach (net-thickness) grids were constructed for use in volumetric calculations.

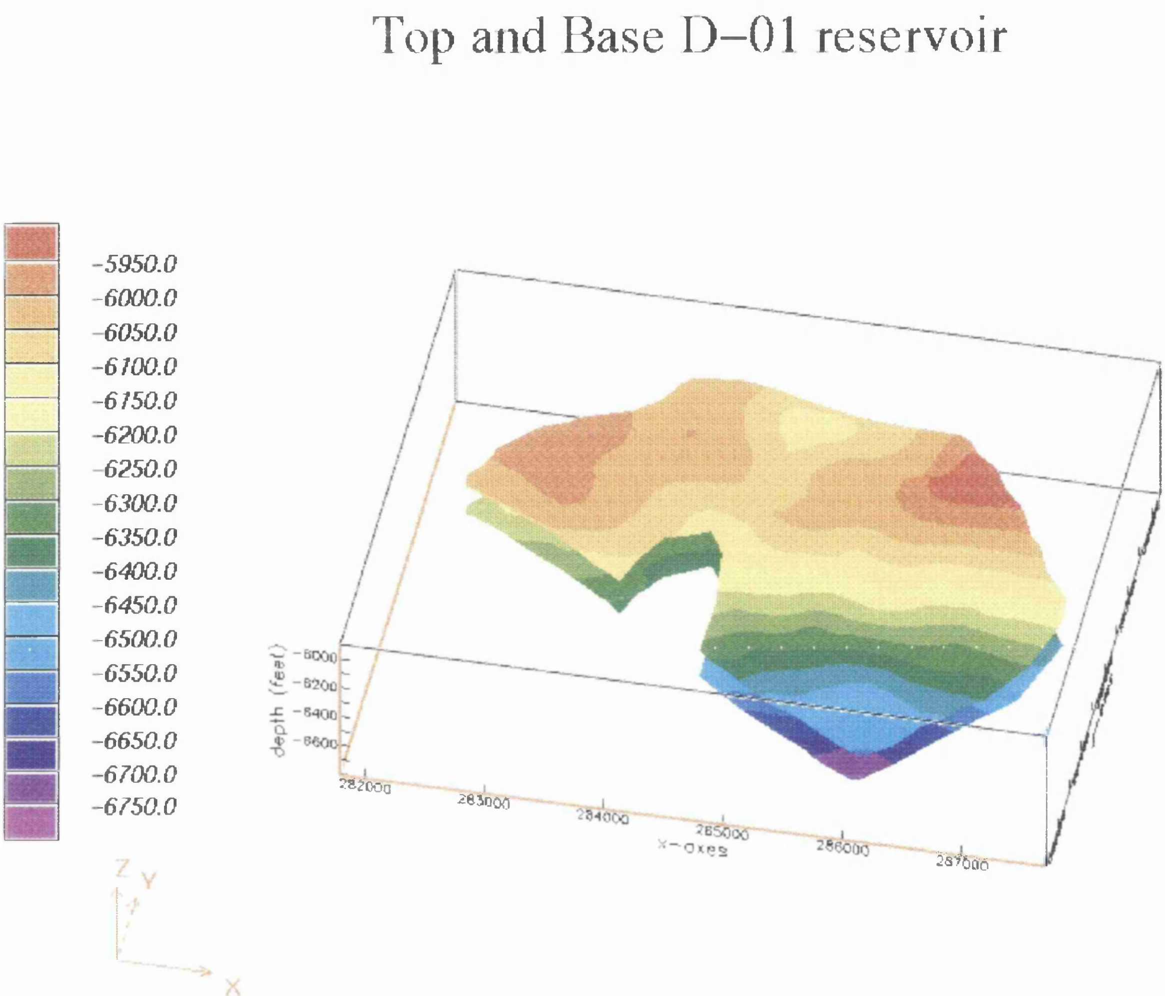


Figure 5.1 3-D view of the top and base horizons of the D-01 reservoir displayed together, with the depth contours displayed on the top.

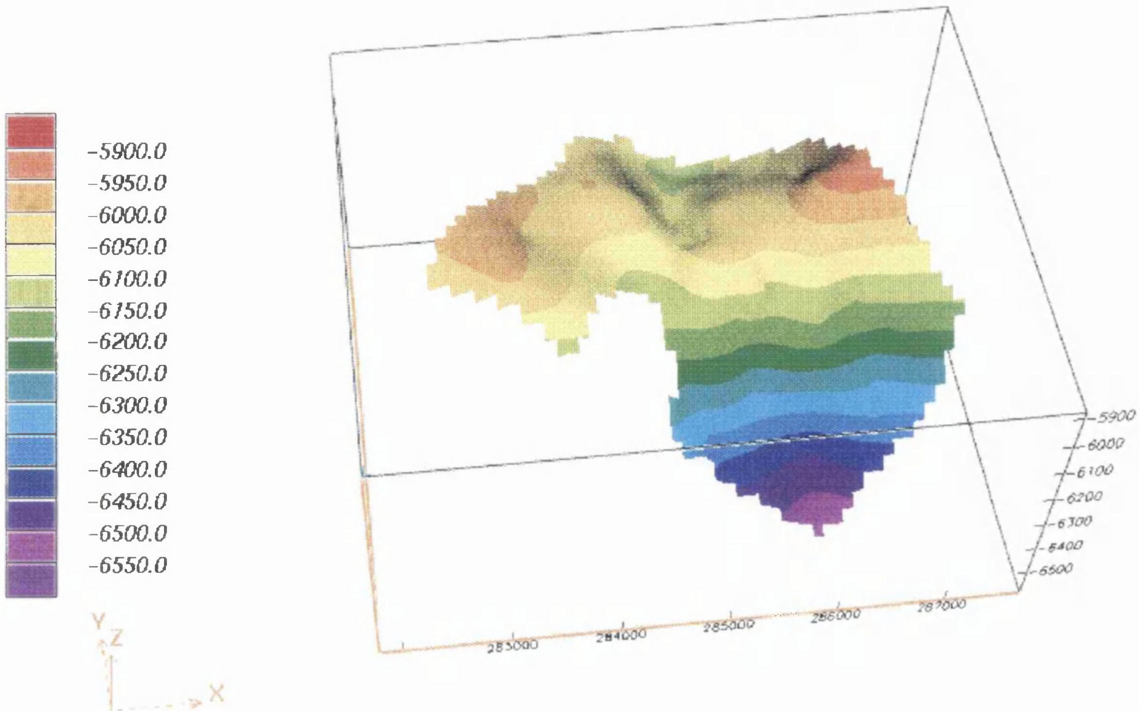


Figure 5.2 3D view of 2-D grid of top horizon D-01 reservoir with contours displayed on it, showing the two anticlinal lobes of the reservoir

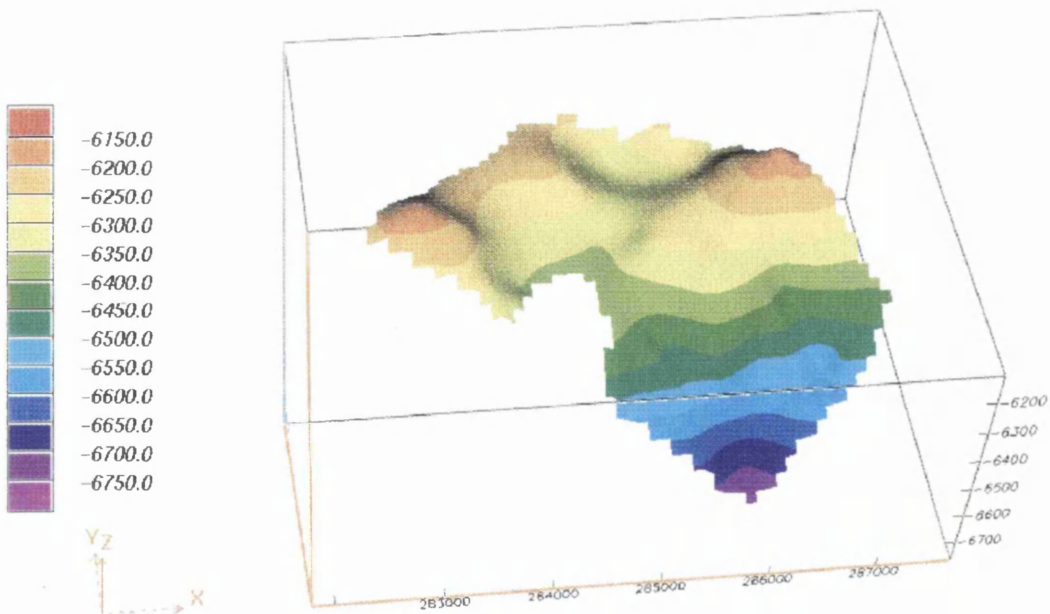


Figure 5.3 3-D view of 2-D grid of base horizon D-01 reservoir with contours displayed on it. The plot shows the two anticlinal lobes of the reservoir

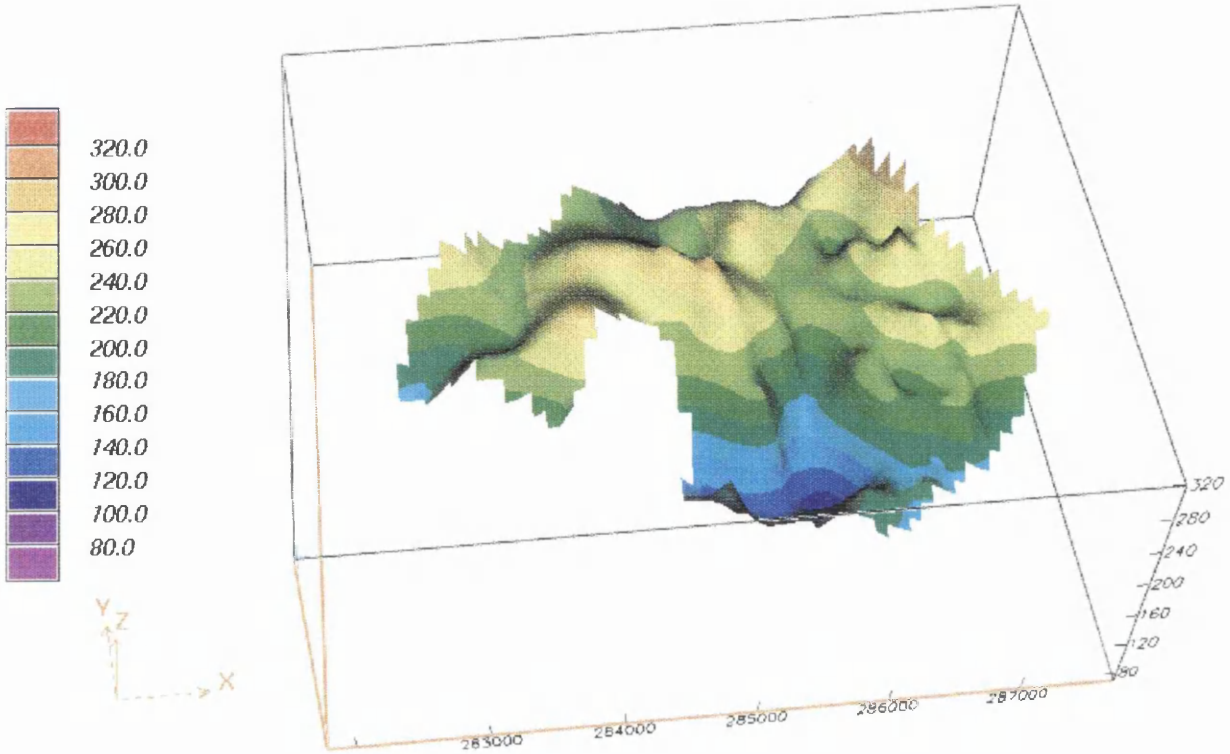


Figure 5.4 3-D view of 2-D grid of isopach map, with contours displayed on it. The area with the highest sand thickness clearly sticks out.

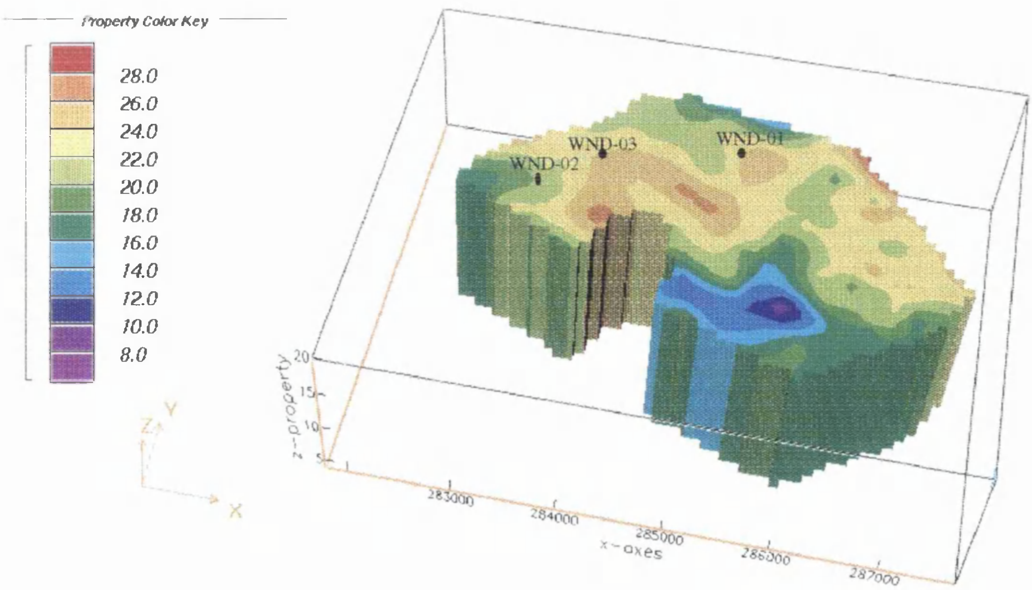


Figure 5.6 3-D geologic model of the D-01 reservoir. It shows the area with highest sand thickness at the middle of the field with red colour, implying that the highest volume of oil reserve is located in that area.

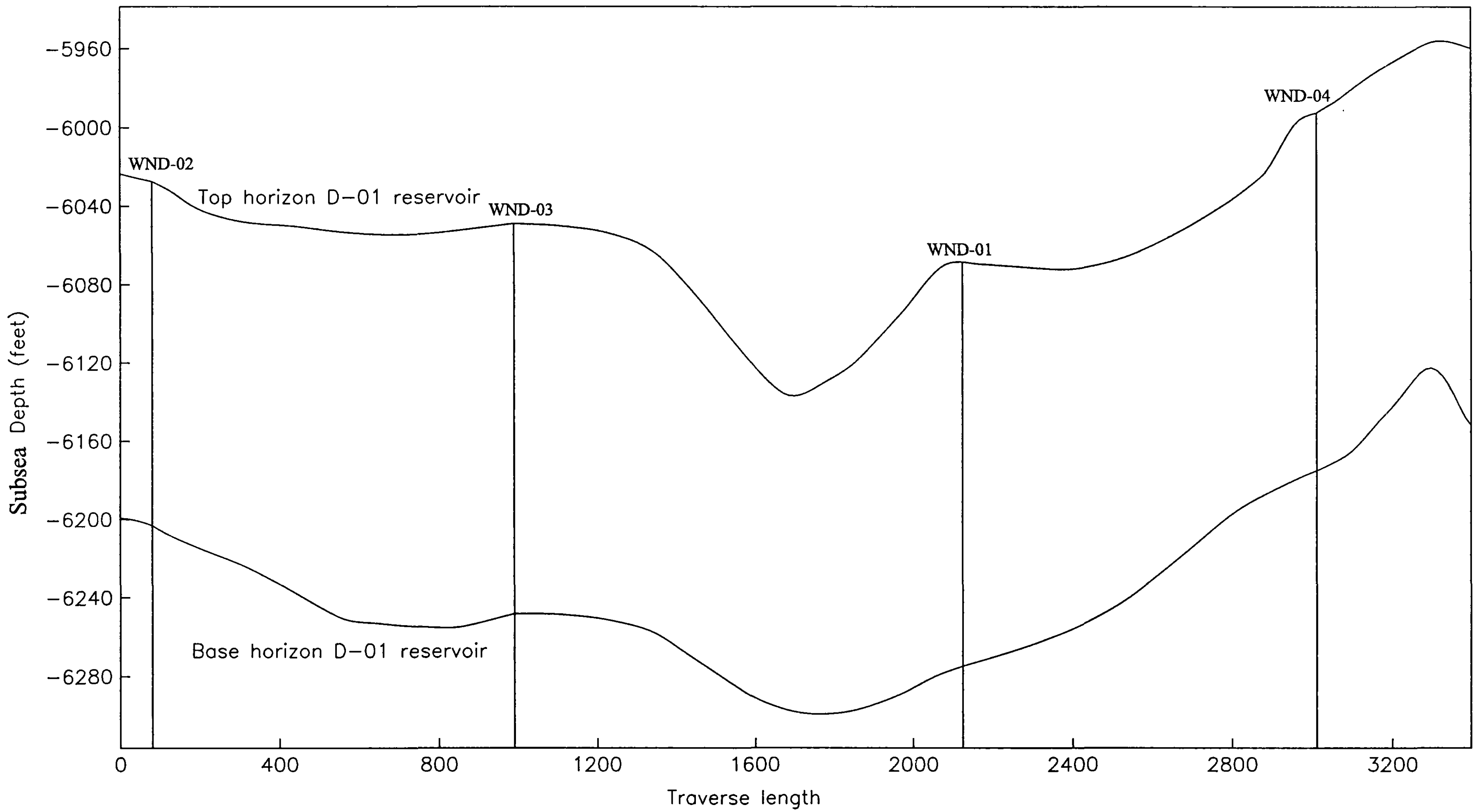


Figure 5.5 Structural cross section of the D-01 reservoir showing the top and base horizons of the reservoir, and the positions of the wells.

For this study, 2-D grids were constructed for thickness, net thickness defined by the net: gross ratio, reservoir net-thickness defined by the oil-water contact, porespace, oil-in-place, stock tank oil in place (STOOIP), and the recoverable reserve. 3-D grids were constructed from these 2-D grids, for all the above parameters using grid functions in the formula processor window in the utilities menu in EARTHVISION.
The 2-D grid constructed for reservoir thickness defined by the oil-water contact was constructed using the formula:

Thickness = maximum(top 2-D grid – OWC) – maximum(base 2-D grid – OWC).

The contour on resultant thickness 2-D grid from this operation (figure 4.9) when compared with the conventional thickness map (isopach map) is more suitable for reservoir volumetric calculations. It shows just the contours for the area of the field containing oil in the D-01 reservoir, rather than as a graphic representation of the vertical thickness of the reservoir. Three-dimensional views of the 2-D grids constructed for the top and base D-01 reservoir and isopach are shown in figures 5.1 to 5.4. A structural cross section of the D-01 reservoir (figure 5.5) was also constructed with a traverse line that passes through all the well positions in the field.

The result of the integration of cores and log data to construct a 3-D geologic model using EARTH-VISION software is a 60 by 49 by 10 grid of cells model of the D-01 reservoir, (figure 5.7) constructed to examine the reservoir architecture spatially and for volumetric purposes.

5.2 Volumetric calculations

Volumetric estimate of reserves is a method of estimating potential reserves for development purpose (Laudon, 1996). The recoverable reserve in a reservoir is the volume of oil in place that is expected to be recovered as estimated by the recovery factor. The recovery factor is dependent on many factors such as the reservoir quality, drive mechanism, well spacing, time, the recovery techniques and type of fluid recovered (Laudon, 1996).

The steps followed and formulas used to calculate the D-01 reservoir recoverable reserves is as shown in the flow chart in figure 5.7. The first step was the calculation of the rock volume (A * h), this was calculated from the net-oil isopach map made from the depth contour map defined by the oil-water contact. The oil-water contact as defined from log

Determination of rock volume — A*h

↓

Determination of the net rock thickness volume — A*h*n/g

↓

Determination of the bulk pore volume — A*h*n/g*porosity

↓

Determination of the oil in place volume — A*h*n/g*porosity*(1-Sw)

↓

Determination of the STOOIP volume — A*h*n/g*porosity*(1-Sw)*(1/Bo)

↓

Determination of the recoverable reserve — A*h*n/g*porosity*(1-Sw)*(1/Bo)*R.F*constant

Figure 5.7 Flow chart showing the general procedures and steps followed to calculate the reserves in the D-01 reservoir, as well as to produce the D-01 geologic model.

interpretations tied with seismic interpretations is 6142 ft measured depth (6068 ft subsea depth)

(Thickness = (maximum (top horizon-6068) – maximum (base horizon -6068))

Next, the net rock (thickness) volume was determined by multiplying the rock volume with the net: gross ratio (A * h *n/g), (0.64 net/gross ratio was used).

The bulk pore volume in the D-01 reservoir was calculated next by multiplying the net rock volume by the average porosity value, which is 0.3 for the D-01 reservoir. For this study a constant average porosity value was used for the whole field.
(A *h * n/g * average porosity).

Volume of oil-in-place was then calculated by multiplying the bulk pore volume by the oil saturation value (which is 1- water saturation). The average water saturation value of 0.28 calculated for the reservoir was used.
(A *h *n /g * porosity * (1-Sw)).

The stock tank oil originally in place (STOOIP) was then calculated by multiplying the volume of oil in place by the formation volume factor, Bo. A typical oil reservoir normally will have an oil formation volume factor in the range of 1.1 to 1.5 reservoir barrels/surface barrels (Laudon, 1996; Selley, 1997). A formation volume factor of 1.22 supplied by the operator of the WND field was used for this study.
(A * h * n/g * porosity * (1-Sw) *(1/Bo)).

Finally, the recoverable oil reserve was calculated by multiplying the STOOIP by the recovery factor. The recoverable factor of a reservoir is usually determined by the reservoir engineers and is dependent on amongst other factors the reservoir quality (porosity, permeability, lateral and vertical continuity). The world average recovery factor for primary oil recovery is approximately 35% (Laudon, 1996). In sandstone reservoirs the R.F is commonly of the range of 30 to 50% (Stoneley, 1995; Laudon. 1996 and Selley, 1997). Based on this, a recovery factor of 0.35 was used for this study.
(A* h * n/g * porosity * (1-Sw) * (1/Bo) * R.F * constant.

The formula used for the volumetric calculation in this study from bulk rock volume to the recoverable reserve is given below:
Recoverable reserve = A * h * n/g * porosity * (1-Sw) * (1/Bo) * R.F * constant.

Where:

A	=	area of the reservoir
h	=	reservoir interval thickness, or the net-thickness.
n/g	=	net : gross ratio (0.64 for this study)
porosity	=	0.3 for this study
Sw	=	water saturation (0.28 for this study)
Bo	=	formation volume factor (1.22 for this study)
R.F	=	recovery factor (0.35 for this study)
Constant	=	6.290 (is the conversion factor used to adjust the unit from cubic meters to barrels).

- **Volumetrics Calculation Results**

The results of the volumetric calculations done for the different parameters discussed above are as shown in figures 5.9 and 5.10, listed below are just the volumes calculated:

Rock volume	=	236,000,000 m^3
Net rock volume	=	151,040,000 m^3
Hydrocarbon pore volume	=	45,312,000 m^3
Oil in place volume	=	32,624,640 m^3
Stock tank oil originally in place	=	26,741,508 Bbls/ m^3
Recoverable reserve	=	9,359,528m^3

Multiply by 6.290 to convert cubic meters to barrels

Therefore,

Recoverable reserve	=	58,871,431 Bbls

5.3 Volumetric calculation results compared with Production data

More than 58 million Bbls of oil have been estimated from this study to be potentially recoverable from the D-01 reservoir sandstones in the WND field, but only an estimated 6,538,811 Bbls of oil have been produced from 1995 to February of 1997, implying that only a small percentage is being recovered.

Analysis of the production data available for this study (tables 5.1) shows that the north-west side of the D-01 reservoir in the WND field have better production performance than the east side; with well WND-02 having the highest production in barrels. Table 5.1 shows volume of oil produced for the individual wells from the D-01 reservoir in the WND field from 1995 to February 1997. While table 5.2 shows the cumulative volume of oil produced from the D-01 reservoir from 1995 to February 1997. It shows that there was a significant increase in the total production from 1995 to 1996. The monthly production data from the D-01 reservoir shows a decline in the volume of oil produced from January to February 1997.

Comparing the volume of the calculated recoverable reserve for the D-01 reservoir with the cumulative volume of oil already produced from this reservoir, it is shows that there is still 52,332,620 Bbls (recoverable reserve – cumulative production) of oil left to be recovered from the D-01 reservoir.

Well Name	Production (Bbls) for the D-01 reservoir January, 1995 to February, 1997	Approximate Daily Production (BOPD)
WND-01	399938.00	510
WND-02	2561304.00	3,250
WND-03	1059247.00	1,350
WND-04	2518322.00	3,200

Figure 5.1 Production in barrels for the individual well in the WND field from January 1995 to February 1997, and approximate daily production

Year	Cumulative Yearly oil Production (Barrels)
1995	2,553,168.00
1996	3,571,862.00
Feb, 1997	413,781.00
Total oil Production (barrels)	6,538,811.00

Figure 5.2 Cumulative yearly oil production from the D-01 reservoir, as well as the total oil produced from the reservoir from 1995 to February 1997.

Chapter Six Summary

6.1 Conclusions

The analysis of core descriptions, establishment of lithofacies transformation of core-derived facies to log character, the correlation of log character to non-cored wells, integration of porosity and permeability data and establishment of depositional environment form the basis for the predictive assessment of the D-01 reservoir quality and continuity.

The main objectives of this research work as listed in the beginning of this thesis in chapter one were:

- to describe the D-01 reservoir
- to find out if the D-01 sand is actually in two lobes.
- to be able to arrive at a precise oil-water contact
- to determine the extent of the field in other to optimise recovery of oil reserves
- to quantify the significant oil remaining for additional recovery beyond what is being produced at present.

In achieving these aims several approaches which integrated petrophysical and seismic data resulting in the construction of a three dimensional model were adapted.

The conclusions arrived at from this study are as follows:

1. The different rock types and their facies associations present in this reservoir have been identified and characterised by the integration of mud-log, core, log data quantitatively and qualitatively, through the detailed analysis done in chapter three. It can be concluded that beds or intervals with minimal clay content, porosity equal to or greater than 0.25, permeability equal to or greater than 150 mD, and water saturation equal to or less than 0.28 have high production potential in the WND field.

Six lithofacies have been identified from grain size, textures, sedimentary structures, trace fossils and mineralogical compositions, and they were calibrated well with the logs. These have been related to specific depositional conditions. The paleo-environmental information obtained from the cored wells have been used as a control for field wide correlation with gamma-ray and resistivity logs, and for reconstructing the depositional history of the D-01 reservoir.

By integrating lithology, log and trace fossil data, it has been possible to identify and interpret the depositional environment of the D-01 reservoir. These data indicate that the reservoir was deposited in middle to lower shoreface and open marine prodelta environment. The sediments are mainly barrier bar sandstones deposited in a wave-dominated, prograding deltaic environment with marine shales filling the channels which eroded into the barrier bar sands. Finley and Tyler (1986) have shown that laterally extensive wave-dominated delta facies, such as in the D-01 reservoir, have above average recovery efficiencies.

2. Seismic interpretation was done in this study to define the top and bottom, and to delineate the extent of the D-01 reservoir in the WND field. From the seismic interpretation and analysis done in this, it was shown that the D-01 reservoir is actually of two lobes, as seen on the time and depth structure contour maps (figures 4.4, 4.5, 4.6 and 4.7). The map of the top and bottom D-01 reservoir shows the reservoir to be separated into two isolated oil accumulations with the OWC always above the bottom of the reservoir across the field.

3. It was possible to arrive at an oil-water contact through well log and seismic interpretations aided by check-shot data. This was mapped and is shown on the top and base structure maps. The oil-water contact arrived at in this study is at 6068 subsea depth (6142 ft measured depth) and it was used to define the net-sand thickness used in reserve estimates. The OWC is always above the bottom of the reservoir across the field. The top of the reservoir is below the OWC in the middle of the map. This shows OWC determined in one well may not be applicable across the field. WND-02 in the NW lobe have shales at depth approximating the OWC and the value for the LKO and HKW bracket the OWC determined in WND-01, therefore this OWC is a reasonable estimate. With this oil-water contact it was also possible to determine the areas in the WND field that is most likely to contain oil, and the parts that will contain water.

4. The extent of the D-01 reservoir in the WND field was defined by the bounding polygon constructed from seismic interpretations done in this study, as shown on the contour maps constructed for both top and base of the D-01 reservoir.

5. The estimation of significant oil remaining for additional recovery beyond what is being produced right now was achieved through volumetric calculations done in chapter five using the software EARTHVISION. The calculation of the reserves in this reservoir was achieved by the construction of 2-D and 3-D grids, which modelled petrophysical parameters such as porosity, permeability and water saturation, and net to gross sand ratio. A 3-D geological model satisfying all the available data was the end product of the reserve estimates. All the reservoir properties calculated, such as net:gross ratio, thickness within

the geologic model can be exported for use in reservoir simulation and for reservoir management purposes.

Results of the reservoir estimates show that there is still 52,332,620 barrels of oil left to be recovered, and this can be achieved by more detail reservoir characterisation, simulation activities and improved recovery mechanisms.

6.2 Recommendations for Reservoir Management

The delineation of the D-01 reservoir character in the WND field is dependent on the recognition of genetically related depositional units (Finley and Tyler, 1986), made possible by understanding the litho-facies associations and the depositional system in the field of study, as well as doing seismic analysis and interpretations.

The litho-facies defined for the D-01 reservoir directly control the reservoir continuity, and the ultimate recovery efficiency as well as the fluid migration path. The geometries of the D-01 reservoir mapped in this study are considered to be good, as shown by the isopach maps constructed as well as the structure maps (figures 4.6 and 4.8).

The significance of the results of this study for reservoir management and field developments are as follows:

(i) The results of this study can be used for the D-01 reservoir architecture description for simulation, also for production in this field, and can be used as analog for exploration targets in nearby fields.

(ii) The D-01 sands develop more towards the middle of the field, so that area is recommended for development. The oil water contact cannot be seen on the base structure of the sand.

(iii) Over fifty million Bbls of oil remains to be recovered as indicated from the volumetric calculation results, and much of this oil is potentially recoverable, therefore additional work should be done to evaluate the placement of wells to maximise recovery of this volume of oil.

(iv) Also, core data from new and old wells will most likely refine and yield new information on rock property.

(v) Describing the reservoir is usually the area of greatest uncertainty for all reservoir simulation (Ginger et. al., 1995). But since this study is a background study to simulation it is recommended that to maintain the reliability and usefulness of the geologic model produced for simulation purpose, it should be updated as new data become available in form of core and log data from new wells, geophysical survey interpretations and general updated geologic interpretations.

(vi) The products of this reservoir characterization research are a facies model, depositional model, 2-D maps which includes structure contour maps for the top and base of D-01 reservoir, thickness, net-thickness maps, and finally, the 3-D, 60 by 49 by 10 grid of cells, geological reservoir model, of the D-01 reservoir in the WND field. This geological model can be integrated with an engineering model to form a 3-D model that will be used for simulation purposes to optimise recovery of the oils in this reservoir.

6.3 Concluding Statement.

This study has shown how the integration of petrophysical and seismic data aids in detail characterisation of a reservoir. This study have shown that the core description and analysis, wireline log interpretation, correlation, maps and three dimensional reservoir model are the geologic foundation on which reservoir management and simulation concepts can be applied.

The overall results achieved from the reservoir characterisation of the D-01 reservoir in this study have good implications for improving the oil recovery in the WND field.

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