Log interpretation in horizontal wells

Thesis submitted for the degree of
Doctor of Philosophy
at the University of Leicester

by

Stefan Eric Edward Calvert BSc (Birmingham, 1995) MSc (Durham, 1996)
Department of Geology
University of Leicester

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To my family
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Disclaimer

The comments or opinions contained within this thesis are those of the author. Comments that are referenced directly are those of authors referred to. Any inferences to equipment performance or views of any specific Oil or Service Companies should not be drawn from the contents of this thesis.
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<td>$\phi$</td>
<td>Fraction, Percentage or pu</td>
<td>Porosity</td>
</tr>
<tr>
<td>$\mu$</td>
<td>cP</td>
<td>Viscosity of the fluid</td>
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<tr>
<td>$\gamma$</td>
<td>Hz</td>
<td>Ratio of the Larmor frequency to the magnetic intensity</td>
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<tr>
<td>$\xi$</td>
<td>MeV</td>
<td>Energy lost in a typical collision</td>
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<td>$\phi_{D(Lime)}$</td>
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<td>$(\rho_i)_e$</td>
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<td>Mud filtrate viscosity</td>
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<td>$\phi_{N(corrected)}$</td>
<td>pu</td>
<td>Chart corrected neutron porosity</td>
</tr>
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<td>$\phi_{neutron for the appropriate matrix}$</td>
<td>Fraction, Percentage or pu</td>
<td>Neutron porosity for the appropriate matrix</td>
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<td>pu</td>
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<td>$\phi_{DS}$</td>
<td>pu</td>
<td>Shale neutron porosity</td>
</tr>
<tr>
<td>$\rho_{oil}$</td>
<td></td>
<td>Surface relaxivity of oil</td>
</tr>
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</table>
Nomenclature

\( \rho_s \) \( g/cm^3 \) Density value measured at the short spaced detector

\( \rho_{sh} \) \( g/cm^3 \) Shale density

\( \rho_{sur} \) \( g/cm^3 \) Surface relaxivity

\( \Delta t \) mSec Travel Time

\( \Delta t_f \) mSec Fluid travel time

\( \Delta t_m \) mSec Matrix travel time

\( \Delta t_{sh} \) mSec Shale travel time

\( \rho_x \) \( g/cm^3 \) Density of the appropriate material

\( a \) Empirical constant

\( A \) Mass number

\( A, B, C \) Empirical constants

\( Al \) Aluminium

\( AmBe \) Americium and Beryllium

\( API \) American Petroleum Institute

\( B \) Barns \( (10^{-24} \text{ cm}^2) \)

\( BHA \) Bottom hole assembly

\( BP \) British Petroleum Amoco ACRO

\( C \) Carbon

e electron

\( G \) Spatial gradient of the magnetic field intensity

\( Gd \) Galdanium

\( G_{fr} \) dynes/cm\(^2\) Dry frame shear modulus

\( GM \) Geiger-Müller

\( GR \) API Gamma Ray

\( GR_{sand} \) API Sand gamma ray count

\( GR_{shale} \) API Shale gamma ray count

\( G_x \) dynes/cm\(^2\) Shear modulus of the appropriate material

\( h \) Feet or metres Formation thickness

\( He \) Helium

\( H_{Formation} \) per cm\(^3\) Concentration of hydrogen atoms in the formation

\( HI \) Hydrogen index

\( hr \) hour

\( H_{Water} \) per cm\(^3\) Concentration of hydrogen atoms in water

\( Hz \) Hertz

\( I \) Gamma ray intensity

\( I_{LD} \) Ohm-m Deep induction resistivity

\( I_{LM} \) Ohm-m Medium induction resistivity

\( I_o \) cps Initial gamma ray intensity
<table>
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<th>Symbol</th>
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<td>K</td>
<td>Potassium</td>
</tr>
<tr>
<td>k</td>
<td>Constant of proportionality</td>
</tr>
<tr>
<td>kppm</td>
<td>One thousand parts per million</td>
</tr>
<tr>
<td>KCl</td>
<td>Potassium Chloride</td>
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<td>Kf</td>
<td>Formation permeability</td>
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<td>Dry frame bulk modulus</td>
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<td>Ky</td>
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<td>K_b</td>
<td>Bulk modulus of the appropriate material</td>
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<tr>
<td>L</td>
<td>Diffusion length</td>
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<td>lbm/gal</td>
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</tr>
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<tr>
<td>B/e</td>
<td></td>
</tr>
<tr>
<td>Ca</td>
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<tr>
<td>CAL2</td>
<td>cm or in</td>
</tr>
<tr>
<td>CALI_DEN</td>
<td>cm or in</td>
</tr>
<tr>
<td>CALLISTO</td>
<td></td>
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<tr>
<td>CDN</td>
<td></td>
</tr>
<tr>
<td>CP</td>
<td>pu or fraction</td>
</tr>
<tr>
<td>CPOR</td>
<td>pu or fraction</td>
</tr>
<tr>
<td>cps</td>
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</tr>
<tr>
<td>Abbreviation</td>
<td>Description</td>
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<td>--------------------------------------------------</td>
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<tr>
<td>CR</td>
<td>Count rate</td>
</tr>
<tr>
<td>Cs\textsuperscript{137}</td>
<td>Cesium\textsuperscript{137}</td>
</tr>
<tr>
<td>D</td>
<td>Molecular self-diffusion coefficient</td>
</tr>
<tr>
<td>DCAL</td>
<td>Differential caliper</td>
</tr>
<tr>
<td>DDS</td>
<td>Drillstring dynamics sensor</td>
</tr>
<tr>
<td>DEN</td>
<td>Density log or density value</td>
</tr>
<tr>
<td>DenPor</td>
<td>Density porosity</td>
</tr>
<tr>
<td>DRHO</td>
<td>Density correction</td>
</tr>
<tr>
<td>DT</td>
<td>Acoustic travel time</td>
</tr>
<tr>
<td>DTCO</td>
<td>Compressional acoustic travel time</td>
</tr>
<tr>
<td>DTST</td>
<td>Stoneley travel time</td>
</tr>
<tr>
<td>Dw</td>
<td>Dimensionless well spacing</td>
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<td>DWS</td>
<td>Short spaced count rate</td>
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<td>EWR</td>
<td>Electromagnetic wave resistivity</td>
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<td>Fe</td>
<td>Iron</td>
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<td>Frac.</td>
<td>Fraction</td>
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<td>Gas oil contact</td>
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<td>GPDEN</td>
<td>Gaymard &amp; Poupon density values</td>
</tr>
<tr>
<td>GPNEUT</td>
<td>Gaymard &amp; Poupon neutron values</td>
</tr>
<tr>
<td>HC</td>
<td>Hydrocarbon</td>
</tr>
<tr>
<td>IOC</td>
<td>Irreducible oil water contact</td>
</tr>
<tr>
<td>LADN/LAD\textsubscript{P}</td>
<td>LWD average density and neutron porosity</td>
</tr>
<tr>
<td>LAP\textsubscript{P}</td>
<td>LWD average density porosity</td>
</tr>
<tr>
<td>LARES</td>
<td>LWD amplitude resistivity</td>
</tr>
<tr>
<td>LARHOB</td>
<td>LWD average density porosity</td>
</tr>
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<td>LCALI</td>
<td>LWD caliper</td>
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<td>LDRHO</td>
<td>LWD density correction</td>
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<td>LGR</td>
<td>LWD gamma ray</td>
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<td>LWD photoelectric factor</td>
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<td>LWD phase resistivity</td>
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<td>LWD resistivity</td>
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<tr>
<td>LROP</td>
<td>LWD rate of penetration</td>
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<td>MMstb</td>
<td>Million stock tank barrels</td>
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<td>Limestone neutron porosity</td>
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<td>NPHI\textsubscript{S}</td>
<td>Sandstone neutron porosity</td>
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Nomenclature

OC          Oil Company (values)
OC_AcouPor  Oil Company acoustic porosity
OC_DenPor   Oil Company density porosity
OWC         Oil water contact
PCL         Pipe conveyed logging
ppb         Pounds per barrel
QUAL        g/cm³  Density correction

r 0.01 (-)  Statistical significance at negative values to 99%
            confidence level
r 0.01 (+)  Statistical significance at positive values to 99%
            confidence level
r 0.05 (-)  Statistical significance at negative values to 95%
            confidence level
r 0.05 (+)  Statistical significance at positive values to 95%
            confidence level
r(L)        Autocorrelation function
ROPS        ft/hr or m/hr  Rate of penetration
Rt          Ωm  True resistivity
RT_SHIFT    Ωm  Shifted true resistivity values
SDS         cps  Standard deviation of short spaced count rate
SGR         API  Uranium free gamma ray
SQ_HC       Square root with hydrocarbon corrections
SQ_P        pu or fraction  Square root porosity
SQPOR       pu or fraction  Square root porosity
WAP         pu or fraction  Wireline acoustic porosity
WCALI       cm or in  Wireline caliper
WDN         pu or fraction  Wireline density and neutron porosity
WDP         pu or fraction  Wireline density porosity
WDT         μsec/ft  Wireline acoustic travel time
WGR         API  Wireline gamma ray
WILD        Ωm  Wireline deep induction
WILM        Ωm  Wireline medium induction
WNP          pu or fraction  Wireline neutron porosity
WP_HC       Wiley & Patchett hydrocarbon corrected
WP_P         pu or fraction  Wiley & Patchett porosity
WPPOR       pu or fraction  Wiley & Patchett porosity
WPEF        B/e  Wireline photoelectric factor
WRHOB       g/cm³  Wireline density
x            cm  Source to detector spacing
Chapter 1: Introduction

1.1 Horizontal Well Porosity Anomalies

Horizontal well porosity log data is often anomalous when compared with vertical well porosity log data through the same formation, typically resulting in increased porosity values (notably density), although the first example in this thesis demonstrates decreased porosity values in the horizontal well examined. Several causes can be proposed, such as: permeability anisotropy leading to irregular invasion and variable water saturation above and below the borehole (Woodhouse et al. 1991; Cuddy et al. 1994), differential stress, micro-fractures and disturbed tool placement (Austin et al. 1994; Cuddy et al. 1994), debris (Cuddy et al. 1994) and bed boundary dip (White 1991). The well data are the best information available that can shed light on these porosity anomalies hence there is a need to assess which logs provide acceptable porosity estimates.

1.2 A history of horizontal wells

The beginnings of the modern oil industry can be dated to Edwin Drake’s discovery on Sunday 28th August 1859 (Howarth 1997), in Oil Creek, near Titusville, Pennsylvania, where a 69½ foot well produced oil. However, the Chinese had been producing oil for over 2000 years and gas for over 3000 years with wells reaching 3500 feet with only bamboo poles with brass attachments. Drake’s motivation was to produce lamp fuel, since oil was safer than other available forms of lighting at the time. However, Drake died in 1880 nearly penniless as the oil price fell from $20 to 10c a barrel in the two years since he first produced oil, due to over production and the inability of the oil lamp manufacturers to meet demand.

The first published report of a modern horizontal well was in 1939 (Ranney 1939), but horizontal wells had been drilled in the 1920’s. Again, horizontal wells were not a new idea and had been used by the Greeks, Persians and Egyptians for water extraction more than 2500 years ago (Nurmi 1995). In southeast England 7500ft long horizontal tunnels were dug into the chalk for water extraction (Nurmi 1995).
Chapter 1: Introduction

However, it was not until the late 1980's that horizontal wells were drilled to any great extent. Since then the numbers have increased dramatically especially throughout the 1990s [Figure 1.1](Nurmi 1995).

Horizontal wells are now commonplace and often form an integral part of planning reservoir drainage, especially for offshore fields. In the Middle East 80% of all new wells drilled are horizontal (Nurmi 1995). Increased production from horizontal wells, as shown in Figure 1.2 (Weber 1999), and the additional benefits for solving drainage problems mean that horizontal wells are often the method of choice.

Having briefly demonstrated the importance of horizontal wells it is necessary to justify the motivation for the research presented in this thesis. Horizontal wells offer not only the potential for increased production, but also provide an unparalleled window into the geology and extent of a reservoir that is impossible from vertical wells with limited exposure or seismics with limited resolution, thus enhancing upon previous knowledge. However, log analysis in horizontal wells is not directly analogous with that in vertical wells primarily because logging tools and interpretation methods were designed for vertical wells. The petrophysical community is in a constant process of developing horizontal well log interpretation methods and this is the principle reason for the London Petrophysical Society interest and funding of the research presented.

Figure 1.1 Number of horizontal wells drilled by calendar year (Figure 1.5 Nurmi 1995).
Chapter 1: Introduction

Oil column horizontal wells (1,000 m. long)

Vertical well

Figure 1.2 Comparison of typical vertical and horizontal well performance (Figure 3 Weber 1999). Recovery factor is the volume of oil recovered divided by the volume of oil in place and the $D_w$, the dimensionless well spacing is well spacing divided by the height of the oil column all multiplied by the square root of vertical divided by horizontal permeability.

1.3 Objectives and hypotheses

1.3.1 Objectives

The aims of the thesis study are:

- To identify horizontal well porosity anomalies.
- To describe the potential causes of the horizontal well porosity anomalies.
- To postulate the most likely cause of porosity anomalies using the data sets studied.
- To propose methods of obtaining the formation porosity from log measurements.
1.3.2 Hypotheses

1. Log derived porosity values give poor estimates formation porosity in horizontal wells, regardless of tool type.
2. LWD density-derived porosity provides the best LWD porosity tool estimate of the true formation porosity in horizontal wells.
3. Rugose and washed-out wellbore conditions in horizontal wells increases porosity log values to a greater extent than in vertical wells.
4. Formation fluid affects the magnitude of porosity anomalies in horizontal wells to a greater extent than in vertical wells.
5. In horizontal gas wells, anisotropic mud invasion increases density derived porosity values and decreases neutron porosity values, without increasing the apparent variability in the measurements.
6. Bedding and relative dip affect porosity calculations in wells.

The intention was to investigate all the above hypotheses, but data was not available for use to assess hypotheses 4, 5 and 6. Despite this useful conclusions were possible.

1.4 Thesis Structure

This thesis consists of five chapters. Chapters 1 to 3 explain the background and theory behind the thesis. Chapters 4 detail the analysis of two data sets with conclusions and a discussion of their limitations. The final chapter provides a summary of the conclusions of the work presented and suggestions for possible further work.

- **Chapter 1: Introduction** The introduction provides the background to the work presented and outlines the structure of the thesis.
- **Chapter 2: Porosity: Definitions, measurement and calculations** The principles of porosity calculation from log and core measurements are described and the problems involved are assessed.
• Chapter 3: Horizontal well porosity anomalies A summary of notable literature regarding horizontal well porosity anomalies highlighting fundamental difficulties of horizontal well porosity calculation and examples of previous works.

• Chapter 4: Analysis of data sets Details the work to resolve porosity anomalies from two fields. The southern North Sea data set consists of one vertical and one horizontal well from a Rotliegend sandstone gas field. The northern North Sea data set consists of two vertical and three horizontal wells from a Palaeocene sandstone/shale gas and oil field. Porosity anomalies are identified, several porosity algorithms are statistically tested against core porosity. Conclusions are drawn from the results of these analyses.

• Chapter 5: Conclusions and suggested further work
Formation porosity can be determined from core measurements or a number of different logging tools: litho-density, neutron porosity, sonic, nuclear magnetic resonance and resistivity (Ellis 1987). The tools all derive porosity from different physical measurements and therefore may provide different formation porosity values. No technique either core or downhole logging measures porosity directly and therefore no single method provides the true formation porosity in all situations.

Core porosity is often the most reliable measure of porosity, but has probably never been measured continuously through an entire reservoir section in all wells of any field. The only scientific projects routinely attempt to recover continuous core from all wells has been with projects such as the Ocean Drilling Program (ODP).

Continuous formation porosity is usually derived from the density tool measurements and is regarded as the most reliable log estimation of formation porosity (Bedford et al. 1997). In general one or two of the porosity tool logs are calibrated against core in post-logging processing to establish the correct match with formation porosity. In formations with 10-15% clay content or more correction for the clay is required, although the correction factors used are almost all without exception empirical and petrophysicist dependent (i.e. subjective). The empirical relationship is usually derived from a comparison between core clay content and well log responses. Note: clay is called shale by petrophysicists regardless of if the clay is a shale or not.

This chapter describes porosity and its role in formation evaluation. The logging tool principles and porosity estimation from their logs is detailed. Crossplots and numerical porosity calculations are explained.
2.1 Porosity definition

Porosity is the void space between solid matter in the rock volume and is occupied by fluids (Tiab and Donaldson 1996). This capacity of rock to store fluid and its uses form the basis of the entire oil and gas industry. Accurate and precise measurement of rock porosity may be better described as an art than a science due to difficulty of the processes involved. This statement may be justified by the number of methods used to measure porosity and the expense of obtaining good porosity values.

Accurate and precise porosity values are critical in formation evaluation. Porosity is often used for many purposes although not always reliably; such as an input for water saturation, permeability, hydrocarbon in place and economic viability estimates. There are many pitfalls; the most common and problematic is the presence of significant volumes of shale within the formation of interest. For example, porosity is often empirically related to the logarithm of permeability from core measurements allowing permeability to be predicted from porosity logs. However, depending on the clay content and distribution within the pores this relationship may be complex and invalid when applied throughout the entire reservoir. This is often where the experience of the petrophysicist is critical. A relationship may be invoked based on accumulated knowledge with no scientific data to back up the specific relationship. The only justification required in this case is the predictive capability of the relationship is better than previous methods thus it is frequently difficult to evaluate the validity of such a relationship on any basis other than the specific reservoir or reservoir interval.

2.1.1 The definition of porosity

Porosity refers to the volume fraction of void space of a rock (called total porosity), but may be described in numerous ways (Bourbie et al. 1987; Dullien 1992; Tiab and Donaldson 1996). The importance of the measure of porosity for reservoir evaluation should not be underestimated. Formation porosity defines the upper limit of the formation’s capacity to store fluid. Porosity is an essential input for water saturation and permeability estimates, notable problems being clay content and distribution. Permeability is often estimated from log-derived porosity using an empirical
relationship from core measurements (Bourbie et al. 1987). However, this relationship is often invalid, since porosity is only one of many factors that affect permeability such as cementation, clay content and connectivity. Without precise and accurate porosity estimates it is impossible to calculate the economic value of any reservoir with any degree of confidence, provided that permeability is great enough to extract the hydrocarbons at all.

The structure of the pore systems is of significant interest to petrophysicists, since many rock properties are controlled by the pore structure. For example, the effective porosity, or the volume fraction of the interconnected voids, is the volume of rock through which fluids may flow and thus be extracted. Clay content and distribution is often a factor in determining effective porosity and permeability. However, the effective porosity does not account for dead end pores. Although dead end pores are connected to the connected pore volume, they do not contribute to fluid flow pathways and thus hydrocarbon production (Bourbie et al. 1987; Dullien 1992; Tiab and Donaldson 1996).

The pore structure itself is controlled by a number of factors (Bourbie et al. 1987; Dullien 1992; Tiab and Donaldson 1996). Porosity is reduced by an increased range of the grain size distribution that is dependent on depositional environment, current distribution and the duration of the sedimentary process (Tiab and Donaldson 1996). Cementation affects porosity by filling pore space with material during lithification and the circulation of fluids during geological history. Diagenetic alteration of minerals to clay also contributes to the ultimate reduction of porosity by lowering the strength of the rock and occupying a portion of the pore space, although clay can possess micro-porosity. Compaction of rock over geological time closes pores and forces out fluids from the rock. Increasing the degree of order of grain packing reduces porosity generally because of increased overburden pressure that may also deform or crush the grains particularly at pore openings providing accumulation sites for clay.

Geologists classify rock porosity to help evaluate the history of a particular rock sample (Bourbie et al. 1987; Tiab and Donaldson 1996). Two main categories are used. Primary porosity is the porosity formed at the time of deposition. Secondary porosity is porosity formed by diagenetic processes such as dissolution, fracturing and catagenesis (clay alteration due to elevated temperatures and/or pressures). Primary porosity maybe intercrystalline - voids between crystals, cleavage planes of crystals and voids in crystal lattices; intergranular - voids between grains; or bedding planes - voids between
Chapter 2: Porosity: Definitions, measurement and calculation

Sediments and facies (Tiab and Donaldson 1996). Primary porosity voids can also be formed by detrital fossil fragments; the packing of oolites; depositional vugs or caverns; and by living organisms at the time of deposition. Secondary porosity is formed by dissolution - enlargement of voids by warm fluids; dolomitization - the replacement of calcium by magnesium from solution; or fractures - openings formed as a result of structural failure. Secondary porosity can also be formed by saddle reefs, openings at crests of closely folded narrow anticlines; and pitches and flats, openings formed by beds during slight slumping (Tiab and Donaldson 1996).

An additional problem is that core porosity measurements typically measure the effective porosity, whereas log derived porosity generally measures the total porosity. This difference is usually within the errors of the measurements for sandstones because the non-effective porosity in sandstones is usually negligible (Tiab and Donaldson 1996). However, evaluating carbonates in which the effective porosity may be 0%, but simultaneously the total porosity could range from 0-50%, results in gross overestimates of effective porosity (Bourbie et al. 1987; Tiab and Donaldson 1996). In this extreme case the core porosity, permeability and repeat formation tester measurements would resolve the issue because without connected porosity there will be no permeability and no pressure draw down.

For the purpose of this thesis, core porosity is assumed to provide correct formation porosity since only sandstones are analysed. Inconsistencies that arise are generally assumed to result from the logging environment or tool malfunctions. This thesis is only concerned with the porosity that can be estimated from logging tool and gas expansion core measurements. In this study, porosity can be estimated using core measurements and the following logging tool measurements: density, neutron, sonic, resistivity and nuclear magnetic resonance (NMR). All porosity measurement methods can only estimate porosity but when several methods agree one may have greater confidence in the estimate of porosity. Note that resistivity and NMR measurement derived porosity estimates are not used when analysing data in this thesis but brief descriptions are provided for completeness.
2.2 Porosity measurements: Core

Core sample porosity can be measured in a number of ways, most of which involve measuring two of the following volumes; total, pore or solid. The methods include the direct, gas expansion, mercury injection, imbibition, and optical methods. Porosity may also be calculated from the solid and bulk density of the sample (Bourbie et al. 1987). The gas expansion method is the most frequently used method. Mercury injection and imbibition are also common, although mercury injection leaves the sample unusable for any other measurements such as permeability. Gas expansion, mercury injection and imbibition measure the connected porosity. Direct, optical and density methods measure the total porosity of the sample. Generally, the error in porosity estimation from logging tool measurements is ±1pu and ±0.2pu for core gas expansion porosity.

Gas expansion

The gas expansion method uses two chambers connected via a two-way valve (Tiab and Donaldson 1996). One chamber is filled with Helium gas at ambient temperature and 100psi pressure. A sample is placed in the other chamber and evacuated. The valve is opened between the two chambers, allowing the gas to expand into the combined volume. The sample chamber volume, \( V_i \), may be calculated using Boyle’s Law \( (P_1V_1 = P_2V_2) \) knowing the initial, \( P_i \), and final, \( P_o \), pressures and the volume of the other chamber, \( V_o \). Knowing the volume of the sample chamber when it contains a sample, \( V_i \), and the sample chamber volume when empty, \( V_o \), the sample grain volume, \( V_g \), may be calculated. By measuring the bulk volume, \( V_b \), the porosity, \( \phi \), may be calculated:

\[
\phi = \frac{V_b - V_g}{V_b}. \tag{2.1}
\]

Equation 2.1
Chapter 2: Porosity: Definitions, measurement and calculation

Mercury injection

Mercury injection is used because most substances are not wetted (surface affinity) by mercury (Dullien 1992). The sample is immersed in mercury because mercury will not penetrate the pore to measure the bulk volume. The sample is evacuated then placed in a mercury filled chamber. The chamber pressure is increased to force the mercury into the pores. The mercury pressure and volume measurements allow porosity to be calculated.

Imbibition

Imbibition involves weighing the sample before and after imbibing the sample with a fluid of known density (Dullien 1992). The sample is immersed in a wetting fluid under vacuum and, given time, the sample will become fully saturated. The pore volume is calculated by weight after, minus weight before, imbibing divided by the fluid density, knowing bulk volume porosity is pore volume divided by bulk volume.

Optical

Optical methods use thin or polished sections of core samples, usually impregnated with epoxy (Dullien 1992). The sample is assumed to be representative of the formation. The pore area is epoxy filled on the sections and measured visually with a microscope or, with the use of a microscope camera the section can be digitised. The digitised image can then be analysed with appropriate software to calculate porosity.

Density

The density method for a dry sample assumes that the solids contain all the mass. Knowing the bulk volume and density, the porosity equals one, minus the bulk, divided by the solid density. The solid density may be calculated from the mineralogy.
Chapter 2: Porosity: Definitions, measurement and calculation

Direct

The direct method is infrequently used because the method is destructive. The bulk volume is measured and then the sample is ground to remove the pores (Bourbie et al. 1987). The volume of the solids is measured. Porosity is calculated by bulk minus solid volume, all divided by bulk volume.
2.3 Porosity measurements: Logs

This section describes the tool principles and the typical manner in which porosity is estimated from logs: litho-density, neutron, sonic, nuclear magnetic resonance (NMR) and resistivity. The aim is to furnish the reader with an understanding of the fundamental principles of the logging tools and, in addition, to highlight some of the difficulties involved in deriving continuous porosity estimates from downhole logs.

2.3.1 Density and litho-density logs

*Theory: Density*

Litho-density tools measure the formation bulk density and photoelectric factor of the formation. Porosity is estimated using the following equation:

\[
\phi = \frac{(\rho_m - \rho_b)}{(\rho_m - \rho_f)}
\]

Equation 2.2

where \( \phi \) = porosity, \( \rho_m \) = matrix density (estimated or known), \( \rho_f \) = formation fluid density (estimated or known) and \( \rho_b \) = bulk density as measured by the litho-density tool (Bateman 1985). The bulk density is calculated based on the count rates of two (or three) gamma ray detectors at known spacing from a gamma ray source [Figure 2.1]. A caliper is used to eccentric the sonde to reduce the influence of mud. The count rates over a specific range of gamma-ray energies can be directly related to the bulk density of the material between the source and the detectors (Ellis 1987). High bulk density means more gamma rays are absorbed and so a low count rate is recorded.

The gamma rays interact with the formation in three ways: Compton scattering, photoelectric absorption and pair production [Figure 2.2](Tittman 1986). Pair production is avoided by using a source that produces gamma rays at less than 1.02MeV (positron plus electron rest mass energy), but the photoelectric effect does affect readings. The influence of the photoelectric effect is reduced to an insignificant level by windowing the gamma-ray spectrum to cut out most of the photoelectric region.
(<100keV). The most important of these effects is the Compton scattering, because it is related to the atomic electron density and therefore the bulk density.

Compton scattering is the process of inelastic scattering of gamma rays from orbital electrons [Figure 2.3](Tittman 1986). Electrons gain energy by collision with approximately 2keV-2MeV gamma rays. The electrons are ejected from their host atoms and the gamma rays lose some of their energy. After a number of collisions, the gamma rays are absorbed by the photoelectric effect. The greater the electron density, the more rapidly the gamma rays are attenuated. Compton scattering is the dominant process between energies of 100keV-10MeV.

![Figure 2.1 Schematic of a density logging tool (Schlumberger 1999).](image)

![Figure 2.2 Gamma ray mass absorption coefficients over the energy range used by density logging tools (Figure 1 Tittman et al. 1965).](image)
In common formation elements, Ca, Si, O, C, Mg, K, Fe, Al, etc., the number of protons, and therefore the number of electrons, is almost half the total number of nucleons in the atom (the Z/A ratio) [Table 2.1] (Ellis 1987). Since these atoms are a similar size, and the nucleus contains their mass, the formation density can be related to the gamma ray absorption response of the formation. The higher the density, the lower the number of recorded gamma rays. The count rate rates for 2 or 3 detectors spaced at different distances from the source are recorded and the electron density is calculated as a function of these count rates.

The formation bulk density, \( \rho_b \) is related to the electron density, \( \rho_e \), by,

\[
\rho_e = \rho_b \left( \frac{Z}{A} \right) N
\]

**Equation 2.3**

\[
(\rho_e)_i = \left( \frac{2\rho_e}{N} \right)
\]

**Equation 2.4**

where \((\rho_e)_i\) = electron density index, \(Z\) = number of nucleons, \(A\) = number of protons and \(N\) = Avogadro’s number (\(6.02 \times 10^{23}\)). However, one notable exception is hydrogen with only one proton and one electron (Z/A ratio = 1, not \(\frac{1}{2}\)). This does cause problems so the density recorded is an apparent density, \(\rho_a\). Hydrogen is normally found in the formation fluids and so an adjustment for the hydrogen effect is applied in the form of an empirical tool compensation.
Chapter 2: Porosity: Definitions, measurement and calculation

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<th>Electron Density Index (Rhoe)</th>
<th>Density seen by the tool (Rhoh)</th>
<th>Photoelectric Index (PEF)</th>
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<td>32.07</td>
<td>0.9978</td>
<td>2.07</td>
<td>2.066</td>
<td>2.022</td>
<td>5.4304</td>
</tr>
<tr>
<td>Chlorine</td>
<td>17</td>
<td>35.46</td>
<td>0.9588</td>
<td>---</td>
<td>---</td>
<td>---</td>
<td>6.7549</td>
</tr>
<tr>
<td>Potassium</td>
<td>19</td>
<td>39.1</td>
<td>0.9719</td>
<td>---</td>
<td>---</td>
<td>---</td>
<td>10.081</td>
</tr>
<tr>
<td>Calcium</td>
<td>20</td>
<td>40.08</td>
<td>0.998</td>
<td>---</td>
<td>---</td>
<td>---</td>
<td>12.126</td>
</tr>
<tr>
<td>Quartz</td>
<td>11.78</td>
<td>60.09</td>
<td>0.9985</td>
<td>2.654</td>
<td>2.65</td>
<td>2.648</td>
<td>1.806</td>
</tr>
<tr>
<td>Calcite</td>
<td>15.71</td>
<td>100.09</td>
<td>0.9991</td>
<td>2.71</td>
<td>2.708</td>
<td>2.71</td>
<td>5.084</td>
</tr>
<tr>
<td>Dolomite</td>
<td>13.74</td>
<td>184.42</td>
<td>0.9977</td>
<td>2.85</td>
<td>2.863</td>
<td>2.85</td>
<td>3.142</td>
</tr>
<tr>
<td>Anhydrite</td>
<td>15.69</td>
<td>136.146</td>
<td>0.999</td>
<td>2.96</td>
<td>2.957</td>
<td>2.977</td>
<td>5.055</td>
</tr>
<tr>
<td>Sylvite</td>
<td>18.13</td>
<td>74.557</td>
<td>0.9657</td>
<td>1.984</td>
<td>1.916</td>
<td>1.863</td>
<td>8.51</td>
</tr>
<tr>
<td>Halite</td>
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<td>58.45</td>
<td>0.9581</td>
<td>2.165</td>
<td>2.074</td>
<td>2.032</td>
<td>4.169</td>
</tr>
<tr>
<td>Gypsum</td>
<td>14.07</td>
<td>172.18</td>
<td>1.0222</td>
<td>2.32</td>
<td>2.372</td>
<td>2.351</td>
<td>3.42</td>
</tr>
<tr>
<td>Anthracite coal</td>
<td>6.02</td>
<td>---</td>
<td>1.03</td>
<td>1.4</td>
<td>1.442</td>
<td>1.355</td>
<td>0.161</td>
</tr>
<tr>
<td>Bituminous coal</td>
<td>6.21</td>
<td>---</td>
<td>1.06</td>
<td>1.2</td>
<td>1.272</td>
<td>1.173</td>
<td>0.18</td>
</tr>
<tr>
<td>Fresh water</td>
<td>7.52</td>
<td>18.016</td>
<td>1.1101</td>
<td>1</td>
<td>1.11</td>
<td>1</td>
<td>0.358</td>
</tr>
<tr>
<td>Salt water</td>
<td>9.42</td>
<td>---</td>
<td>1.0797</td>
<td>1.146</td>
<td>1.237</td>
<td>1.135</td>
<td>0.807</td>
</tr>
<tr>
<td>Oil</td>
<td>5.61</td>
<td>---</td>
<td>1.1407</td>
<td>0.85</td>
<td>0.97</td>
<td>0.85</td>
<td>0.119</td>
</tr>
<tr>
<td>Methane</td>
<td>---</td>
<td>---</td>
<td>1.247</td>
<td>---</td>
<td>---</td>
<td>---</td>
<td>---</td>
</tr>
<tr>
<td>Gas</td>
<td>---</td>
<td>---</td>
<td>1.238</td>
<td>---</td>
<td>---</td>
<td>---</td>
<td>---</td>
</tr>
</tbody>
</table>

Table 2.1 Table of density parameters for common elements and compounds (Schlumberger 1999).

The compensation formula,

\[
\rho_a = 1.07(\rho_e) - 0.1883, \quad \text{Equation 2.5}
\]

is derived from calibration in freshwater saturated limestone (Ellis 1987). In practice, this formula is also a good approximation in water-saturated sandstones and dolomites.

The apparent density, \( \rho_a \), is taken as the bulk density and is used to calculate the porosity, \( \phi \) using Equation 2.2.

At a detector, the gamma ray intensity, \( I \), behaves exponentially and linearly depending on the source intensity, \( I_0 \), bulk density, \( \rho_b \), mass absorption coefficient, \( \nu_m \), and the source-detector spacing, \( x \) (Samworth 1980):

2-11
This equation has a turning point, but the lowest expected bulk density is that of water, so the tool is designed so that there is an unambiguous count rate to bulk density relationship. The detector closest to the source is positioned such that the detector essentially reads mostly the rugosity and mudcake and not the formation (the job of the second detector). Combination of the count rates from the two detectors is used to correct for the presence of mudcake. Typically, the density correction, $DRHO$ is,

$$DRHO = \frac{1}{3}(\rho_L - \rho_S),$$  \hspace{1cm} \text{Equation 2.7}$$

where $\rho_L$ is the density value measured at the long spaced detector, and $\rho_S$ is the density value measured at the short spaced detector. Therefore, the recorded density value, $\rho_b$ is,

$$\rho_b = \frac{1}{3}(4\rho_L - \rho_S).$$  \hspace{1cm} \text{Equation 2.8}$$

The value of correction, $DRHO$, is also recorded to provide a quality control check on the derived density and porosity values. Corrections may be required for the mud density and borehole size. The larger the borehole size and the greater the mud contrast between the mud and bulk density, the greater the reduction in the apparent bulk density measured, because more mud (low density) is seen by the detector. Generally shale with bounded water will give an overestimate of porosity as will natural gas because of its low-density compared with water/oil.

*Theory: Photoelectric factor*

The photoelectric factor uses the gamma-ray spectrum affected by the photoelectric effect [Figure 2.4](Ellis 1987). The photoelectric effect is the process of gamma ray absorption by orbital electrons. Orbital electrons are ejected from atoms by absorbing all the energy from incident gamma rays. The absorbed energy from the
incident gamma ray provides at least the binding energy of the electron and the remainder is transferred as kinetic energy to the electron. High atomic masses and therefore greater inner electron shell binding energies require greater gamma ray energies to eject electrons from an atom. The photoelectric effect becomes significant with incident gamma ray energies less than 150keV, but is the dominant process for energies below about 80keV [Figure 2.2]. The spectrum energy of the detected gamma rays in the density tool is split into soft (low energy, normally about 40-80keV) and hard (high energy, normally about 180-540keV)[Figure 2.5]. The photoelectric factor, \( PEF \), is related to the ratio of the soft/hard part of the energy spectrum and is a function of the effective electron density in the formation, \( Z_{\text{eff}} \).

\[
PEF = \left( \frac{Z_{\text{eff}}}{10} \right)^{3.6}.
\]

Equation 2.9

The photoelectric factor is therefore an indication of the total chemistry of the formation, aiding lithology and clay identification (~3.5B/e)(Ellis 1987). Typical \( PEF \) values are given above [Table 2.1]. The high photoelectric factor materials can affect the count rates in the hard part of the spectrum. The weighting agents barite (\( PEF=267 \)) and hematite (\( PEF=21.48 \)) in drilling muds are a common source of this problem. These particular weighting agents have high \( PEF \) and density values that in combination result in apparently high bulk density values being recorded [Figure 2.6]. The high bulk density leads to incorrect (too low) porosity values being calculated. Where the photoelectric factor is measured, the \( PEF \) values are sometimes used in compensation for the density values and are included in the correction curve. However, this is not sufficient to compensate fully for the effects of barite and hematite. The example below [Figure 2.6] illustrates only the response of the short spaced detector. The long spaced detector response is sufficiently different over the range of \( PEF \) and density values expected in the presence of barite and hematite as to make accurate compensation difficult to achieve. An additional problem is that often barite or hematite is surreptitiously added to mud systems by drillers without recording its presence! Therefore, high \( PEF \) values should be seen as indicators of possible problems with the bulk density values. However, siderite (\( PEF=14.7 \)) and other minerals with high iron concentrations also have a similar effect on the \( PEF \) and bulk density values.
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Figure 2.4 Photoelectric absorption (Schlumberger 1999).

![Photoelectric Absorption Diagram](image)

**Effect of Bulk Density on the Spectrum**
*(Short spacing detector example)*

- **Lithology window**
  Region of photoelectric effect
  ($P_b$ and $Z$ information)

- **Density window**
  Region of Compton scattering
  ($P_b$ information)

**Figure 2.5** Energy spectrum of a density tool for bulk density and PEF calculation (Schlumberger 1999).
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Effect of Barite Mud on the Spectrum
(Short spacing detector example)

Lithology window
Region of photoelectric effect
($P_b$ and $Z$ information)

Density window
Region of compton scattering
($P_b$ information)

Low barite and mud thickness

Effect of mud thickness and barite concentration

High barite and mud thickness

Figure 2.6 Energy spectrum of a density tool for bulk density and PEF calculation in the presence of a barite mud (Schlumberger 1999).

Tool differences

The descriptions given in this section rely heavily on Schlumberger documents, however the fundamental physics of the gamma ray density and photoelectric factor measurement has firm grounding in the pioneering nuclear physics of the late nineteenth and first half of the twentieth century. An excellent and relatively accessible summary of the background physics and detection systems used in all modern density tools can be found in (Staub et al. 1953; Harvey 1969).

Several descriptions of tools, processing techniques and discussion of error sources from a number of different service companies are found in the following references (Czubek 1960; Wahl et al. 1964; Moake 1991) and only minor changes to wireline tools have occurred since the 1960s. All service companies measure gamma ray density and photoelectric factor in the same manner because the physics dictates the nature of this process. The main differences between service companies occur in the data collection and processing as detailed in the references given above and not the tool
construction i.e. source type (Cs$^{137}$), scintillation detectors and the spacings are all fundamentally the same for both wireline and LWD tools.

**Common problems**

Some notable exclusions are made from the discussion of the operation of density tools within the literature. This is the process of the application of the source and detectors to the borehole. The corrections made to the density measurements in processing are dominantly for parallel standoff of the pad. The problem of non-parallel standoff is almost ignored in the literature over the past nearly fifty years and is often glossed over as an intractable problem on the occasions this topic is broached.

The effects of non-parallel standoff can result in poor density values being recorded and often little or no indication of a problem is evident from the density correction curve. To safeguard against this effect Oil Companies plot histograms of density logs across known intervals within a field or region and note inconsistencies. However, by suitably altering the construction of pad the density measurement can be constructed more robustly. As important is the toolstring dressing (bowspring, cranks...), since imbalance of the mechanical forces acting on the entire toolstring can impart turning motions leading to non-parallel standoff. Analysis of the individual detector count rates can also provide an indication of this problem, as can the caliper log. An under-gauge caliper log may indicate mudcake, but also the tool running across a chord rather than the diameter of the borehole giving non-parallel standoff.

The photoelectric factor log does not indicate standoff as the mud (water) provides almost no contribution to the photoelectric factor log unless barite is used as a mud weighting agent [Table 2.1].
2.3.2 Neutron log

Theory

The neutron tool irradiates the formation with neutrons and measures the neutron count rates at two detectors at different spacing from the source [Figure 2.7](Desbrandes 1985). A bowspring forces the whole sonde against the borehole wall and shielding behind the detectors helps to reduce the number of detected neutrons that pass through the mud column. The ratio of the two detector count rates is proportional to the hydrogen content of the formation within the volume irradiated by the neutrons, assuming the hydrogen content of the formation to be within water (or hydrocarbon) molecules of the formation pore volume (Rider 1996). The count rate ratio, \( \frac{cps_{\text{near}}}{cps_{\text{far}}} \), is approximately proportional to formation porosity, \( \phi \) where \( k \) is the constant of proportionality (Ellis 1986):

\[
\phi = k \frac{cps_{\text{near}}}{cps_{\text{far}}} \quad \text{Equation 2.10}
\]

Porosity derived from the neutron porosity tool is calculated using the following equation:

\[
\phi = \phi_{\text{neutron for the appropriate matrix}} \quad \text{Equation 2.11}
\]

where \( \phi_{\text{neutron for the appropriate matrix}} \) = neutron porosity as measured by the neutron porosity tool lithology corrected (Bateman 1985).

The neutron porosity tool measurement is based on fast (\( >>100\text{eV} \)) neutrons scattering from hydrogen atoms (Tittman 1986). During the lifetime of a fast neutron there are a number of processes that affect its passage through the formation prior to detection; elastic scattering, inelastic scattering, diffusion or capture by a thermal neutron absorber [Figure 2.8].
A fast neutron (3-4MeV) will scatter (predominantly elastically) randomly through the formation losing energy until the neutron reaches epithermal energies (0.1-100eV), at which point it may be detected or continue scattering until it reaches thermal energies (approximately 0.025eV). At thermal energies the neutron diffuses randomly through the formation and may be detected or undergo capture.

Figure 2.7 Neutron logging tool (Schlumberger 1999).

Figure 2.8 Lifetime of a neutron (Schlumberger 1999).
Elastic scattering between a neutron and a nucleus is analogous to two billiard balls colliding i.e. dependent on the angle of incidence [Figure 2.9]. From this analogy it is clear that a collision with a body of equal mass to that of a neutron (like the single proton in a hydrogen nucleus) will result in the greatest loss of energy. This process is the most significant energy loss mechanism for neutrons at epithermal energies and above (Ellis 1986).

Inelastic scattering is a process in which the target nucleus is excited by gaining some internal energy from an incident neutron [Figure 2.10]. This excitation energy is immediately re-emitted as gamma rays. The amount of energy remaining is dependent on two factors, the energy of the incident neutron and the target nucleus. There are characteristic minimum neutron energies below which a target nucleus will not undergo inelastic scattering i.e. the first excitation state of the nucleus [Figure 2.11]. The remaining kinetic energy is shared between the target nucleus and neutron according to the mass ratio. This process is significant for epithermal energies and above.

Diffusion is a process in which the neutrons move after having achieved a state of energy equilibrium (Barber 1989). For neutrons this equilibrium state is a homogeneous isotropic concentration of neutrons of the same energy. On average the neutrons gain as much energy as they lose in collisions, i.e. no net loss in energy. The neutrons are approximately in thermal equilibrium with the formation, but not in spatial equilibrium. The net flow direction is from high neutron concentrations to low neutron concentrations. In logging, at the detectors, this flow direction is normally from the formation towards the borehole. This is due to the relatively high capture cross-section of the borehole fluids compared with the formation. The borehole acts as a sink for thermal neutrons. Diffusion occurs at thermal energies.

Capture gamma rays are produced from nuclei after absorption of (thermal) neutrons [Figure 2.12]. The new nucleus is excited by the energy gained mainly by a reduction in the total binding energy of the nucleus. This energy is immediately emitted as a gamma ray, or series of gamma rays, the energy being dependent on the structure of the new nucleus.

Neutrons are emitted from the source, experiencing a number of interactions during their passage through the formation prior to detection (Ellis 1986). As stated above, elastic and inelastic scattering are the dominant processes that slow the fast neutrons from the source to epithermal and thermal energies. This slowing down is highly dependent on the concentration of atoms (hydrogen) per cm³, \( N_{\text{H}} \), the average
collision cross-section, \( \sigma_c \) and the energy lost in a typical collision, \( \xi \). This effect is referred to as the slowing down power, \( SDP \), such that for any particular element (Ellis 1987),

\[
SDP = N_{hi} \sigma_c \xi .
\]

Equation 2.12

**Figure 2.9** Elastic scattering, N is a neutron and P is a proton (Schlumberger 1999).

**Figure 2.10** Inelastic scattering (Schlumberger 1999).
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Figure 2.11 Gamma ray spectrum emitted by inelastic scattering of neutrons with particular elements (Schlumberger 1999).

Figure 2.12 Thermal neutron capture and gamma ray emission (Schlumberger 1999).
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<table>
<thead>
<tr>
<th>Material (Pure)</th>
<th>Computed Sigma @ 20°C</th>
<th>Rock Matrix</th>
<th>Apparent Sigma**</th>
</tr>
</thead>
<tbody>
<tr>
<td>Quartz (SiO₂)</td>
<td>4.26</td>
<td>Sandstone</td>
<td>8 to 10</td>
</tr>
<tr>
<td>Calcite (CaCO₃)</td>
<td>7.07</td>
<td>Limestone</td>
<td>12</td>
</tr>
<tr>
<td>Dolomite (CaCO₃·MgCO₃)</td>
<td>4.70</td>
<td>Dolomite</td>
<td>8</td>
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<tr>
<td>Anhydrite (CaCO₄)</td>
<td>12.5</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gypsum (CaSO₄·2H₂O)</td>
<td>18.4</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Magnesite (MgCO₃)</td>
<td>1.44</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Iron</td>
<td>193</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Rock salt (NaCl)</td>
<td>753</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Boron (B)</td>
<td>99,405</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cadmium (Cd)</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Fresh water (H₂O)</td>
<td>22</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Salt water</td>
<td>30 to 130</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil</td>
<td>20*</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gas</td>
<td>5</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**These are real-world values, not computations made from pure materials. These values vary slightly from the theoretical values because of a range of factors, such as trace contamination.

Table 2.2 Capture cross-section values for common minerals and lithologies (Schlumberger 1999).

The slowing down length is typically of the order of 10-20cm (porosity and lithology dependent), but the detectors are typically 40cm and 60cm away from the source (Ellis 1986). The slowing-down length/power is not the only factor that is measured by the detectors. The thermal neutrons normally diffuse within the formation for some distance before being captured by the detector. Another parameter is required to account for this. The distance travelled by a neutron between its first reaching thermal energies and its detection (or eventual capture by a nucleus in the formation) is called the diffusion distance, typically 10-30cm (porosity and lithology dependant). The slowing-down length, $L_s$, and diffusion length, $L$, are normally combined together to give an estimation of the average distance travelled by a neutron from the source. This parameter is the migration length, $L_m$, and is defined as,

$$L_m = \sqrt{L^2 + L_s^2}.$$  

Equation 2.13
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Assuming that elastic scattering from hydrogen atoms in the formation is the only variable, the measurement of count rate ratio will be a measure of the hydrogen index, \( HI \), which is proportional to the porosity, \( \phi \). Such that,

\[
HI = \left( \frac{H_{\text{Formation}}}{H_{\text{Water}}} \right) \propto \phi \tag{Equation 2.14}
\]

where \( H_{\text{Formation}} \) = concentration of hydrogen atoms in the formation and \( H_{\text{Water}} \) = concentration of hydrogen atoms in an equal volume of water. Therefore, for a given borehole diameter the porosity can be calculated [Equation 2.10].

However, the porosity calculation is dependent on lithology, salinity (borehole and formation), mudcake thickness, borehole diameter, standoff, pressure and temperature [Figure 2.13]. Other effects include inelastic scattering, the chlorine absorption, the bound water in shale, the breakdown of porosity calculation at high porosity (>40pu) and the low hydrogen concentration in zones containing natural gas (Ellis 1986). These effects are compensated for by the use of tool-dependent correction charts. However, the rugose and caved boreholes tend to lead to the neutron tool reading too much mud and overestimates of porosity. The lithology has a significant effect on neutron porosity measurements [Figure 2.32] because the average collision cross-section of the composite elements of the formation compounds is significantly different (Ellis 1986). This is especially problematic where mixed/thinly laminated formations exist. Hydrated minerals are a particular problem and result in porosity overestimates (Rider 1996). The most common hydrated minerals are clays, in which accurate porosity estimates from neutron porosity measurements is impossible. Other examples include gypsum, polyhalite, chamosite, carnallite and kainite. Minerals such as halite, anhydrite and sylvite have no hydration or porosity and have negative neutron porosity values! Another problem with shale formations is that they may contain significant quantities of boron (3-4ppm) which would lead to very high neutron porosity values (Ellis 1986).

Depth of investigation of the wireline neutron porosity tool at 15pu is approximately 12inches (30cm) with a vertical resolution of approximately 10inches (25cm) (Rider 1996). The LWD neutron porosity tools are combined with the density tool. An LWD tool built into a 6½inch drill collar has a precision of ±0.5pu in 30pu
formation at a rate of penetration of 50ft/hr (Wraight et al. 1989). Note that the common size of LWD tools are 4½, 8½ and 12½ inch drill collars.

General rules are that shale (bound water) will give an overestimate of porosity but, most importantly, natural gas will give an underestimate because of its low hydrogen concentration compared with water/oil. However, neutron porosity values in oils may also be affected by the difference between oxygen and carbon collision cross-section values leading to slight overestimates of neutron porosity in oils (Sherman et al. 1983).

Tool Differences

The neutron tool descriptions given above are from Schlumberger documents. The measurement technique is physics based from the nuclear physics of the late nineteenth and first half of the twentieth century and is consistent between Service Companies. Accessible summaries of the background physics and detection systems used in neutron porosity tool design are found in (Morrison and Feld 1953; Harvey 1969). Several descriptions of tools, processing techniques and discussion of error sources from a number of different service companies are found in the following references (Tittle 1961; Tittle and Allen 1966; Allen et al. 1967; Arnold and Smith 1981; Scott et al. 1982; Scott et al. 1994).

Several generations of neutron porosity tools have existed, although the most common modern type is the thermal type as described above. The main differences between service companies occur in the data collection and processing as detailed in the references given above. The tool construction does alter between Service Companies to exploit different aspects of the physics of neutron transport through porous materials however this does not alter the underlying principles described above.

Neutron porosity logs from different Service Companies can vary significantly for several reasons. The main reason is that the data processing techniques employed vary considerably. Companies use polynomial fits to laboratory standards directly, calculating for porosity and correcting for environmental condition; semi-empirical methods using theoretical formulae with adjustable parameters that are defined by laboratory calibration for environmental correction; and near fully theoretical methods using downhole measurements for environmental corrections based on laboratory standards. The detailed construction of the neutron tool has bearing on the response.
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The effect of these differences is seldom noticeable in reservoir rocks (sandstone, limestone and dolomite) which are well within the calibration range and standards used. The log responses in shales can be markedly different and can cause significant problems when making shale corrections to logs in shaly sand. This often results from shales being out of the calibration range of the tool. Shale is not generally modelled or calibrated for since the definition of shale is extremely broad. Shale may contain a variety of rare earth minerals in minute quantities and variable amounts of bound water that can have large effects on the neutron response. Shale may alter by chemical interaction with the drilling mud, thus changing the expected neutron response.

Additional effects of the toolstring configuration whilst logging are significant. The neutron log is not as susceptible to standoff as the density log due to the increased detector spacings used in a neutron tool. Though similar arguments regarding mud balling/rings (build up of mud on the tools e.g. on the leading edge of the density pad), turning motions and non-parallel standoff resulting from inappropriate tool dressing are also appropriate for the neutron tool.

The author is aware of 12pu differences in shales, but matching responses in sandstones in which two Service Companies were run in the same borehole back to back. This was explained purely on the basis of differing algorithms used to derive porosity and environmental corrections.
Figure 2.13 Neutron porosity correction chart (Por-14c Schlumberger 1999).
2.3.3 Sonic log

Theory

The sonic tool [Figure 2.15] emits successive pulses of acoustic energy into the formation from two sources and measures the first arrival times of the acoustic energy pulses [Figure 2.14] at a number of detectors (Rider 1996). The recorded travel time, $\Delta t$, is inversely proportional to the formation acoustic velocity within the volume of investigation. By assuming values for matrix, $\Delta t_m$, and fluid, $\Delta t_f$, p-wave travel times, the porosity of the formation may be estimated (Wyllie et al. 1956):

$$
\phi = \frac{(\Delta t - \Delta t_m)}{(\Delta t_f - \Delta t_m)}.
$$

Equation 2.15

**First Motion Detection (FMD) and Amplitude Measurement**

A time gate opens at the first motion detection point. A peak search is performed on the received signal within this gate. The maximum value of the signal within this gate is the amplitude.

Detection gate starts when the receiver signal exceeds the detection level.

The basis of acoustic logging is the effect of the formation on the propagation of elastic waves (Rider 1996). The main component of the elastic energy that is used to evaluate formation porosity is the compressional wave which generally travels faster and
arrives first, although other components such as the shear, Stoneley, Rayleigh, Love and guided waves are also present (Tittman 1986). All these modes of propagation provide information about the elastic properties of the formation.

Compressional waves propagate by the particle vibrations in the direction of energy propagation [Figure 2.16]. The wave velocity is dependent on the density and elastic properties of the medium. Compressional waves are always the fastest waves through a given medium and therefore first to arrive at a receiver. They are also the only mode of elastic energy to propagate through liquids (Sheriff and Geldart 1995).

Shear waves propagate by particle vibrations perpendicular to the direction of energy propagation [Figure 2.16](Ellis 1987). They travel more slowly than the compressional waves and so arrive after them. They are produced at the boundary between the mud and the formation/mudcake by mode conversion. Mode conversion is the process by which the energy of an incident wave (the emitted compressional wave from the transmitter in logging) is converted into a number of different modes (shear, Stoneley...) dependent on the elastic properties of the formation/mudcake. Note that only compressional wave travel times are used in this thesis for the calculation of porosity.
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**Wave Propagation Modes**

At rest | Compressional | Shear

Figure 2.16 Compressional and shear wave motion (Schlumberger 1999).

Stoneley waves are surface waves (tube waves) produced as a result of partial acoustic coupling between the borehole mud and the formation (Tittman 1986). A tube or borehole surface ripples transversely to the long axis of the borehole. The particle motion is retrograde (in the opposite direction) and elliptical (one motion parallel and one motion perpendicular to the interface) to the direction of energy propagation. The displacement is circumferential, like a ring travelling along the tube. Stoneley waves are produced by interaction between the compressional wave in the mud and the shear wave in the solid. As the Stoneley wave propagates along the borehole surface, energy seeps away. The amplitude of the wave decays exponentially away from the interface in both the formation and the mud. This energy in the decay is mode converted to compressional waves and it is the mode converted compressional wave that is detectable through the mud. Stoneley waves are slower than compressional and shear waves, having a velocity of 86% to 96% of the shear wave (Sheriff and Geldart 1995).

The transmitters are fired in succession after the pulse from the first has died away. The acoustic pulses are received by four receivers in the middle of the tool position so that they are typically 3 feet away from one transmitter and 5 feet away from the other [Figure 2.15]. This system provides borehole compensated travel times (Kearey et al. 1991). The acoustic pulse is fired from one of the transmitters and received by a pair of receivers. The time difference between the first arrivals of the pulse at the receivers is the interval travel time, $\Delta t$. The other transmitter is then fired and a second $\Delta t$ is measured. If the two $\Delta t$'s are the same then the borehole is assumed
smooth and the sonde axis is parallel to the borehole wall, so no compensation is required. Compensation is achieved by averaging the two travel times.

There are numerous variations on the basic tool design (Tittman 1986), the most important is that the array sonic tools [Figure 2.17] provide a full acoustic waveform recording from receiver array. The main purpose is to obtain the shear and Stoneley wave velocities that are useful for estimating the elastic properties of the formation and fracture identification respectively. This sonde has two transmitters 2 feet apart at the bottom of the sonde and two receivers at 3 feet and 5 feet from the closer of the two transmitters. This allows borehole compensated AC's to be measured. At 8 feet from the closest transmitter are eight receivers placed at 6 inches apart [Figure 2.18]. The waveform is recorded at all eight of the array receivers for about 2500 µs to allow all parts of the wavetrain to be recorded. These waveforms are stacked vertically to create a variable density plot [Figure 2.19]. These data are processed in a number of ways, depending on the application.

Porosity

Porosity calculation is dependent on assuming values for travel time through the matrix, $\Delta t_m$, and formation fluid, $\Delta t_f$. The log derived travel time provides the bulk travel time, $\Delta t$, so porosity, $\phi$, can be evaluated using Equation 2.15. This is Wyllie’s equation (Wyllie et al. 1956) and is based on empirical evidence from experimentation (Rider 1996). The formula provides accurate porosity values for clean, compacted water filled sandstones (very low clay content) and carbonates. However, inaccurate values are produced in dirty (high clay content) formations; undercompacted and over pressured units, which require compensation or alternative formulae (Dvorkin and Nur 1998; Khaksar and Griffiths 1999).

There are numerous alternative formulae for calculating porosity from sonic logs theoretically or empirically derived. One notable empirical formula is the Raymer-Hunt-Gardner formula (Raymer et al. 1980):
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**Figure 2.17** Modern sonic logging tool (Schlumberger 1999).

**Figure 2.18** Array sonic tool (Schlumberger 1999).
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Array Waveform Example

Figure 2.19 Array sonic tool waveforms used for mode identification and travel time calculations (Schlumberger 1999).

\[
\phi = \frac{(\Delta t_m - \Delta t)}{\Delta t \left(2 - \Delta t_m^{-1/2} \Delta f_{f}^{-1/2}\right)},
\]

Equation 2.16

where \(\Delta t\) = travel time, \(\Delta t_m\) = matrix travel time and \(\Delta f_f\) = fluid travel time.

Common Problems

Oil and gas do not normally adversely affect sonic derived porosity estimates (Schlumberger 1989) because they are displaced by mud filtrate within the volume of investigation. Acoustic velocities through mud and formation fluids are similar and small compared with the matrix (Rider 1996). An appropriate fluid travel time is usually sufficient to correct hydrocarbon effects, except if porosity and gas saturation are high. Additional problems in rugose and enlarged boreholes are cycle skipping [Figure 2.20] and slipping (or \(\Delta t\) stretch) [Figure 2.21](Tittman 1986). Cycle skipping is when a whole multiple of the signal wavelength is missed. Cycle slipping is when less than a whole multiple of the wavelength is missed.

Cycle skipping can be accounted for in later processing, because whole cycles are involved causing large and abrupt increases in travel times. However, cycle slipping is difficult to account for since the portion of a cycle that has been slipped is unknown. The usual cause of cycle slipping is poor tool centralisation, unless full waveforms are recorded these problems can be impossible to correct for, although back projecting the first motion “sine wave” reduces the effect of cycle slipping.

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In boreholes where large washouts or extensive invasion alteration is expected long sonic tools are run (Rider 1996). These tools consist of two transmitters two feet apart at the bottom and two receivers two feet apart, eight feet from the closest transmitter [Figure 2.22]. The depth of investigation is typically deeper at 15-20inches, allowing the long sonic tool to measure the undamaged formation beyond the altered zone compared with 6-10inches of the standard tools. This can be especially helpful in gas saturated formations in which the standard tools depth of investigation may be only 2inches compared to at least 10inches of the long sonic tools (Rider 1996). Cycle slipping and skipping are more likely by the use of the long sonic tools due to the method of borehole compensation employed [Figure 2.22](Rider 1996).
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Depth Derived Borehole Compensated (DDBHC)
The results from tool positions 1 and 2 are added together to produce borehole compensated results similar to the BHC method.

Tool Moving Up

Tool Position 2 records transit times from two transmitters to a single receiver. The zone of investigation is the area between the two transmitters.

Tool Position 1 records transit times from a single transmitter to two receivers. The zone of investigation is the area between the two receivers.

\[ \text{Slowness} = \frac{\text{TT3} - \text{TT4}}{4} + \frac{\text{TT3}' - \text{TT1}'}{4} \]

Figure 2.22 Long sonic tool and borehole compensation (Schlumberger 1999).

Additional uses of sonic tools

Sonic logs are far more useful as seismic interpretation tools for geophysicists to tie-in with seismic surveys than as porosity tools (Sheriff and Geldart 1995). This can be further justified by the increased use of dipole and quadrapole sonic tools.

A dipole tool has transmitters and receivers constructed such that the transmitter causes the formation to be excited with a “shear-like” motion by compression waves which “push on” one side of the borehole and “suck in” the other (Chen 1988). A quadrapole (cross-dipole) tool has additional transmitters and receivers mounted at 90° to the other set to allow for the calculation of shear wave anisotropy (Patterson and Schell 1997; Vernik and Liu 1997; Tang 1999).
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The dipole (and quadrapole) tools are more efficient in energy transfer into the formation than compressional tools because the energy transmitted through the formation via the shear mode is greater than the compressional mode. The compressional (mode-converted) and shear (and other modes) are recorded and can be used to calculate seismic attributes related to reservoir properties allowing geophysicists to create attribute maps of the reservoir (Goodway 2001). One such seismic attribute can be the residual hydrocarbon saturation which when mapped can be used to plan infill drilling campaigns (Goodway 2001).

Porosity from a sonic tool is generally regarded as a poor substitute for porosity calculated from a density tool. The use of the sonic tool, although affected by porosity, is greater in combination with the density tool as the formation density is a useful input into seismic attribute calculations. The theory on which the sonic log is based has been available for many years (Wood 1941) and therefore the methods used to record sonic logs are common to all Service Companies. The use of the sonic log for porosity estimation was developed early in its’ use (Pickett 1963). As discussed above many factors affect the quality of sonic logs, mostly noise sources of one type or another. In a similar manner to the density and neutron tools, the sonic measurements are affected by perturbations to the ideal toolstring configuration within the borehole. Non-parallel standoff is accounted for in the tool design, but noise from the actions of tool jewellery against the borehole can lead to poor results. Stacking the waveforms from each receiver provides some immunity to this problem for array and dipole tools, while the rejection of poor data from receivers improves velocity estimates (Kimball and Scheibner 1998).

Wyllie et al. (1956) and Raymer et al. (1980) are empirical equations [Equation 2.15 and Equation 2.16] and both are in common use. Other methods including theoretical methods for calculating sonic porosity, are discussed below in section 2.4.2.
2.3.4 Nuclear magnetic resonance log

The NMR tool irradiates the formation with pulses of high intensity electromagnetic energy at a specific high frequency in the radio region and subjects the formation to an intense magnetic field (Allen et al. 1997). The tool measures the amplitude of the radio pulses emitted by the protons (hydrogen in the pore water or oil) within the formation as result of the magnetic resonance induced by the tool. The integral of the decay of the radio pulse amplitudes, $M_t$ (relaxation time, $T_2$), over a pre-set time period, $t$, is proportional to the formation porosity (Kenyon 1997):

$$\phi = \sum \left( M_i \exp \left( -\frac{t}{T_2} \right) \right). \quad \text{Equation 2.17}$$

The hydrogen nuclei (protons) within the formation fluids align themselves with the intense magnetic field (polarisation). The tool pulses polarised radio energy into the formation, which forces the protons (within the volume of investigation) to precess about the magnetic field in a plane perpendicular (transverse) to the magnetic field at a specific frequency, the Larmor frequency.

The Larmor frequency corresponds to the absorption energy between two energy levels within the proton's nuclear magnetic spin structure. Upon removal of the radio energy pulse the protons precess at different rates due to local variations in the magnetic field (de-phasing)(Allen et al. 1997). To compensate for this effect the tool alternates the polarisation of the radio pulses (by 180° between pulses). The direction of precession is alternate and this increases the amplitude of the radio signal emitted by the protons in the transverse plane, (which is measured by the tool) as they lose energy by interactions.

The protons lose energy in three principle ways: interactions with the pore surface relaxation, $T_s$, bulk relaxation, $T_b$, and molecular diffusion, $T_{DG}$ (Kenyon 1997). The transverse relaxation, $T_2$, measured by the logging tool is a sum of these components in parallel:
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\[
\frac{1}{T_2} = \frac{1}{T_s} + \frac{1}{T_b} + \frac{1}{T_{DG}}. \quad \text{Equation 2.18}
\]

This may be re-stated as spin-echo amplitudes from the 180° pulse sequence, \( M(t) \), that are actually recorded:

\[
M(t) = M_0 \exp(-t/T_s) \exp(-t/T_b) \exp(-t/T_{DG}), \quad \text{Equation 2.19}
\]

where \( M_0 \) = the initial amplitude that reflects the porosity.

Proton interactions with the pore surface are most important for the calculation of porosity with NMR logging tools. The other two components are unrelated to the porosity and are therefore noise as far as porosity estimation is concerned.

The protons transfer their energy to the lattice of the matrix at the pore surfaces as they relax. The rate of energy transfer is dependent on the pore size, \( S/V_p \) (surface to volume ratio), and the surface relaxivity, \( \rho_{\text{sur}} \) (ability of the surface to cause the relaxation of the proton magnetisation):

\[
\frac{1}{T_s} = \rho_{\text{sur}} \frac{S}{V_p}. \quad \text{Equation 2.20}
\]

Thus the larger the pore the larger the signal amplitude recorded because the protons are able to resonate for longer before relaxation. The surface relaxivity, \( \rho_{\text{sur}} \), is a constant for any particular formation. The ‘constants’ are similar for sandstones, but different ‘constants’ are required for carbonates and other lithologies. The porosity can be directly measured by the sum of NMR \( T_2 \) amplitudes, provided the effect of the other two components is minimal:

\[
\phi = \sum \left( M_i \exp\left( -\frac{t}{T_2} \right) \right) = \sum \left( M_0 \exp \left( \rho_{\text{sur}} \frac{S}{V_p} t \right) \right). \quad \text{Equation 2.21}
\]

Interestingly, the surface relaxivity, \( \rho_{\text{oil}} \), of oil is usually smaller than for water. Therefore, by inspection of the \( T_2 \) amplitudes, oil and water maybe differentiated. The sum of the amplitudes will still provide accurate porosity values.
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The bulk relaxation, $T_b$, is dependent on temperature, $T$, and viscosity of the fluid, $\mu$.

$$\frac{1}{T_b} \approx \frac{\mu}{T}.$$  \hspace{1cm} \text{Equation 2.22}

Since the temperature can be measured and the viscosity of water is a constant at a given temperature, $T_b$ is usually a constant. The bulk relaxation can become significant in oils (especially tar), dependent on their viscosity.

In practice, the molecular diffusion relaxation time, $T_{DG}$, is not usually a problem for modern NMR logging tools (Kenyon 1997). The molecular diffusion relaxation, $T_{DG}$, is due to the inhomogeneity of the magnetic field and magnetic susceptibility differences between the matrix and fluids:

$$T_{DG} = \frac{12}{\gamma^2 G^2 D T_E^2},$$  \hspace{1cm} \text{Equation 2.23}

where $\gamma$ = the ratio of the Larmor frequency to the magnetic intensity, $G$ = spatial gradient of the magnetic field intensity, $T_E$ = echo spacing and $D$ = the molecular self-diffusion coefficient of the fluid. This effect can be important in formations or fluids containing paramagnetic ions. For example, siderite sandstone formations or oils containing vanadium.

Modern NMR tools are designed as pad mounted or mandrel openhole wireline tools (Allen et al. 1997). Both designs are such that they are insensitive to the borehole and rugosity assuming the effects are within the tolerances of the tool. The pad tools are focused so that their volume of investigation is sensitive to a depth of 1-6 inches (2.5-15 cm) into the formation. The tool can tolerate rugosity at least as well, if not better than, the density tools. The mandrel tools are focused on a cylindrical volume approximately 6 inches (15 cm) into the formation and can tolerate rugosity and washouts close to 6 inches (15 cm). LWD NMR tools are just becoming commercially available at present.
2.3.5 Resistivity log

There are a number of resistivity tools that measure the conductivity of the formation (Schlumberger 1989). The primary control on the resistivity (reciprocal of conductivity) is the formation porosity. The resistivity of shale free brine saturated formation, $R_t$, divided by the resistivity of the brine, $R_w$, is proportional to the reciprocal of the porosity, $\phi$, to the power, $m$ (typically 2) (Archie 1942):

$$\phi = \frac{R_w}{R_t}.$$  

Equation 2.24

Resistivity is seldom used for estimating porosity since its primary use is for calculating water saturation, which requires porosity as an input (Worthington 1985). However, the above equation can be used in water-saturated formations.

**Resistivity Cube**

1. Apply a known (regulated) DC voltage ($V$) across opposite sides of a 1 cubic meter sample.
2. Measure the current ($I$) flow.
3. Determine the resistance ($R$) from Ohm's law ($R = V/I$).

![Resistivity cube](Figure 2.23 Resistivity cube (Schlumberger 1999)).

The rock matrix can usually be assumed to be insulating. The conductive medium in the formation is the pore water (Archie 1942). If a cube is 100% water the porosity is 100% and the formation resistivity is equal to the resistivity of the water [Figure 2.23]. If rock, an insulator, is added to the same cube the porosity decreases and the formation resistivity increases. The relationship between formation resistivity and porosity is to the inverse square. However, the formation resistivity is also dependent
on the salinity, cementation, tortuosity, granular shape and size. This complicates the relationship between formation resistivity, \( R_n \), and porosity, \( \phi \) (Winsauer et al. 1952):

\[
R_n = \frac{a R_w}{\phi^m},
\]

Equation 2.25

where \( m = \) cementation factor (usually 2), \( R_w = \) water resistivity, \( a = \) constant (usually 1). One common variation is the Humble equation in which \( a=0.62 \) and \( m=2.15 \) (Winsauer et al. 1952). However, when hydrocarbons are present the proportion of pore space occupied by the hydrocarbon must be accommodated. The effect on formation resistivity of the water saturation, \( S_w \) is:

\[
R_n = \frac{a R_w}{\phi^m S_w^n},
\]

Equation 2.26

where \( n = \) the saturation exponent (usually 2). Therefore, in the presence of hydrocarbons an independent porosity or water saturation measurement is required. In practice, the density porosity is usually used for \( \phi \) and Equation 2.20 is rearranged for \( S_w \). The constants \( a, m, n \) and \( R_w \) are usually derived from core or using a Pickett plot [Figure 2.24]. Note that the main use of the resistivity measurement is to calculate a water saturation log with an independent porosity log as input.

Figure 2.24 Pickett Plot (Por-1 Schlumberger 1999).
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2.3.6 LWD Tools

This section describes LWD density and neutron porosity tools and highlights the differences between LWD and wireline tools. This section is only intended as a guide since a fair comparison between LWD and wireline tools can only be made with extensive computer modelling and field examples and is covered to a degree in the following chapter. The majority of the information in this section was derived from Schlumberger's Logging While Drilling booklet (Schlumberger 1995).

Most LWD companies combine the density and neutron tool into one drill collar [Figure 2.25]. The specifications of LWD density and neutron tools are similar between Service Companies, Schlumberger's specifications are given [Table 2.3]. The density neutron tool is always placed at the top of the toolstring furthest from the bit so that the nuclear sources can be retrieved by slickline if they become stuck [Figure 2.26]. Consequently the time when measurements are recorded may be several hours after penetration depending on the rate of penetration and bottom hole assembly.

<table>
<thead>
<tr>
<th>Measurement</th>
<th>Range</th>
<th>Accuracy</th>
<th>Statistical Precision</th>
<th>Vertical Resolution</th>
</tr>
</thead>
<tbody>
<tr>
<td>Neutron Porosity</td>
<td>0 to 100pu</td>
<td>0.5pu below 10pu 5% of reading for 10 to 50 pu</td>
<td>±1pu at 30pu at 50ft/hr [15m/hr]</td>
<td>13.2in [33.5cm]</td>
</tr>
<tr>
<td>Bulk Density</td>
<td>1 to 3.1g/cm³</td>
<td>±0.02g/cm³</td>
<td>±0.1g/cm at 2.5g/cm³ at 50ft/hr</td>
<td>6.2in [15.7cm]</td>
</tr>
<tr>
<td>Photoelectric effect</td>
<td>1 to 10units</td>
<td>±0.25units from 1 to 5.1units</td>
<td>±0.05units at 3units at 50ft/hr</td>
<td>2in [5cm]</td>
</tr>
</tbody>
</table>

Table 2.3 LWD porosity tool specifications (Table 6.1 Schlumberger 1995).
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Figure 2.25 Schematic of the CDN density neutron tool (Figure 6.2 Schlumberger 1995).

Figure 2.26 Schematic of typical LWD toolstring (Figure 2.4 Schlumberger 1995).
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LWD neutron porosity tools

There are at least three different LWD neutron porosity tool designs in present use. One design uses 3 He\(^3\) detector banks and 1 Geiger-Müller detector bank with a centralised 7Curie AmBe source. Another design uses an eccentric source with Li\(^6\) detector banks. The final design employs 4 banks of 4 Geiger-Müller detectors with an eccentric source (Hutchinson et al. 1991). All the LWD neutron porosity tool source/detector spacings are comparable with wireline neutron porosity tools.

The main differences between LWD and wireline neutron porosity tools are their environmental responses. The environmental corrections required are similar in magnitude for LWD and wireline apart from the standoff corrections. Due to the centralised source in the LWD tool, the sensitivity to standoff is much greater than for wireline. For example, at 40pu a 2in standoff would increase the LWD neutron porosity value by 12pu, but only 1.5pu to 3.0pu for the wireline values. This is due to the LWD tool being affected by removal of formation in all directions. The wireline tool is only affected by the removal of formation in front of the tool. This difference is particularly important for horizontal wells where LWD tools often experience significant standoff.

The different designs are used to overcome the problem of drill collar iron absorption of thermal neutrons (Burnett et al. 1990). Thermal and epithermal neutron measurement (He\(^3\) detectors) of apparent porosity show slightly less sensitivity to formation porosity than capture gamma ray measurement (Geiger-Müller detectors) in the LWD logging environment. The iron drill collar radiates the captured neutron energy as capture gamma rays, the resulting tool measurement characteristics are dependent on the iron drill collar. However, one advantage is that the collar displaces borehole fluid that has greater neutron slowing down power, but iron absorbs 9.8 times more thermal neutrons than water/mud. Thus, LWD neutron porosity tools (all have some capture gamma ray response) are less sensitive to borehole and formation salinity effects (Evans et al. 1988). This lack of sensitivity (the iron drill collar reduces the thermal neutron flux) leads to lower recorded porosity values than wireline tools, where no washouts are apparent. The effect has been observed to increase in the presence of high iron concentrations (siderite and glauconite)(Sakurai et al. 1992).
LWD density tools

LWD density tools vary in design considerably less than the neutron porosity tools. The detectors are scintillation counters or GM tubes and may be run with or without stabilisers. The 1.7Ci $^{137}\text{Cs}$ source is always eccentred (Hutchinson et al. 1991). The detector spacings for the LWD density tools are comparable with those of their wireline equivalents. Another notable difference is that the source and detectors are not inline, but offset in the direction of rotation [Figure 2.27].

LWD density tools with scintillation counters are dependent on the effectiveness of the stabiliser to exclude mud from in front of the detectors. Their response is more sensitive to enlarged and rugose holes and is different to wireline tools (Allen et al. 1990). The correction required for LWD tools is typically significantly greater than 1.5 times the correction “available” (far to near density difference) across the range of densities encountered in logging, thus magnifying any errors particularly affecting the near detector. The correction required for wireline tools is almost a constant 1.5 times the correction available [Figure 2.28].

The main reason for the superior quality of wireline density tools is that the standoff remains small due to the small size of the pad adjusting to the shape of the borehole. In addition, the photoelectric factor measurement is more challenging in the LWD environment because the 1 inch steel drill collar of the LWD density tools would eliminate all gamma rays with energy <100keV; without low Z (atomic number) ports in front of the source and detectors a photoelectric factor measurement is impossible.

The ports and stabiliser combine to produce a highly forward collimated density measurement. Along with the rotation of the tool leads to variable standoff during the density measurement process [Figure 2.29] and requires correction [Figure 2.30].

A statistical approach is used to account for the variable standoff based on the variability of the recorded count rate:

$$
\Delta \text{Variance} = \Delta \text{Variance}_{\text{measured}} - \Delta \text{Variance}_{\text{expected}}
$$

[Equation 2.27]
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Figure 2.27 Schlumberger CDN tool with stabiliser (Figure 6.1 Schlumberger 1995).

\[
\rho_{\text{true}} = 2.71 \text{ g/cm}^3 \text{ limestone formation}
\]

Correction required (\(\rho_{\text{true}} - \rho_{\text{ls}}\))

Correction available (\(\rho_{\text{ls}} - \rho_{\text{ss}}\))

Long-spacing density (\(\rho_{\text{ls}}\))

Short-spacing density (\(\rho_{\text{ss}}\))

1.5-g/cm\(^3\) nonbarite mud

Figure 2.28 Modelled CDN density response with stabiliser (Figure 6.12 Schlumberger 1995).

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where $\Delta$Variance is attributed to standoff. The standard deviation of the short spaced detector count rate is used to measure the variance due to its sensitivity to standoff. The short spaced count rate is sampled every 100msec and after 10sec (100 samples) the average and standard deviation are calculated (accounted for in the calculations [Equation 2.28]). The expected distribution is a normal distribution, if the variation is bigger than expected, then the change in count rate, $\Delta CR$ is such that:

\[
\Delta CR = 10\left(\sqrt{(SDS)^2} - \sqrt{0.1 \times DWS^2}\right), \quad [\text{Equation 2.28}]
\]

where $SDS$ = standard deviation of the short spaced count rate and $DWS$ = short spaced count rate. The maximum and minimum count rates are at one standard deviation, $DWS \pm ACR$, a compromise due to range of borehole shapes possible. The rotational correction, $\Delta \rho_{\text{rotate}}$ is based on this difference:

\[
\Delta \rho_{\text{rotate}} = \text{ShortSens} \times \ln\left(\frac{DWS + ACR}{DWS - ACR}\right), \quad [\text{Equation 2.29}]
\]

where $\text{ShortSens}$ = the short spaced detector sensitivity. The formation density is represented by the lowest count rate from around the borehole, $DWS - ACR$ and is used to calculate the short spaced maximum density. The maximum density observed, $\Delta \rho_{\text{max}}$, is equal to the average plus half the rotational variation correction of the short spaced detector, $\Delta \rho_{\text{rotate}}$ plus the usual corrections (See Section 2.3.1);

\[
\rho_{\text{max}} = \rho_l + \Delta \rho + B \times \rho_{\text{rotate}}, \quad [\text{Equation 2.30}]
\]

where $\rho_l$ = long spaced count rate, $\Delta \rho$ = density correction [$C(\rho_l - \rho)$, constant, $C > 1.5$] times the difference in the long and short spaced densities] and $B$= constant (0.5 in light muds and $-0.1$ in heavy muds).
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Figure 2.29 LWD density neutron tool in a vertical (top) and horizontal (bottom) borehole (Figure 6.10 Schlumberger 1995).

Figure 2.30 Standard deviation rotational correction method (Figure 6.14 Schlumberger 1995).
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LWD Caliper

Differential caliper values, \(DCAL\), can be generated by a statistical approach to the density count rate distribution (Best et al. 1990). The standoff effect, \(DCAL\), being dependent on the amount of standoff and the formation, \(\rho_b\), to mud density, \(\rho_{m eff}\), contrast;

\[
DCAL = \frac{A \times \Delta \rho_{rotate}}{\rho_b - \rho_{m eff}},
\]

where \(A\) = sensitivity factor is a polynomial [Figure 2.31]. The effective mud density is used because barite in the mud can make the measured bulk density appear greater than the actual bulk density.

Inaccuracies in density derived caliper values can arise due to the linear averaging of count rates in the algorithm (Spross et al. 1995). However, bulk density is dependent on the logarithm of the count rates. Hole size, hole shape, sample rate and density contrast affects the density value accuracy up to a 1" stand-off tolerance.

Figure 2.31 LWD density caliper response data (Figure 6.16 Schlumberger 1995).
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New LWD tools

New developments in tool design have included an LWD azimuthal density neutron tool, which is capable of producing a density image of the borehole from 16 sectors around the borehole (Holenka et al. 1995). This new LWD density tool is now using three ultrasonic transducers 120° apart to measure borehole diameter. A logical future development would be to produce an ultrasonic image of the borehole from the measurements to further aid the analysts.

LWD sonic tools are also available and an LWD NMR is in field trials. Soon there will be LWD measurement type equivalents of all the available wireline tools. However, it is doubtful if LWD measurements will ever truly match the intrinsic quality of wireline tools purely because of the adverse conditions under which the LWD measurements are made. Their primary advantage is still the early, if limited, data delivery and the potential of measuring the formation in near virgin conditions.

Brami (1991) provides a discussion of the effects of the different LWD tools offered by several Service Companies.
2.4 Porosity estimation/calculation

2.4.1 Crossplots

This section details common ways in which two or more porosity estimates are used to calculate porosity by the use of crossplots. The effects of shale and hydrocarbon on porosity estimates are discussed. It is stressed that particularly in the case of the choice of shale equations that the choice is preferably based on scientific data from core measurements. However, often subjective empirical correction factors are used, or a prescribed correction for equity reasons (to meet regulatory requirements), rather than a sound scientific relationship between the core and log data. There are a number of reasons for this approach:

- Firstly at present no logging tool provides accurate measures of clay volume or distribution therefore many comprises have to be made. Until an accurate clay-logging tool is developed, clay estimation will remain an art not a science.
- Secondly core data is often very sparse and therefore a core-log relationship may not necessarily be applicable on field wide basis.
- Thirdly specific relations between the measurable properties of minerals in a core lab are particularly difficult e.g. X-ray diffraction mineral identification may be in error by 50% or more (Doveton 1994). These errors are amplified in the logging environment.
- Fourthly there may be operational reasons for correction factors, such as the use of different companies’ logging tools and different generations of tools or due to tool minor malfunctions (e.g. poor calibration).

Frequently linear relationships are used for simplicity in the full knowledge that the true core-log clay relationship is non-linear. Most of the clay equations used are a derivative of the generic equations presented below.

It is normal to crossplot porosity logs to improve the porosity estimation (Schlumberger 1989). The common crossplots are density-neutron (Figure 2.32), density-acoustic, and neutron-acoustic. Logging company chart books contain
crossplots with the theoretical porosity curves for common lithologies assuming fresh water or brine is the saturating fluid. Modern logging software includes the porosity charts from which the appropriate crossplot porosity may be estimated. The crossplot porosity for the density/neutron crossplot may be estimated by (Bateman 1985):

\[
\phi = \frac{\phi_{n(Lime)} + \phi_{D(Lime)}}{2},
\]

Equation 2.32

where \( \phi_{n(Lime)} \) = neutron porosity in limestone porosity units and \( \phi_{D(Lime)} \) = density porosity in limestone porosity units. Although this method is in common use it is accepted only as a porosity estimate. Porosity crossplots are effective if the formation contains a linear mix of two of the three aforementioned lithologies (sandstone, limestone and dolomite) and are used with reference to theoretical curves for single lithologies to aid lithology identification. For more than two lithologies more logs are required as inputs [Figure 2.33].

Clay is the most common group of secondary matrix minerals and effectively replaces matrix and/or porosity with a material with different properties from that of the matrix and pore fluids (Bateman 1985). The crossplots can be adapted for shaly formations (Schlumberger 1989). Using the appropriate matrix values for clay, water and matrix, a triangle is formed. By equally dividing the triangle into ten percentile sectors the shale volume and porosity can be estimated (Figure 2.34). In addition, a clay indicator may be added to this plot, as a third input, by colour coding. For example, gamma ray values are useful to quantify the relationship between the crossplot clay volume. Clay is indicated by high gamma ray values, although problems exist with non-radioactive shales (some clays have very low K and Th contents), radioactive sands (often K-feldspar) and U rich formation fluids, U-salt deposits in organic matter or hardgrounds (Hurst 1990). This empirical method is frequently used despite its drawbacks. The principal drawback is that the choice of shale/clay point is subjective (Society 2001), therefore implementation is rarely repeatable.

The gamma ray log measures the natural gamma ray radiation of the formation and can be very useful for estimating the clay content of the formation (Ellis 1987). Predominant gamma ray emitters in common formations are Potassium, Thorium and Uranium, Potassium and Thorium being usually associated with clay minerals. Generally, the total gamma ray count rate is an excellent quantitative clay/shale volume...
measurement. The volume of clay/shale, $V_{sh}$, may be calculated from the gamma ray log, $GR$, by using empirical values for the shale gamma ray count, $GR_{shale}$, and the sand gamma ray count, $GR_{sand}$:

$$V_{sh} = \frac{GR - GR_{sand}}{GR_{shale} - GR_{sand}}.$$  \hspace{1cm} \text{Equation 2.33}

Problems with this clay volume estimate may occur when Uranium ions are mobile within the formation waters, or when the formation contains significant micas, feldspars, potassium evaporites, etc (Ellis 1987; Hurst 1990; Rider 1996). Clay distribution within the formation alters the choice of shale volume equation as this impacts the volume proportion of the formation calculated that is clay and therefore the porosity values (Katahara 1995).

Spectral gamma ray tools are able to separate the contributions to the total count rate of the three components. The use of the separate components can aid lithology identification. Thorium is usually associated with heavy minerals within clay and is usually the most reliable clay indicator especially when used in conjunction with Potassium (Hurst 1990). Potassium is associated with feldspars (arkose sandstones, granite) as well as clay minerals. Uranium is mobile, but may also associate itself with organic matter, often found within clay rich sediments (Hurst 1990). The spectral gamma ray can be invaluable in certain circumstances when it is impossible to differentiate lithology by any other means.

Where three or more lithologies are present additional information from other logs is required for accurate porosity estimation (Doveton 1994). In addition complex core, mineralogical and petrophysical studies may be required to establish relationships between the log measurements and the formation properties. Typically, gamma ray, $PEF$, SP and resistivity logs are used to indicate changes in formation properties as well as the porosity logs.

The photoelectric factor, $PEF$, is directly related to the formation chemistry [Equation 2.9] and can aid lithology interpretation when the volumetric components are considered (Bateman 1985). The total volumetric cross-section, $U_{total}$:

$$U_{total} = \sum_i (P_e \rho_e) V_i,$$  \hspace{1cm} \text{Equation 2.34}
where $\rho_e = \text{the electron density and } V = \text{the volume fraction of that material}$, is useful for lithology identification (porosity must be included as one of the volumetric components) and is a useful check for other methods of lithology identification [Figure 2.35].

**Figure 2.32** Company Crossplot for density and neutron porosity estimate (CP-1f Schlumberger 1999).
This crossplot may be used to help identify mineral mixtures from sonic, density and neutron logs. (The CNL neutron log is used in the above chart; the time average sonic response is assumed.) Except in gas-bearing formations, M and N are practically independent of porosity. They are defined as:

\[
M = \frac{t_1 - t}{\rho_h - \rho_f} \times 0.01 \text{ (English)}
\]

\[
M = \frac{t_1 - t}{\rho_h - \rho_f} \times 0.003 \text{ (metric)}
\]

\[
N = \frac{(\Phi_N) - \Phi_h}{\rho_h - \rho_f} \text{ (English or metric)}
\]

Points for binary mixtures plot along a line connecting the two mineral points. Ternary mixtures plot within the triangle defined by the three constituent minerals. The effect of gas, shaliness, secondary porosity, etc., is to shift data points in the directions shown by the arrows.

The dolomite and sandstone lines on Chart CP-8 are divided by porosity range as follows: 1) \(\phi = 0\) (tight formation); 2) \(\phi = 0\) to 12 p.u.; 3) \(\phi = 12\) to 27 p.u.; and 4) \(\phi = 27\) to 40 p.u.

**Figure 2.33** MID plot use density, neutron and sonic logs (CP-8a Schlumberger 1999).
Figure 2.34 Density-Neutron crossplot for shaley sandstones (Figure 8-15 Schlumberger 1989).

When only neutron and density logs are available, two different neutron and density formulae can be used to eliminate the effect of shale (Bateman 1985):

$$
\phi = \frac{\phi_D \times \phi_{NSh} - \phi_N \times \phi_{DSh}}{\phi_{NSh} - \phi_{DSh}}.
$$

Equation 2.35

$$
\phi = \frac{\phi_D \times \phi_{NSh} - \phi_N \times \phi_{DSh}}{(\phi_{NSh} - \phi_{DSh}) - (\phi_N - \phi_D)}.
$$

Equation 2.36
where $\phi_D = \text{density porosity}$, $\phi_{Dsh} = \text{shale density porosity (known or estimated)}$, $\phi_N = \text{neutron porosity}$, $\phi_{Nsh} = \text{shale neutron porosity (known or estimated)}$. This empirical method is used to offset the non-porosity effect of the two porosity measures and is analogous with the density-neutron-gamma ray crossplot where the shale point requires selection and suffers from the same drawbacks.

Typically, it is simple to solve the problem of shale by use of a crossplot, such as Figure 2.34, or more commonly to use a shale indicator and an appropriate shale property. Often the shale property (density, travel time, neutron porosity) differs from the matrix properties in such a way that porosity is overestimated (Ellis 1987).

The shale effect can be compensated for by using the appropriate shale property value measured in an adjacent shale bed (or estimated) and $V_{sh}$ is estimated from the gamma-ray log (Rider 1996)[Equation 2.33]. The appropriate formulae for density, neutron and sonic porosity with shale are respectively:

$$
\phi = \left( \frac{\rho_m (1-V_{sh}) + \rho_{sh} V_{sh} - \rho_b}{\rho_m - \rho_b} \right), \quad \text{Equation 2.37}
$$

$$
\phi = \phi_{\text{corrected}} - V_{sh} \phi_{\text{sh}}, \quad \text{Equation 2.38}
$$

$$
\phi = \left( \frac{\Delta t - (1-V_{sh}) \Delta t_m - V_{sh} \Delta t_{sh}}{\Delta t_m - \Delta t_b} \right), \quad \text{Equation 2.39}
$$

where $\rho_m = \text{matrix density}$, $\rho_{sh} = \text{shale density}$, $\rho_b = \text{bulk density}$, $\phi_{\text{corrected}} = \text{chart corrected neutron porosity}$, $\phi_{\text{sh}} = \text{shale neutron porosity}$, $\Delta t = \text{travel time}$, $\Delta t_m = \text{matrix travel time}$, $\Delta t_b = \text{fluid travel time}$ and $\Delta t_{sh} = \text{shale travel time}$ (Western 1985). The main problem is choice of shale point that can significantly alter the porosity values.

Empirical formulae are also in significant use for sonic porosity calculation, which are based on core. There are several formulae of the form (Khaksar et al. 1998):

$$
\frac{1}{\phi} = \frac{\Delta t}{A - B V_{sh}}, \quad \text{Equation 2.40}
$$

where $A$, $B$ and $C$ are empirically derived constants for core measurements. For example, the Han equation (Han et al. 1986):
This approach is often adequate to solve the problem of clay on a local or regional level. (Khaksar and Griffiths 1998) provides a detailed comparison of sonic porosity calculation methods.

Figure 2.35 Bulk density and apparent matrix volumetric photoelectric factor (CP-21 Schlumberger 1999).
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Note that NMR porosity is not affected to any significant extent by clay or lithology due to the processing used to calculate porosity although pore morphology can affect NMR porosity. New tools that have very short dead times (<5ms) can be used to estimate the effect/volume of clay (Allen et al. 1997).

Hydrocarbons can affect log porosity estimates because of the physical properties of the hydrocarbons. The most frequent problem is the hydrocarbon density/travel time compared with water. The fluid density is often lower (greater travel time) than water, especially for natural gas fields in which density and sonic measurements overestimate the porosity, whereas neutron measurements underestimate porosity (Bateman 1985). Generally, the correct porosity can be calculated by an appropriate choice of fluid density [Equation 2.2] and travel time [Figure 2.36]. An exception is tar, which can be of greater fluid density and lower travel time than water (Cunningham et al. 1992).

Figure 2.36 Fluid density estimate from density and neutron logs where \( S_{hr} \) is the hydrocarbon saturation and \( \rho_n \) is the hydrocarbon density (CP-10 Schlumberger 1999).
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The neutron porosity may be affected in a number of ways. The hydrogen index of the formation fluids is often less than that of water, especially for gas (Ellis 1986). This increases the neutron slowing-down length, decreasing the recorded porosity.

An additional feature of oils is the fact that carbon is a better moderator of neutrons than oxygen (Sherman et al. 1983). This effect results in a reduction in the slowing-down length (increased cross-section) and an apparent porosity increase compared with water of as much as 4-5% (reverse excavation effect). The details of the effect of crude oil are dependent on its composition compared with water. A correction can be applied once the oil’s hydrogen index is known. This could be acquired from a pressure tester sample.

Saturation may also need to be considered. Hydrocarbon saturation affects the pore fluid density, hydrogen index and neutron cross-section because the neutron and density values will be affected by the mix of the water and hydrocarbon properties (Schlumberger 1989). This is most frequently applied when gas is present (Cuddy et al. 1994). Using Equation 2.26 if resistivity logs are available and the hydrocarbon saturation, porosity may be corrected for hydrocarbons using a chart [Figure 2.37].

Another method uses an infrequently used empirical formulae to estimate the correction for the neutron and density porosity (Bateman 1985) based on (Gaymard and Poupon 1968):

\[ \phi_{Nh} = 2.2 \rho_h - 1.2 \rho_h^2, \quad \text{Equation 2.42} \]

\[ \phi_{Dh} = 1.7 - 0.7 \rho_h, \quad \text{Equation 2.43} \]

where \( \phi_{Dh} \) = density porosity hydrocarbon correction, \( \phi_{Nh} \) = neutron porosity hydrocarbon correction and \( \rho_h \) = hydrocarbon density. The correction is dependent on the hydrocarbon saturation, \( S_w \):

\[ \phi = \frac{\phi_N}{S_w + \phi_{Nh}(1-S_w)}, \quad \text{Equation 2.44} \]

\[ \phi = \frac{\phi_D}{S_w + \phi_{Dh}(1-S_w)}, \quad \text{Equation 2.45} \]
A simple and often used empirical method for calculating porosity in the presence of hydrocarbons (especially gas) is the square root porosity:

\[ \phi = \sqrt{\frac{\phi_{\text{corrected}}^2 + \phi_{\text{ncorrected}}^2}{2}} \]

where \( \phi_{\text{corrected}} \) = corrected density porosity and \( \phi_{\text{ncorrected}} \) = corrected neutron porosity (Bateman 1985). Hydrocarbon (especially gas) reduces neutron porosity, because of the low formation hydrogen index, but increases density porosity because of the low formation fluid density (Bateman 1985). The square root porosity does improve the precision of the porosity estimation compared to a single porosity estimator, but does not usually provide accurate porosity values. Tool responses and volumes of investigation differences result in different magnitudes of the gas effect on the density and neutron measurements (Cowan and Wright 1997).

NMR porosity is affected by hydrocarbon in a number of ways. Viscosity is important for oils, since this increases the recorded \( T_2 \) arrival time because of the smaller surface relaxivity of oil compared with water (Kenyon 1997). Most reservoirs are water wet and oil residing in the centre of the pores adds to the long relaxation times. However, the signal amplitude (proportional to porosity) is usually unaffected (but not always!). Oils containing vanadium (paramagnetic ions) have very different surface relaxivity compared with water. This may cause the oil to relax very rapidly, so the oil signal may be lost during the dead time before the tool starts recording the formation response. The signal amplitude of gas is usually very low compared with water because of the low proton concentration in the pore fluids. Therefore, low porosity and long \( T_2 \) arrival times (infrequent relaxations because of the low proton concentration) are recorded for gas. Special processing is often required if accurate porosity is required (Kenyon 1997).

In addition, clay bound water often relaxes very rapidly and a new generation of tools has been developed to capitalise on this property to provide an estimation of the clay volume. Although the distribution of the bound water is dependent on the clay structure which tends to produce underestimates of the clay volume due to bound water not being connected directly to the main pore volume by filament like clay particles.
Clay is conductive and leads to a reduction in resistivity giving the impression of greater porosity, but also more importantly masking the presence of hydrocarbons. The effect of clay on the travel times is primarily dependent on the mechanical strength of the shale comparatively with the mechanical strength of the matrix minerals. As a result the shale tends to have slower travel times compared with the matrix minerals, but this is not necessarily always the case.

The drawback with any of these combined measurement approaches to porosity estimation is that if one of the input porosity logs is incorrect then the derived porosity values will also be incorrect. The possibility exists for calculating a far worse porosity value than any of the individual components.

This nomograph estimates porosity in hydrocarbon-bearing formations using neutron, density and $R_o$ logs. The neutron and density logs must be corrected for environmental effects and lithology prior to entry into the nomograph. The chart includes an approximate correction for excavation effect, but if $p_i < 0.25$ (gases), the chart may not be accurate in some extreme cases: very high values of porosity (> 35 p.u.) coupled with medium to high values of $S_w$, and for $S_w = 100\%$ for medium to high values of porosity.

To use, connect the apparent neutron porosity point on the appropriate neutron stem with the apparent density porosity on the density stem with a straight line. From the intersection of this line with the porosity, $\phi$, stem, draw a line to the origin of the $S_h$ versus $\Delta \phi$ chart. Entering this chart with the hydrocarbon saturation, $S_h$, $(S_h = 1 - S_w)$ defines a porosity correction factor $\Delta \phi$. This correction factor algebraically added to porosity, $\phi$, gives the true porosity.

Example:

- $\phi_{\text{CNL}} = 12$ p.u.
- $\phi_{\text{Daw}} = 38$ p.u.
- $S_w = 50\%$

Therefore, $\phi = 32.2 - 1.6 = 30.6$ p.u.

Figure 2.37 Porosity correction hydrocarbon (CP-9 Schlumberger 1999).
2.4.2 Numerical solutions

A straightforward approach to porosity estimation may not be valid for example, complex lithologies in which the matrix of the formation may be limestone with significant dolomite and clay, a shaly arkose sandstone, or the presence of heavy minerals (Bateman, 1985; Doveton, 1994; Ellis, 1987; Rider, 1986; Schlumberger, 1989). Often, if more than one porosity tool is available, the different porosity estimates can be used to check or correct the porosity values calculated. However, this may still provide inadequate porosity estimates when compared with core porosity values due to the clay contents.

Empirical relationships may be used in these cases, but are often field or region specific. A number of techniques are used to derive porosity (and other) relationships: polynomial regression, mineral inversion, factor/principal-component analysis, cluster analysis, neural networks, genetic algorithms, and fuzzy logic (Doveton 1994; Elphick et al. 1996; Cuddy 1997). These methods all normally require the use of additional log values. The resistivity logs such as SP, laterolog, induction and electromagnetic propagation are less sensitive to lithology than the other logs and so are not always useful for differentiating complex lithologies, but nevertheless can resolve complex cases (Pickett 1973).

The problem with some of these techniques (neural networks and genetic algorithms) is that they may solve the problem of calculating porosity, but they may not provide any addition information. In other words, it is often difficult to relate any physical reasoning to the formulated relationship, for example the presence of micas.

Another method of obtaining accurate porosity in complex lithologies and facies is to run advanced logging tools (Lofts et al. 1995). The geochemical tool (Elemental Capture Spectroscopy tool) can provide the abundance of numerous elements (Si, Al, Ti, Fe, Ca, K, S, Gd, Th, U, indirectly Mg + Na) from which the formation mineralogy may be calculated. From a detailed mineralogy the formation density, and therefore porosity, may be calculated with increased accuracy (compared with density tools). However, the geochemical tool is very rarely used for oilfield evaluation because of the
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The Gassmann (1951) equation may be used to improve sonic porosity estimates. The Gassmann equation considers the mechanical properties of the formation and the fluids. The formation mechanical properties are dependent on the formation bulk and shear rigidity. The fluid properties are dependent on fluid salinity, dissolved gas, fluid pressure, temperature, water saturation, gas/oil ratio and fluid density. These properties may be described by the bulk moduli of the dry rock frame, the rock grains and fluid, and the shear modulus of the dry rock frame. The Gassmann equation (Gassmann 1951) re-arranged for porosity is:

\[
\phi = \left( \frac{K_f}{K_{gr} - K_f} \right) \left[ K_f \left( \frac{1 - \frac{K_f}{K_{gr}}}{\rho_b \frac{1}{\Delta t^2} - K_f - \frac{4}{3} G_f} \right) + \frac{K_f}{K_{gr}} - 1 \right], \quad \text{Equation 2.47}
\]

where \( K_f \) = dry frame bulk modulus (dynes/cm²), \( G_f \) = dry frame shear modulus (dynes/cm²), \( K_{gr} \) = grain bulk modulus (dynes/cm²), \( K_f \) = fluid bulk modulus (dynes/cm²), \( \rho_b \) = bulk density (g/cm³) and \( \Delta t \) = compressional wave travel time (m/μsec).

The bulk moduli of the dry rock frame, the rock grains and fluids may be measured in the laboratory or are known constants (Alberty 1996):

\[
K_x = V_{px}^2 \rho_x, \quad \text{Equation 2.48}
\]

\[
G_x = V_{sx}^2 \rho_x, \quad \text{Equation 2.49}
\]

where \( K_x \) = bulk modulus of the appropriate material, \( G_x \) = shear modulus of the appropriate material, \( V_{px} \) = compressional velocity of the appropriate material, \( V_{sx} \) = shear velocity of the appropriate material and \( \rho_x \) = density of the appropriate material. Several investigations of the magnitudes of altering the different parameters and the consequences (Whitman and Towle 1992; Holbrook et al. 1999). Other formulation are used such as Biot-Stoll model which is examined in Leurer (1997) and probably the most frequently used variant of the Gassman model (Xu and White 1995).
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When an array or dipole sonic tool is used in conjunction with a density tool the compressional and shear wave velocities and bulk density are measured continuously. Thus the dry frame bulk and shear moduli may be inferred and the bulk moduli for grains are published in data books (Alberty 1996). The bulk moduli for brines may be calculated using a chart given the salinity, temperature and pressure. However, the values of $K$ and $G$ should always be measured on core samples since textbook values are likely to be inaccurate. The effects of hydrocarbon can be significant. However, many studies exist on these effects and, with the aid of modelling the appropriate moduli values can be derived (Bourbie et al. 1987; Alberty 1996) and require significant core data to calibrate the equations.
2.4.3 Porosity: Approach used for thesis

This section describes techniques that are used in the data chapter (chapter 4) of this thesis (Gaymard and Poupon 1968; Wiley and Patchett 1994; Cowan and Wright 1997).

Gaymard

Gaymard and Poupon (1968) considered the effects of hydrocarbon and mud salinity on density and neutron measurements. A theoretical approach for log correction was derived, given that porosity may be more accurately calculated when the density, neutron absorption and hydrogen index of the formation fluids are accounted for. The theory assumes that the neutron and density tools measure the porosity of the invaded zone, which is saturated with mud filtrate and residual hydrocarbons with hydrocarbon density between 0 and 0.9 g/cm³. The formulae derived for density and neutron porosity estimates are (Gaymard and Poupon 1968):

\[
\phi_n = \phi \left(1 + S_h \left[ \frac{\rho_h (1.674 + 3.24 \rho_h + 9 \rho_h^2)}{1 - 0.4P} \right] - 1 + 0.4P \right), \quad \text{Equation 2.50}
\]

\[
\phi_d = \phi \left(1 + \frac{1.07 S_h [1.11 + 0.65P - \rho_h (1.186 + 0.36 \rho_h + \rho_h^2)]}{\rho_{mf} - 1 - 0.7P} \right), \quad \text{Equation 2.51}
\]

where \( \phi_d \) = density porosity, \( \phi_n \) = neutron porosity, \( \phi \) = true porosity, \( S_h \) = hydrocarbon saturation, \( \rho_h \) = hydrocarbon density and \( P \) = mud filtrate salinity. This method includes the presence of residual formation water. It ignores the possibility of significantly different salinity compared with the mud filtrate. In addition, through gas-oil transition zones, gas, oil, formation water and mud filtrate will all be present. In such cases the above formulae are unable to realistically represent the combinations of formation fluids. However, this method should still improve porosity estimates if the estimates/measurements of the mud filtrate salinity, hydrocarbon density and hydrocarbon saturation are accurate as would be available for a mature oilfield. Note: the effects of hydrocarbon will be greater at large formation porosity values. Porosity
estimates from the density and neutron tools maybe very different if invasion is less than 10 inches (25 cm) because of their differing depths of investigation (Cowan and Wright 1997). This method is rarely used as a simpler empirical method for calculating porosity will have been established prior to all the required information being available.

Wiley & Patchett

Wiley and Patchett (1994) used several different numerical codes to derive formulae for density and neutron measurements to calculate porosity estimates. The effects of lithology, invasion, tool investigation depths and reservoir fluids were considered. The codes used for the neutron and density measurements were three-group, three-dimensional, three region diffusion codes, which were benchmarked against stochastic Monte Carlo codes.

Accurate porosity (±1 pu) can be problematic; especially in high porosity, gas saturated reservoirs due to the uncertainties in the responses of the porosity tools in these circumstances. The formulae were developed primarily due to the inaccuracies of the standard square root porosity estimator for gas reservoirs [Equation 2.46]. The (Wiley and Patchett 1994) porosity formula derived for clean (shale free) sandstone is:

\[
\phi = 1.916 + 0.4253 \phi_n + 1.828 E^{-3} \phi_n^2 - 1.885 E^{-5} \phi_n^3 - 0.4903 \phi_D \\
+ 3.882 E^{-3} \phi_D^2 - 0.4397 E^{-3} (\phi_D^3 / 100)
\]

Equation 2.52

where \(\phi_D\) = density porosity (matrix density = 2.65 g/cm\(^3\) and fluid density = 1 g/cm\(^3\)), \(\phi_n\) = neutron porosity (sandstone scale). Additional formulae were also derived for alternative lithologies. This method is not in common use due to the modelling overheads required for the specific formation and borehole conditions encountered; there is significant appeal for generating porosity values given the correct input data.
Cowan and Wright (1997) studied anomalous porosity values in horizontal gas wells. Details of porosity estimation methods were given including the square method [Equation 2.46], (Wiley and Patchett 1994) [Equation 2.52] and a shallow iterative method. The shallow iterative method consisted of using:

1) The square root porosity with chart corrected neutron porosity values and density porosity assuming a sandstone matrix.
2) Calculating the hydrocarbon saturation \((1-S_w)\) using Archie’s equation [Equation 2.26] with the square root porosity.
3) Estimate the hydrocarbon density using a chart [Figure 2.36] or assume it is known.
4) Calculating corrections for bulk density and neutron porosity using the (modified) Gaymard and Poupon (1968) equations given below.
5) Add the corrections and calculate new density and neutron porosities.
6) Repeat until convergence.

Cowan and Wright (1997) modified Gaymard equations (Gaymard and Poupon 1968):

\[
\Delta \rho_b = \phi S_h \left[ (1.19 - 0.16 P) \rho_{mf} - A \rho_h - B \right], \quad \text{Equation 2.53}
\]

\[
\Delta \phi_N = \phi S_h \left[ (1 - P) \rho_{mf} - C \rho_h - D \right] \rho_{mf} (1 - P) + \Delta \phi_{Nex}, \quad \text{Equation 2.54}
\]

where \(\phi_D\) = density porosity, \(\phi_N\) = neutron porosity, \(\phi\) = true porosity, \(S_h\) = hydrocarbon saturation, \(\rho_{mf}\) = mud filtrate density, \(\rho_h\) = hydrocarbon density, \(P\) = mud filtrate salinity and \(\Delta \phi_{Nex}\) = excavation correction. For oil reservoirs, \(A = 1.19, B = 0.032, C = 1\) and \(D = 0.3\) and for gas reservoirs, \(A = 1.33, B = 0, C = 2.2\) and \(D = 0\).

The shallow iterative method provides water saturation values. However, it includes the same pitfalls as the Gaymard and Poupon (1968) method, but are largely compensated for by the process of iteration. Cowan and Wright (1997) suggested replacing the square root equation with the Wiley and Patchett (1994) equation in the shallow iterative method would further improve the accuracy of the porosity estimation.
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2.5 Summary

This chapter defines porosity in a geological and petrophysical context. An explanation of the basis of porosity estimation from core samples and openhole wireline and LWD logs is given. The theory and methodology covers density, neutron, sonic, NMR and resistivity tools and includes several core-based porosity measurements. The limitations of these techniques are explained and techniques to improve porosity estimation from log measurements are detailed with reference to clay.

Gas expansion core porosity is taken to be representative of the formation porosity for the purposes of this thesis. It is stressed that no method (core or logging) directly measures porosity. Porosity can only be estimated based on a related formation property. Density porosity estimates are the most reliable log porosity estimator in most circumstances. However, the use of more than one porosity estimation can improve accuracy. The agreement of more than one porosity estimation technique adds to the confidence in the porosity values estimated, but does not provide proof of correct porosity values. Simple techniques such as crossplotting can improve porosity estimates.

The gamma ray log can be used to estimate the volume of clay/shale that in turn can be accounted for. However, care must be taken because gamma ray logs can be affected by many factors related and not related to the presence of clay minerals. Likewise the photoelectric factor can be used to account for mixed lithologies, but maybe affected by weighted muds.

Specialist techniques such as polynomial regression, mineral inversion, factor/principal-component analysis, cluster analysis, neural networks, genetic algorithms, and fuzzy logic are mentioned and can be used in complex situations. However, these methods are time consuming and may not improve porosity estimation.

The descriptions given above rely heavily on published Schlumberger documents. The fundamentals of the measurements have firm groundings in physics and vary little between Service Companies. The main differences between service companies occur in the data collection and processing and not tool design where detectors and the spacings are all fundamentally the same wireline and LWD tools. Note that more than half the data used in this thesis was recorded by Schlumberger.

Tool related effects
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- The effects of non-parallel standoff can result in poor porosity values being recorded and often little or no indication of a problem is evident from the logs, although analysis of the individual detector count rates can provide an indication. For sonic tools, non-parallel standoff is accounted for in the tool design. There seems little recognition in the general literature of these (often significant) effects.
- Toolstring dressing (bowspring, cranks...) is important, since imbalance of the mechanical forces acting on the entire toolstring can impart turning motions leading to non-parallel standoff.
- Mud balling/rings (build up of mud on the tools e.g. on the leading edge of the density pad) can cause turning motions and non-parallel standoff.
- An under-gauge caliper log may indicate mudcake, but could be the tool running across a chord rather than the diameter of the borehole giving non-parallel standoff.

Clay/Shales

- Log responses in shales can be markedly different and can cause problems when making shale corrections to logs in shaly sand, often resulting from shales being out of the calibration range of the tool. Shale may contain a variety of rare earth minerals in minute quantities and variable amounts of bound water that can affect log responses.
- Problems exist with non-radioactive shales, radioactive sands, micas, feldspars, potassium evaporites and U rich formation fluids, U-salt deposits in organic matter or hardgrounds (Ellis 1987; Hurst 1990; Rider 1996).
- The effect of clay on the sonic travel time is primarily dependent on the mechanical strength of the shale compared with the mechanical strength of the matrix minerals. Shale tends to have slower travel times compared with the matrix minerals, but this is not necessarily always the case.
- Clay distribution within the formation alters the choice of shale volume equation as this impacts the volume proportion of the formation calculated that is clay and therefore the porosity values (Katahara 1995).

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- No logging tool provides an accurate measure of clay volume or distribution, therefore many compromises have to be made. Until an accurate clay-logging tool is developed, clay estimation will remain an art not a science.
- Specific relations between the measurable properties of minerals in a core lab are particularly difficult e.g. X-ray diffraction mineral identification may be in error by 50% or more (Doveton 1994). These errors are amplified in the logging environment.
- The principal drawback is that the choice of shale/clay point is subjective (Society 2001), and therefore implementation is rarely repeatable.

Noise

- Sonic log quality is mostly affected by noise sources of one type or another particularly from the actions of tool jewellery against the borehole. Stacking the waveforms from each receiver provides some immunity for array and dipole tools. The rejection of poor data from receivers improves the data (Kimball and Scheibner 1998).
- There may be operational reasons for correction factors, such as the use of different companies’ logging tools and different generations of tools or due to tool minor malfunctions (e.g. poor calibration).
- Additional problems in rugose and enlarged boreholes are often cyclic and require careful filtering (Nieto et al. 1995).

Hydrocarbon effects

- Hydrocarbons can affect log porosity estimates. The fluid density is often lower (greater travel time) than water, especially for natural gas fields in which density and sonic measurements overestimate the porosity, whereas neutron measurements underestimate porosity (Bateman 1985). The hydrogen index and capture neutron cross-section of the formation fluids is often less than that of water, especially for gas (Ellis 1986). This increases the neutron slowing-down length, decreasing the porosity (Sherman et al. 1983).
Chapter 2: Porosity: Definitions, measurement and calculation

- The effects of hydrocarbon can be significant on elastic moduli values of formations and can alter sonic porosity values.

**Multi-log porosity estimation**

- The drawback with any of these combined measurement approaches to porosity estimation is that if one of the input porosity logs is incorrect then the derived porosity values will also be incorrect. The possibility exists to calculate a far worse porosity value than any of the individual components.
- Accurate porosity in complex lithologies and facies may be achieved using data from advanced logging tools (Lofts et al. 1995), but because of the tools, poor performance in resolving different minerals and the non-unique chemistry of rock forming minerals (Harvey et al. 1992) can give poor results.
- Elastic moduli values require significant core data to calibrate the equations which may not be available.
- Tool responses and differences in volumes of investigation result in different magnitudes of the gas effect on the density and neutron measurements for example (Cowan and Wright 1997).
- Core data is often very sparse and therefore a core-log relationship may not necessarily be applicable on field wide basis.

**Log quality**

An extensive set of papers on log quality that deals with most of the issues raised in this chapter can be found in The Log Analyst (LPS 1994). The papers describe the problems of all core, wireline and LWD data collection and the potential effects on interpretation. In addition, Myers (1992) provides a thorough review of neutron logging and Brami (1991) provides a discussion of the effects of the different LWD tools offered by several Service Companies.
Chapter 3: Horizontal well porosity anomalies

This chapter reviews publications to provide an overview of present knowledge of horizontal well porosity anomalies. Firstly, horizontal wells and their uses are explained. Secondly, observed porosity anomalies in horizontal wells are described and the potential causes are detailed.

3.1 Horizontal wells and their application

Definitions of what constitutes a horizontal well vary considerably. “A horizontal well is a well drilled approximately horizontally within the confines of a reservoir approximately parallel to the formation boundaries” (Fritz 1991). For wireline logging tools any well greater than 60° (angles are always measured from vertical) will require pipe or coiled tubing conveyed logging to push the tools down the borehole. However, the term ‘horizontal well’ is used more frequently to refer to any well that deviates significantly from vertical (>75°). The diameter, length and radius of build (rate at which the angle of the borehole inclination is increased) of horizontal wells vary considerably depending on their purpose and are classified by radius of build [Figure 3.1](Bigelow et al. 1992). The radius of build of the borehole controls whether or not logs can be run and/or core can be extracted [Figure 3.1].

In recent years increasing numbers of horizontal wells have been drilled to improve reservoir drainage (Weber 1999). Drilling horizontal wells offshore is expensive and must be justified as the most cost-effective manner of overcoming a specific production problem, or simply the most cost efficient way to drain the reservoir. The production problems that may be encountered are:

- Tight formations. Horizontal wells open more migration paths or are possibly used as injector wells to provide water/gas drive or to induce fractures into the formation.
- Fractured formations. Drilling perpendicular to the fracture orientation means as many fractures as possible are intersected, often this requires horizontal drilling because fractures are oriented in the plane of minimum stress (often vertical).
- Channel sands. Drilling horizontally to intersect as many channels as possible.
• Water and/or gas coning problems can be delayed by using horizontal wells.
• Permeability barriers. Horizontal wells can drain otherwise inaccessible parts of the reservoir.

Figure 3.1 Schematic to demonstrate different types of horizontal wells (Figure 9 Bigelow et al. 1992) with radius and build information (Figure 3 Fritz 1991).
Chapter 3: Horizontal well porosity anomalies

3.2 Observed porosity anomalies in horizontal wells

Examples of porosity anomalies in horizontal well logs and different logging techniques are presented below. Possible sources of the perturbations and their likely affect on the recorded porosity values are discussed.

In recent years the validity of log-derived porosity and water saturation estimates from horizontal wells has been questioned. Numerous authors have suggested possible causes for high porosity values in horizontal wells (Allen et al. 1990; Betts et al. 1990; Day and Petler 1990; Woodhouse et al. 1991; Bigelow et al. 1992; Austin et al. 1994; Cuddy et al. 1994; Bedford et al. 1997; Cowan and Wright 1997; Ellis and Chiaramonte 2000). However, no comprehensive solutions have yet been put forward that explain convincingly the physical processes that result in anomalous porosity values from horizontal wells. The challenge is to produce robust guidelines for the interpretation of horizontal well porosity logs. Unfortunately, cores are seldom recovered from horizontal wells and direct comparison with the vertical well core porosity values may indicate anomalous porosity values in the horizontal well, but the cause of the porosity anomalies maybe ambiguous. Great care must be taken when comparing vertical well measurements with horizontal well measurements since lithology and facies, borehole and formation conditions may be radically different. Logging horizontal wells is often problematic for operational reasons, even when conditions are favourable.

A number of problems may adversely affect the log measurements from horizontal wells, which do not affect vertical well logs to the same degree for example, anisotropic mud invasion (either by gravity or high permeability anisotropy \([K_h/K_v]\)) (Woodhouse et al. 1991; Cuddy et al. 1994), debris (Cuddy et al. 1994), fractured/unstable borehole (Allen et al. 1990; Austin et al. 1994; Cuddy et al. 1994), bed boundary dip (White 1991), oval/enlarged hole (Cuddy et al. 1994) and preferential tool orientation (White 1991; Cuddy et al. 1994) can all affect the accuracy of porosity estimations from horizontal wells [Figure 3.2].

Note that Cuddy et al. 1994’s conclusions with regard to the incorrect pad alignment scenario [Figure 3.2] are not born out by experience of in excess of 100 horizontal wells analysed. In addition from observation of the diagram in Figure 3.2, it is clear that the caliper will read under bit size where the borehole is not washed out. It
is rare to observe an effect on the density correction log (DRHO), but not unknown and is dependent on mud type as DRHO compensates for parallel standoff. In this case the standoff is non-parallel therefore DRHO does not provide good standoff correction to bulk density, RHOB.

Asymmetric invasion.

This invasion profile is produced by asymmetric invasion because of high Kv/Kh ratio associated with the aeolian deposits. Typical Kv/Kh values lie in the range 5-10.

Fracturing.

Stress deformation of wellbore may increase pore space. However little or no sign of washouts were seen that would support such an idea, and any fractures would normally be seen at the side, not the bottom.

Loss of filtrate by gravity segregation.

It is possible that the filtrate could fall down and away from the wellbore due to gravity segregation. However this would require high vertical permeability, which is not observed in these wells.

Hole condition affected by keyseat.

A groove cut in the low side of the wellbore might give a low density, particularly if filled with cuttings. However no effects on DRHO or caliper logs were seen which would be expected.

Incorrect pad alignment.

Incorrectly oriented drillpipe may align the density tool sideways rather than down. This poor pad application might read tool low density. However, no effects on DRHO or the caliper were seen that would support this.

Figure 3.2 Horizontal well logging environment and the effect on measurements (Figure 3 Bedford et al. 1997).
Chapter 3: Horizontal well porosity anomalies

In the North Sea new vertical wells are often logged with wireline and/or LWD tools, but horizontal wells are generally only logged with LWD tools (Rider 1996). The differences between wireline and LWD tool responses can be significant (Coope 1983; Sakurai et al. 1992) as well as perturbations due to tool to formation contact, formation conditions, well conditions and the lithologies encountered.

- Wireline and LWD nuclear tools are not calibrated in shales therefore their readings will differ from one another and differ between Service Companies.

The above perturbations will generally lead to increased porosity measured in horizontal wells, as has been demonstrated by BP in four North Sea fields [Figure 3.3](Bedford et al. 1997). Figure 3.3 demonstrates that when considering horizontal porosity anomalies wells >75° inclination should be considered as horizontal since significantly lower densities (higher porosities) are observed at these deviations and will be used throughout this thesis. However, an exception is logging while drilling (LWD) neutron porosity values, which are expected to be slightly lower in a horizontal well than those observed in a vertical well, because of the eccentring of the LWD tool (Day and Petler 1990). For resistivity tools the main effect in horizontal wells is the low borehole to bed angle, which requires modelling and has been well documented (Anderson et al. 1990; Anderson et al. 1992; Gianzero et al. 1992; Vernon et al. 1993; Li et al. 1994; Anderson et al. 1996; Koelma et al. 1996; Wu et al. 1997). In contrast, there have been relatively few investigations that have included modelling of porosity tool responses (Day and Petler 1990; Austin et al. 1994; Cuddy et al. 1994; Bedford et al. 1997; Cowan and Wright 1997; Ellis and Chiaramonte 2000; Cannon and Kienitz 1999).

One long-term study described a large number of vertical and horizontal gas wells from the southern North Sea that were examined for porosity anomalies (Cuddy et al., Day et al. 1994; Bedford et al. 1997; Cowan and Wright 1997). The study illustrated that log porosity values overestimated porosity in horizontal wells regardless of tool type [Figure 3.3 and Table 3.1]. The overestimates appeared to increase with increased porosity and permeability.
Chapter 3: Horizontal well porosity anomalies

<table>
<thead>
<tr>
<th>Field</th>
<th>Number of Wells</th>
<th>Average Porosity (Horizontal - Vertical) (pu)</th>
<th>Average Porosity (pu)</th>
<th>Kf/Kv</th>
<th>Tool Types</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Vertical</td>
<td>Horizontal</td>
<td>Density</td>
<td>Neutron</td>
<td>Sonic</td>
</tr>
<tr>
<td>A</td>
<td>25</td>
<td>3</td>
<td>6</td>
<td>-2</td>
<td>2</td>
</tr>
<tr>
<td>B</td>
<td>18</td>
<td>2</td>
<td>4</td>
<td>1</td>
<td>2</td>
</tr>
<tr>
<td>C</td>
<td>17</td>
<td>1</td>
<td>9</td>
<td>4</td>
<td>12</td>
</tr>
<tr>
<td>D</td>
<td>11</td>
<td>3</td>
<td>15</td>
<td>2</td>
<td>N/A</td>
</tr>
</tbody>
</table>

Table 3.1 Horizontal/Vertical well porosity comparison (Table 1 Cowan and Wright 1997).

Figure 3.3 Comparison of density logs with borehole inclination from four fields with measurements from more than 80 wells (Figure 2 Bedford et al. 1997).
Chapter 3: Horizontal well porosity anomalies

The main source of perturbation was thought to be the well-known permeability anisotropy of the southern North Sea Rotliegend formation (Bedford et al. 1997). In horizontal wells the invasion will be generally greater at the sides of the borehole than below it because of permeability anisotropy (Woodhouse et al. 1991; Bedford et al. 1997; Cowan and Wright 1997). A porosity tool lying on the floor of a horizontal borehole would measure lower porosity (apparently more gas) in this situation, in the absence of fractures at the sides of the borehole, compared with the same tool in a vertical well (Bedford et al. 1997).

The author's experience of Canadian horizontal heavy oil wells where permeability anisotropy is insignificant, gas is 'seen' above the borehole roof even though nuclear tools are almost insensitive to the region behind them. If gas detection is a priority running the nuclear tools along the well roof should be considered. Tailoring the wireline toolstring configuration and/or processing algorithms (for LWD also) in a non-standard manner can meet the objectives of the logging program.

One horizontal well was studied using a wireline toolstring that included two density tools orthogonal to one another; included in the toolstring were sonic, resistivity and ultrasonic imaging tools (Bedford et al. 1997). The results demonstrated that, in this case, the downward facing wireline density tool porosity values measured higher porosity compared with vertical wells in that particular field [Figure 3.4]. The side facing density porosity values were expected to measure the true formation porosity. However, unexpectedly the side facing density measured greater porosity values than the downward facing density tool. The ultrasonic images revealed that there were fractures in the side of the borehole, which increased the formation porosity calculated [Figure 3.35]. The sonic porosity values were comparable with the vertical well values. The solution was to gas correct the density porosity values using the calculated water saturation values. A good match with the sonic porosity values could then be achieved.

• Running two orthogonal density tools as in the case of (Cuddy et al. 1994) to attempt to obtain at least one good quality density log can lead to the two density tools pulling towards one another giving two poor density logs (Samworth 2000).
Chapter 3: Horizontal well porosity anomalies

The study concluded that wireline sonic porosity was generally providing more reliable porosity values in horizontal gas wells (Note: Not always the case, see Austin et al. 1994 below). However, borehole conditions (fractures) and the proximity of ‘fast’ beds may affect the sonic porosity values, in which case the density porosity values would be used.

In the few horizontal wells in which sonic tools are run (approximately 5 to 10%), the sonic porosity seldom matches the other calculated porosities (Samworth 2000). This is especially so in low porosity formations (<5pu) in which the sonic travel time appears to be independent of porosity, although this is not born out by Austin et al. (1994) in which porosities were >5pu (see below). Sonic tools are rarely run in horizontal wells due to the sonic tool’s physical weakness and thus the increased risk of toolstring loss.

Figure 3.4 Schematic of results to demonstrate improvement of horizontal well porosity estimation from (Figure 5 Bedford et al. 1997).
Chapter 3: Horizontal well porosity anomalies

The permeability anisotropy resulted in shallow invasion below the borehole (<3cm) where the density readings were made and high porosity values were estimated due to poor fluid density estimation due to the presence of gas. Modelling was commissioned to support these results (Cowan and Wright 1997). The porosity estimation could be resolved by using wireline shallow resistivity or epithermal neutron tools to measure the gas saturation or if LWD tools were run to use the azimuthal density neutron tools available (Bedford et al. 1997). Several recommendations were made (Cuddy et al. 1994):

- Run an LWD azimuth density and neutron porosity tool.
- Shallow LWD resistivity needed to measure $S_{nx}$ and $S_g$.
- Time lapse LWD and wireline measurements allow time lapse studies of dynamic changes.
- Shear wave velocity values may solve porosity measurement problems because the shear wave is insensitive to fluid.
- Horizontal core can be used to calibrate porosity values.

The first two recommendations have subsequently been examined by Cannon and Kienitz 1999 in a deviated well (see below).

- Time lapse density porosity from up and down wireline logs in which several hours have elapsed between passes do not appear to show any discernible differences from some 100+ horizontal wells.

A more detailed study has investigated southern North Sea acoustic log responses; core acoustic travel times and core porosity values demonstrated discrepancies between the expected and observed sonic porosity values (Austin et al. 1994). The observed sonic travel time values were 2-3μs/ft lower than expected at 6pu porosity, but approximately 10μs/ft lower than expected at 15pu porosity. This would have led to overestimates of porosity by 5pu and underestimates of rock strength, resulting in conservative well completion strategies (Austin et al. 1994). Conventional core analysis, travel time readings in nearby calibration beds (50μs/ft anhydrite), core acoustic measurements [Table 3.2 and Table 3.3] and porosity values for the formation
from nearby vertical wells [Table 3.4] suggested that the sonic travel time logs were anomalous and not the other porosity logs. Image logs were run to assess situations where ‘fast’ beds were influencing the sonic logs. The acoustic core measurements and theoretical calculations were unable to account for the anomalous sonic porosity values, either by the presence of gas (as a result of anisotropic invasion) or in-situ stresses around the borehole [Table 3.3](Austin et al. 1994). Note that these observations contradict Cuddy et al. (1994) and Bedford et al. (1997)’s results above.

<table>
<thead>
<tr>
<th>Sample Number</th>
<th>Porosity (pu)</th>
<th>Core Travel Time (μs/ft)</th>
<th>Wireline Log Travel Time (μs/ft)</th>
<th>Difference Log-Core Travel Time (μs/ft)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>4.3</td>
<td>64.4</td>
<td>62.5</td>
<td>-1.9</td>
</tr>
<tr>
<td>2</td>
<td>7.1</td>
<td>78.1</td>
<td>76.3</td>
<td>-1.8</td>
</tr>
<tr>
<td>3</td>
<td>11.8</td>
<td>75.7</td>
<td>74.5</td>
<td>-1.2</td>
</tr>
<tr>
<td>4</td>
<td>11.1</td>
<td>74.5</td>
<td>73.3</td>
<td>-1.2</td>
</tr>
<tr>
<td>5</td>
<td>10.5</td>
<td>72.1</td>
<td>71.0</td>
<td>-1.1</td>
</tr>
<tr>
<td>6</td>
<td>12.9</td>
<td>73.9</td>
<td>73.7</td>
<td>-0.2</td>
</tr>
</tbody>
</table>

**Table 3.2** Comparison of core and log travel time values in vertical wells (Table 1a Austin et al. 1994).

<table>
<thead>
<tr>
<th>Sample Number</th>
<th>Porosity (pu)</th>
<th>Core Travel Time (μs/ft)</th>
<th>Wireline Log Travel Time (μs/ft)</th>
<th>Difference Log-Core Travel Time (μs/ft)</th>
<th>Theoretical Difference due to Gas Saturation* (μs/ft)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>17.8</td>
<td>84.4</td>
<td>94.8</td>
<td>10.4</td>
<td>6.7</td>
</tr>
<tr>
<td>2</td>
<td>19.3</td>
<td>84.5</td>
<td>91.5</td>
<td>7.0</td>
<td>7.1</td>
</tr>
<tr>
<td>3</td>
<td>18.1</td>
<td>82.7</td>
<td>92.3</td>
<td>9.6</td>
<td>6.1</td>
</tr>
<tr>
<td>4</td>
<td>17.1</td>
<td>80.2</td>
<td>90.3</td>
<td>10.1</td>
<td>5.4</td>
</tr>
<tr>
<td>5</td>
<td>16.5</td>
<td>80.4</td>
<td>90.6</td>
<td>10.2</td>
<td>6.0</td>
</tr>
</tbody>
</table>

* assumes 40su gas saturation, 60su liquid saturation.

**Table 3.3** Comparison of core and log travel time values in horizontal wells (Table 1b Austin et al. 1994).

<table>
<thead>
<tr>
<th>Horizontal Well</th>
<th>Average Density Derived Porosity (pu)</th>
<th>Average Sonic Derived Porosity (pu)</th>
<th>Average Vertical Well ‘Target’ Porosity (pu)</th>
<th>Density Derived Porosity minus ‘Target’ Porosity (pu)</th>
<th>Sonic Derived Porosity minus ‘Target’ Porosity (pu)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>13.5</td>
<td>18.4</td>
<td>14.4</td>
<td>-0.9</td>
<td>4.0</td>
</tr>
<tr>
<td>B</td>
<td>16.7</td>
<td>22.4</td>
<td>14.2</td>
<td>2.5</td>
<td>8.2</td>
</tr>
<tr>
<td>C</td>
<td>12.7</td>
<td>Sonic Failed</td>
<td>13.1</td>
<td>-0.4</td>
<td>N/A</td>
</tr>
<tr>
<td>D</td>
<td>11.2</td>
<td>15.2</td>
<td>10.8</td>
<td>0.4</td>
<td>4.4</td>
</tr>
</tbody>
</table>

**Table 3.4** Comparison of log sonic and density porosity values in horizontal and vertical wells (Table 2 Austin et al. 1994).
Chapter 3: Horizontal well porosity anomalies

Recommendations for sonic logging in horizontal wells were (Austin et al. 1994):

- Sonic velocity values must be calibrated with core.
- Log responses can often be explained by borehole images.
- Sonic velocity values are slow in horizontal gas wells because the sonic travel time log values are too high in high porosities.
- Core sonic porosity match non-sonic log porosity.
- Sonic logs cannot be used for porosity or rock strength calculations in horizontal gas wells.
- Shear wave velocity values may provide a solution because the shear wave is insensitive to fluids.

Summary of observed porosity anomalies

Anomalous porosity values are observed in horizontal wells when compared with vertical wells within the same reservoir unit. Two studies (Cuddy et al. 1994; Austin et al. 1994) from the North Sea both concluded that horizontal well porosity values were too high compared with expected values. A number of recommendations (below) were made some of which are examined in the next section of this chapter.

- Run an LWD azimuth density and neutron porosity tool to search azimuthal porosity values for the most representative porosity value (Cuddy et al. 1994).
- Shallow LWD resistivity needed to measure $S_{xo}$ and $S_g$ for hydrocarbon corrections to porosity logs (Cuddy et al. 1994).
- Time lapse LWD and wireline measurements allow time lapse studies of dynamic changes and potential a measure of formation permeability (Cuddy et al. 1994).
- Shear wave velocity values may solve porosity measurement problems because the shear wave velocity is insensitive to fluid (Cuddy et al. 1994; Austin et al. 1994).
- Horizontal core can be used to calibrate porosity values. (Austin et al. 1994).
- Log responses can often be explained by borehole images allowing the rejection of data affected by fast beds (Austin et al. 1994).
Chapter 3: Horizontal well porosity anomalies

- Sonic velocity values are slow in horizontal gas wells because the sonic travel time log values are too high in high porosities (Austin et al. 1994).
- Sonic logs cannot be used for porosity or rock strength calculations in horizontal gas wells (Austin et al. 1994).

The author’s opinion is that the problems of logging tool deployment (either LWD or wireline) in horizontal wells is not sufficiently addressed in published papers. The author’s experience is that wireline tools may not be running in-hole as intended and that inclination and deviation data should routinely be recorded for all horizontal wells (including LWD) as log quality control. Common calibration standards for wireline and LWD tools in limestone, dolomite, sandstone and importantly shale need to be established, although the CALLISTO facility does address this need for limestone, dolomite and sandstone (Samworth and Lovell 2000). Additional observations are:

- Time lapse density porosity from up and down wireline logs in which several hours have elapsed between passes do not appear to show any discernible differences.
- Wireline and LWD nuclear tools are not calibrated in shales therefore their readings will differ from one another and differ between Service Companies. This affects shale volume corrections to porosity logs.
- Running two orthogonal density tools can lead to the two density tools pulling towards one another, resulting in poor alignment of both tools against the borehole and giving two poor density logs (Samworth 2000).
3.3 Perturbation sources

The sources of porosity and tool response anomalies can be broken down into three categories, 3.3.1 tool errors, 3.3.2 borehole conditions and 3.3.3 formation conditions. The questions are:

- Is a tool response due to a formation property, borehole condition or a tool measurement error?
- What methods are the best for estimating the actual formation properties?

The problem is less straightforward than for vertical wells when comparing idealised logs in vertical and horizontal wells (White 1991)[Figure 3.5].

3.3.1 Tool errors

*LWD and wireline comparison*

There are two different types of tools used for formation evaluation in open-holes: wireline and logging while drilling (LWD).

Open hole wireline logging is performed post-drilling and pre-casing, once mud circulation has ceased. Wireline logs are accepted as the most reliable logging form of continuous formation evaluation data but all wireline formation evaluation tools are primarily designed for logging vertical wells. Nuclear wireline tools are all calibrated to the same standard formations at the University of Houston notably all limestones, no sandstone, dolomite or shale [Figure 3.6].

- Wireline logs from tools built by different companies can vary significantly as conditions deviate from the standard conditions (Coope 1983).

LWD logging tools are an integral part of the bottom hole assembly (BHA) which often consists of the bit, downhole motor, bent sub, stabilisers, drill collars and a directional/inclination measuring tool [Figure 3.8]. The LWD tools primary purposes are to act as drill collars and to remain in one piece while drilling, not as logging tools (Allen et al. 1990; Woodhouse et al. 1991; Jackson et al. 1994; Prilliman et al 1995).
LWD tools have to cope with many more measurement perturbations (mud circulation, chippings, vibrations) in comparison with wireline tools in the same well, although new memory wireline tools can operate during mud circulation.

![Deep resistivity response seen by sensor logged across 300' of formation. Response changes at depths 'A' and 'B'.](image1)

![Unique geological model derived from curve in Fig. 1a assuming near vertical incidence to bed boundaries.](image2)

**Figures 1c to If** - These models show four possible different interpretations of Figure 1a assuming wellbore is horizontal. Here more data is needed to identify the correct geological model.

![Approximate volume seen by induction tool.](image3)
![Approximate volume seen by density tool.](image4)

**Figure 3.5** Schematic to demonstrate the non-uniqueness problem when interpreting horizontal well logs (Page 7 White 1991).
Chapter 3: Horizontal well porosity anomalies

The LWD tool design varies greatly between manufacturers and there are no common calibration tools available. LWD data should be analyzed directly using the API standards, and then compared to log data from conventional measurement while drilling (MWD) tools using the University of Houston calibration pit (Kleinschmidt et al., 1990).

Continuity, however, can be improved if the calibrations are of formation evaluation quality (Ohtsuka et al., 1993). These calibrations, especially in the horizontal well environment, are subject to measurement artifacts that should not be confused with formation boundaries. Additional calibrations are available from various sources.

Figure 3.6 Schematic of the nuclear tool calibration pit at the University of Houston (Analysts 1997).

Figure 3.7 Schematic of the assumed logging environment (Gen3 Schlumberger 1999).
Chapter 3: Horizontal well porosity anomalies

The LWD tool design varies greatly between manufacturers and there are no common calibration standards, although Service Companies attempt to replicate wireline responses. LWD tools are not calibrated to API standards directly because the tools outside diameters are too large to run in the API calibration pits at the University of Houston [Figure 3.6]. The calibrations are carried out in-house to a convenient standard and then extrapolated to an apparent API value (Hutchinson et al. 1996).

Confusingly, LWD measurements are also called measurement while drilling (MWD), but the important difference is that LWD measurements are of formation evaluation quality (2-3 samples per ft) whilst MWD measurements are of lower resolution (Theys et al. 1996). However, LWD and MWD are often used interchangeably in the literature and to add to the confusion, measurement after drilling (MAD) also uses the same tools as LWD and MWD. The author is only aware of MAD measurements of formation evaluation quality, but it should not be assumed that MAD measurements are always of formation evaluation quality.

Wireline drawbacks

The logging assumption that the formation is approximately isotropic perpendicular to the borehole axis is more likely to be violated in horizontal wells [Figure 3.7, Figure 3.27 and Figure 3.28] and conditions are more likely to deviate from calibration conditions (primary calibration in vertical wells). For example, shoulder beds can affect horizontal well values for hundreds of feet (Singer 1992).

When horizontal wells are logged with wireline tools the tools may not perform optimally. Wireline tools also require a tool turner that orientates the tools so that directional sensors run along the low side of the borehole pointing into the formation. For vertical well logging the toolstring is pulled to the bottom of the borehole by gravity. The process of logging in horizontal wells is time consuming and more likely to damage tools and the borehole due to the need to push the tools down.
Chapter 3: Horizontal well porosity anomalies

Figure 3.8 Schematic of a BHA including an LWD tool (INTEQ 1999).
Chapter 3: Horizontal well porosity anomalies

Wireline tools use skids and pads in combination with bowsprings and caliper arms to eccentric the tool body to attempt good formation contact in both vertical and horizontal wells. Pad/skid to formation contact or centralisation of a wireline tool also may not be as reliable in horizontal wells as compared with vertical wells. Poor pad/skid to formation contact normally produces increased apparent formation porosity values. A non-zero density correction, $DRHO$, and out of gauge (different from the bit size) caliper reading may also indicate standoff (poor pad/formation contact).

Logging speed affects not only the location of the measurements but also the tool performance. Problems of the borehole bridging can cause the toolstring to become stuck. Sticking is more problematic for wireline tools due to the greater formation exposure time to mud. Normally sticking problems are automatically corrected for and are not usually detrimental to the final wireline logs. Note: sticking in horizontal wells is more likely because mud formation exposure is usually longer than with vertical wells and the conveyance technique is physically larger than a wireline cable.

**LWD drawbacks**

LWD and wireline logs usually agree in vertical wells, mainly because LWD tools remain centralised in the borehole while drilling (as during calibration). However as Data Set 1 [See Chapter 4] demonstrated that MAD (after wireline logging in this case) and wireline measurements can be quite different in vertical wells. LWD logs are often the only formation evaluation data obtained from a horizontal well (Rider 1996).

The main advantage of LWD measurements is that mud invasion can be very shallow and so the likelihood of measuring the virgin formation properties is greater than that for wireline tools. LWD data can be of superior quality to wireline when extensive formation damage and/or invasion occur while mud circulates for long periods prior to wireline logging. LWD tools are often run as insurance logs or as a cost saving measure in horizontal wells, since pipe conveyed wireline logging is expensive because of the additional rig time as usually a dedicated well trip is required. However, wireline memory logging negates a dedicated trip as the well is logged during well conditioning.

For LWD tools the logging speed or ROP (rate of penetration) is dependent on the drilling operation and the sample rate. The LWD data is recorded downhole in time and converted to depth at surface. LWD data quality can be affected if the well is
drilled too fast as there will be too few samples per unit length (indicated by tick marks on the log), then the values will not be representative of formation properties and a saw-toothed log may result. Nuclear logs are statistical measurements and require a minimum acquisition time per depth increment, sample rate $\div$ ROP, to produce a reliable continuous log. Conversely, if the well is drilled too slowly, the tool memory may be full before the zone of interest is logged completely or at all (Allen et al. 1990; Brami et al. 1991; Hutchinson et al. 1996).

Poor quality LWD log data can result from poor time-depth data provided by the drilling system. Often drilling depth systems are not robust or reliable; producing data that contains errors such as communication errors leading to lost time-depth data; driller’s depth corrections; and algorithm corrections to the depth. The physical position of the depth encoder on the rig can also be a factor for accurate depth recording. The problems with time-depth data result in misplacing of log data in depth which alters the apparent bed thickness, also depth derived logs such as array resistivity and sonic logs depend on correct depth indexing for their log processing.

LWD and wireline logs may not be the same because the tools’ spectral responses are different and will diverge further when the measurement conditions and formation become increasingly different from the standard conditions. If core data is available core calibration of the logs should be used to provide a common point of reference between LWD and wireline tool responses. This approach may suggest the source of any differences between the logs. Another approach may be applied if tools are run to log a specific horizon in a horizontal well. The tools can be calibrated within the reservoir using a well-known marker bed (e.g. anhydrite bed) from knowledge gained in previous logging runs, including core and log data in nearby pilot holes. If there are differences between expected and actual values, and the borehole conditions are good, then there may be a tool problem or new formation property information.

The two main constraints on LWD tools are that the sensors are behind an inch of steel and direct formation contact is not possible. This imposes restrictions on LWD porosity tool design, especially the density tool which is very sensitive to standoff. Essentially LWD tools are mandrel tools (a smooth pipe) with varying degrees of eccentricing in the borehole (Allen et al. 1990; Day and Petler 1990). LWD tools are normally centralised in vertical wells, but eccentric in horizontal wells because gravity and the restrictions of the borehole prevent centralisation. To overcome some of these
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problems LWD density tools use the minimum azimuthal count rate to provide the bulk density measurement (Allen et al. 1990). This is based on the premise that errors due to standoff tend to increase the count rate. The measurement is most probably made from the low side of the borehole because the tool is weighted on to the low side of the borehole, although instances of the LWD tools ‘riding’ the borehole to the right hand wall during drilling (always clockwise) have been reported leading to the maximum density values being recorded from the right hand quadrant.

Data recorded with azimuthal LWD neutron and density tools; after the Data Set 1 data presented in Chapter 4 was recorded but in the same field, demonstrated the ‘riding the borehole’ effect in horizontal wells. In fact the LWD density and neutron tool ‘riding the borehole’ and the eccentric tool were the reasons for the poor LWD porosity measurements detailed in Chapter 4. This demonstrates that new LWD logging tool technology is being driven by the need to evaluate horizontal wells as well as by the need to provide data as close to wireline quality as attainable. This is being progressed, for example, by improvements in LWD tool design to cope with such gravity related effects.

Summary of LWD and wireline differences

The differences in recorded wireline and LWD values can be attributed to (Jackson et al. 1994):

- Differences in sensor physics can produce different logs in identical conditions due to the slightly different source-detector spacings, investigation depths and spectral responses. In particular, neutron porosity can vary by 4-6pu due to epithermal, thermal, capture gamma ray and lithology responses. LWD gamma ray tools measure potassium rich values, so are more sensitive to shale and KCl mud.
- The method of source-detector to formation contact will affect responses. Wireline tools uses pad, skid or mandrel contact but LWD tools may use low absorption ports through the stabilisers or can be run slick (without stabilisers). This is problematic for the LWD density measurements particularly due to the effects of standoff.
- The basic reference standards are different.
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- Environmental corrections must be applied to the wireline and LWD data to common standard conditions.
- Filtrate invasion effects change between LWD, MAD and wireline logging runs.
- Formation alteration including clay alteration can have occurred.

LWD neutron porosity tool modelling

Day and Petler (1990) undertook numerical modelling of an LWD capture gamma ray neutron porosity tool in a horizontal well (eccentred on the low side of the hole) as compared with a vertical well (centred) to assess the likely error in apparent porosity measured by the tool [Figure 3.9]. The modelled tool’s outside diameter was 7 inches and the near and far detectors were assumed annular. The simulated formation was 25pu fresh water saturated sandstone, the borehole diameter and borehole fluids were altered and the centred and eccentred responses compared [Table 3.5].

One example of a LWD neutron detecting porosity tool was numerically modelled [Figure 3.10] clearly demonstrated that eccentring a LWD neutron porosity tool would decrease the measured porosity. This is as a result of the displaced fluid from in front of the detectors as the tool is against the wall.

- LWD neutron porosity values in horizontal wells should measure lower values than the same tool would in an equivalent vertical well (Day and Petler 1990).

<table>
<thead>
<tr>
<th>Borehole Diameter (inches)</th>
<th>Borehole Fluid</th>
<th>Near Detector Porosity (pu)</th>
<th>Far Detector Porosity (pu)</th>
</tr>
</thead>
<tbody>
<tr>
<td>9</td>
<td>Water</td>
<td>22</td>
<td>24</td>
</tr>
<tr>
<td>10</td>
<td>Water</td>
<td>17</td>
<td>22</td>
</tr>
<tr>
<td>10</td>
<td>12 ppg Mud</td>
<td>20</td>
<td>23</td>
</tr>
<tr>
<td>10*</td>
<td>Water</td>
<td>15</td>
<td>20</td>
</tr>
</tbody>
</table>

* Calculated for a neutron detecting LWD neutron porosity tool.

Table 3.5 Porosity values for a modelled LWD capture gamma ray neutron porosity in a horizontal well (Constructed from Figures 3 to 5 Day and Petler 1990).
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Figure 3.9 Schematic of an LWD neutron porosity in a vertical (and calibration) well and a horizontal well (Figure 2 Day and Petler 1990).

Figure 3.10 Detector response for an eccentric LWD neutron porosity (neutron detecting) tool rotating in 10inch water filled borehole. The solid lines represent the centred tool and the dotted lines represent the eccentric tool (Figure 5 Day and Petler 1990).

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LWD and wireline comparisons

A comparison of LWD and wireline porosity tools in the Alaskan Endicott field horizontal wells demonstrated that LWD tool stabilisation and sampling frequency are important considerations for LWD logging (Cunningham et al. 1990), especially when a long bit run is expected such as for MAD runs that are useful for monitoring invasion. Table 3.7 compares wireline and LWD formation evaluations for the horizontal well 4 and Table 3.6 the formation properties used for the comparisons.

- The results showed LWD tools should be stabilised with full gauge stabilisers immediately above and below the tool to reduce lateral drillstring motion and poor centralisation, which would lead to erratic readings.

Positioning of the LWD tools as close to the bit as possible is also critical. The closer the tools are to the bit, the shorter the formation exposure time to the mud and thus invasion is shallower. However, the neutron tool (usually combined with the density) is usually furthest from the bit in the LWD toolstring to allow source retrieval if the LWD tools become stuck and to avoid formation activation that may affect gamma ray readings. The neutron porosity comparison of wireline and LWD readings demonstrated good agreement, except in shale and coal intervals [Figure 3.11] where differences greater than 2-3pu were observed affecting the shale volume calculation.

- A different shale point would be required in the density and neutron porosity calculation leading to potentially incorrect porosity and water saturation values.

<table>
<thead>
<tr>
<th>Kekiktuk Formation</th>
<th>OOIP (MMstb)</th>
<th>Porosity (pu)</th>
<th>Permeability (mD)</th>
<th>Gross Thickness (feet)</th>
<th>Net/Gross</th>
<th>(1-sw) (su)</th>
</tr>
</thead>
<tbody>
<tr>
<td>3C</td>
<td>258 (23%)</td>
<td>18</td>
<td>300</td>
<td>180-250</td>
<td>0.33</td>
<td>82</td>
</tr>
<tr>
<td>3B</td>
<td>107 (9%)</td>
<td>18</td>
<td>150</td>
<td>90-170</td>
<td>0.21</td>
<td>80</td>
</tr>
<tr>
<td>3A</td>
<td>185 (17%)</td>
<td>23</td>
<td>800</td>
<td>115-240</td>
<td>0.45</td>
<td>91</td>
</tr>
<tr>
<td>2B</td>
<td>256 (23%)</td>
<td>23</td>
<td>1500</td>
<td>30-160</td>
<td>0.90</td>
<td>90</td>
</tr>
<tr>
<td>2A</td>
<td>291 (26%)</td>
<td>22</td>
<td>1500</td>
<td>190-230</td>
<td>0.81</td>
<td>94</td>
</tr>
<tr>
<td>1</td>
<td>20 (2%)</td>
<td>15</td>
<td>150</td>
<td>105-280</td>
<td>0.19</td>
<td>78</td>
</tr>
</tbody>
</table>

Table 3.6 Properties of the formation used for the comparisons (Figure 2 Cunningham et al. 1992).
Chapter 3: Horizontal well porosity anomalies

<table>
<thead>
<tr>
<th>Zone</th>
<th>Net Pay (feet)</th>
<th>Average Porosity (pu)</th>
<th>Average S_e (su)</th>
</tr>
</thead>
<tbody>
<tr>
<td>3C</td>
<td>Wireline 78.4</td>
<td>16.76</td>
<td>22.71</td>
</tr>
<tr>
<td></td>
<td>LWD 92.3</td>
<td>22.22</td>
<td>15.61</td>
</tr>
<tr>
<td>3B</td>
<td>Wireline 37.9</td>
<td>19.71</td>
<td>15.61</td>
</tr>
<tr>
<td></td>
<td>LWD 40.1</td>
<td>15.49</td>
<td>23.64</td>
</tr>
<tr>
<td>3A</td>
<td>Wireline 164.9</td>
<td>23.52</td>
<td>7.73</td>
</tr>
<tr>
<td></td>
<td>LWD 153.5</td>
<td>22.54</td>
<td>8.68</td>
</tr>
<tr>
<td>2B</td>
<td>Wireline 97.5</td>
<td>24.26</td>
<td>24.28</td>
</tr>
<tr>
<td></td>
<td>LWD 96.7</td>
<td>24.60</td>
<td>36.02</td>
</tr>
<tr>
<td>2A</td>
<td>Wireline 163.2</td>
<td>21.41</td>
<td>16.28</td>
</tr>
<tr>
<td></td>
<td>LWD 165.2</td>
<td>22.43</td>
<td>22.80</td>
</tr>
<tr>
<td>OIL</td>
<td>Wireline 212.8</td>
<td>23.73</td>
<td>7.92</td>
</tr>
<tr>
<td></td>
<td>LWD 195.3</td>
<td>22.87</td>
<td>8.28</td>
</tr>
<tr>
<td>GAS</td>
<td>Wireline 141.3</td>
<td>17.14</td>
<td>23.73</td>
</tr>
<tr>
<td></td>
<td>LWD 142.8</td>
<td>22.74</td>
<td>20.31</td>
</tr>
</tbody>
</table>

Table 3.7 LWD/Wireline porosity comparison in well 4 [non-stabilised density] (Table 1 Cunningham et al. 1992).

The LWD density tool measurements may be compared with wireline measurements in Table 3.7 and Figure 3.11. In zones 3C and 3B, there may be differences of up to 5pu between wireline and LWD readings potentially affecting shale volume and hence porosity values. Often the large differences correspond to non-pay shaley intervals with up to 10 inches of borehole enlargement. However, horizontal well 12 demonstrated that the LWD density was reading too high bulk density (low porosity) when checks were made against wireline and core measurements.

- Clay hydration between the LWD density and wireline measurements could not be ruled out and could have caused the departure of the logs (Cunningham et al. 1990).
- Non-parallel standoff from LWD and/or wireline tool running across a chord could also result in the LWD and wireline differences (Samworth 2000).

A dual source LWD density was run in another well in tandem with a single source tool and a LWD neutron tool, although no wireline tools were run. The logs demonstrate that the dual source density readings were less erratic and in close agreement with the neutron porosity values in shale free formations [Figure 3.12] due to improved count rate statistics and standoff correction available from dual source tools.
Cunningham et al. (1992)'s recommendations included well-stabilised LWD density (preferably dual source) tools with pseudo-caliper corrections can provide reasonable results, except in boreholes in which rugosity and washout are likely to be an issue. However, the quality of LWD tool measurements is as yet far from resolved while significant differences between LWD, wireline and core measurements persist.

- The author's experience of LWD logs are that they are poor quality when compared with wireline data, the main differences being depth of investigation, bed boundary resolution and noise rejection of the LWD data.

LWD tools from different manufacturers (Teleco, Sperry Sun, Schlumberger) were compared with wireline tools from different manufacturers (Halliburton, Schlumberger) in vertical wells of the Alaskan Kuparuk river field (Sakurai et al. 1992). The Kuparuk river formation units A and C are the main producing units within the formation. Wireline and LWD log response comparisons were used to assess the quality of the LWD measurements for formation evaluation purposes.

- Differences in tool design and in logging environments between wireline and LWD lead to differences between the recorded measurement values (Sakurai et al. 1992).
- Primary LWD tool characterisation to API standards and outside of API standard conditions could be poor when compared with wireline tools.

Gamma ray measurements were used to calculate clay content in the A sands and as an input for mineral determinations with other logs for the C sands. Figure 3.13 demonstrates that the gamma ray readings from LWD Company 1 were consistently higher than the wireline measurements, possibly due to incorrect calibration procedures (Sakurai et al. 1992).

Wireline and Company 1 LWD neutron porosity comparisons from vertical well 4 found reasonable agreement [Figure 3.14]. However, wireline and Company 3 LWD neutron porosity comparisons in vertical well 5 show that large differences are apparent in the C sands in vertical well 5 where heavy minerals are present [Figure 3.14]. The heavy minerals increase the formation density, which decreases the count rates of capture gamma rays used by Company 3 to calculate neutron porosity.
Figure 3.11 Wireline and LWD neutron and density (non-stabilised density) comparisons for horizontal well 4. Wireline and LWD density (stabilised density) comparison with core porosity for horizontal well 12 (Figures 12 and 13 Cunningham et al. 1992).
Figure 3.12 Tandem LWD tools run of single and dual source non-stabilised density tools, neutron was also run (Figure 14 Cunningham et al. 1992).

Figure 3.13 Crossplot of wireline and MWD gamma ray by Company 2 from vertical well 5 (Figure 2 Sakurai et al 1992).
Figure 3.12 Tandem LWD tools run of single and dual source non-stabilised density tools, neutron was also run (Figure 14 Cunningham et al. 1992).

Figure 3.13 Crossplot of wireline and MWD gamma ray by Company 2 from vertical well 5 (Figure 2 Sakurai et al 1992).
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Histograms of density porosity difference (wireline-LWD) separated by company and sand unit show that Company 1’s measurements were in closer agreement with wireline than Companies 2 and 3 [Figure 3.15] (Sakurai et al 1992). LWD density porosity measurements in the C sands showed larger scatter than in the A or B sands for all companies [Table 3.9]. The scatter was generally greater for LWD density measurements than wireline measurements.

- LWD tools tended to over correct for borehole conditions due to the strong dependency of the short spaced detector response (Sakurai et al 1992).

The differences between wireline and LWD porosity measurements are given in Table 3.8 and Table 3.9 for the density and neutron tools. The investigation discovered that the LWD tools of Company 1 were in closest agreement with wireline tool responses. A mismatch of up to 8pu could be expected from some of the tools (Sakurai et al 1992). When compared with their wireline counterparts LWD density values were twice as poor as LWD neutron porosity values, which broadly agrees with the results of numerical modelling studies (Day and Petler 1990).

- LWD and wireline differences demonstrated that the porosity anomalies were not solely tool based (Sakurai et al 1992) but also due to environmental effects, i.e. borehole conditions and shale alternation due to hydration.

<table>
<thead>
<tr>
<th>LWD Company</th>
<th>1</th>
<th>2</th>
<th>3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Well</td>
<td>4</td>
<td>5</td>
<td>5</td>
</tr>
<tr>
<td>C Sand</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mean Difference (wireline - LWD) Neutron Porosity (pu)</td>
<td>-0.3</td>
<td>-0.6</td>
<td>-2.9</td>
</tr>
<tr>
<td>Standard deviation (pu)</td>
<td>1.8</td>
<td>1.6</td>
<td>3.6</td>
</tr>
<tr>
<td>A/B Sands</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mean Difference (wireline - LWD) Neutron Porosity (pu)</td>
<td>-0.3</td>
<td>0.7</td>
<td>0.2</td>
</tr>
<tr>
<td>Standard deviation (pu)</td>
<td>1.4</td>
<td>1.6</td>
<td>1.6</td>
</tr>
</tbody>
</table>

**Table 3.8** Wireline/LWD neutron porosity tool comparison (Table 3 Sakurai et al 1992).

<table>
<thead>
<tr>
<th>LWD Company</th>
<th>1</th>
<th>2</th>
<th>3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Well</td>
<td>4</td>
<td>5</td>
<td>5</td>
</tr>
<tr>
<td>C Sand</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mean Difference (wireline - LWD) Density Porosity (pu)</td>
<td>-0.7</td>
<td>4.2</td>
<td>-3.3</td>
</tr>
<tr>
<td>Standard deviation (pu)</td>
<td>3.2</td>
<td>8.1</td>
<td>6.1</td>
</tr>
<tr>
<td>A/B Sands</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mean Difference (wireline - LWD) Density Porosity (pu)</td>
<td>-0.5</td>
<td>-0.9</td>
<td>-0.9</td>
</tr>
<tr>
<td>Standard deviation (pu)</td>
<td>1.2</td>
<td>2.8</td>
<td>2.9</td>
</tr>
</tbody>
</table>

**Table 3.9** Wireline/LWD density tool comparison (Table 4 Sakurai et al 1992).
Figure 3.14 Crossplots of wireline and MWD neutron porosity by Company 1 from vertical well 4 and by Company 3 in vertical well 5 respectively (Figures 7 and 8 Sakurai et al 1992). Reasonable agreement is found for vertical well 4, but large differences are apparent in the C sands in vertical well 5 where heavy minerals are present. Company 3 uses capture gamma-ray methods.

Figure 3.15 Crossplots of wireline neutron porosity against MWD neutron porosity by Company from vertical well 5 (Figure 6 Sakurai et al 1992). Data to the left of centre represents an overestimate of porosity by the MWD neutron porosity tool.
Standoff

Standoff corrections for LWD density and neutron tools have always been problematic (Moake et al. 1996). At the introduction of LWD density and neutron tools it was generally thought that the effects of standoff would be negligible, based on the assumption of no significant borehole enlargement prior to LWD logging. This assumption was soon known to be incorrect and that standoff was particularly problematic in horizontal wells. Wireline density and neutron tools are much less susceptible to standoff effects than their LWD counterparts due to the use of a caliper and/or bowspring, except possibly in severely eroded/elliptical holes when wireline tools may not sit along the major axis.

Four techniques have been developed to reduce the standoff errors (Best et al. 1990; Holenka et al. 1995; Spross et al 1995; Moake et al. 1996). Best et al. (1990) used a histogram of count rates over a time interval that included several revolutions of the tool. Standard deviations of the near detector count rates were compared with expected count rates at various values of standoff. This provided an indirect estimate of the standoff, an azimuthal average density value and a maximum density value. This method was an improvement to no correction at all [Figure 3.17], but even with only modest standoff low bulk density values resulted [Figure 3.16]. Spross et al (1995) used a histogram of count rates over a time interval that was much shorter than one revolution of the tool. Again the standard deviations of the count rates were compared with expected count rates at various values of standoff, but the near and far count rates were summed for this purpose. If the ratio of the two standard deviations was sufficient the count rates are binned, dependent on the ratio. A spine and ribs analysis was then used to evaluate which bin represents the least amount of standoff, which was then used as the value of $\text{RHOB}$. The Spross et al (1995) method was still indirect but improved the standoff correction at the expense of throwing away much of the data [Figure 3.17]. Holenka et al. (1995) used four bins based on tool orientation in the borehole. It was assumed that the smallest standoff occurred in the ‘down’ direction, not always the case, and the appropriate $\text{DRHO}$ indicated the likely error for each quadrant. Generally the method was an improvement on the two previous methods [Figure 3.17]. Moake et al. (1996) uses ultrasonic transducer measurements of standoff, which were then used to weight the count rates, exponentially decreasing the weight with increasing standoff. The main improvement in this method was that the standoff was measured directly, so
one would expect values that are more accurate. However, any standoffs greater than 1 inch is more than any wireline or LWD correction algorithm can correct for.

Moake et al. (1996) added two new correction values, Corr P and Corr M, which summed together equal the familiar density correction log. Corr P measures the density contrast and is usually positive, while Corr M measures the PEF contrast and is usually negative. These values are useful in heavy muds {high PEF values [Figure 3.18] (Minette 1996)} in which DRHO can be zero but Corr P and Corr M would be large and have opposite sign. The difficulty is in how to compensate for these high PEF values because of similarity of the slopes of the formation and heavy mud PEF as defined by the hard count rate versus the hard/soft ratio [Figure 3.19].

The Evans et al. (1999) neutron compensation method, for borehole invariant porosity, effectively makes the neutron porosity measurement insensitive to the first 1 ⅛ inches of the tool’s depth of investigation. This is achieved by modification of the far detector count rate by the use of a functional relationship with the near detector. The ratio of the modified far count rate and the near count rate is then used to calculate porosity.

![Figure 3.16](image)

**Figure 3.16** Illustration to show the non-linear effect of rotation on the LWD density measurement in a 2.6g/cm³ formation with 13lbm/gal mud in a 10inch well (a) count rate versus standoff and (b) spine and ribs format (Figure 1 Moake et al. 1996). The double arrow in (b) indicates the oscillations along the rib when the LWD 6.75inch tool is lying on the bottom of a horizontal well. The solid circle represents the average count rates measured during one oscillation.
Figure 3.17 Density errors associated with various processing techniques (a) first statistical method (Best et al. 1990), (b) second statistical method (Spross et al 1995) and (c) quadrant method (Holenka et al. 1995) from (Figure 6 Moake et al. 1996). Note: Errors from average data with no special processing (raw) are compared with the errors presented. The environmental conditions are as Figure 3.16.

Figure 3.18 Plot to demonstrate the effects of light ($\rho = 1.3g/cm^3$, $PEF = 0.3B/e$) and heavy ($\rho = 2.5g/cm^3$, $PEF = 101B/e$) mudcake on the spectra obtained from a 2.7g/cm$^3$ ($PEF = 2.57B/e$) aluminium formation (Figure 7 Minette 1996).
Figure 3.19 Plot to demonstrate that the density measurement is less affected (similar slope to the formation response) than the PEF measurement for 'heavy' muds (i.e. mud with high PEF) (Figure 8 Minette 1996). The effects for light mudcake response on the spectra are due to both the density and PEF of the mud, a different slope to that of the formation or heavy mud. The heavy, light and formation values are as for Figure 3.18.

**Gamma ray tools**

Thorium/Potassium (Th/K) crossplots are often used for mineral identification when natural gamma ray spectrometry (NGS) logs are available [Figure 3.20](Hurst 1990). At present no LWD NGS tools exist and, considering the effect on the spectral response of the tool by the drill collars (makes logs K rich), no LWD NGS tools are likely in the near future (Sakurai et al 1992). However, the use of such crossplots is limited, since there is no theoretical basis for their use for mineral identification [Figure 3.21](Hurst 1990). Figure 3.21 demonstrates that the mineral boundaries of Figure 3.20 typical of the crossplots found in Service Company chartbooks are fictional at best. Mineral identification is made significantly more difficult in sandstones with moderate K-feldspar contents, as is common in the North Sea, for example, the associated error of the proportion of K-feldspar is such that the error would completely overwhelm any measurement of illite content.

- The measurement of illite could be potentially useful for evaluating reservoir quality because of the effect of illite on permeability (Hurst 1990).
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Figure 3.20 Thorium versus Potassium plot for mineral identification (CP-19 Schlumberger 1999).

Kaolinite
Muscovite
Illite
Illite and Muscovite
Muscovite and K Feldspar

Figure 3.21 Thorium versus Potassium plot (Redrawn Figure 6 Hurst 1990). Note: The considerable areas of overlap between potassic minerals and the broad kaolinite field. Kaolinite normally has negligible potassium content.
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Filtering

Filtering of log data effects not only character of log curves, but also the interpretation of the curves themselves. All log curves are filtered for several reasons, such as resolution matching of different detector spacings and noise removal, but also most logs have presentation filters applied to them to improve the visual appearance of the curves. Typically a 1' and $1\frac{1}{2}'$ convolved moving average filter is applied to the porosity logs. The filter retains the fine bed resolution data (to 1') whilst removing most of the high frequency random noise in the data. If faithful comparisons between LWD and wireline data are to be made presentation filters need to be removed. Unfortunately obtaining data without presentation filters applied is extremely difficult, as these filters are often not optional in the log processing of the Service Companies. When comparing wireline and LWD logs filtering the data to the same wavelength can be useful so that the logs can be compared at the same resolution, usually 2ft and can help with depth correlation because the filter matches the vertical resolutions (Schroeder et al. 1991).

Summary of tool errors

Tool errors for porosity tools largely result from differences in detailed tool design and toolstring configuration whilst logging. Calibration and modelling of LWD tools is often insufficient to replicate wireline responses and common standards for all logging tools need to be established. Poor understanding and control of logging tool position within the borehole whilst logging leads to poor porosity logs particularly in horizontal wells and wells in which lithologies which deviate significantly from calibration points are encountered.

- Wireline logs from tools built by different companies can vary significantly as measurement conditions deviate from the standard conditions (Coope 1983; Sakurai et al 1992).
- Differences in sensor physics can produce different wireline and LWD logs in identical conditions due to the slightly different source-detector spacings, depths of investigation and spectral responses (Jackson et al. 1994; Sakurai et al. 1992).
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- Method of source-detector to formation contact will affect responses. Wireline tools use pad, skid or mandrel contact but LWD tools may use low absorption ports through the stabilisers or can be run slick. LWD density measurements are particularly problematic due to the effects of standoff (Jackson et al. 1994), over correction for standoff is due to the strong dependency of the short spaced detector response (Sakurai et al 1992).

- Basic reference standards are different (Jackson et al. 1994).

- Environmental corrections must be applied to the wireline and LWD data to common standard conditions (Jackson et al. 1994).

- LWD neutron porosity values in horizontal wells should measure lower values than the same tool would in an equivalent vertical well (Day and Petler 1990).

- The results showed LWD tools should be stabilised with full gauge stabilisers immediately above and below the tool to reduce lateral drillstring motion and poor centralisation, which would lead to erratic readings (Cunningham et al. 1990).

The author's experience of LWD logs are they are often poor quality when compared with wireline data, the main differences being depth of investigation, bed boundary resolution and noise rejection of the LWD data. Other problems occur such as:

- A different shale point would be required in density and neutron porosity calculation where tool responses differ. Failure to recalculate the shale point may lead to potentially incorrect porosity and water saturation values.

- Non-parallel standoff from LWD and/or wireline tool running across a chord could result in the LWD and wireline differences (Samworth 2000).

Jackson et al. (1994) provides a good discussion of the differences of LWD and wireline while Brami et al. (1991) has a detailed description of the differences in LWD tools offered by several Service Companies.
3.3.2 Borehole conditions

Borehole conditions that affect logging tools include mud density changes, mud additives (Barite, KCl and Hematite), rugosity, hole size, temperature, pressure, borehole salinity and invasion (Hutchinson et al. 1996). Before comparing different logs they must be corrected for the same borehole conditions (Jackson et al. 1994).

**Hole size**

LWD density tools are critically dependent on good standoff corrections and the density contrast between the formation and mud (Spross et al. 1995). For LWD density tools, if standoff is small and the tool size to hole volume ratio is not significantly increased by hole enlargement (mud volume), the standoff effect is small (Minette et al 1995). Several LWD tool sizes are required for the appropriate hole size compared with wireline tools where only one tool size is used for all hole sizes, although different Service Companies have different sized wireline tools from one another.

- The standoff effect on LWD density tools may be especially severe when the drillstring is sliding; the standoff algorithm may become ineffective because of the dependence on the short spaced detector values from all azimuths (Allen et al. 1990; Best et al. 1990).

LWD neutron porosity tools are designed to run centralised and are more affected by the hole condition (particularly standoff) than the eccentric wireline neutron porosity tools (Allen et al. 1990). The formation is effectively removed from all around the LWD tool but is only on one side of the wireline tool and leads to the LWD tools reading too high apparent porosity (Brami et al. 1991). An LWD neutron porosity tool is affected by approximately 5pu per inch standoff (Jackson et al. 1994).

- For a 40pu formation and a 2inch standoff, the error for a wireline tool is approximately 1.5 to 3.0pu, but approximately 12pu for a LWD tool (Allen et al. 1990).
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Deviated holes are often oval and can cause the LWD density tools to make inconsistent formation contact, especially when the drill string is sliding and the sensors can be facing into the mud column (Brami et al. 1991). No or slow rotation of LWD tools may lead to standoff algorithms being unable to correct for oval holes (Day and Petler 1990). A dual source LWD density tools improves density calculation due to better count rate statistics and improved compensation (Cunningham et al. 1992).

- Wireline tools can also suffer from poor formation contact if the toolstring rolls over and the pad is orientated into the mud column. This results in under-gauge caliper values, because the tool weight partially collapses the caliper and possibly non-zero $\text{DRHO}$ values (Samworth 2000).

Typically LWD density-neutron crossover is greater in gas than for comparable wireline tools, because invasion is usually less extensive (Carpenter et al. 1997). Time after bit is a useful indicator for possible washouts or if the log was recorded during a pipe or conditioning trip. Often time after bit and LWD top quadrant (ADN tool) $\text{DRHO}$ correlate because barite mud adversely affects top density values, and often only the bottom density value is reliable. Thus an understanding of the effect of standoff on $\text{PEF}$ in barite muds [Figure 3.22] can assist interpretation, as can LWD density and $\text{PEF}$ images [Figure 3.26].

- The selection of logging tools has a dramatic effect on the data quality recorded.
- The selection of logging tools should be based on the expected borehole conditions [Figure 3.23][Allen et al. 1990].

**Formation compaction**

Formation compaction, caused by the drill pipe, may occur immediately below a keyseated borehole (low side borehole enlargement) providing a place for debris to collect. A positive $\text{DRHO}$ would be measured (Cuddy et al. 1994)[Figure 3.24] and would thus reduce log quality (Nieto et al. 1995).
Figure 3.22 Plot of PEF versus standoff for different mud weights (Figure 1 Carpenter et al. 1997).

Figure 3.23 Guide for selecting logging tool type depending on expected borehole conditions (Allen et al. 1990). Note: the CDN is Schlumberger’s LWD Combinable Density Neutron tool.
Figure 3.24 Possible horizontal well borehole conditions redrawn (Figure 16 and 17 Cuddy et al. 1994).
Rugosity

Rugosity introduces variable standoff and pad tilt for wireline tools that is not corrected for by standard corrections (Jackson et al. 1994) and may be due to spiral grooves caused by drilling (Nørve et al. 1989; Betts et al. 1990). Spiralled boreholes were encountered in logs from Data Set 1 [See Chapter 4]. In rotation the LWD density tool, if the average compensation is >0.1g/cm³ will under compensate (Minette et al. 1995). In sliding, if the LWD density tool is measuring the horizontal well floor, a large DRHO may result. There is no preferred LWD density tool orientation in vertical wells.

The BHA stabilisation assumes the LWD tools are rotating about the borehole centre and parallel to the borehole wall (Cunningham et al. 1992). Full gauge stabilisers above and below LWD tools help to centralise the sensors and dampen the lateral BHA movement (Cunningham et al. 1990), however BHA modelling shows lateral BHA motion is possible (Delafor 1984). Full gauge stabilisers with sensors behind them may not totally solve these problems and results in highly forwarded focused density measurements. In addition, drillers are usually unhappy drilling with stabilisers while building (increasing hole inclination) because of the increased potential for BHA sticking, borehole and drill string damage.

- BHA motion is not strictly rugosity but the motion will manifest itself as variable standoff as rugosity does (Betts et al. 1990).
- Debris in horizontal wells collects along the borehole floor and can introduce variable standoff (Woodhouse et al. 1991).

Betts et al. (1990) demonstrated that stabilisers caused LWD density (and neutron porosity) log to vary by ±0.2g/cm³ (±20% porosity) on a 3ft wavelength with rugosity no more than 0.2inches (6mm). Conventional filtering removed too much low frequency response making the log too smooth (Betts et al. 1990). The BHA was possibly wobbling between the first and second stabilisers or the first stabiliser and bit. The period was the same in the LWD density and caliper curves and unaffected by change in rate of penetration. A Weiner filter and 3ft-notch filter was used to remove periodicity. Another period of 75ft was observed, but no plausible explanation was found.
Figure 3.25 LWD density image of a spiralled borehole above 12012ft, below a near bit stabiliser was added to prevent spiralling (Figure 3 Maeso et al. 1999).
Figure 3.26 Density and PEF images in a spiralled borehole with clockwise sense above x170ft, but anticlockwise sense below (Figure 5 Carpenter et al. 1997).
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The bent sub used to alter hole angle enlarged the hole when the BHA was rotating (Betts et al. 1990; Nieto et al. 1995). The offset that resulted in the low bulk density values was removed by taking half the near/far count rate difference to give a corrected count rate. The bulk density and photoelectric factor values were recalculated and the neutron porosity log was reprocessed in a similar manner (Betts et al. 1990). The first stabiliser is normally $\frac{1}{2}-3$ ft behind the bit and acts as a node (Betts et al. 1990). The groove wavelength produced was comparable with the source to detector/s spacing/s and so interfere with density and neutron measurement.

- The periodicity is twice the bit to first stabiliser distance and the modulation depends on the weight on bit and bent sub angle (Betts et al. 1990).

Borehole spiralling by a drill bit can produce periodic variation of LWD density logs/images (Maeso et al. 1999), usually at a wavelength of approximately 3 ft, caused by oscillation of the bit and stabiliser [Figure 3.25]. However, the mechanism is not fully understood (Carpenter et al. 1997), because observed instantaneous sense reversals of the variations cannot be explained [Figure 3.26]. Inclusion of a near bit stabiliser can prevent the oscillations. Modelling demonstrated that LWD density images allow carbonate nodules to be differentiated from carbonate beds, which may avoid expensive wells being drilled to penetrate the apparent ‘carbonate bed’ (Maeso et al. 1999).

Mud type

Nørve et al. (1989) studied the effects of mud type with LWD and wireline logging in vertical wells from a Norwegian North Sea field and demonstrated that LWD measurements are sensitive to mud type. The field used was comprised of low resistivity pay zones, in which accurate porosity determination is critical for a reliable $S_w$ calculation [Table 3.10].

- The LWD porosity tools performed best in oil based mud (OBM), followed by NaCl mud and were poorer still in KCl mud (Nørve et al. 1989).
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This was possibly due to the mud Cl content and the differences in spectral responses of the tools. The best LWD logs were obtained when the rate of penetration was less than 40m/hr (120ft/hr) (Nørve et al. 1989). Mud additives can affect the quality of log derived porosity values. The effect of barite and hematite is negligible on PEF for mud weights less than 10.5lbm/gal (1.26g/cm³)(Jackson et al. 1994). There is usually less barite or hematite in the mud when LWD tools are run than wireline tools because of the settling of the heavy minerals over time.

- The author is aware of numerous wells with mud weights well below 10.5lbm/gal (1.26g/cm³) especially OBM in which barite can have substantial effects on PEF logs to the point that they are rendered useless.

<table>
<thead>
<tr>
<th>Pay Type</th>
<th>Net/Gross (Frac.)</th>
<th>Porosity (pu)</th>
<th>Sr (su)</th>
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<tbody>
<tr>
<td></td>
<td>LWD</td>
<td>Wireline</td>
<td>LWD</td>
</tr>
<tr>
<td>NaCl mud</td>
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<td></td>
<td></td>
</tr>
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<td>0.59</td>
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</tr>
<tr>
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<td>0.33</td>
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</tr>
<tr>
<td>KCl mud</td>
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</tr>
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</tr>
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<td></td>
</tr>
<tr>
<td>Oil</td>
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<td>0.56</td>
<td>22.3</td>
</tr>
</tbody>
</table>

Table 3.10 LWD/Wireline comparison against mud type (Tables 2 to 4 Nørve et al. 1989).
Chapter 3: Horizontal well porosity anomalies

Summary of borehole conditions

Borehole conditions affect porosity logs. Poor conditions can result in poor logs, especially from LWD porosity tools and affect the control of logging tool position within the borehole. Horizontal well conditions are likely to be worse than a comparable vertical well due to increased stress on the borehole from overburden pressure and debris collecting along the length of the well.

- In sliding mode, the standoff effect on LWD density tools may be especially severe; the standoff algorithm may become ineffective because of the dependence on the short spaced detector values from all azimuths (Allen et al. 1990; Best et al. 1990).
- Debris in horizontal wells collects along the borehole floor and can introduce variable standoff (Woodhouse et al. 1991).
- For a 40pu formation and a 2inch standoff, the error for a wireline neutron tool is approximately 1.5 to 3.0pu, but approximately 12pu for a LWD tool (Allen et al. 1990).
- The selection of logging tools should be based on the expected borehole conditions, (Allen et al. 1990), though a chart should to devised based on regional best practice.
- The spiral rugosity periodicity is twice the bit to first stabiliser distance and the modulation depends on the weight on bit and bent sub angle (Betts et al. 1990).
- The LWD porosity tools performed best in oil based mud (OBM), followed by NaCl mud and were poorer still in KC1 mud (Nørve et al. 1989).

The author’s experience of LWD logs indicates they are often poor quality when compared with wireline data, the main differences being depth of investigation, bed boundary resolution and noise rejection of the LWD data. Most of the degradation in borehole quality occurs prior to LWD logging and in many cases there is little difference in borehole conditions. The wireline porosity tools normally will cope better with the poor borehole condition providing better logs. However in some areas this is not so due to regional stresses (e.g. The Caspian), where washout and the risk of borehole collapse are such that wireline tools are seldom used. Other problems occur such as:
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- Numerous wells with mud weights well below 10.5 lbm/gal (1.26 g/cm$^3$) especially OBM in which barite can have substantial effects on PEF logs to the point that they are rendered useless.

- Wireline tools suffer from poor formation contact if the toolstring rolls over resulting in poor density values and under-gauge caliper values (due to the tool weight partially collapsing the caliper) and possibly non-zero $DRHO$ values (Samworth 2000).

- BHA motion will manifest itself as variable standoff similar to rugosity.

Jackson et al. (1994) provides a discussion of the effects of differences of LWD and wireline values on formation evaluation and Allen et al. (1990) provides a guide for the porosity logging method to be employed dependent on the borehole conditions expected.
3.3.3 Altered formation conditions

Formation evaluation attempts to calculate the virgin formation conditions from the tool responses. However, the very process of drilling a borehole alters the formation conditions. The effect of the altered conditions is to change the log responses accordingly. The main processes that affect the formation condition are mud invasion, fractures, formation alteration and bedding.

**Invasion**

Mud filtrate invasion alters the formation fluid content displacing connate water, oil and gas to irreducible saturation when invasion is complete. If the tool measured volume and the invaded volume coincide the measured formation properties will not be representative of the virgin conditions, unless the mud filtrate is accounted for. In vertical wells mud invasion is assumed piston-like with the invasion front moving out radially from the borehole.

- Gravity and permeability anisotropy have a combined effect on mud invasion in horizontal wells that may produce non-uniform invasion profiles, consequently affecting log measurements (Woodhouse et al. 1991).

The primary control on invasion is formation permeability and secondly mudcake permeability (Harris et al. 1993). Note that porosity is also a major factor as it’s a measure of the fluid volume capacity of the rock. Invasion is insignificant due to effective mudcake usually in 8-10hrs after drilling with a typical mudcake permeability of 0.00006mD to 0.00013mD (Woodhouse et al. 1991). Deep invasion can be caused by excessive mud (pressure) overbalance and placing the LWD tools too far from the bit results in excessive formation exposure time (Brami et al. 1991).

- Generally the invasion process is static by the time wireline tools are logged (>8-10hrs after bit penetration, equilibrium having been established).
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An important factor is that the logging suite can measure the saturation of the various formation fluids and account for their effects on the formation parameters (resistivity profile). However, without running resistivity tools with similar depths and volumes of investigation as the porosity tools, the resistivity profile may be useless for interpreting and correcting porosity logs. In fact, the resistivity logs may not suggest that invasion had occurred to any extent whilst the porosity log may suggest otherwise.

Woodhouse et al. (1991) examined the effects of gravity and mud density contrast in driving vertical mud invasion in horizontal wells. Oil based mud (OBM) falls in gas reservoirs, rises in water reservoirs and does not invade in oil reservoirs [Figure 3.29]. In the case of OBM in a gas reservoir, initially gas saturation, $S_g$, is reduced near the borehole. $S_g$ increases once mudcake forms and the invaded ‘mud tear drop’ will fall away leaving a trail of irreducible mud filtrate in the formation. LWD, MAD and wireline logs can be used to document the dynamic formation fluid changes [Figure 3.27]. Invasion is driven by the mud/formation pressure gradient, permeability of the formation and mudcake, viscosity, diffusion, capillary pressure, gravity segregation and porosity (Woodhouse et al. 1991). There are three steps to invasion:

- Spurt loss occurs before mudcake is formed, lasting only a few seconds.
- Dynamic loss occurs while drilling and during mud circulation. Mud circulation erodes mudcake, allowing invasion to continue. When the rate of erosion equals the rate of deposition, then Darcy’s Law governs fluid loss. Generally after 10-15 hours of circulation, the rate of fluid loss is constant.
- Static loss occurs after mud circulation has stopped and is controlled by mudcake permeability and not formation permeability. The volume of fluid loss is proportional to the square root of time.

LWD nuclear tools are normally 150ft (45m) to 250ft (76m) behind the bit when drilling a horizontal well but may be only 17ft (5m) behind the bit in vertical wells. At a typical drilling speed of 12m/hr (39ft/hr), LWD nuclear tools are 6 hours (72m) behind the bit. The invasion front may be beyond the depth of investigation of some tools.

- Neutron porosity values measured in multiple passes over several days in a gas well can be seen to decrease (Woodhouse et al. 1991).
Figure 3.27 Under dynamic filtration, invasion in the oil leg is circular. In the gas column, gravitational effects distort the invaded mud into an elliptical form. Under equilibrium conditions this body drips free from the borehole and falls downwards leaving a trail of residual oil redrawn (Figure 11 Woodhouse et al. 1991).

Figure 3.28 Mud invasion profile versus time along a horizontal gas well redrawn (Figure 12 Woodhouse et al. 1991).
In a horizontal gas well apparent porosity increased as OBM/WBM invaded with a Hydrogen index (HI) of approximately 1.0 (Woodhouse et al. 1991). Once mudcake had formed, gas (HI approximately 0) reinvaded the formation close to the borehole and a lower apparent porosity was measured [Figure 3.28](Woodhouse et al. 1991). "No reasonable scenario could be proposed where gas would immiscibly work around the OBM filtrate for the suggested filtrate rates and volumes, antithetic to liquid phase pressure gradient and filtrate recharge flow" (Woodhouse et al. 1991).
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If the neutron porosity interpretation were correct then other factors must affect OBM filtrate behaviour. $K_h/K_v > 1000$ is required for a non-circular invasion profile in a horizontal well (Woodhouse et al. 1991). However, $K_h/K_v$ rarely exceeds 10, so non-circular invasion is unlikely. If $K_h/K_v = 1$, OBM in gas would drop 12.9 ft (3.93 m) in 8 days after mudcake sealed the borehole (Woodhouse et al. 1991). In water OBM would rise approximately 6 ft (1.83 m) in the same period of 8 days. If invasion were greater than 10 inches after 5-7 hours, the invasion front would be well beyond the depth of investigation of porosity tools. The invaded zone measured by the tools would contain OBM filtrate, connate water and residual gas.

Calculations show that gravity segregation occurs when $K_h/K_v < 100$ [Figure 3.27] (Woodhouse et al. 1991). In a vertical well the fluid is pushed away from the borehole, but in a horizontal well the fluid is pushed around the borehole.

- Field evidence shows that when $K_h/K_v < 10$, tear drops can form when dynamic filtration is low (<2 ml/hr-in$^2$) (Woodhouse et al. 1991).

Invasion estimates

To estimate the dynamic flow of invading mud filtrate at least two passes are required (Harris et al. 1993). Resistivity can be used to estimate depth of invasion and formation permeability may be calculated. The following equations do not account for flow ahead of the bit, which may be a significant factor in highly permeable formations:

$$ \frac{\partial V_{mf}}{\partial t} = \frac{2 \pi h (P_b - P_f)}{\frac{\mu_{mf}}{K_{mc}} \ln \left(\frac{r_b}{r_{mc}}\right) + \frac{\mu_f}{K_f} \ln \left(\frac{r_f}{r_b}\right)} $$

Equation 3.1

where $V_{mf} =$ volume of invaded mud filtrate, $t =$ time passed, $h =$ formation thickness, $\mu_{mf} =$ mud filtrate viscosity, $K_{mc} =$ mudcake permeability, $\mu_f =$ formation filtrate viscosity, $K_f =$ formation permeability, $r_b =$ borehole radius, $r_{mc} =$ distance to mudcake from borehole centre, $r_f =$ distance to limit of reservoir, $P_b =$ borehole fluid pressure and $P_f =$ formation fluid pressure.
Chapter 3: Horizontal well porosity anomalies

\[
\frac{\partial V_{mf}}{\partial t} = \frac{\Delta V_{mf}}{\Delta t} = \frac{V_{mf}(t_2) - V_{mf}(t_1)}{t_2 - t_1} = \phi S_{xo} \pi h \frac{r_i^2(t_2) - r_i^2(t_1)}{t_2 - t_1},
\]

Equation 3.2

where \( \phi \) = porosity, \( S_{xo} \) = water saturation of invaded zone, \( r_i \) = radius of invasion.

Assuming that no mudcake exists, at \( t=0 \), \( r_{mc}=r_i=r_b \).

\[
\frac{\partial V_{mf}}{\partial t} = 2\pi hr_b \frac{\partial r_i}{\partial t} \bigg|_{t=0} = 2\pi h(P_b - P_f) \frac{K_f}{\mu_f} \left( \ln \left( \frac{r_f}{r_b} \right) - 1 \right).
\]

Equation 3.3

Combining Equation 3.2 and Equation 3.3 at \( t=0 \), \( r_{mc}=r_i=r_b \),

\[
\phi S_{xo} \pi h \frac{r_i^2(t_2) - r_b^2}{t_2} = 2\pi h(P_b - P_f) \frac{K_f}{\mu_f} \left( \ln \left( \frac{r_f}{r_b} \right) - 1 \right),
\]

Equation 3.4

and rearrange for \( r_i(t_2) \),

\[
r_{i}(t_2) = r_b + \sqrt{\frac{2(P_b - P_f)K_f t_2}{\mu_f \phi S_{xo}}} \left( \ln \left( \frac{r_f}{r_b} \right) - 1 \right).
\]

Equation 3.5

A minimum amount of invasion is necessary to be able to detect a departure from \( R_i \) and a difference between resistivity at two depths of investigation. Generally invasion affects neutron porosity responses less than density responses because of the greater depth of investigation of the neutron measurement (Allen et al. 1990; Jackson et al. 1994). If invasion/alteration is less than 1 inch then both LWD and wireline density tools will detect the invasion and a non-zero \( DRHO \) will be recorded.

- The effect of mud invasion on the density values is dependent on density contrasts and the depth of invasion.
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Modelled invasion effects in density and neutron values

Non-uniform invasion (caused by permeability anisotropy) was investigated for southern North Sea horizontal gas wells (Cowan and Wright 1997), because non-uniform invasion was suspected to be the cause of anomalously high porosity readings (Cuddy et al. 1994). Numerical modelling of wireline neutron porosity and density tools for various sandstone porosity and saturation values in a horizontal well including the effects of non-uniform invasion was carried out (Cowan and Wright 1997).

- The results indicated that the wireline density tool would read 6.5-19.0pu too high, but the wireline neutron porosity tool would read 3-12.5pu too low in the non-uniform case compared with the uniform case.

The numerical (Monte Carlo) modelling was laboratory benchmarked against density (RODENT) and neutron tools (WILT), which have slightly shallower depths of invasion (DOI) than commercial tools but display the same kind of differences observed with commercial wireline tools. RODENT’s DOI is between 8-9cm whereas commercial wireline tools are between 11-13cm. WILT’s DOI is between 20-26cm whereas commercial wireline tools are between 24-30cm (Cowan and Wright 1997).

From Darcy’s Law [See Equation 1-4 Hilchie (1982)], a permeability ratio of 10:1 (horizontal:vertical) would lead to invasion at the sides approximately three times greater than above and below the borehole [Figure 3.30]. As invasion increases in gas sand wireline density porosity decreases (increasing bulk density) and wireline neutron porosity increases (increasing hydrogen index [HI]) as shown in Figure 3.31. The density tool’s DOI increases slightly with porosity, but the neutron porosity tool’s DOI decreases with porosity as the HI increases with porosity. There is a slight increase in the neutron porosity tool’s DOI when the brine mud is replaced by oil based mud due to the reduction in formation sigma (formation of absorption thermal neutrons).

Table 3.11 shows the maximum difference in apparent porosity between non-uniform and uniform invasion at the respective uniform invasion depths at which they occur. As the depth of non-uniform invasion increases density porosity increases and neutron porosity decreases at a given equivalent uniform invasion depth [Figure 3.32].
Figure 3.30 Models of uniform and non-uniform invasion (Figure 2 Cowan and Wright 1997).
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Figure 3.31 Apparent porosity against invasion depth for uniform brine invasion of a 20pu gas sandstone, 10su water saturation (Figure 3 Cowan and Wright 1997).

Figure 3.32 Difference in apparent porosity between non-uniform and uniform brine invasion against invasion depth for uniform brine invasion of a 20pu gas sandstone, 10su water saturation (Figure 4 Cowan and Wright 1997).
Chapter 3: Horizontal well porosity anomalies

<table>
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<tr>
<th>Formation Porosity (pu)</th>
<th>Formation Saturation (su)</th>
<th>Borehole &amp; Invasion Fluid</th>
<th>Max Difference Apparent Density Porosity Difference (pu)</th>
<th>Invasion (cm)</th>
<th>Max Difference Apparent Neutron Porosity Difference (pu)</th>
<th>Invasion (cm)</th>
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<tr>
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Table 3.11 Maximum differences in apparent porosity between non-uniform and uniform Invasions (Table 3 Cowan and Wright 1997).

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<tr>
<th>Tool</th>
<th>Increase porosity</th>
<th>Increase invading fluid density</th>
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<tr>
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<td>Increases</td>
<td>decreases</td>
</tr>
</tbody>
</table>

Table 3.12 Change in porosity difference when one parameter is increased, while the other two remain constant (From the conclusions Cowan and Wright 1997).

The tools measured more gas-filled formation below the borehole than at the sides because invasion was three times greater at the sides than below where the tools measure. Density porosity values are greater but the neutron porosity values are lower than expected, assuming uniform invasion. Note: full invasion for the density tool is approximately 10cm, but 18-30cm for the neutron. Table 3.12 summaries the changes in the density and neutron porosity difference between the uniform to non-uniform.

Sensitivity analyses of the density and neutron tools are summarised in Figure 3.33 for the density tool and Figure 3.34 for the neutron tool. The results show that the density tool was highly forward focused with the long spaced detector three times more sensitive to the formation than the short spaced detector and both detectors were insensitive to the borehole fluid.

- The highly forward focused nature of the density tool means that the readings were greatly affected by non-uniform invasion (Cowan and Wright 1997).
- The results show that the wireline neutron tool was less forward focused than the wireline density tool, but it was still affected by non-uniform invasion (Cowan and Wright 1997).
Figure 3.33 RODENT (density) sensitivity results (Figure 5 Cowan and Wright 1997).
Figure 3.34 WILT (neutron) sensitivity results (Figure 6 Cowan and Wright 1997).
Modelling of the presence of fractures demonstrated that the neutron tool has some sensitivity to the sides of the borehole in a horizontal well, where fractures are most likely to occur because of overburden pressure (Cowan and Wright 1997). The maximum increase in porosity caused by fractures at the borehole sides would be 1pu, which would be insufficient to explain the anomalous neutron porosity values observed in the southern North Sea (Cuddy et al. 1994). Further modelling of fractures at the side of the borehole demonstrated that for a side facing density tool, compared with a down facing density tool, the observed porosity could increase by 1 to 15pu. Observed southern North Sea horizontal well porosity values between a down and side facing density tool were approximately 3pu, so fractures would explain these observations although fracture type may alter results. The rugosity was known from the scanner data in this case.

- From the author's recent employment borehole rugosity was a possible explanation for the poor match of the neutron and density measurement with modelled results.

**Effect of porosity algorithm**

The final part of the Cowan and Wright (1997) study involved a comparison of a number of standard porosity calculations [Table 3.13, Table 3.14, Table 3.15, Figure 3.36 and Figure 3.37]. All the methods [see section 2.4.3] compared rely on density and neutron porosity values alone, but the Shallow iterative and Wiley & Patchett (Wiley and Patchett 1994) methods still overestimated porosity by 2 to 5pu. For southern North Sea the observed porosity anomalies were between 2 to 4pu compared with core porosity values (Cuddy et al. 1994).

Both Data Sets examined in this thesis [Chapters 4] were used to assess the applicability of the above porosity algorithms on test data. Some success was evident with Data Set 1 [Chapter 4] from the southern North Sea, but little success was gained with application to Data Set 2 [See Chapter 4] due to the effects of clay.
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Figure 3.35 Ultrasonic images showing fractures at the sides of a horizontal borehole (Figure 8 Bedford et al. 1997).

Figure 3.36 Predicted formation porosity against invasion depth for uniform brine invasion for a 20pu gas sandstone at 10su water saturation (Figure 7 Cowan and Wright 1997).
Figure 3.37 Difference in predicted formation porosity between non-uniform and uniform brine invasion for a 20pu gas sandstone at 10su water saturation (Figure 8 Cowan and Wright 1997).

Table 3.13 RMS values of porosity and saturation predictions (Table 5 Cowan and Wright 1997).
Chapter 3: Horizontal well porosity anomalies

<table>
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Table 3.14 Maximum predicted porosity differences (Table 6 Cowan and Wright 1997).

<table>
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<th>Formation Porosity (pu)</th>
<th>Formation Saturation (su)</th>
<th>Borehole &amp; Invasion Fluid</th>
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<th>Porosity (pu)</th>
<th>Saturation (su)</th>
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</tr>
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</table>

Table 3.15 RMS values of porosity and saturation for shallow iterative method with Wiley and Patchett porosity estimates (Table 7 Cowan and Wright 1997).

- The square root method was shown to be the least reliable, while the Shallow Iterative and Wiley & Patchett (Wiley and Patchett 1994) methods were comparable and improved porosity estimation (Cowan and Wright 1997).

The sonic tool derived porosity best matched the expected porosity values from offset vertical wells [Figure 3.4](Bedford et al. 1997). However, if fracturing and washout is evident then the sonic porosity estimates will also be inaccurate. Running sonic logs in horizontal wells is considered risky due to tool losses. LWD sonic tools are available although their quality is a relative unknown. In horizontal wells the recorded sonic velocity may only be representative of faster layers approximately parallel to the borehole (Cuddy et al. 1994), also sonic anisotropy in shale layers could affect values if shale beds are close enough. Data set 2 [See Chapter 4] demonstrates an interesting variation in which the sandstone beds appear to be reading 'fast'.
Most significant effects of invasion on the neutron measurement are observed when the formation fluid is predominantly gas because neutrons are "gas seeking" (Ellis and Chiaramonte 2000). When a neutron tool enters a water zone from a gas zone, the neutron tool only detects the water zone once the tool is within the water zone. However, a neutron tool entering a gas zone from a water zone will detect the gas zone from approximately 20 cm (approximately 8 inches) true vertical depth above Figure 3.38. Gas will lower measured neutron porosity.

- Neutron count rate analysis has revealed the presence of gas cap from within an oil reservoir although the effect on the neutron porosity logs was very subtle (Samworth 2000).

In a 40° deviated gas well the LWD neutron porosity was almost constant but the density showed variation (Cannon 1998). The well was logged with azimuthal LWD density, neutron and resistivity tools giving improved accuracy in the calculation of porosity, $S_w$ and mineralogy primarily due to depth of investigation, matching two of the azimuthal resistivity measurements with the density (Shallow) and neutron (Deep) measurement [Figure 3.39]. In addition, direct measurement of the borehole diameter with ultrasonic transducers has improved the quality of the density and neutron measurements. In this case the azimuthal LWD density and neutron porosity tool recorded 10pu density variations between bottom, left and right sectors, which corresponded with LWD shallow resistivity images. The mud filtrate was more conductive and denser than the gas filled formation [Figure 3.41] (Cannon and Kienitz 1999). The neutron porosity measurement tended to see only gas, but the density measurement recorded varying amounts of mud invasion. The mud invasion was deeper underneath the borehole. The density values increased in gas compared with the ‘true’ density (water filled) because the mud appeared to be heavy to the density measurement i.e. a negative $DRHO$ was produced as the tool tried to remove the effect (Cannon and Kienitz 1999). The differential invasion causes the negative $DRHO$, resulting in density porosity estimates 5-6pu too high but overestimates of 10pu were recorded.

- Teardrop invasion can be identified in an in-gauge horizontal gas well with resistivity and density images [Figure 3.41] (Cannon and Kienitz 1999).
Figure 3.38 Chart to show the effect on the modelled response of a LWD azimuthal neutron porosity tool in a horizontal well (89°) passing through a 25pu water filled sand into a 25pu gas filled sand. The tool provides four neutron porosity measurements from which the TOP detector faces ‘up’ and the bottom detector faces ‘down’, redrawn from (Slide 22 Ellis and Chiaramonte 2000). Note: Values in standard apparent limestone porosity units.
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Figure 3.39 LWD density and neutron responses compared with resistivity at bit (RAB) responses (Figure 6 Cannon and Kienitz 1999). Note: The close match of the shallow curve and density, and the deep curve and neutron in this environment.

Figure 3.40 Modelled horizontal gas well LWD neutron responses sand with tear drop mud invasion (Figure 5 Cannon and Kienitz 1999). An invasion difference of 5cm in the shallow direction has a bigger effect than a 20cm difference in the draped direction, confirming that the gas closest to the well dominates the neutron response. Note: \( R_{i\text{min}} \) is the minimum invasion length and \( L \) is the maximum (teardrop or draped invasion).
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Figure 3.41 The left-hand column contains from left to right the RAB shallow button down, shallow button up, deep button up and CDR (combinable dual resistivity) attenuation. The darker shading indicates additional invasion on the bottom of the hole that is not detected on the top. In track 2 from left to right are density up, density down and neutron. The shading between the two density curves also indicates additional invasion down. There are two images on the right from RAB and ADN tools. Each image is presented with the top of the hole on the left, bottom in the middle and back to the top on the right. The darker the RAB image the more filtrate present. The lighter the ADN image the more filtrate present. Even though the ADN tool does not have the same resolution as the RAB tool, it still finds the maximum invasion in the same direction as the RAB tool, which is not always down (Figure 10 Cannon and Kienitz 1999).
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As a rule: “All the filtrate that leaves the well eventually migrates downdip, even the filtrate that leaves from the updip side of the wellbore” (Cannon and Kienitz 1999). This effect is accelerated if vertical permeability is large and can lead to an apparent water leg when filtrate ponds above the impermeable layer. The neutron measurement is dominated by the gas closest to the tool almost regardless of azimuth [Figure 3.40]. The neutron log appears to be ‘lazy’ (varies only slowly) and appears to ignore the invasion. However, the new LWD tools do not solve all the problems associated with horizontal wells (Cannon and Kienitz 1999). Fluid distributions, well deviation and bed dip require 3D modelling due to asymmetric mud invasion, which require 3D log measurements. At present, 2D plus dip modelling is available and is performed on each quadrant and the measurements are not yet fully 3D.

- The density measurements vary considerably in the presence of teardrop invasion, the neutron measurement does not (Cannon and Kienitz 1999).
- The teardrop does not always form in the down direction but moves in the down direction of the bedding [Figure 3.41](Cannon and Kienitz 1999).

Fluid density changes between the two logging runs in the same borehole cause problems when comparing LWD and wireline density values (Hansen and Shray 1996). Tools capable of measuring elliptical invasion profiles are required to understand fully the borehole environment with associated software to model for the effects of borehole signal, shoulder beds, non-circular invasion with fluid segregation, dipping beds and anisotropy. Likewise, “The development of a computer program that simultaneously inverts resistivity and porosity logs, by minimising the differences between real tool readings and reconstructed logs is recommended” (Peeters et al. 1999).

Mud invasion is more complex than has been described above. Although a piston invasion model may be adequate for interpretation of deep resistivity curves, the model is not sufficiently detailed for near borehole invasion profile (Peeters et al. 1999). Saturation and salinity fronts exist as well as invasion fronts [Figure 3.42]. OBM may alter wettability and reduce $S_w$ below irreducible levels possibly dehydrating shales. Clearly changes in formation properties occur in space and time (4D). An additional problem with LWD logs is that the tools have far higher chance of loss of formation contact compared with their wireline counterparts.
Figure 3.42 Two front invasion model of fluid displacement (Figure 3 Peeters et al. 1999).

Alteration

Formation alteration in the vicinity of the borehole generally affects neutron porosity less than density measurement because of the larger depth of invasion of the neutron measurement (Allen et al. 1990; Jackson et al. 1994). Both density (decreasing bulk density) and neutron (increasing HI) porosity values will increase because of water absorption from the drilling mud. Drilling induced fractures in a horizontal well are likely to be at the sides of the borehole because the overburden pressure represents the maximum principal stress. The partial collapse will further increase $K_h/K_v$ and therefore invasion at the sides of the borehole [Figure 3.35](Cuddy et al., Day et al. 1994). Fracturing can affect $DRHO$ if it is serious and the density caliper may indicate if break out occurs along the roof of the borehole.
Chapter 3: Horizontal well porosity anomalies

Figure 7a - Formation model used to simulate curves in Fig 7b - 7c. The upper and lower parts of the wellbore cut the bed boundaries at measured depths A, B, C and D. Log measurements in each formation are summarized in Table 2.

Table 2 - Summary of log measurements used for simulation in Figure 7b-c.

<table>
<thead>
<tr>
<th></th>
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<th>gamma ray</th>
<th>sonic</th>
<th>resistivity</th>
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<td>120</td>
<td>2.3</td>
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<td>sand</td>
<td>2.2</td>
<td>20</td>
<td>90</td>
<td>50</td>
</tr>
</tbody>
</table>

Figure 7b.
Simulation of Induction and CDR curves across the 2' sand shown in Figure 7a.

Figure 7c
Simulation of density, gamma ray and sonic across the formation shown in Figure 7a. (Measured depths A, B, C and D correspond to those in Figure 7a.)

Figure 3.43 Schematic to illustrate bed boundary detection in horizontal wells (Page 10 White 1991).
Chapter 3: Horizontal well porosity anomalies

Downhole temperature will change between LWD and wireline tool runs. Clay alteration between drilling, LWD, MAD and wireline runs can alter formation porosity by 2-6pu because of water absorption from the mud (Bedford et al. 1997). This process reduces formation density, increases the hydrogen content of the formation and alters the elastic properties, increasing all the porosity estimates.

- Inaccurate neutron and density porosity in shale will shift the shale point in the neutron-density crossplot (Allen et al. 1990; Jackson et al. 1994).

**Bedding**

In horizontal wells the orientations of log measuring systems are usually anisotropic with respect to bedding (Bigelow et al. 1992). An unusual effect was observed in a numerically modelled well with a deviation of 89°. The borehole was intersected by a 6inch thick low porosity horizontal bed (90°), producing density and neutron responses such that an apparent gas crossover was bordered by apparent shale effect (Ellis and Chiaramonte 2000).

- The depth of investigation of the tools (LWD and wireline) does affect the position along the borehole at which bed boundaries are detected (White 1991; Singer 1992).

Different tools will measure different lithologies and/or fluids simultaneously at the same depth location [Figure 3.5 and Figure 3.43](White 1991; Singer 1992).
Summary of altered formation conditions

Altered formation conditions often degrade the quality of porosity logs. The effect of drilling the borehole and the mud used are to alter the formation from its native state. Mud invasion replaces the native fluids and may alter clay minerals by hydration or dehydration. Drilling can induce fracturing in the near borehole environment. Both the invasion and fracturing processes are dependent on the orientation of the borehole with respect to the applied forces (e.g. gravitational and regional stress fields).

Invasion

• Dynamic loss occurs while drilling and during mud circulation. Mud circulation erodes mudcake, allowing invasion to continue. When the rate of erosion equals the rate of deposition, then Darcy’s Law governs fluid loss (Woodhouse et al. 1991).
• Static loss occurs after mud circulation has stopped and is controlled by mudcake permeability and not formation permeability. The volume of fluid loss is proportional to the square root of time (Woodhouse et al. 1991).
• Generally the invasion process is static by the time wireline tools are logged (>8 to 10hrs after bit penetration, equilibrium is established)(Woodhouse et al. 1991).
• Gravity and permeability anisotropy have a combined effect on mud invasion in horizontal wells that may produce non-uniform invasion profiles, consequently affecting log measurements (Woodhouse et al. 1991).
• Field evidence shows that when $K_h/K_v < 10$, tear drops can form when dynamic filtration is low (<2ml/hr-in$^2$)(Woodhouse et al. 1991).
• Teardrop invasion can be identified in an in-gauge horizontal gas well with resistivity and density images. The teardrop moves in the down direction of the bedding [Figure 3.41](Cannon and Kienitz 1999).

Effect on logs of altered formation conditions

• Neutron porosity values measured in a gas well with multiple passes over several days decrease as gas migrates towards the borehole (Woodhouse et al. 1991)
Chapter 3: Horizontal well porosity anomalies

- The effect of mud invasion on the density values is dependent on density contrasts and the depth of invasion (Woodhouse et al. 1991).
- When invasion is 3 times greater at the sides than above and below the well compared with uniform invasion, modelling indicated that the wireline density tool would read 6.5 to 19.0pu too high, but the wireline neutron porosity tool would read 3 to 12.5pu too low (Cowan and Wright 1997).
- The square root method was shown to be the least reliable, while the Shallow iterative and Wiley & Patchett (Wiley and Patchett 1994) methods were comparable and improved porosity estimation (Cowan and Wright 1997).
- The density measurements vary considerably in the presence of teardrop invasion, the neutron measurement does not (Cannon and Kienitz 1999).
- Inaccurate neutron and density porosity in shale will shift the shale point in the neutron-density crossplot (Allen et al. 1990; Jackson et al. 1994).
- The depth of investigation of the tools (LWD and wireline) does affect the position along the borehole of the detection of bed boundaries (White 1991; Singer 1992).

The author's experience of altered formation conditions is that the effects of invasion are common in all wells and that fractures are often only identifiable from image logs. Clay alteration is frequently encountered and can cause the well to be bridged preventing wireline tool access beyond that point without special techniques. In horizontal wells formation alteration and features may be overlooked as they only change very gradually along the length of the well. Plotting the logs on a reduced scale such as 1:1000 can help identify unusual features like increased depth of invasion due to a change in permeability.

- Neutron count rate analysis has revealed the presence of a gas cap from within an oil reservoir although the effect on the neutron porosity logs was very subtle (Samworth 2000).
Chapter 3: Horizontal well porosity anomalies

3.4 Summary

This chapter provided published evidence of anomalous porosity values in horizontal wells. Two North Sea studies (Cuddy et al. 1994; Austin et al. 1994) concluded that horizontal well porosity values were too high compared with expected values from vertical wells. In addition an overview of the complications experienced when evaluating horizontal well porosity logs was given, perturbations include:

- Tool effects. Preferential tool orientation, differences in sensor physics, differences in source-detector spacings, investigation depths, spectral responses, method of source-detector to formation contact, basic reference standards differences, and environmental corrections to common standard conditions.
- Borehole conditions. Debris, fractured/unstable borehole, hole size, mud density changes and additives (Barite, KCl and Hematite), standoff and rugosity.
- Altered formation conditions. Mud invasion, bed boundary dip and clay alteration.

Jackson et al. (1994) provides a helpful discussion of the effects of differences of LWD and wireline values on formation evaluation from tool errors, borehole and altered formation conditions. Allen et al. (1990) provides a guide for the porosity logging method to be employed dependent on borehole conditions expected.

Porosity anomalies

Cuddy et al. (1994) compared a large number of vertical and horizontal gas wells from the southern North Sea and illustrated that log porosity values overestimated porosity in horizontal wells regardless of tool type [Figure 3.3 and Table 3.1] and the overestimates appeared to increase with increased porosity and permeability.

Bedford et al. (1997) demonstrated that in one horizontal well, downward facing wireline density tool porosity values measured higher porosity compared with vertical wells in that particular field due to the additional gas effect on density porosity from anisotropic invasion. Side facing density porosity values unexpectedly measured greater porosity values than the downward facing density values. Ultrasonic images revealed fractures in the side of the borehole that increased the formation porosity calculated.
Chapter 3: Horizontal well porosity anomalies

Sonic porosity values were comparable with the vertical well values. The solution was to gas correct the down facing density porosity values using the calculated water saturation values thus obtain a good match with the sonic porosity values.

In a detailed study (Austin et al. 1994) of southern North Sea acoustic log responses, sonic travel time values were 2-3\(\mu\)s/ft lower than core porosity values at 6pu porosity, but approximately 10\(\mu\)s/ft lower than expected at 15pu porosity. This would have led to overestimates of porosity by 5pu and underestimates of rock strength, resulting in conservative well completion strategies. Image logs were run to assess situations where "fast" beds were influencing the sonic logs. The acoustic core measurements and theoretical calculations were unable to account for the anomalous sonic porosity values, either by the presence of gas or in-situ stresses.

In the few horizontal wells in which sonic tools are run (approximately 5 to 10%), sonic porosity seldom matches the other calculated porosities (Samworth 2000). This is especially so in low porosity formations (<5pu) in which the sonic travel time appears to be independent of porosity. In addition, borehole conditions (fractures) and the proximity of "fast" beds may affect sonic porosity values, in which case density porosity values would be used. Sonic tools are rarely run in horizontal wells due to the sonic tool’s physical weakness and thus the increased risk of toolstring loss.

**Tool errors**

Differences in detailed tool design and toolstring configuration lead to LWD and wireline measurements that do not always replicate each others responses. Common standards for all logging tools need to be established in a wider range of lithologies than currently available. Poor understanding and control of logging tool position within the borehole whilst logging leads to poor porosity logs particularly in horizontal wells and wells in which lithologies that deviate significantly from calibration points are encountered.

- Wireline logs from tools built by different companies can vary significantly as conditions deviate from the standard conditions (Coope 1983; Sakurai et al 1992).
Chapter 3: Horizontal well porosity anomalies

- Differences in sensor physics can produce different wireline and LWD logs in identical conditions due to the slightly different source-detector spacings, depths of investigation and spectral responses (Jackson et al. 1994; Sakurai et al. 1992).
- Method of source-detector to formation contact will affect responses (Jackson et al. 1994; Sakurai et al. 1992).
- Basic reference standards are different (Jackson et al. 1994).
- LWD neutron porosity values in horizontal wells should measure lower values than the same tool would in an equivalent vertical well (Day and Petler 1990).
- LWD tools should be stabilised with full gauge stabilisers immediately above and below the tool to reduce lateral drillstring motion and poor centralisation, which would lead to erratic readings (Cunningham et al. 1990).

The author's opinion is that the problems of logging tool deployment (either LWD or wireline) in horizontal wells is not sufficiently addressed in published papers. For instance wireline tools may not be running in hole as intended facing the floor without rocking to the sides and that inclination and deviation data should routinely be recorded for all horizontal wells (including LWD) as log quality control. Common calibration standards for wireline and LWD tools in limestone, dolomite, sandstone and importantly shale need to be established. The author's experience of LWD logs are they are often poor quality when compared with wireline data, the main differences being depth of investigation, bed boundary resolution and noise rejection of the LWD data. Other problems occur (Samworth 2000) such as:

- Non-parallel standoff from LWD and/or wireline tool running across a chord could result in the LWD and wireline differences.
- Time lapse density porosity from up and down wireline logs in which several hours have elapsed between passes do not appear to show any discernible differences.
- Running two orthogonal density tools can lead to the two density tools pulling towards one another giving two poor density logs.
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Borehole conditions

Poor borehole conditions can result in poor logs. Problems affecting horizontal porosity logs: worse conditions than a comparable vertical well due to overburden driven breakout; debris collecting along the length of the well and the composition of the drilling mud. The selection of logging tools should be based on the expected borehole conditions (Allen et al. 1990), some of the problems are:

- LWD density tools in sliding mode, the standoff algorithm may become ineffective because of the dependence on the short spaced detector values from all azimuths (Allen et al. 1990; Best et al. 1990).
- Debris in horizontal wells collects along the borehole floor and can introduce variable standoff (Woodhouse et al. 1991).
- The spiral rugosity periodicity is twice the bit to first stabiliser distance and the modulation depends on the weight on bit and bent sub angle (Betts et al. 1990).
- For a 40pu formation and a 2inch standoff, the error for a wireline neutron tool is approximately 1.5 to 3.0pu, but approximately 12pu for a LWD tool (Allen et al. 1990).
- The LWD porosity tools performed best in OBM, followed by NaCl mud and were poorer still in KCl mud (Nørve et al. 1989).

The author’s experience is that often LWD logs are poor quality when compared with wireline because borehole degradation occurs prior to LWD logging therefore there is little difference in borehole conditions, wireline porosity tools normally cope better with the borehole condition than LWD. However, in some areas of the World (e.g. The Caspian), where washout and the risk of borehole collapse are significant, wireline tools are seldom used. Other problems occur such as:

- Numerous wells with mud weights well below 10.5lbm/gal (1.26g/cm³) especially OBM in which barite can effect PEF logs to the point that they are rendered useless.
- Wireline tool rollover leads to bad formation contact resulting in poor density values indicated under-gauge caliper values due to tool weight partially collapsing the caliper and possibly non-zero DRHO (Samworth 2000).
Chapter 3: Horizontal well porosity anomalies

- BHA motion is not strictly rugosity but may manifest itself as variable standoff.

Altered formation conditions

Degraded porosity logs result from mud invasion replacing the native fluids and altering clay minerals by hydration or dehydration. Invasion and formation alteration can affect log values by:

- Gravity and permeability anisotropy in horizontal wells combined effect on mud invasion may produce non-uniform invasion profiles (Woodhouse et al. 1991). Teardrop invasion moves in the down direction of the bedding [Figure 3.41] (Cannon and Kienitz 1999).
- Neutron porosity values measured in a gas well with multiple passes over several days decrease as gas migrates towards the borehole (Woodhouse et al. 1991)
- Density values are dependent on mud density contrasts and invasion depth (Woodhouse et al. 1991). Density values vary considerably in the presence of teardrop invasion, the neutron values do not (Cannon and Kienitz 1999).
- When invasion is 3 times greater at the sides than above and below the well compared with uniform invasion modelling indicates that the wireline density tool would read 6.5 to 19.0pu too high, but the wireline neutron porosity tool would read 3 to 12.5pu too low (Cowan and Wright 1997).
- In horizontal wells in the presence of invasion 3 times greater at the sides than above and below the well, the square root method was shown to be the least reliable, while the Shallow iterative and Wiley & Patchett (Wiley and Patchett 1994) methods were comparable and improved porosity estimation (Cowan and Wright 1997).
- Inaccurate neutron and density porosity in shale will shift the shale point in the neutron-density crossplot (Allen et al. 1990; Jackson et al. 1994).
- The depth of investigation of the tools (LWD and wireline) does affect the position along the borehole of the detection of bed boundaries (White 1991; Singer 1992).
- Neutron count rate analysis can reveal a gas cap from within an oil reservoir although the effect on the neutron porosity logs is very subtle (Samworth 2000).
The author's experiences are that altered formation conditions are common in all wells. Clay alteration is frequently encountered and can cause the borehole to be bridged preventing wireline tool access beyond that point without special deployment techniques. The effects of invasion and fractures are often only identifiable from image logs. In horizontal wells formation alteration and features may be overlooked as they only change very gradually along the length of the well and plotting the logs on a reduced scale such as 1:1000 can help identify such features.

Horizontal well formation evaluation is still in its infancy. This is not aided by the use of tools designed for vertical wells and the lack of appropriate software to handle the complexity of these situations. In the future tools designed for horizontal wells are required that will provide azimuthal images at several depths of investigation. Resistivity tools are needed with depths of investigation matched to the porosity tools in combination with the deep resistivity measurements are essential. These tools already exist for LWD but in wireline mode. Multiple logging runs will be required to acquire the time dependency of invasion related factors and the use of affordable and quick four-dimensional interpretation software will enable complete formation evaluation.
This chapter examines two data sets, one from a southern North Sea gas field (Data Set 1) and the second from a northern North Sea oil and gas field (Data Set 2).

The southern North Sea example consists of data from one vertical well and one horizontal sidetrack well that demonstrated inconsistencies in porosity values. The data from the vertical well include wireline, LWD and core data, but only LWD data for the horizontal sidetrack well. The horizontal well LWD porosity values (maximum density and neutron) were lower than those calculated from the vertical well.

The northern North Sea oil and gas field example oil leg is being developed with numerous horizontal wells [Figure 4.3] and an understanding of any unusual porosity values would be advantageous. The data set comprises log data from five wells, two vertical wells (well 1, 33° from vertical, and well 5, 21°), one horizontal sidetrack and two horizontal wells (wells 1z, 3 and 6, all 90°). Core data was available for both vertical wells and one horizontal well (well 1z). The horizontal well porosity values from the three horizontal wells were significantly different from the measured values from the vertical well data. The data demonstrate that there are no simple explanations for horizontal well porosity anomalies. However, this data set highlights the need for image logs in horizontal wells and the use of frequency analysis to aid log interpretation.

This chapter aims to draw conclusions from the data analyses presented and to identify the cause(s) of the observed porosity anomalies. Firstly, an explanation of the data sets and of the horizontal well porosity anomalies observed are given. Porosity analysis of the data sets includes the use of several different porosity algorithms (§2.4.3) and splitting the reservoir into a number of generic units to assess the applicability of the algorithms using statistical tests. Spectral analysis of the data sets enables the evaluation of contributing factors and the removal of some these unwanted influences. Finally, conclusions are presented that detail the causes of the porosity inconsistencies.

Note that descriptions of the geology of data set 1 and data set are presented in appendices 1 and 2 respectively.
4.1 Description of data sets

4.1.1 Data set 1

The data set consists of logging data from a vertical well and its horizontal sidetrack well [Figure 4.1 and Figure 4.2]. Both wells were drilled using 8.5 inch bits with barite weighted 10.5 lbm/gal (1.26 g/cm$^3$) OBM (70% oil, 30% water). The 'vertical' well was deviated at 57° from vertical through the reservoir (§3.1). Both wireline and LWD tools were run in the vertical well with a complete core section through the reservoir. This was achieved by coring the well first, then logging with the wireline tools 36 hours after mud circulation was stopped. The LWD tools were run 2 days after the wireline tools. The wireline tools included gamma ray, litho-density, neutron porosity, acoustic travel time, induction resistivity and in a later run formation tester [Figure 4.1]. The LWD tools run were gamma ray, litho-density, neutron porosity (sandstone corrected porosity is used throughout this thesis unless otherwise stated), and electromagnetic propagation resistivity [Figure 4.1]. The core data included horizontal and vertical helium porosity (overburden corrected), vertical and horizontal permeability, gamma ray and grain density [Table 4.2 and Table 4.10]. Horizontal core plugs were cut either perpendicular to the long axis of the core section or parallel with any visible bedding present. The vertical core plugs are cut perpendicular to the horizontal core plugs. The horizontal sidetrack well was horizontal (88°) in the Leman sands. Only LWD tools were run in the horizontal well [Figure 4.2].

The vertical well intersected 134 ft (40m) measured depth of Weissliegend at the top of the reservoir, 94 ft (28 m) of Rotliegend dune/interdune sands in the bottom of the well [Figure 4.1]. The horizontal well intersected 772 ft (235 m) of Weissliegend at the top of the reservoir, 749 ft (228 m) of Rotliegend dune/interdune sands in the middle and 405 ft (123 m) of Weissliegend at end of the well [Figure 4.2]. Geological description of the field for data set 1 is given appendix 1.

Wireline and LWD logs were in generally good agreement in the vertical well as discussed below [Figure 4.1]. The caliper logs indicated that the vertical well was in-gauge and smooth. However, the horizontal well LWD caliper had increased on average by (0.6±0.2) inches greater than the bit size, therefore the horizontal borehole conditions were significantly more rugose and/or non-circular than the vertical well [Table 4.1].
Chapter 4: Analysis of the Data Sets

The wallet at the back of the thesis contains all the log plots.

**Figure 4.1** Data set 1 vertical well 1 wireline and LWD logs. Note, the apparently high permeability values are due to the scale allowing “back-up” so these values are in fact read between 0.02 to 0.2 mD, not 200 to 2000 mD.

The wallet at the back of the thesis contains all the log plots.

**Figure 4.2** Data set 1 horizontal well 1z LWD Horizontal well logs. Note, the periodic signature in the log curves with a wavelength of ~8 ft.
Chapter 4: Analysis of the Data Sets

The LWD caliper measurement used is not independent of the density measurement (§3.3.1)(Best et al. 1990). Any unusual values in the density measurement will be reflected directly in the caliper values and therefore it is very difficult to identify the source of the measured density perturbation, although simply incorrect calculation of the apparent caliper can not be ruled out. Vertical well wireline density and neutron porosity values were slightly lower than the LWD values [Figure 4.1 and Table 4.1]. Vertical well wireline acoustic and density derived porosity values matched closely with the core porosity values [Figure 4.16].

The horizontal well LWD maximum density porosity and neutron porosity values were lower than expected from the vertical well values [Figure 4.16a, Figure 4.18a and Table 4.2]. The LWD maximum density derived porosity values were in good agreement with the vertical well core porosity values [Figure 4.18a]. This indicated that the formation fluids were flushed from in front of the density tool’s detectors and there was little gas to perturb the maximum density measurements. The horizontal well LWD average bulk density values were 0.18g/cm$^3$ lower (9pu greater) than the maximum bulk density due to borehole enlargement and/or LWD tool eccentric.

The respective density corrections in the vertical well are small showing that there was minimal mudcake thickness. The wireline density correction was slightly positive which may indicate some presence of gas. The average LWD density correction in the vertical well was -0.012g/cm$^3$ resulting from barite in the mud, but +0.020g/cm$^3$ in the horizontal well due to standoff [Table 4.1].

The vertical well wireline and LWD photoelectric factor values were both greater than expected for sandstone (1.745B/e), demonstrating that the barite (266.8B/e) in the mud had effected the logs. The horizontal well LWD PEF was significantly greater (+2.3B/e) than the vertical well responses [Table 4.1]. This demonstrated that the standoff/mudcake must have been at least 0.15 inches thick (Carpenter et al. 1997). However, this may be due to barite in the invaded mud perturbing the measurement. This is supported by the fact the LWD PEF log follows the rate of penetration log indicating mudcake build-up/mud invasion [Figure 4.2]. In an overlying anhydrite bed (5.055B/e), the PEF was 6B/e in the vertical well and close in value for both the wireline and LWD tools. However, the equivalent anhydrite bed measured >12B/e in the horizontal well (well deviation >70°). The horizontal well PEF was responding to lithology changes, but the values were far greater than expected due to the barite.
Chapter 4: Analysis of the Data Sets

<table>
<thead>
<tr>
<th>Variable</th>
<th>Minimum</th>
<th>Maximum</th>
<th>Mean</th>
<th>Standard Deviation</th>
</tr>
</thead>
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<tr>
<td><strong>Vertical Well</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>LWD</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Amplitude Resistivity (Ωm)</td>
<td>2.068</td>
<td>159.519</td>
<td>9.698</td>
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<tr>
<td>Phase Resistivity (Ωm)</td>
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<td>76.408</td>
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<td>9.297</td>
</tr>
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<td>Maximum Density (g/cm³)</td>
<td>2.278</td>
<td>2.683</td>
<td>2.435</td>
<td>0.059</td>
</tr>
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<td>Average Density (g/cm³)</td>
<td>2.277</td>
<td>2.659</td>
<td>2.424</td>
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<td>Density Correction (g/cm³)</td>
<td>-0.039</td>
<td>0.011</td>
<td>-0.012</td>
<td>0.009</td>
</tr>
<tr>
<td>Neutron Porosity (%)</td>
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<td>0.157</td>
<td>0.095</td>
<td>0.031</td>
</tr>
<tr>
<td>Gamma Ray (API)</td>
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<td>89.086</td>
<td>38.188</td>
<td>5.403</td>
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<td>Photoelectric Factor (B/e)</td>
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<td>Rate of Penetration (*5 ft/hr)</td>
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<td>190.252</td>
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<td>Caliper (inches)</td>
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<td>8.656</td>
<td>8.536</td>
<td>0.036</td>
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<tr>
<td><strong>Wireline</strong></td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Deep Resistivity (Ωm)</td>
<td>2.237</td>
<td>281.081</td>
<td>12.650</td>
<td>23.073</td>
</tr>
<tr>
<td>Medium Resistivity (Ωm)</td>
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<td>53.409</td>
<td>8.831</td>
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</tr>
<tr>
<td>Density (g/cm³)</td>
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<td>0.017</td>
<td>0.010</td>
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<tr>
<td>Neutron Porosity (%)</td>
<td>0.013</td>
<td>0.144</td>
<td>0.081</td>
<td>0.034</td>
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<td>Acoustic Travel Time (μsec/ft)</td>
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<td>83.493</td>
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<td>5.959</td>
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<td>Gamma Ray (API)</td>
<td>34.228</td>
<td>62.947</td>
<td>41.037</td>
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<td>0.656</td>
<td>4.269</td>
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<td>8.572</td>
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<td>8.595</td>
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<tr>
<td><strong>Horizontal Well</strong></td>
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<td></td>
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</tr>
<tr>
<td><strong>LWD</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Resistivity (Ωm)*</td>
<td>4.145</td>
<td>23.158</td>
<td>8.197</td>
<td>3.352</td>
</tr>
<tr>
<td>Maximum Density (g/cm³)</td>
<td>2.196</td>
<td>2.645</td>
<td>2.482</td>
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<tr>
<td>Average Density (g/cm³)</td>
<td>1.908</td>
<td>2.514</td>
<td>2.309</td>
<td>0.087</td>
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<td>Density Correction (g/cm³)</td>
<td>-0.089</td>
<td>0.120</td>
<td>0.020</td>
<td>0.020</td>
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<tr>
<td>Neutron Porosity (%)</td>
<td>0.019</td>
<td>0.176</td>
<td>0.088</td>
<td>0.024</td>
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<tr>
<td>Gamma Ray (API)</td>
<td>20.556</td>
<td>138.309</td>
<td>32.036</td>
<td>5.806</td>
</tr>
<tr>
<td>Photoelectric Factor (B/e)</td>
<td>2.705</td>
<td>21.761</td>
<td>4.995</td>
<td>1.663</td>
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<tr>
<td>Rate of Penetration (x5 ft/hr)</td>
<td>9.828</td>
<td>170.186</td>
<td>35.418</td>
<td>16.748</td>
</tr>
<tr>
<td>Caliper (inches)</td>
<td>8.629</td>
<td>10.236</td>
<td>9.122</td>
<td>0.266</td>
</tr>
</tbody>
</table>

Table 4.1 Log value statistics. * resistivity values were modified to provide a continuous log for calculations.
Chapter 4: Analysis of the Data Sets

<table>
<thead>
<tr>
<th>Variable</th>
<th>Minimum</th>
<th>Maximum</th>
<th>Mean</th>
<th>Standard Deviation</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Vertical Well</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LWD</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Average Density Porosity (%)</td>
<td>-0.005</td>
<td>0.226</td>
<td>0.137</td>
<td>0.035</td>
</tr>
<tr>
<td>Maximum Density Porosity (%)</td>
<td>-0.020</td>
<td>0.225</td>
<td>0.131</td>
<td>0.036</td>
</tr>
<tr>
<td>Neutron Porosity (%)</td>
<td>0.020</td>
<td>0.157</td>
<td>0.095</td>
<td>0.031</td>
</tr>
<tr>
<td><strong>Core</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Horizontal Helium Porosity (%)</td>
<td>0.054</td>
<td>0.194</td>
<td>0.114</td>
<td>0.033</td>
</tr>
<tr>
<td>Horizontal Permeability (mD)</td>
<td>0.020</td>
<td>88.000</td>
<td>5.180</td>
<td>13.380</td>
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<tr>
<td>Vertical Permeability (mD)</td>
<td>0.010</td>
<td>44.000</td>
<td>1.860</td>
<td>5.310</td>
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<tr>
<td><strong>Wireline</strong></td>
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<td></td>
</tr>
<tr>
<td>Acoustic Porosity (%)</td>
<td>0.028</td>
<td>0.213</td>
<td>0.106</td>
<td>0.044</td>
</tr>
<tr>
<td>Density Porosity (%)</td>
<td>0.011</td>
<td>0.201</td>
<td>0.112</td>
<td>0.035</td>
</tr>
<tr>
<td>Neutron Porosity (%)</td>
<td>0.013</td>
<td>0.144</td>
<td>0.081</td>
<td>0.034</td>
</tr>
<tr>
<td><strong>Horizontal Well</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LWD</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Average Density Porosity (%)</td>
<td>-0.092</td>
<td>0.450</td>
<td>0.193</td>
<td>0.073</td>
</tr>
<tr>
<td>Maximum Density Porosity (%)</td>
<td>-0.249</td>
<td>0.275</td>
<td>0.085</td>
<td>0.078</td>
</tr>
<tr>
<td>Neutron Porosity (%)</td>
<td>-0.034</td>
<td>0.301</td>
<td>0.083</td>
<td>0.033</td>
</tr>
</tbody>
</table>

Table 4.2 Derived porosity statistics (fluid: 1g/cm³ density and 189μs/ft travel time).

The vertical well wireline and LWD resistivity values [Figure 4.1 and Table 4.1] were in good agreement. This suggested that the mud invasion profile was similar when wireline and LWD tools were logged. The resistivity tools used all have a depth of investigation greater than 10", beyond the investigation depth of the porosity tools.

The horizontal well amplitude resistivity measurement failed downhole and was not present between depths x131-x687ft and x961.5-x962.5ft. A linear regression was used at these depths to obtain resistivity and between x1878-1987ft where data appeared to be spurious. The horizontal well phase resistivity log was continuous. A linear regression between phase and amplitude resistivity provided a resistivity log for continuous water saturation calculation in the horizontal well.

The core permeability values and the formation tester responses agree well indicating that the Rotliegend dune/interdune sands interval (x138-x232ft) contained the best quality reservoir rock (porous and permeable)[Figure 4.1]. Above this interval, the core and chippings show that siliceous, dolomitic and anhydritic cements effect the reservoir quality.

4-6
Chapter 4: Analysis of the Data Sets

The formation exposure time for the LWD tools (105 ft behind bit) were 3 1/2 days for the vertical well and 18 hours for the horizontal well. The LWD tools were assumed to be working in the same manner for both the vertical and horizontal wells. However, the LWD tools were seriously damaged during the drilling of the horizontal well, which may have had a detrimental effect on the tool responses. The damage suggests that the tools were not only being worn by abrasion, but also from being continuously knocked against the borehole walls. For example, the memory port hatch was torn off during one run. The variability in the LWD caliper (0.25 inches) proves some indication of the amount of movement of the tools within the borehole. Also, there was a periodic signature with a wavelength of 8 ft (2.4 m) throughout the horizontal well data.
Chapter 4: Analysis of the Data Sets

4.1.2 Data set 2

The data comprises log data sets from five wells; two vertical wells (wells 1, 33° from vertical and 5, 21°), one horizontal sidetrack and two horizontal wells (wells 1z, 3 and 6, all 90°). Core data were available for both vertical wells and one horizontal well (well 1z). The data used in this chapter from the five wells are summarised below in Table 4.3. All the wells were drilled with OBM. Through the reservoir section, the vertical wells/vertical sections (<75°) were drilled with 12½ inch bits. The horizontal sections/wells were drilled with 8½inch bits. All three horizontal wells analysed in this chapter were first drilled at medium angle (30-75°) through the reservoir. The well trajectories were then turned to 90° through the B2 sand unit and drilled horizontally through the reservoir, but advance up through the stratigraphy due to 5° bed dips.

Vertical wells 1 and 5 penetrate 221m (725ft) and 237.5m (779ft) of the reservoir respectively. The medium angle sections of the horizontal wells 3 and 6 penetrate 139m (456ft) and 156.5m (513.5ft) of the reservoir respectively prior to penetrating in the B2 unit [Table 4.4]. The horizontal reservoir sections of wells 1z, 3 and 6 are 2076m (6811ft), 920m (3018ft) and 1528.5m (5015ft) respectively.

The gas and oil-bearing reservoir rocks are shale capped and the trap is a four-way dip structure enclosed above a salt diapir. The gas leg is approximately 40m (132ft) thick and the oil leg 58m (190ft). The horizontal wells were positioned approximately two thirds into the oil leg below the GOC (gas/oil contact). Well 5 is a gas injector in the centre of the field, the other four wells are oil producers [Figure 4.3].

The reservoir has been subdivided into three distinct units named A, B and C; the unit tops are given below [Table 4.4]. The oil leg is contained within the B sandstone, almost entirely within the B2 unit. The unit A3 is predominantly shaley and may form a field wide permeability barrier reducing the effectiveness of the gas injection. Unit A being uppermost, relates to the waning of the fan. Unit B represents the most sand rich and thus productive unit consisting of amalgamated channel sands. The lowermost unit C represents the early development of the fan, although predominantly sand rich the unit is below the OWC. The sub-units relate to correlatable features within the log data related to lobe switching within the fan. The GOC is typically found within unit B1 and the OWC in unit B2. Geological description of the field for data set 2 is given appendix 2.
Figure 4.3 Field map with well locations (provided by the Oil Company).

Top Palaeocene Reservoir & Well Locations

- **Gas cap**
  - Initial GOC = 496 m TVDSS

- **Oil leg**
  - Initial OWC = 554 m TVDSS

- **Aquifer**

- **Fault**

- **Appraisal well**

- **Well trajectory**

- **Horizontal oil producer**

- **Gas injector**

- **OWC monitoring**

- **Proposed**

1000 m
Well 1

Well 1 was drilled with OBM, both wireline and core data sets were available for this vertical well [Figure 4.4 and Table 4.3]. The borehole was logged 9½ hours after mud circulation stopped. The caliper values indicated that the borehole was smooth, but slightly enlarged by approximately 0.2 inches through the reservoir. The density correction log was positive due to mudcake [Table 4.5]. Barite was used in the mud (144 ppb) resulting in the slightly high PEF values (2.5B/e) in the sandstone layers. The gamma ray (>45 API) and photoelectric factor (>3B/e) indicated that shale layers were present through the reservoir. Low GR (<50 API) and high PE (>4B/e) spikes were due to doggers (thin limestone bed or sandstone with limestone cement, usually significantly reducing porosity and permeability).

At the top of unit A1 (x571m) [Table 4.4], gas crossover was evident and the induction resistivity values indicated the presence of hydrocarbons [Figure 4.4]. The Oil company picked the GOC contact at x619m in unit A3. Above x652m in unit B1 the oil was at irreducible water saturation marked by the irreducible oil contact (IOC) [Figure 4.4]. The OWC contact was picked from the resistivity logs at x702m. There was little separation of resistivity values through the reservoir showing only shallow mud invasion.

The acoustic travel time and compressional acoustic travel time logs separate (i.e. noisy) between x575.5-580m and x604-620.5m in shaley beds within the gas leg. The acoustic travel time log values increase (>100 μs/ft) in comparison with the compressional acoustic travel time log values (87-97 μs/ft). The most plausible case being weak beds, barring the possibility of poor data processing, because there was no significant change in the neutron porosity or bulk density expected due to the shale beds. Another feature of the both acoustic travel time logs was the low travel time spikes at x659m and x679m. Both spikes were associated with low neutron porosity values and high bulk density values. Comparison with the core records show that both peaks resulted from doggers.
### Chapter 4: Analysis of the Data Sets

#### Table 4.3 Summary of well log data used in this chapter (WL = wireline).

<table>
<thead>
<tr>
<th>Well</th>
<th>1</th>
<th>1z</th>
<th>3</th>
<th>5</th>
<th>6</th>
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<tr>
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<td>40-65</td>
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<td>8 1/2&quot;</td>
<td>12 1/2&quot;</td>
<td>8 1/2&quot;</td>
<td>12 1/2&quot;</td>
</tr>
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<td>OBM</td>
<td>OBM</td>
<td>OBM</td>
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<td>192000</td>
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<td>58.42</td>
<td>62.38</td>
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<tr>
<td>Top depth of data (m)</td>
<td>x500</td>
<td>x300</td>
<td>x500</td>
<td>x721</td>
<td>x500</td>
</tr>
<tr>
<td>Bottom depth of data (m)</td>
<td>x789</td>
<td>x2376</td>
<td>x721</td>
<td>x1636</td>
<td>x757</td>
</tr>
</tbody>
</table>

#### Table 4.4 Oil company formation tops (sst = sandstone, mst = mudstone).

<table>
<thead>
<tr>
<th>Well</th>
<th>1</th>
<th>1z</th>
<th>3</th>
<th>5</th>
<th>6</th>
</tr>
</thead>
<tbody>
<tr>
<td>A1 (sst w. mst)</td>
<td>x571.00</td>
<td>x529.00</td>
<td>x1588.00</td>
<td>x519.50</td>
<td>x652.00</td>
</tr>
<tr>
<td>A2.1 (clean sst)</td>
<td>x581.21</td>
<td>x552.00</td>
<td>x1529.00</td>
<td>x538.50</td>
<td>x667.00</td>
</tr>
<tr>
<td>A2.2 (sst w. mst)</td>
<td>x604.67</td>
<td>x916.00</td>
<td>x592.00</td>
<td>x1473.00</td>
<td>x550.00</td>
</tr>
<tr>
<td>A3 (sst w. mst)</td>
<td>x616.87</td>
<td>x1104.50</td>
<td>x627.00</td>
<td>x1407.00</td>
<td>x568.00</td>
</tr>
<tr>
<td>B1 (clean sst)</td>
<td>x630.02</td>
<td>x1333.00</td>
<td>x638.00</td>
<td>x1283.00</td>
<td>x587.00</td>
</tr>
<tr>
<td>B2 (sst w. mst)</td>
<td>x655.96</td>
<td>x1851.50</td>
<td>x668.00</td>
<td>x1069.00</td>
<td>x593.50</td>
</tr>
<tr>
<td>C (sst w. mst)</td>
<td>x760.00</td>
<td>x685.00</td>
<td></td>
<td></td>
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</tr>
</tbody>
</table>
Chapter 4: Analysis of the Data Sets

<table>
<thead>
<tr>
<th>Measurement</th>
<th>Mean</th>
<th>Standard Deviation</th>
<th>Minimum</th>
<th>Maximum</th>
</tr>
</thead>
<tbody>
<tr>
<td>RHOB (g/cm³)</td>
<td>2.286</td>
<td>0.094</td>
<td>2.112</td>
<td>2.703</td>
</tr>
<tr>
<td>RHOB2 (g/cm³)</td>
<td>2.296</td>
<td>0.083</td>
<td>2.164</td>
<td>2.706</td>
</tr>
<tr>
<td>NPHI (n_rW)</td>
<td>0.182</td>
<td>0.052</td>
<td>0.050</td>
<td>0.363</td>
</tr>
<tr>
<td>ILM (Ohm.m)</td>
<td>12.714</td>
<td>20.715</td>
<td>0.411</td>
<td>98.669</td>
</tr>
<tr>
<td>ILD (Ohm.m)</td>
<td>13.465</td>
<td>23.379</td>
<td>0.360</td>
<td>105.151</td>
</tr>
<tr>
<td>Rt (Ohm.m)</td>
<td>13.454</td>
<td>23.394</td>
<td>0.360</td>
<td>104.956</td>
</tr>
<tr>
<td>GR (API)</td>
<td>48.529</td>
<td>19.467</td>
<td>29.837</td>
<td>199.963</td>
</tr>
<tr>
<td>PEF (B/e)</td>
<td>3.025</td>
<td>0.679</td>
<td>2.062</td>
<td>6.002</td>
</tr>
<tr>
<td>DT (µs/ft)</td>
<td>92.611</td>
<td>12.565</td>
<td>61.293</td>
<td>224.257</td>
</tr>
<tr>
<td>DTCO (µs/ft)</td>
<td>90.338</td>
<td>5.759</td>
<td>61.638</td>
<td>113.316</td>
</tr>
<tr>
<td>DRHO (g/cm³)</td>
<td>0.025</td>
<td>0.013</td>
<td>-0.037</td>
<td>0.082</td>
</tr>
<tr>
<td>CALI (inches)</td>
<td>12.519</td>
<td>0.191</td>
<td>12.420</td>
<td>13.346</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>Mean</th>
<th>Standard Deviation</th>
<th>Minimum</th>
<th>Maximum</th>
</tr>
</thead>
<tbody>
<tr>
<td>CPOR (m³/m³)</td>
<td>0.205</td>
<td>0.045</td>
<td>0.024</td>
<td>0.266</td>
</tr>
<tr>
<td>K_v (mD)</td>
<td>226.171</td>
<td>190.762</td>
<td>0.010</td>
<td>810.000</td>
</tr>
<tr>
<td>K_h (mD)</td>
<td>244.553</td>
<td>219.548</td>
<td>0.010</td>
<td>1320.000</td>
</tr>
<tr>
<td>Grain Density (g/cm³)</td>
<td>2.647</td>
<td>0.038</td>
<td>2.560</td>
<td>3.150</td>
</tr>
<tr>
<td>Sw (%)</td>
<td>14.913</td>
<td>17.013</td>
<td>0.700</td>
<td>94.400</td>
</tr>
</tbody>
</table>

Table 4.5 Well 1 wireline descriptive statistics.

Well 1z

Well 1z was drilled with OBM, LWD and core data sets were available for this horizontal well [Table 4.3]. The LWD data acquired was in the 8½" hole section and was logged approximately 2.3 hours behind the bit (measured from the LWD density/neutron tool measurement point). The rate of penetration was approximately 15 m/hr throughout drilling the well [Table 4.6]. The logs were cyclical due to borehole spiralling on a wavelength of 1-2 m.

The LWD density correction was close to zero, yet highly erratic with some significant spikes in the data (>±0.1 g/cm³)[Figure 4.5]. Notable spikes occur between x1185-1240m (due to caving), x2023-2072m and x2209-2217m, both due to drilling difficulties, as the formation becomes muddier. The drilling fluid report noted that the mud weight was increased early in drilling the well. It was assumed for the purposes of
Chapter 4: Analysis of the Data Sets

this thesis that barite was used in the mud considering that 144ppb barite was used in
the drilling the vertical well 1.

The Oil Company considered the LWD bulk density values to be of poor
quality. The LWD bulk density values were much lower than expected from the vertical
well 1 [Figure 4.5]. The LWD bulk density log appears to be greatly affected by
variable standoff of the tool. The GOC gradational contact was picked between
x1547.0-1596.0m (Unit B1).

The neutron porosity values were greater than expected from well 1. This was
likely due to the standoff, but invasion could also be a factor. The drilling report noted
that large quantities of mud were lost during the drilling and therefore invasion was
likely to be deep. However, the match between core and neutron porosity was good,
contradicting standoff as the cause of the 'high' neutron porosity values [Figure 4.5].

The LWD resistivity values were slightly lower than the resistivity values
recorded in the vertical well 1 [Figure 4.5]. This was likely to be due to differences in
the operating frequencies of the tools used. The peaks observed in the pressure log
(DDS) were generally due to bit trips (removing the entire drill pipe to change the bit
prior to continuation of drilling). The rate of penetration was low throughout most of
the well, large increases were noted in shalier sections of the borehole.

Well 3

Well 3 was drilled with OBM and logged with wireline (pipe conveyed) and
LWD through the 8½inch horizontal well. The rate of penetration was between 10-
20m/hr [Figure 4.6]. The LWD amplitude resistivity log “straight lines” [e.g. x640-
655m], indicating that the measurement conditions were exceeded, the phase resistivity
log was not similarly affected. The LWD nuclear logs were noisy due to a rugose well
and barite in the mud. The gradational GOC was picked between x647.0-652.5m (Unit
B1).

From the wireline logs, the caliper values show that the borehole was rugose
with several caves and ledges and all the logs were cyclical due to 1-2m borehole
spiralling, especially between x850-1010m resulting from a damaged bit. The wireline
density correction log was close to zero, but negative excursions occurred in muddier
beds and doggers. The drilling fluid report noted that barite mud was used, resulting in
high and erratic PEF values (2.3-2.5B/e) in the sandstone layers with large departures
due to the shale beds and doggers. Bulk density and neutron porosity values were comparable in values with the well 1 values [Figure 4.4, Figure 4.6b, Table 4.5 and Table 4.7].

<table>
<thead>
<tr>
<th>Measurement</th>
<th>Mean</th>
<th>Standard Deviation</th>
<th>Minimum</th>
<th>Maximum</th>
</tr>
</thead>
<tbody>
<tr>
<td>RHOB (g/cm³)</td>
<td>2.104</td>
<td>0.113</td>
<td>1.650</td>
<td>3.110</td>
</tr>
<tr>
<td>NPHI (m³/m³)</td>
<td>0.233</td>
<td>0.010</td>
<td>0.214</td>
<td>0.329</td>
</tr>
<tr>
<td>EWR (Ohm.m)</td>
<td>9.543</td>
<td>15.013</td>
<td>2.570</td>
<td>650.270</td>
</tr>
<tr>
<td>Rₖ (Ohm.m)</td>
<td>9.543</td>
<td>15.013</td>
<td>2.570</td>
<td>650.270</td>
</tr>
<tr>
<td>GR1 (API)</td>
<td>15.307</td>
<td>2.765</td>
<td>9.440</td>
<td>34.300</td>
</tr>
<tr>
<td>GR2 (API)</td>
<td>28.557</td>
<td>9.194</td>
<td>13.740</td>
<td>88.390</td>
</tr>
<tr>
<td>DRHO (g/cm³)</td>
<td>-0.002</td>
<td>0.040</td>
<td>-0.430</td>
<td>0.330</td>
</tr>
<tr>
<td>ROP (m/s)</td>
<td>0.025</td>
<td>0.058</td>
<td>0.000</td>
<td>0.939</td>
</tr>
<tr>
<td>DDS (psi)</td>
<td>12392.045</td>
<td>40460.029</td>
<td>684.000</td>
<td>365939.969</td>
</tr>
</tbody>
</table>

Table 4.6 Well 1z LWD descriptive statistics.

<table>
<thead>
<tr>
<th>Measurement</th>
<th>Mean</th>
<th>Standard Deviation</th>
<th>Minimum</th>
<th>Maximum</th>
</tr>
</thead>
<tbody>
<tr>
<td>CPOR (m³/m³)</td>
<td>0.240</td>
<td>0.011</td>
<td>0.215</td>
<td>0.289</td>
</tr>
<tr>
<td>Kᵥ (mD)</td>
<td>237.311</td>
<td>78.398</td>
<td>4.930</td>
<td>416.000</td>
</tr>
<tr>
<td>Kₖ (mD)</td>
<td>229.204</td>
<td>67.583</td>
<td>24.500</td>
<td>345.000</td>
</tr>
<tr>
<td>Grain Density (g/cm³)</td>
<td>2.640</td>
<td>0.007</td>
<td>2.590</td>
<td>2.650</td>
</tr>
<tr>
<td>Sw (%)</td>
<td>11.285</td>
<td>3.526</td>
<td>2.800</td>
<td>18.100</td>
</tr>
</tbody>
</table>

Table 4.7 Well 3 wireline descriptive statistics.
Well 5

Well 5 was drilled with OBM, both wireline and core data sets were available for this 12½ inch vertical well [Figure 4.7 and Table 4.3]. The borehole was logged 19 hours after mud circulation stopped, except the acoustic and dual-arm caliper tools that were logged after 44½ hours.

The density caliper values indicated that the borehole was rugose, but in-gauge, however the dual-arm caliper demonstrated that the borehole was slightly enlarged by approximately 0.1 inches along the major axis followed by the density caliper [Figure 4.7]. The other arm of the caliper (perpendicular to the first) revealed that the minor axis of the borehole was less rugose and approximately 1 inch under-gauge, an indication of the unconsolidated nature of the sandstone, although mudcake could not be ruled out as the cause. The density correction log was slightly negative due to barite (196 lb/bbl) and the rugose borehole [Figure 4.7]. The effect of the barite was not as great on the PEF log values as expected from well 1 [Figure 4.7 and Figure 4.4].

The gradational GOC was picked between x597.0-600.0m (Unit B2). For the purposes of this thesis the OWC was picked at x665.5m. The oil column was at irreducible water saturation (IOC) above x640m. There was some separation of resistivity values through the reservoir, due to mud invasion (>10 inches)[Figure 4.7]. The acoustic travel time log values were near constant (>90 µs/ft) through the units A2.2 to B2. The shale beds in units A1 and A2.1 appeared to be ‘fast’ (competent), but the sandstone beds were ‘slow’ probably due to gas, but the unconsolidated beds may be a factor. There were no doggers readily apparent through the reservoir.
Well 6

Well 6 was drilled with OBM, the datasets included wireline (pipe conveyed) and LWD for this 8½inch horizontal well. However, there were large gaps in the LWD data set [Table 4.3]. The LWD bulk density and neutron porosity data only covered x770-815m, which allowed the gradational GOC to be picked between x797-804m (Oil Company depths)[Figure 4.8b]. Comparison of the resistivity logs, suggested that well 6 remains in the oil leg over the interval covered by wireline data [Figure 4.8a].

There was no wireline caliper log for this well, however, the tension provided some indication of the downhole conditions whilst logging. The tension log was erratic in comparison with the tension log of well 5 [Figure 4.7 and Figure 4.8a]. The erratic nature was a result of the nature of pipe conveyed logging being a stop/start operation and the rugose borehole condition, though could result from poor drilling crew operation of the pipe conveyed logging (PCL). Often PCL depths are poor due to inability to keep the wireline taut at all times directly effecting the quality of the depth derived logs such as acoustic and induction. Additionally, the Stoneley wave travel time could be used as an indicator of poor hole conditions. Large increases in Stoneley wave travel time may indicate the presence of fractures or incompetent beds [x1955-1990m Figure 4.8a].

The wireline gamma ray and resistivity values were similar to the expected values from the other wells [Figure 4.8a]. However, the compressional travel time log was approximately 10μs/ft slower through the sandstone beds compared with wells 1 and 5 [Figure 4.8a, Figure 4.4 and Figure 4.7]. The shale beds were faster than the sandstone beds and effectted the compressional travel time log to a greater extent than in both wells 1 and 5. This was possibly a result of shale acoustic anisotropy or may be evidence of sand acoustic anisotropy. Another possibility was that the acoustic tool was not running parallel with the borehole. This can produce both faster and slower travel times than expected. Well 6 also encountered many more doggers than observed in the other wells [Figure 4.8a]. However, some of the fast peaks correlated with the tension log and suggested that those peaks were a result of noise induced by the pipe conveyed logging operation [x1060m Figure 4.8a].
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<table>
<thead>
<tr>
<th>Measurement</th>
<th>Mean</th>
<th>Standard Deviation</th>
<th>Minimum</th>
<th>Maximum</th>
</tr>
</thead>
<tbody>
<tr>
<td>RHOB (g/cm³)</td>
<td>2.279</td>
<td>0.124</td>
<td>2.038</td>
<td>2.825</td>
</tr>
<tr>
<td>NPHI (pu)</td>
<td>0.196</td>
<td>0.062</td>
<td>0.027</td>
<td>0.401</td>
</tr>
<tr>
<td>AT10 (Ohm.m)</td>
<td>16.596</td>
<td>29.193</td>
<td>0.347</td>
<td>170.347</td>
</tr>
<tr>
<td>AT20 (Ohm.m)</td>
<td>16.004</td>
<td>28.549</td>
<td>0.320</td>
<td>161.892</td>
</tr>
<tr>
<td>AT30 (Ohm.m)</td>
<td>15.570</td>
<td>27.788</td>
<td>0.323</td>
<td>156.529</td>
</tr>
<tr>
<td>AT60 (Ohm.m)</td>
<td>15.505</td>
<td>28.147</td>
<td>0.339</td>
<td>215.159</td>
</tr>
<tr>
<td>AT90 (Ohm.m)</td>
<td>15.120</td>
<td>27.028</td>
<td>0.342</td>
<td>218.142</td>
</tr>
<tr>
<td>Rt (Ohm.m)</td>
<td>15.120</td>
<td>27.036</td>
<td>0.342</td>
<td>218.142</td>
</tr>
<tr>
<td>GR (API)</td>
<td>57.095</td>
<td>29.537</td>
<td>22.705</td>
<td>218.019</td>
</tr>
<tr>
<td>PEF (B/e)</td>
<td>1.995</td>
<td>0.473</td>
<td>0.953</td>
<td>4.213</td>
</tr>
<tr>
<td>DT (µs/ft)</td>
<td>90.501</td>
<td>8.845</td>
<td>49.199</td>
<td>129.771</td>
</tr>
<tr>
<td>DRHO (g/cm³)</td>
<td>-0.006</td>
<td>0.016</td>
<td>-0.048</td>
<td>0.074</td>
</tr>
<tr>
<td>CAL1_1 (ins)</td>
<td>11.231</td>
<td>0.123</td>
<td>11.179</td>
<td>11.647</td>
</tr>
<tr>
<td>CAL2_1 (ins)</td>
<td>12.308</td>
<td>0.124</td>
<td>12.127</td>
<td>13.143</td>
</tr>
<tr>
<td>CALI_DEN (ins)</td>
<td>12.348</td>
<td>0.354</td>
<td>12.105</td>
<td>14.215</td>
</tr>
<tr>
<td>TENS (lb/ft)</td>
<td>4052.401</td>
<td>104.119</td>
<td>3856.000</td>
<td>4443.000</td>
</tr>
</tbody>
</table>

**Table 4.9 Well 5 wireline descriptive statistics.**

<table>
<thead>
<tr>
<th>Measurement</th>
<th>Mean</th>
<th>Standard Deviation</th>
<th>Minimum</th>
<th>Maximum</th>
</tr>
</thead>
<tbody>
<tr>
<td>CPOR (m³/m³)</td>
<td>0.238</td>
<td>0.026</td>
<td>0.181</td>
<td>0.275</td>
</tr>
<tr>
<td>Kₐ (mD)</td>
<td>257.933</td>
<td>159.429</td>
<td>2.800</td>
<td>536.000</td>
</tr>
<tr>
<td>Grain Density (g/cm³)</td>
<td>2.648</td>
<td>0.004</td>
<td>2.640</td>
<td>2.650</td>
</tr>
<tr>
<td>S_w (%)</td>
<td>37.472</td>
<td>21.219</td>
<td>12.700</td>
<td>83.500</td>
</tr>
</tbody>
</table>

**Table 4.10 Well 6 wireline descriptive statistics.**
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The wallet at the back of the thesis contains all the log plots.

Figure 4.4 Well 1 wireline logs.

Figure 4.5 Well 1z LWD logs.

a) Well 3 Wireline logs
b) Well 3 LWD logs

Figure 4.7 Well 3 logs.

Figure 4.8 Well 5 wireline logs.

a) Well 6 Wireline logs
b) Well 6 LWD logs

Figure 4.10 Well 6 logs.
4.2 Porosity Anomalies

4.2.1 Porosity anomalies - data Set 1

Calculating porosity for clean sandstone reservoirs in a vertical well is usually relatively straightforward, even for gas reservoirs. Once the correct hydrocarbon density has been estimated/calculated, the hydrocarbon corrections (usually only fluid density is needed) can be calculated and porosity determined. Core porosity values (if available) are used to calibrate the porosity values from the logs (§2.2). This approach provides accurate and reliable porosity values from the logs.

In horizontal wells, the problem of calculating porosity is less straightforward. Often the borehole and formation conditions are significantly different from the situation found in vertical wells (See Chapter 3) leading to incorrect porosity estimation when the vertical well approach is used. Incorrect porosity estimation is caused by perturbations to the log measurement, most likely as result of one or all of the following: anisotropic mud invasion, borehole damage and tool orientation.

For the data set 1, the porosity estimation in the vertical well was simple. However, porosity estimation was more complicated in the horizontal well. In the section above, borehole and tool damages were mentioned and the former is self-evident from the logs, especially the caliper logs that show cyclic rugosity [Figure 4.2]. Permeability anisotropy [Table 4.10, Figure 4.9 and Figure 4.10] and therefore mud invasion anisotropy is well known for the Leman sands (Bedford et al. 1997). Most reported cases of unusual porosity values in horizontal wells discuss estimated porosity that is ‘too high’ [Equation 2.2]. In this case study, unusually the porosity values calculated were too low and this was of concern to Oil Company 1.

<table>
<thead>
<tr>
<th></th>
<th>Horizontal Permeability (mD)</th>
<th>Vertical Permeability (mD)</th>
<th>Overburden Corrected Core Porosity (%)</th>
<th>Grain Density (g/cm³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mean</td>
<td>5.18</td>
<td>1.86</td>
<td>11.41</td>
<td>2.66</td>
</tr>
<tr>
<td>SD</td>
<td>13.38</td>
<td>5.31</td>
<td>3.32</td>
<td>0.02</td>
</tr>
<tr>
<td>Min</td>
<td>0.02</td>
<td>0.01</td>
<td>5.40</td>
<td>2.63</td>
</tr>
<tr>
<td>Max</td>
<td>88.00</td>
<td>40.00</td>
<td>19.40</td>
<td>2.79</td>
</tr>
</tbody>
</table>

Table 4.10 Data set 1 vertical well core data descriptive statistics.
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Permeability Histogram

Figure 4.9 Vertical well core permeability histogram. Note: the horizontal and vertical permeability distributions are very similar, but when plotted against porosity [Figure 4.10], permeability anisotropy is evident.

**Porosity verses Log Permeability**

- Log Kv (mD)
- Log Kh (mD)
- Linear (Log Kv (mD))
- Linear (Log Kh (mD))

\[
y = 0.2283x - 2.7478 \\
R^2 = 0.8534
\]

\[
y = 0.1878x - 2.565 \\
R^2 = 0.8217
\]

Figure 4.10 Vertical well core porosity permeability plot.
Crossplotting horizontal well LWD standard model porosity values [Table 4.11] against depth distributed core porosity values (Weissliegend and Rotliegend gas only) from the vertical well show that the match was poor especially with LWD average density porosity [Figure 4.11c]. However, there was substantial scope for altering the position of the core porosity values in depth with respect to the horizontal well porosity data and thereby changing the match achieved. After testing a number of different approaches, the best comprise was to evenly distribute the core porosity values in depth.

Despite this potential for compromise of the comparison the horizontal and vertical well density porosity data still clearly demonstrate low horizontal well density porosity values compared with the vertical well [Table 4.12]. This is clear even though the rugosity, indicated by the greater standard deviation, acts to increase the porosity values in the horizontal well.

Comparison of the neutron porosity mean values would suggest that the horizontal and vertical wells were in good agreement [Table 4.12], but as for the density porosity values, rugosity acts to increase the recorded porosity values. Section 4.4 shows that filtering to reduce the effect of rugosity lowers both the mean and standard deviation of the horizontal well neutron porosity values.

The observations of low porosity values presented form the basis of the investigation of the horizontal well porosity values for data set 1. The calculation of reserves is very sensitive to the porosity value and low values may suggest that the field could be uneconomic to develop or to continue development.

<table>
<thead>
<tr>
<th>Porosity Parameter</th>
<th>Standard values</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fluid Density (g/cm³) used for density logs</td>
<td>1.000</td>
</tr>
<tr>
<td>Excavation correction (percentage porosity) used for neutron porosity logs</td>
<td>0.000</td>
</tr>
</tbody>
</table>

Table 4.11 Parameters used for porosity calculations.
Chapter 4: Analysis of the Data Sets

<table>
<thead>
<tr>
<th>Variable</th>
<th>Minimum</th>
<th>Maximum</th>
<th>Mean</th>
<th>Standard Deviation</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Variable</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Vertical Well</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LWD</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Average Density Porosity (%)</td>
<td>0.005</td>
<td>0.226</td>
<td>0.137</td>
<td>0.035</td>
</tr>
<tr>
<td>Maximum Density Porosity (%)</td>
<td>0.020</td>
<td>0.157</td>
<td>0.095</td>
<td>0.031</td>
</tr>
<tr>
<td>Neutron Porosity (%)</td>
<td>0.020</td>
<td>0.157</td>
<td>0.095</td>
<td>0.031</td>
</tr>
<tr>
<td><strong>Core</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Horizontal Helium Porosity (%)</td>
<td>0.054</td>
<td>0.194</td>
<td>0.114</td>
<td>0.033</td>
</tr>
<tr>
<td><strong>Wireline</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Acoustic Porosity (%)</td>
<td>0.028</td>
<td>0.213</td>
<td>0.106</td>
<td>0.044</td>
</tr>
<tr>
<td>Density Porosity (%)</td>
<td>0.011</td>
<td>0.201</td>
<td>0.112</td>
<td>0.035</td>
</tr>
<tr>
<td>Neutron Porosity (%)</td>
<td>0.013</td>
<td>0.144</td>
<td>0.081</td>
<td>0.034</td>
</tr>
<tr>
<td><strong>Horizontal Well</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LWD</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Average Density Porosity (%)</td>
<td>-0.092</td>
<td>0.450</td>
<td>0.193</td>
<td>0.073</td>
</tr>
<tr>
<td>Maximum Density Porosity (%)</td>
<td>-0.249</td>
<td>0.275</td>
<td>0.085</td>
<td>0.078</td>
</tr>
<tr>
<td>Neutron Porosity (%)</td>
<td>-0.034</td>
<td>0.301</td>
<td>0.083</td>
<td>0.033</td>
</tr>
</tbody>
</table>

Table 4.12 Derived porosity statistics (fluid: 1g/cm³ density and 189μs/ft travel time).

![Vertical Well Wireline Porosity Crossplot](image_url)

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Chapter 4: Analysis of the Data Sets

Figure 4.11 Core porosity against calculated porosity crossplots using standard parameters for vertical well a) wireline and b) LWD data. c) horizontal well LWD data.
4.2.2 Porosity anomalies - data Set 2

Data set 2 required a different approach to data set 1 for calculating porosity in the mixed-fluid shaley sandstone reservoir. The shale needed to be accounted for and the correct hydrocarbon densities had to be estimated/calculated. The shale parameters used for data set 2 are given in Table 4.14. Core porosity values were used to calibrate the porosity values from the logs (See Chapter 2).

In the horizontal wells, calculating porosity was problematic due to borehole and formation conditions differing from the vertical wells (See Chapter 3). A further complication was that horizontal wells are not logged with the same class of tools (wireline/LWD) or the same suite of tools (different measurements)[Table 4.3].

<table>
<thead>
<tr>
<th>Shale Parameter</th>
<th>Values</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shale density (g/cm³) used for density logs</td>
<td>2.500</td>
</tr>
<tr>
<td>Shale point (percentage porosity) used for neutron porosity logs</td>
<td>Not applicable</td>
</tr>
<tr>
<td>Shale travel time (µs/ft) used for acoustic travel time logs</td>
<td>100.000</td>
</tr>
</tbody>
</table>

Table 4.14 Parameters used for shale corrections.

A number of porosity algorithms were used: shale corrected density, shale corrected acoustic [Equations 2.32 and 2.34] and sandstone neutron porosity. Shale corrected neutron porosity was not used due to over correction of the 'shale' effect in the sands. Log and core porosity values were compared in vertical and horizontal wells to determine if the log porosity over estimated porosity in horizontal wells with parameters used given in Table 4.15 and the calculated porosity values in Table 4.16.

A direct comparison of porosity values between wells was not necessarily valid due to lateral variations in reservoir characteristics and cross-section of the reservoir intersected by the wells differs. There was little reason to assume that porosity was laterally constant, since the sands were shaley and turbiditic with several doggers. However, without additional core porosity data no conclusive assessment of porosity homogeneity could be made. For example, well 1 core porosity was sampled every 25cm through the reservoir (~450 samples), but <20 samples spread through the reservoir were available for well 5. More than 80 samples from a single bed were available for horizontal sidetrack well 1z. A decision was made to use well 1 core
porosity data for the statistical comparisons in section 4.4 in all but well 1z where the large number of core samples permitted their use.

<table>
<thead>
<tr>
<th>Fluid density (g/cm³) used for density logs</th>
<th>Standard values</th>
</tr>
</thead>
<tbody>
<tr>
<td>Excavation correction (percentage porosity) used for neutron porosity logs</td>
<td>0.000</td>
</tr>
<tr>
<td>Fluid travel time (µs/ft) used for acoustic travel time logs</td>
<td>189.000</td>
</tr>
</tbody>
</table>

**Table 4.15** Parameters used for porosity calculations.

<table>
<thead>
<tr>
<th>Measurement</th>
<th>Mean</th>
<th>Standard Deviation</th>
<th>Minimum</th>
<th>Maximum</th>
</tr>
</thead>
<tbody>
<tr>
<td>RHOB</td>
<td>0.221</td>
<td>0.057</td>
<td>0.326</td>
<td>-0.032</td>
</tr>
<tr>
<td>RHOB2</td>
<td>0.219</td>
<td>0.050</td>
<td>0.295</td>
<td>-0.034</td>
</tr>
<tr>
<td>NPHI</td>
<td>0.182</td>
<td>0.052</td>
<td>0.050</td>
<td>0.363</td>
</tr>
<tr>
<td>DT</td>
<td>0.264</td>
<td>0.094</td>
<td>0.295</td>
<td>0.435</td>
</tr>
<tr>
<td>DTCO</td>
<td>0.216</td>
<td>0.043</td>
<td>0.305</td>
<td>0.027</td>
</tr>
<tr>
<td>RHOB</td>
<td>0.180</td>
<td>0.029</td>
<td>0.050</td>
<td>0.272</td>
</tr>
<tr>
<td>NPHI</td>
<td>0.252</td>
<td>0.003</td>
<td>0.050</td>
<td>0.350</td>
</tr>
<tr>
<td>DT</td>
<td>0.241</td>
<td>0.036</td>
<td>0.050</td>
<td>0.321</td>
</tr>
<tr>
<td>DTCO</td>
<td>0.205</td>
<td>0.045</td>
<td>0.024</td>
<td>0.266</td>
</tr>
</tbody>
</table>
| CPOR        | 0.198 | 0.055              | 0.054   | 0.266   | 4-25

**Table 4.16** Data set 2 comparison of porosity descriptive statistics in m³/m³. Values from the whole reservoir are in white cells. Values from the unit B2 are in grey cells.
Comparison of the porosity values in Table 4.16 shows that for the horizontal wells 1z, 3 and 6 all measure greater porosity values (>1 standard deviation) in the whole reservoir section and unit B2 (least shaley unit) when compared with the vertical wells 1 and 5 log and core porosity values. Notably the acoustic porosity values were significantly greater than other porosity measurements.

The high observed porosity values could result in over optimistic reserves estimates from the horizontal well data. Oil Company 2 was developing the field predominantly with horizontal wells therefore inaccurate porosity was of concern. This evidence of high porosity values in the horizontal wells of data set 2 forms the basis of the investigation presented below in section 4.4.
4.3 Analysis techniques

This section provides an explanation of how the analyses of the horizontal well porosity values were performed. The first section (§4.3.1) describes the approaches used for the porosity calculations and the decision process used to choose the best method is discussed in section 4.3.2 with a worked example from each data set. Finally, a description of the spectral analysis of the data used is provided with a worked example from each data set, used to reduce the effects of borehole conditions resulting from spiralling. The results of the analyses of the two data sets are presented in the following section 4.4.

4.3.1 Porosity algorithms

The porosity algorithms used for the analysis were detailed in chapter 2. The porosity algorithms used were density [Equation 2.2], neutron [Equation 2.11], acoustic [Equation 2.15], square root [Equation 2.46], Wiley & Patchett [Equation 2.44] and hydrocarbon corrected [Equations 2.50 and 2.51] using iterative calculations in which the fluid parameters were used to achieve good agreement with core porosity values as defined in section 4.3.2. Section 2.4.3 described the Gaymard and Poupon (1968), Wiley and Patchett (1994) and Cowan and Wright (1997) methods. Porosity histograms and statistical comparisons with core porosity values were used to determine the validity log porosity values and test which method provided the most reliable values as detailed in section 4.3.2. A different approach for porosity calculation was used for each data set due to the different lithologies and fluid contents of the reservoirs.

Data set 1

The field from which data set 1 was obtained consisted of the Leman gas sand of the southern North Sea. For the purposes of this thesis the reservoir was subdivided into three units based on the vertical well; Weissliegend x008ft-x153ft, Rotliegend gas x153ft-x191ft and Rotliegend water x191ft-x236ft [Figure 4.1, layers marked]. This was based on the change in facies from the Weissliegend to the Rotliegend (at x153ft) and the change in formation fluid from gas to water (at x191ft). The porosity analyses
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were performed on the whole reservoir and the three units separately for each of the porosity algorithms in turn. The porosity algorithms used were density, neutron, acoustic, square root, Wiley & Patchett and iterative hydrocarbon corrected calculations. Note that the Rotliegend water unit was not observed in the horizontal well so only the other two units were used in this case.

In the vertical well, it was possible to calculate porosity values from the density, neutron and acoustic logs from both the wireline and LWD (no acoustic) tool measurements using the methods described above. The objective was to determine which method/s were sufficient to calculate accurate porosity values, since there is no point in practice opting for a complex method over a simple method without any notable improvement in accuracy. It was also important to find satisfactory LWD derived porosity to core porosity agreement because no wireline logs for the horizontal well exist.

Initially, the density derived porosity values (both wireline and LWD) were calculated assuming a matrix density = 2.65g/cm$^3$ (used for all density porosity calculations) and fluid density = 1g/cm$^3$. The neutron derived porosity values (both wireline and LWD) were calculated in sandstone units assuming no corrections were required. The acoustic derived porosity values (only wireline) were calculated assuming the matrix acoustic slowness = 55μsec/ft (used for all acoustic porosity calculations) and fluid acoustic slowness = 189μsec/ft. This approach was applied to the whole reservoir section and was called the standard model in this thesis for data set 1.

The single layer method used to improve the calculation of log porosity was a simple linear shift over the whole interval of interest i.e. finding the optimum fluid density, neutron porosity excavation constant (a constant added to account for gas) and acoustic fluid travel time. The core porosity data was used to minimise the difference between the core porosity values and the appropriate log derived porosity values by changing the appropriate fluid parameter (using SOLVER™ for EXCEL™). The three-layer model used different fluid density, neutron porosity excavation constant and acoustic fluid travel time (by minimising the core and log derived porosity differences by changing the appropriate fluid parameter) for each of the three layers defined above. The square root and Wiley & Patchett methods were applied to the neutron and density porosity values calculated from the standard, single and three-layer models above for
both LWD and wireline porosity values. The hydrocarbon corrected method used the square root and Wiley & Patchett equations as detailed in section 2.4.3.

In the horizontal well, porosity values were calculated from the LWD density and neutron tool measurements. The same methods for calculating porosity were used as for the vertical well, but without the benefit of horizontal well core porosity data to verify the LWD calculated porosity values. In addition, only two of the three units were observed in the horizontal well; Weissliegend x134-906ft and x1655-1951ft, and Rotliegend gas x906-1655ft [Figure 4.2, layers marked].

Data set 2

Data set 2 required a slightly different approach than was used for data set 1 because of the shaley mixed-fluid sandstone reservoir. The shale needed to be accounted for [Equation 2.33] and the correct hydrocarbon densities had to be estimated/calculated (See Chapter 2). Core porosity values were used to calibrate the porosity values from the logs (See Chapter 2). For the purposes of this thesis, the reservoir was subdivided into four units based on the change in formation fluid from gas to oil to water [Table 4.17]. The porosity analyses were performed on the whole reservoir and the four units separately for each of the porosity algorithms in turn. A number of porosity algorithms were used; shale corrected density, shale corrected acoustic, square root, Wiley & Patchett, Gaymard & Poupon neutron and Gaymard & Poupon density [Equations 2.37, 2.39, 2.46, 2.52, 2.50 and 2.51 respectively] and sandstone neutron porosity. Shale corrected neutron porosity was not used due to over correction of the 'shale' effect in the sands.

The fluid parameters for the density and acoustic shale corrected porosities were investigated in two ways. Firstly, using the Oil Company's (OC) fluid parameter values and secondly with values such that the porosity equations are in agreement with well 1 core porosity values by minimising the core and log derived porosity differences by changing the appropriate fluid parameter. Porosity values were calculated from the logs available from the well; wireline and/or LWD measurements of density, neutron or acoustic logs using the methods described above. The logs were used to determine which method/s were sufficient to calculate accurate porosity values for both LWD and wireline horizontal well data when compared with well 1 core porosity values.
Table 4.17 Top depths of fluid zones for each well in metres.

<table>
<thead>
<tr>
<th>Zone/Well</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>5</th>
<th>6</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas</td>
<td>x571</td>
<td>x884</td>
<td>x572</td>
<td>x519.5</td>
<td></td>
</tr>
<tr>
<td>Oil</td>
<td>x619</td>
<td>x1547-2270</td>
<td>x652.5-1565.5</td>
<td>x597</td>
<td>x926.5-2311</td>
</tr>
<tr>
<td>Transition</td>
<td>x652</td>
<td></td>
<td></td>
<td></td>
<td>x640</td>
</tr>
<tr>
<td>Water</td>
<td>x702-770</td>
<td></td>
<td></td>
<td></td>
<td>x665.5-726.5</td>
</tr>
</tbody>
</table>

The Oil Company’s porosity calculation method was reproduced. The density derived porosity values (both wireline and LWD) were calculated using the matrix density = 2.65g/cm$^3$, shale density = 2.5g/cm$^3$ and water density = 1g/cm$^3$ and hydrocarbon density = 0.7g/cm$^3$ [Equation 2.37]. The neutron derived porosity values (both wireline and LWD) were calculated in sandstone units assuming no corrections were required. The acoustic derived porosity values (only wireline) were calculated assuming the matrix acoustic slowness = 55μsec/ft and the shale acoustic slowness = 100μsec/ft (used for all acoustic porosity calculations) and fluid acoustic slowness = 189μsec/ft [Equations 2.37]. The Oil company shale parameters were used for all density and acoustic porosity calculations.

The method used to improve the calculation of log porosity was a simple linear shift over the fluid unit of interest i.e. finding the optimum fluid density, neutron porosity excavation constant (a constant added to account for gas) and acoustic fluid travel time. The core porosity data was used to minimise the difference between the core porosity values and the appropriate log derived porosity values by changing the appropriate fluid parameter (using SOLVER™ for EXCEL™). The square root and Wiley & Patchett and hydrocarbon corrected methods were applied to the neutron and density porosity values calculated from the optimised shift values above for both LWD and wireline porosity values. Porosity histograms and statistical comparisons with core porosity values were used to determine the validity of the hypothesis that the calculated porosity values were over estimated in horizontal wells (§4.2.2).
4.3.2 Statistical tests

Porosity histograms and statistical comparisons with core porosity values were used to determine the validity of the hypothesis that log porosity values were anomalous in the horizontal wells of both data sets. Using data set 1 the horizontal well was tested to verify that the porosity values were underestimated in comparison with the vertical well core porosity values. Using data set 2 the horizontal wells were tested to verify that the porosity values were overestimated in comparison with the vertical (well 1) core porosity values (except horizontal well 1z which was tested against core porosity values from well 1z itself). The vertical wells of both data sets were also compared with core in the same manner to confirm the hypothesis that the horizontal and not the vertical well log porosity values were anomalous for both data sets.

Porosity histograms allowed a direct visual comparison of the core and log derived porosity values, whilst the statistical tests used, Student’s t and Chi² tests, enabled quantitative assessments of the comparisons (examples given below). Student’s t-tests were used for all cases where F-tests demonstrated their distributions closely approximated a normal distribution. F-tests of the standard deviations of the distributions were used to verify the use of Student’s t-tests was robust; in all other cases Chi² tests were used. For Student’s t-tests, the hypothesised difference in the means being equal to zero and unequal variance are assumed. For whole reservoir cases, the Chi² goodness of fit test was used due to the non-normal distributions evident from the histogram plots of the data (see §4.4 and examples given below). The statistical tests were all comparisons of the core porosity values against the log derived porosity values as stated for each test in section 4.4 and the examples below.

For the purposes of this thesis, good agreement between porosity values of a given model and the core porosity values is defined as when the result of an appropriate two-tailed statistical test was within the 95% confidence limit. Tables in section 4.4 and the examples below detail the Student’s t-tests for clear cells and Chi² tests for the grey cells. A tick or cross (✓ / X) represents acceptance or rejection of the hypothesis, at the 95% confidence level, that there is zero difference between that porosity equation and core porosity values over the unit stated.

Correlation coefficients were also calculated to provide an indication of the relative spatial relationship between core and calculated porosity values over the whole
reservoir. Correlation was not valid between the vertical well core porosity and horizontal well calculated porosity values because the data were not spatially related.

A direct comparison of porosity values between wells was not necessarily valid (§4.2.1). For data set 1, crossplotting horizontal well LWD standard model porosity values against depth distributed core porosity values (Weissliegend and Rotliegend gas only) from the vertical well showed that the match was poor especially with LWD average density porosity [Figure 4.11].

For data set 2, well 1 core porosity was sampled every 25cm through the reservoir (~450 samples), but <20 samples spread through the reservoir were available for well 5. For the horizontal sidetrack (well 1z) there were >80 samples from a single bed. A decision was made to use well 1 core porosity data for the statistical comparisons in all but well 1z where the large number of core samples permitted their use (§4.2.2).

The lack of core porosity data was problematic for accurate determination of which method(s) were appropriate to calculate accurate horizontal well porosity values. However, comparison of log calculated porosity with the scaled vertical well core porosity values over the relevant units allowed rejection of methods which were certainly inaccurate.

A further complication in the horizontal wells was the borehole and formation conditions differing from the vertical wells (See Chapter 3). Calculating porosity was problematic because the horizontal wells were not logged with the same class of tools (wireline/LWD) or the same suite of tools (different measurements)[Table 4.3]. This was due to operational concerns rather than petrophysical needs and can frequently result in poor quality horizontal well data.
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Data set 1 example

The results of the standard porosity analyses are presented for the vertical well [Figure 4.16, Table 4.19 and Table 4.20] and the fluid parameters used are listed in Table 4.17. The porosity calculations in the vertical well clearly show that porosity calculations were most reliable using wireline density values. The wireline density porosity values were in good agreement with core porosity values over all depth intervals and have the highest correlation with the core porosity values using the standard model [Figure 4.16, Table 4.19 and Table 4.20]. The wireline neutron and LWD maximum density porosity values were only in good agreement with core porosity values over the Rotliegend water intervals. The wireline acoustic and LWD neutron porosity values were in good agreement with core porosity values over the whole and Rotliegend water intervals. LWD average density porosity values were in poor agreement with core porosity values over all depth intervals.

The vertical well was logged with LWD (LAD) 2 days AFTER the wireline tools. LWD neutron, average and maximum density porosity values were greater than their respective wireline porosity values. The LWD neutron porosity values were increased with respect to the wireline values due to the increased depth of mud penetration increasing the hydrogen index of the formation (replacing gas) and therefore the measured porosity values. The LWD average and maximum density porosity values were increased mainly due to the increased fluid density. The wireline acoustic porosity values were a poor match with core porosity values through the Rotliegend gas interval possibly due to the high volume of gas (high porosity) affecting the porosity values. Alternatively preferential acoustic energy propagation along low porosity beds due to the dipping bedding encountered from the alternating dune slip face/lee sands reduced the travel times. Note: Most open wells (uncased) become more rugose and/or enlarged as time increases.
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Figure 4.12 Vertical well model histograms with porosity ranging from 0 to 25% along the x-axis and frequency 0 to 100 counts along the y-axis. Plot a) is the wireline derived porosity standard distribution and plot b) is the LWD derived porosity standard distribution. The black curve on all the plots represents the core porosity distribution. The blue curve represents the wireline acoustic porosity distribution for plot a), but represents the LWD average density porosity distribution for plot b). The red curve represents the wireline acoustic porosity distribution for plots a), but represents the LWD average density porosity distribution for plot b).
Table 4.17 Parameters used for porosity calculations from data set 1 vertical well logs example.

Table 4.19 Vertical well statistical test results against core porosity values using the models detailed above considered over intervals; Whole x008ft-x236ft, Weissliegend x008ft-x153ft, Rotliegend gas x153ft-x191ft and Rotliegend water x191ft-x236ft. \( \times \) = reject the hypothesis and \( \checkmark \) = accept the hypothesis at the 95% confidence level using Chi\(^2\) goodness of fit test for grey cells and Student’s t-test with the hypothesised mean difference=0 for clear cells.

Table 4.20 Vertical well correlation coefficients against core porosity values over the whole interval x008ft-x236ft.
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Data set 2 example

Well 1 wireline calculated and core porosity values were statistically compared and the results of the linear shifted and Oil Company analyses are presented below [Figure 4.17, Table 4.21 and Table 4.20]. The porosity histograms (0-40pu) are plotted for the whole reservoir with well 1 core porosity values [Figure 4.17]. The standard histogram includes the core, density, neutron, acoustic and the Oil Company density and acoustic porosity values. The acronyms used were CPOR=well 1 core porosity, DenPor=shale corrected density porosity, Nphi_S=sandstone neutron porosity, AcouPor=shale corrected acoustic porosity, OC_DenPor=Oil Company shale corrected density porosity and OC_AcouPor=Oil Company shale corrected acoustic porosity.

The first table detailing the Student’s t-tests for the clear cells and Chi² tests for grey cells, a tick/cross (✓/✗) represents acceptance or rejection of the hypothesis at the 95% confidence level that there is zero difference between that porosity equation and well 1 core porosity values over the fluid interval stated [Table 4.21]. The second table gives details of the fluid parameters used in the equations for each fluid zone [Table 4.20]. In the fluid parameter table, OC refers to using the relevant Oil Company’s fluid parameter in that particular porosity equation. The oil zone is defined as oil at irreducible water saturation. The transition zone is defined as oil at greater than irreducible water saturation.

The statistical tests demonstrate that density and acoustic porosity values both matched the core porosity values over each fluid zone, although the match was not good when the comparison was made over the whole reservoir [Table 4.21]. The sandstone neutron porosity values only match core porosity values in the oil zone. The Oil Company’s (OC) density and acoustic porosity values only match core over the water zone. The standard histogram shows that the OC’s fluid parameters [Table 4.20] led to overestimation of the core porosity [Figure 4.17] whilst the density, neutron and acoustic porosity equations match the core porosity values above 19% porosity. The core porosity values around 10% porosity are due to high shale content in the core samples in certain intervals. However, the removal of these values does not alter the results presented. The acoustic and density values used to match with the core porosity values and the OC’s values were quite different. The OC’s density value was derived from the water density at hydrostatic pressure and the OC’s fluid travel time values was that of water. However, the shallow investigation depth (~2inches) and the use of OBM
to drill the well explains the use of 210μsec/ft, the approximate fluid travel time for oil. The fluid densities used reflect the change in fluid density within the formation. These results show that selection of fluid parameters is important if porosity is to be estimated with any accuracy. Interestingly, the OC’s density and acoustic porosity curves have double peaks indicating the presence of the different zones [Figure 4.13].

![Well 1: Standard Porosity Histogram](image)

**Figure 4.13** Well 1 standard porosity histogram.

<table>
<thead>
<tr>
<th>Porosity equation</th>
<th>Density (g/cm³)</th>
<th>Acoustic (μsec/ft)</th>
<th>OC Density (g/cm³)</th>
<th>OC Acoustic (μsec/ft)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas</td>
<td>0.55</td>
<td>210</td>
<td>1.01</td>
<td>189</td>
</tr>
<tr>
<td>Oil</td>
<td>0.85</td>
<td>205</td>
<td>1.01</td>
<td>189</td>
</tr>
<tr>
<td>Transition</td>
<td>0.85</td>
<td>210</td>
<td>1.01</td>
<td>189</td>
</tr>
<tr>
<td>Water</td>
<td>OC</td>
<td>OC</td>
<td>1.01</td>
<td>189</td>
</tr>
</tbody>
</table>

*Table 4.20* Well 1 fluid parameters.
Table 4.21 Well 1 Student's t-tests results against well 1 core porosity values, fluid parameters in Table 4.35. X = reject the hypothesis and ✓ = accept the hypothesis at the 95% confidence level using Chi² goodness of fit test for grey cells and Student’s t-test with the hypothesised mean difference = 0 for clear cells.
4.3.3 Spectral analysis

Spectral analysis of the data was performed to evaluate an apparent cyclicity in some of the horizontal well logs (Data Set 1, well 1z [Figure 4.2] and Data Set 2, wells 3 [Figure 4.6] and 6 [Figure 4.8]). The spectral analysis was calculated using a program that calculates the autocorrelation function of a series and provides the statistical significance of the results. The Fourier transform of the autocorrelation function is the power spectrum. The autocorrelation function is sufficient for the identification of the significant frequencies in the original logs. In practice the autocorrelation of the data is calculated by the inverse Fourier transform of the squared Fourier transform of the data.

Autocorrelation is the process of summing a function and its reversed function at increasing amounts of crossover. High autocorrelation values (greater than the significance level) occur when the result is high. The cause of high autocorrelation values may be a result of geological cyclicity [Figure 4.14], drilling induced or borehole condition. Identification of the cause of any peak is achieved by comparison with autocorrelation function for other measurements. The two most relevant being the autocorrelation functions of the rate of penetration and caliper logs because they relate to drilling effects and borehole conditions respectively. Other significant peaks are assumed to result from geological features.

![Figure 4.14 Schematic demonstrating a 'horizontal' borehole (green) crossing the same bed boundaries (black) several times, imparting a cyclic 'geological' signature on the logs.](image)

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Chapter 4: Analysis of the Data Sets

The log data were filtered to reduce the effect on the porosity values of non-geological perturbations identified from the spectral analysis. The porosity analysis was then repeated to test for improvement of the calculated porosity values. Filtering of the log data was performed using a program that calculates the Fourier series of the input log data to the number of required harmonics. The number of required harmonics having been identified from the autocorrelation functions. The greater the number of harmonics selected the greater the degree of accuracy of the match between the original unfiltered log. The required harmonics were selected to filter the data for data set 1 (§4.4.1). Moving average filters were preferred for the data set 2 as this was less damaging to geological features observed in the data (§4.4.2).

Example of spectral analysis

An example of autocorrelation analyses of the wireline and LWD logs of the data set 1 vertical well (x008-236ft) are presented in Figure 4.15. All the autocorrelation plots in this chapter show the autocorrelation function for the appropriate log (labelled at the head of each plot) and two coloured bands representing the significance level of the autocorrelation function. If the autocorrelation function is outside the yellow band, then the autocorrelation function is significant at that wavelength at the 95% confidence level. If the autocorrelation function is outside the blue and yellow bands, then the autocorrelation function is significant at that wavelength at the 99% confidence level.
The autocorrelation analyses of the data set 1 vertical well wireline density (a), caliper log (b) and LWD rate of penetration log (c) indicate that there was little or no effect on the density log by the borehole condition or drilling process [Figure 4.15]. This conclusion is based on the lack of correlation between the autocorrelation functions of the wireline caliper (flat and characterless) and LWD rate of penetration (no features match with the density) and wireline density log. This approach is repeated for all the logs for both data sets in section 4.4 below to identify if filtering is required.
4.4 Analysis of the data sets

In the following section of this chapter, the analyses of both data sets are presented. The porosity analyses of the data sets included the use of several different porosity algorithms namely; standard formulae, linear shifted, square root, Wiley & Patchett and hydrocarbon corrected using iterative calculations (§2.4.3 and §4.3). The reservoirs were split into a number of generic units based on the facies and fluid changes from the vertical wells in each data set. Each porosity algorithm was applied to each unit for both vertical and horizontal wells to assess the applicability of the algorithms with respect to the core porosity values from the vertical wells. The spectral analyses of the data sets enabled the evaluation of contributing factors and the removal of some of these unwanted influences (§4.3).

4.4.1 Data set 1

The reservoir was split into three generic units; Weissliegend x008-153ft, Rotliegend gas x153-191ft and Rotliegend water x191-236ft for the vertical well [Figure 4.1, layers marked] and Weissliegend x134-906, x1655-1951ft and Rotliegend gas x906-1655ft for the horizontal well [Figure 4.2, layers marked]. The idea was to determine which method/s were sufficient to calculate accurate porosity values, since there is no point in practice opting for a complex method over a simple method without any notable improvement in accuracy and precision. It was also important to find satisfactory LWD derived porosity to core porosity agreement because no wireline logs for the horizontal well exist. Note that the vertical well was logged with LWD (LAD) 2 days AFTER the wireline tools.

**Vertical well**

**Porosity analysis of data set 1: vertical well**

In the vertical well, it was possible to calculate porosity values from the density, neutron and acoustic logs from both the wireline and LWD (no acoustic) tool measurements. Figure 4.16, Table 4.23 and Table 4.24 contain the results of the vertical well standard porosity analyses. Table 4.22 lists the fluid parameters used.
The porosity calculations clearly showed that wireline density porosity values were most reliable. The wireline density porosity values were in good agreement with core porosity values over all depth intervals using standard, single layer, three layer, square root single layer, Wiley & Patchett standard, hydrocarbon corrected square root and Wiley & Patchett models. The wireline density porosity values also had the highest correlation with the core porosity values using the standard model.

The wireline neutron porosity values were in good agreement with core over all depth intervals using single layer, square root single layer, Wiley & Patchett standard, hydrocarbon corrected square root and Wiley & Patchett models. The wireline neutron porosity values were not as accurate as the wireline density porosity values, but in combination, their calculated porosity values were in good agreement with core.

The wireline acoustic porosity values were in poor agreement with core porosity values only over the standard model Weissliegend, single layer Weissliegend and Rotliegend gas and the three layer Rotliegend gas. The wireline acoustic porosity values were a poor match with core porosity values through the Rotliegend gas interval possibly due to the high volume of gas affecting the porosity values. Alternatively preferential acoustic energy propagation along low porosity beds due to the dipping beds encountered from the alternating dune slip face/lee sands reduced the travel times.

<table>
<thead>
<tr>
<th>Parameter Description</th>
<th>Standard</th>
<th>Single Layer</th>
<th>Weissliegend</th>
<th>Rotliegend (Gas)</th>
<th>Rotliegend (Water)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fluid Density (g/cm³) used for LWD Average Density log</td>
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<td>0.535</td>
<td>0.445</td>
<td>0.642</td>
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<tr>
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<tr>
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<td>0.0188</td>
<td>0.004</td>
<td>0.005</td>
</tr>
<tr>
<td>Fluid Density (g/cm³) used for Wireline Density log</td>
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<td>0.947</td>
<td>0.927</td>
<td>0.972</td>
<td>0.977</td>
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<tr>
<td>Fluid Slowness (μs/ft) used for Wireline Acoustic Porosity</td>
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<td>184.0</td>
<td>182.3</td>
<td>185.7</td>
<td>186.3</td>
</tr>
<tr>
<td>Excavation correction (percentage porosity) used for Wireline Neutron Porosity</td>
<td>0.000</td>
<td>0.029</td>
<td>0.038</td>
<td>0.009</td>
<td>0.011</td>
</tr>
</tbody>
</table>

Table 4.22 Parameters used for porosity calculation from the logs.
Chapter 4: Analysis of the Data Sets

All the LWD porosity values were greatly improved by changes in fluid parameters to be in good agreement with core porosity values over all the intervals except for the LWD neutron porosity in the Rotliegend gas interval. The square root method improved the LWD porosity values over the Wiley & Patchett method especially with the average density values. Figure 4.16 showed that LWD porosity generally over estimates core except for the square root single and three layer models.

- The square root single model using the LWD average density and neutron porosity values provides the best LWD derived porosity values in the vertical well.

Although accepted practice is that the LWD maximum density is preferred since its density measurement is more valid and reliable with the LWD tools used (Rider 1996).

LWD neutron, average and maximum density porosity values were greater than the wireline porosity values. The LWD neutron porosity values were increased with respect to the wireline values due to the increased depth of mud penetration increasing the hydrogen index of the formation (replacing gas). The LWD average and maximum porosity values were increased mainly due to increase in formation fluid density resulting from mud invasion. The fluid parameters used indicate the effect of gas.

There was increased borehole rugosity/enlargement and thus worse formation to detector contact than the wireline run indicated by the LWD caliper values. Note: Most open wells (uncased) become more rugose and/or enlarged as time increases. Additional evidence, in that the LWD density correction was negative whilst the wireline density correction was positive indicated that the LWD density tool was correcting for the heavy mud (barite). LWD $PEF$ values were also lower than the wireline $PEF$ values, although if the barite were more significant at the time of LWD logging, the expected LWD $PEF$ values would be greater than the wireline values. Note: barite collects at the bottom of the hole once mud circulation stops due to its high density.
Chapter 4: Analysis of the Data Sets

Porosity histogram for Wireline Standard model

- WAP Standard Frequency
- WDP Standard Frequency
- WNP Standard Frequency
- CP Frequency (Adjusted)

Porosity histogram for LWD Standard model

- LMD P Standard Frequency
- LAD_P Standard Frequency
- LNP Standard Frequency
- CP Frequency (Adjusted)

Porosity histogram for Wireline 1 layer fluid model

- WAP 1 Layer Frequency
- WDP 1 Layer Frequency
- WNP 1 Layer Frequency
- CP Frequency (Adjusted)

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Chapter 4: Analysis of the Data Sets

Porosity histogram for LWD 1 layer fluid model

Porosity histogram for Wireline 3 layer fluid model

Porosity histogram for LWD 3 layer fluid model
Chapter 4: Analysis of the Data Sets

Porosity histogram for Square Root Standard model

Porosity histogram for Wiley & Patchett Standard model

Porosity histogram for Square Root 1 layer fluid model

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Chapter 4: Analysis of the Data Sets

Porosity histogram for Wiley & Patchett 1 layer fluid model

- LADN_WP_P 1 Layer Frequency
- LMDN_WP_P 1 Layer Frequency
- WDN_WP_P 1 Layer Frequency
- CP Frequency (Adjusted)

Porosity histogram for Square Root 3 layer fluid model

- LADN_SQ_P_3_Layer Frequency
- LMDN_SQ_P_3_Layer Frequency
- WDN_SQ_P_3_Layer Frequency
- CP Frequency (Adjusted)

Porosity histogram for Wiley & Patchett 3 layer fluid model

- LADN_WP_P_3_Layer Frequency
- LMDN_WP_P_3_Layer Frequency
- WDN_WP_P_3_Layer Frequency
- CP Frequency (Adjusted)
Chapter 4: Analysis of the Data Sets

Figure 4.16 Vertical well model histograms with porosity ranging from 0 to 25% along the x-axis and frequency 0 to 100 counts along the y-axis. Plots a), c) and e) are wireline derived porosity standard, single and three layer distributions respectively. Plots b), d) and f) are LWD derived porosity standard, single and three layer distributions respectively. The black curve on all the plots represents the core porosity distribution. The blue curve represents the wireline acoustic porosity distribution for plots a), c) and e); the LWD average density porosity distribution for plots b), d) and f); and the resulting LWD average density and neutron porosity distribution for plots g) to n). The red curve represents the wireline acoustic porosity distribution for plots a), c) and e); the LWD average density porosity distribution for plots b), d) and f); and the resulting LWD average density and neutron porosity distribution for plots g) to n).
### Statistical tests at the 95% confidence level (2 tailed) against Core Porosity

<table>
<thead>
<tr>
<th></th>
<th>LWD Average Density Porosity</th>
<th>LWD Maximum Density Porosity</th>
<th>LWD Neutron Porosity</th>
<th>Wireline Acoustic Porosity</th>
<th>Wireline Density Porosity</th>
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### Single Layer

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### Using LWD Average Density and Neutron

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<td>X</td>
</tr>
<tr>
<td>Rotliegend Gas</td>
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<td>✓</td>
</tr>
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<td>Rotliegend Water</td>
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### 3 Layer

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Table 4.23 Vertical well statistical test results against core porosity values using the models detailed above considered over intervals; Whole x008ft-x236ft, Weissliegend x008ft-x153ft, Rotliegend gas x153ft-x191ft and Rotliegend water x191ft-x236ft. 

\( \times \) = reject the hypothesis and \( \checkmark \) = accept the hypothesis at the 95% confidence level using Chi\(^2\) goodness of fit test for the grey cells and Student's t-test with the hypothesised mean difference=0 for the clear cells.

<table>
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<tr>
<th></th>
<th>Whole</th>
<th>Weissliegend</th>
<th>Rotliegend Gas</th>
<th>Rotliegend Water</th>
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<td>✔</td>
</tr>
<tr>
<td><strong>3 Layer</strong></td>
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<tr>
<td>Using LWD Average Density and Neutron</td>
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<td>✔</td>
<td>✔</td>
<td>✔</td>
</tr>
<tr>
<td>Using LWD Maximum Density and Neutron</td>
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<td>✔</td>
<td>✔</td>
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<tr>
<td><strong>Hydrocarbon corrected Wiley &amp; Patchett</strong></td>
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<td>✔</td>
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### Chapter 4: Analysis of the Data Sets

#### Correlation Coefficient against Core Porosity

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<th>Wireline Acoustic</th>
<th>Wireline Density</th>
<th>Wireline Neutron</th>
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</thead>
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<tr>
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<td>0.837</td>
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<td>0.837</td>
<td>0.907</td>
<td>0.831</td>
<td>0.870</td>
</tr>
<tr>
<td>3 Layer</td>
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<td>0.906</td>
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<td>0.798</td>
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</table>

#### Using LWD Average Density and Neutron

#### Using LWD Maximum Density and Neutron

#### Using Wireline Density and Neutron

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<th>LWD Average Density</th>
<th>LWD Maximum Density</th>
<th>LWD Neutron</th>
<th>Wireline Acoustic</th>
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<td>0.876</td>
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<tr>
<td>Single Layer</td>
<td>0.863</td>
<td>0.852</td>
<td></td>
<td></td>
<td></td>
<td>0.881</td>
</tr>
<tr>
<td>3 Layer</td>
<td>0.863</td>
<td>0.853</td>
<td></td>
<td></td>
<td></td>
<td>0.851</td>
</tr>
</tbody>
</table>

|                          |                      |                     |             |                  |                 |                 |
| **Wiley & Patchett**     |                      |                     |             |                  |                 |                 |
| Standard                 | 0.862               | 0.846               |             |                  |                 | 0.876           |
| Single Layer             | 0.864               | 0.850               |             |                  |                 | 0.877           |
| 3 Layer                  | 0.865               | 0.853               |             |                  |                 | 0.850           |

|                          |                      |                     |             |                  |                 |                 |
| **Hydrocarbon Corrected**|                     |                     |             |                  |                 |                 |
| Square Root              | 0.756               | 0.742               |             |                  |                 | 0.833           |
| Wiley & Patchett         | 0.865               | 0.850               |             |                  |                 | 0.881           |

Table 4.24 Vertical well correlation coefficients against core porosity values over the whole interval x008ft-x236ft.
Spectral analysis of data set 1: vertical well

Autocorrelation analyses of the wireline and LWD logs through the reservoir in the vertical well (x008-236ft) are presented below [Figure 4.17]. The plots all show the autocorrelation function for the appropriate log and the significance level of the autocorrelation function (§4.3.3). The autocorrelation analysis is summarised below in Table 4.25 giving the significant wavelengths at the 99% confidence level.

The autocorrelation analyses of the vertical well wireline logs indicated that the logs appear to be largely unaffected by the borehole or drilling process i.e. there is a lack of any correlation between the caliper and LWD rate of penetration autocorrelation functions and that of any of the other logs [Table 4.25 and Figure 4.17]. The only exception was the wireline PEF log with wavelengths at 30-32ft, 45-48ft and 50-52ft which correlated with the LWD caliper log [Table 4.25 and Figure 4.17c and q]. The similarities were unlikely to be coincidental and may have been related to drilling induced spiralling of the vertical well (see examples in §3.3.2). This was especially evident in the LWD caliper which displayed resonance features (repeated significant peaks at equal intervals). The fact that the LWD density correction log was also affected explained why the LWD photoelectric factor and density logs were not affected in the same manner. The LWD density correction had removed these features from the logs and thus removed the effect of the spirals that may have been re-exposed by the drillstring during the LWD logging. However, the same wavelengths did not appear to be affected for the wireline caliper log which was almost constant in value i.e. the borehole was smooth [Figure 4.1 and Figure 4.17q]. Alternatively, mudcake may have filled the spirals, or tool wobble, or preferential mudcake build up on the more porous facies (dune slip faces), which was subsequently measured by the shallow reading PEF log.

- The vertical well wireline and LWD data was not filtered because only marginal improvement in the accuracy of the porosity calculations would be gained.
<table>
<thead>
<tr>
<th>Log</th>
<th>Wireline</th>
<th>Vertical Well</th>
<th>Figure 4.17</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gamma ray</td>
<td>Below 7ft 16-20ft</td>
<td>Below 5ft 8-14ft</td>
<td>a) and b)</td>
</tr>
<tr>
<td>Photoelectric factor</td>
<td>Below 5ft 23-27ft 30-32ft</td>
<td>Below 22ft Above 36ft</td>
<td>c) and d)</td>
</tr>
<tr>
<td></td>
<td>45-48ft</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Deep induction</td>
<td>All</td>
<td>All</td>
<td>e)</td>
</tr>
<tr>
<td>Amplitude resistivity</td>
<td></td>
<td></td>
<td>f)</td>
</tr>
<tr>
<td>Medium induction</td>
<td>All</td>
<td>All</td>
<td>g)</td>
</tr>
<tr>
<td>Phase resistivity</td>
<td>All</td>
<td>All</td>
<td>h)</td>
</tr>
<tr>
<td>Density</td>
<td>Below 42ft</td>
<td>Below 52ft</td>
<td>i)</td>
</tr>
<tr>
<td>Maximum density</td>
<td></td>
<td></td>
<td>j)</td>
</tr>
<tr>
<td>Average density</td>
<td></td>
<td></td>
<td>k)</td>
</tr>
<tr>
<td>Acoustic travel time</td>
<td>All</td>
<td>All</td>
<td>l)</td>
</tr>
<tr>
<td>Neutron porosity</td>
<td>All</td>
<td>All</td>
<td>m) and n)</td>
</tr>
<tr>
<td>Density correction</td>
<td>Below 2ft</td>
<td>Below 5ft 18-26ft</td>
<td>o) and p)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>33-34ft</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>38-39ft</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>43-49ft</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>50-51ft</td>
<td></td>
</tr>
<tr>
<td>Caliper</td>
<td>All</td>
<td>Below 2ft 6-8ft</td>
<td>q) and r)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>12-16ft</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>21-23ft</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>26-31ft</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>32-33ft</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>35-38ft</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>45-46ft</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>48-52ft</td>
<td></td>
</tr>
<tr>
<td>Rate of penetration</td>
<td></td>
<td>Below 24ft</td>
<td>s)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>33-38ft</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Above 42ft</td>
<td></td>
</tr>
</tbody>
</table>

**Table 4.25** Data set 1 vertical well autocorrelation analysis giving the significant wavelengths at the 99% confidence level.
Chapter 4: Analysis of the Data Sets

Autocorrelation for Vertical well Wireline Gamma Ray Log

Autocorrelation for Vertical well LWD Gamma Ray Log

Autocorrelation for Vertical well Wireline Photoelectric factor Log
Chapter 4: Analysis of the Data Sets

**d)** Autocorrelation for Vertical well LWD Photoelectric factor Log

**e)** Autocorrelation for Vertical well Wireline Deep Induction Log

**f)** Autocorrelation for Vertical well LWD Amplitude Resistivity Log
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Autocorrelation for Vertical well Wireline Medium Induction Log

- $r_{0.05}^{(+)}$
- $r_{0.05}^{(-)}$
- $W_{IM}$

Distance (ft)

0 25 50

Autocorrelation $r(L)$

0 0.25 0.5 0.75

Autocorrelation for Vertical well LWD Phase Resistivity Log

- $r_{0.01}^{(-)}$
- $r_{0.01}^{(+)}$
- $r_{0.05}^{(+)}$
- $r_{0.05}^{(-)}$

Distance (ft)

0 25 50

Autocorrelation $r(L)$

0 0.25 0.5 0.75

Autocorrelation for Vertical well Wireline Density Log

- $r_{0.01}^{(-)}$
- $r_{0.01}^{(+)}$
- $r_{0.05}^{(+)}$
- $r_{0.05}^{(-)}$

Distance (ft)

0 25 50

Autocorrelation $r(L)$

0 0.25 0.5 0.75

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Chapter 4: Analysis of the Data Sets

Autocorrelation for Vertical well LWD Maximum Density Log

Autocorrelation for Vertical well LWD Average Density Log

Autocorrelation for Vertical well Wireline Acoustic Travel Time Log

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Chapter 4: Analysis of the Data Sets

Autocorrelation for Vertical well Wireline Neutron Porosity Log

Autocorrelation for Vertical well LWD Neutron Porosity Log

Autocorrelation for Vertical well Wireline Density Correction Log
Chapter 4: Analysis of the Data Sets

Autocorrelation for Vertical well LWD Density Correction Log

Distance (ft)

Autocorrelation r(L)

-0.5

0

0.25

0.5

0.75

1

Autocorrelation for Vertical well Wireline Caliper Log

Distance (ft)

Autocorrelation r(L)

-0.5

0

0.25

0.5

0.75

1

Autocorrelation for Vertical well LWD Caliper Log

Distance (ft)
Figure 4.17 Vertical well spectral analysis of the wireline and LWD logs. Note: x-axis is scaled from Distance 0 to 55 ft, y-axis is scaled from Autocorrelation r(L) 0 to 1 above the x-axis. Values outside the yellow and blue bands are significant at the 0.05 and 0.01 confidence levels respectively.
Chapter 4: Analysis of the Data Sets

Horizontal well

In the horizontal well, porosity values were calculated from the LWD density and neutron tool measurements. The same algorithms for calculating porosity were used as for the vertical well, but without the benefit of horizontal well core porosity data to verify the LWD calculated porosity values. In addition, only two of the three facies intervals were observed in the horizontal well; Weissliegend x134-906ft and x1655-1951ft, and Rotliegend gas x906-1655ft [Figure 4.2, layers marked].

The horizontal well LWD neutron and maximum density porosity values were lower than their respective measurements in the vertical well. The LWD neutron porosity values were lower than the vertical well LWD neutron porosity values, but comparable with the wireline neutron porosity values. The horizontal well LWD measurements were recorded approximately 18 hours after penetration and the vertical well wireline measurements 36 hours after penetration. The volume of mud invasion was similar in both cases when compared with the volume of investigation of the porosity tools. The vertical well LWD neutron porosity measurements were recorded approximately 84 hours after penetration and therefore mud invasion was more extensive, but also allowed gas migration towards the borehole.

The horizontal well LWD average density values were very low and the LWD caliper values were large. This suggested that the borehole was enlarged and rugose. The magnitudes of the LWD average density and caliper values were large enough to mean that both measurements were unreliable for any quantitative use and cast doubts on the reliability of all the other horizontal well LWD measurements.

Porosity analysis of data set 1: horizontal well

The lack of core porosity data made it difficult to determine which method(s) were appropriate for calculating accurate horizontal well porosity values. However, comparison of LWD log calculated porosity with the scaled vertical well core porosity values over the relevant facies intervals allowed rejection of methods which were certainly inaccurate. Correlation was not possible between the vertical well core porosity and horizontal well calculated porosity values. A list of the fluid parameters for all the methods used are given below [Table 4.26].
Chapter 4: Analysis of the Data Sets

<table>
<thead>
<tr>
<th></th>
<th>Standard</th>
<th>Single Layer</th>
<th>Weissliegend</th>
<th>Rotliegend (Gas)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Fluid Density (g/cm³) used for</strong> LWD Average Density log</td>
<td>1.000</td>
<td>0.535</td>
<td>0.445</td>
<td>0.642</td>
</tr>
<tr>
<td><strong>Fluid Density (g/cm³) used for</strong> LWD Maximum Density log</td>
<td>1.000</td>
<td>0.649</td>
<td>0.543</td>
<td>0.781</td>
</tr>
<tr>
<td><strong>Excavation correction (percentage porosity) used for</strong> LWD Neutron Porosity</td>
<td>0.000</td>
<td>0.014</td>
<td>0.0188</td>
<td>0.004</td>
</tr>
</tbody>
</table>

Table 4.26 Parameters used for porosity calculation from the horizontal well logs.

Horizontal well porosity calculations were performed in the same manner as for the vertical well above. The results of the porosity analyses are presented below [Figure 4.18 and Table 4.27]. The horizontal well LWD maximum density and neutron porosity values were in good agreement with core porosity values over the whole and Weissliegend depth intervals using Wiley & Patchett standard, single layer and two layer models. It was possible using the LWD average density porosity values to achieve good agreement with core porosity values over some depth intervals using some of the models. Although the corrections applied were large and unreliable due to the spread of the LWD average density porosity values.

- The standard Wiley & Patchett LWD maximum density porosity values are most likely to provide the best LWD derived porosity values in the horizontal well.

This was not the same model as the vertical well (standard square root model) suggesting that reliable and consistent porosity calculation from these LWD porosity tools was not viable in this well or possibly the whole field.

The horizontal well LWD maximum density porosity values were significantly lower than both the vertical wireline density and LWD maximum density porosity values. This was possibly due to barite mud invasion and mudcake increasing concentration of barite close to the borehole walls in the formation and mudcake at the time of logging compared with the vertical well. This would effectively have increased the formation fluid density to greater than 1g/cm³ reducing the calculated porosity values. The increased effect of the barite was indicated by the very large LWD PEF
values in the horizontal well. The PEF measurement is only sensitive to the first ½inch in front of the short spaced detector indicating that the barite concentration was much greater than in vertical well measurements and presumably lying on the borehole floor.

An alternative scenario was the incorrect LWD tool position within the borehole whilst logging. A known phenomenon is the LWD tool "riding the borehole" in which the tool climbs the borehole wall in the direction of drilling (clockwise) which leads to the possibility of non-parallel standoff (§3.3.1). This non-parallel standoff can lead to either light or heavy bulk density values with no indication from the density correction curve. This situation can be understood if one considers calculating the density from each detector separately. The bulk density is a combination of these two densities, which can be approximated by:

$$\rho_b = \frac{4}{3} \rho_l - \frac{1}{3} \rho_s$$

where $\rho_b = $ bulk density, $\rho_l = $ long spaced density and $\rho_s = $ short spaced density (Sherman and Locke 1975). Thus, in a situation where the short spaced detector reads light (poor contact) and the long spaced detector reads correctly (good contact) then the bulk density would read too heavy. This situation is possible since the long spaced detector leads the short spaced detector and the source down the borehole, the reverse of a wireline tool.
Chapter 4: Analysis of the Data Sets

Porosity histogram for LWD Standard model

- LAD_P Standard Frequency
- LMD_P Standard Frequency
- LNP Standard Frequency
- CP Frequency (Adjusted)

Porosity histogram for LWD 1 layer fluid model

- LADP_1_Layer Frequency
- LMDP_1_Layer Frequency
- LNP_1_Layer Frequency
- CP Frequency (Adjusted)

Porosity histogram for LWD 2 layer fluid model

- LADP_2_Layer Frequency
- LMDP_2_Layer Frequency
- LNP_2_Layer Frequency
- CP Frequency (Adjusted)
Chapter 4: Analysis of the Data Sets

d) Porosity histogram for Square Root Standard model

- LADN_SQ_P Standard Frequency
- LMDN_SQ_P Standard Frequency
- CP Frequency (Adjusted)

Porosity (%)

Frequency

0 10 20 30

Porosity histogram for Wiley & Patchett Standard model

- LADN_WP_P Standard Frequency
- LMDN_WP_P Standard Frequency
- CP Frequency (Adjusted)

Porosity (%)

Frequency

0 10 20 30

Porosity histogram for Square Root 1 layer fluid model

- LADN_SQ_P 1 Layer Frequency
- LMDN_SQ_P 1 Layer Frequency
- CP Frequency (Adjusted)

Porosity (%)

Frequency

0 10 20 30

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Chapter 4: Analysis of the Data Sets

Porosity histogram for Wiley & Patchett 1 layer fluid model

Porosity histogram for Square Root 2 layer fluid model

Porosity histogram for Wiley & Patchett 2 layer fluid model
Figure 4.18 Horizontal well model histograms with porosity ranging from 0 to 35% along the x-axis and frequency 0 to 1000 counts along the y-axis. The black curve on all the plots represents the core porosity distribution. The blue curve represents the LWD average density porosity distribution for plots a) to c), and the resulting LWD average density and neutron porosity distribution for plots d) to k). The red curve represents the LWD maximum density porosity distribution for plots a) to c). The green curve represents the LWD neutron porosity for plots a) to c), and the resulting LWD average density and neutron porosity distribution for plots d) to k).
### Chapter 4: Analysis of the Data Sets

#### Statistical tests at the 95% confidence level (2 tailed) against Core Porosity

<table>
<thead>
<tr>
<th></th>
<th>LWD Average Density Porosity</th>
<th>LWD Maximum Density Porosity</th>
<th>LWD Neutron Porosity</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Whole</strong></td>
<td><img src="#" alt="x" /></td>
<td><img src="#" alt="✓" /></td>
<td><img src="#" alt="✓" /></td>
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<tr>
<td><strong>Weissliegend</strong></td>
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<td><img src="#" alt="✗" /></td>
<td><img src="#" alt="✓" /></td>
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<tr>
<td><strong>Rotliegend Gas</strong></td>
<td><img src="#" alt="x" /></td>
<td><img src="#" alt="✗" /></td>
<td><img src="#" alt="✗" /></td>
</tr>
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</table>

#### Single Layer

<table>
<thead>
<tr>
<th></th>
<th>LWD Average Density Porosity</th>
<th>LWD Maximum Density Porosity</th>
<th>LWD Neutron Porosity</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Whole</strong></td>
<td><img src="#" alt="x" /></td>
<td><img src="#" alt="✗" /></td>
<td><img src="#" alt="✓" /></td>
</tr>
<tr>
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<td><img src="#" alt="✗" /></td>
<td><img src="#" alt="✓" /></td>
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<tr>
<td><strong>Rotliegend Gas</strong></td>
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#### 2 Layer

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#### Student’s t-test at the 95% confidence level (2 tailed) against Core Porosity

<table>
<thead>
<tr>
<th></th>
<th>Using LWD Average Density and Neutron</th>
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</tr>
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<td><strong>Rotliegend Gas</strong></td>
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### Square Root

#### Standard

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#### Single Layer

<table>
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<tr>
<td><strong>Rotliegend Gas</strong></td>
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</table>

### Wiley & Patchett

#### Standard

<table>
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<th>LWD Maximum Density Porosity</th>
<th>LWD Neutron Porosity</th>
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<td><strong>Rotliegend Gas</strong></td>
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</thead>
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</table>
Table 4.27 Horizontal well statistical test results against core porosity considered over intervals; Whole x134ft-x1951ft, Weissliegend x134ft-x906, x1655-1951ft and Rotliegend gas x906ft-x1951ft. \( \times \) = reject the hypothesis and \( \checkmark \) = accept the hypothesis at the 95% confidence level using Chi\(^2\) goodness of fit test for the grey cells and Student’s t-test with the hypothesised mean difference=0 for the clear cells.
Spectral analysis of data set 1: horizontal well

The autocorrelation analysis of the horizontal well (x134-1951ft) LWD logs suggested that most of the logs were affected by drilling or the borehole due to the correlation of the caliper with the other logs [Figure 4.19 and Figure 4.2]. Only the LWD resistivity logs were unaffected. The autocorrelation analyses are summarised below in Table 4.28 giving the significant wavelengths at the 99% confidence level.

The LWD density correction algorithm appeared to be unable to correct sufficiently for the standoff encountered and spiralling is evident at a number of wavelengths in LWD caliper log. Of particular note is the LWD caliper autocorrelation functions with significant wavelength features <180ft, 210-225ft, 270-345ft and 370-385ft [Figure 4.19h]. The most damaging wavelengths appear to be the short wavelengths between 8-10ft. Consequently, the logs were filtered using the first 180 harmonics, which removed all wavelengths below 10ft inclusively. The porosity calculations were then repeated on the filtered horizontal well LWD data.

<table>
<thead>
<tr>
<th>Log</th>
<th>Horizontal Well LWD</th>
<th>Figure 4.19</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gamma ray</td>
<td>Below 180ft</td>
<td>a)</td>
</tr>
<tr>
<td></td>
<td>Above 260ft</td>
<td></td>
</tr>
<tr>
<td>Photoelectric factor</td>
<td>Below 280ft</td>
<td>b)</td>
</tr>
<tr>
<td></td>
<td>310-340ft, 345-370</td>
<td></td>
</tr>
<tr>
<td></td>
<td>390-395, 445-450</td>
<td></td>
</tr>
<tr>
<td>Amplitude resistivity</td>
<td>All</td>
<td>c)</td>
</tr>
<tr>
<td>Phase resistivity</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Maximum density</td>
<td>Maximum Below 395ft</td>
<td>d)</td>
</tr>
<tr>
<td>Average density</td>
<td>(Average all)</td>
<td>e)</td>
</tr>
<tr>
<td>Neutron porosity</td>
<td>All</td>
<td>f)</td>
</tr>
<tr>
<td>Density correction</td>
<td>Below 210ft</td>
<td>g)</td>
</tr>
<tr>
<td></td>
<td>Above 270ft</td>
<td></td>
</tr>
<tr>
<td>Caliper</td>
<td>Below 180ft, 210-225ft</td>
<td>h)</td>
</tr>
<tr>
<td></td>
<td>270-345ft, 370-385ft</td>
<td></td>
</tr>
<tr>
<td>Rate of penetration</td>
<td>Below 340ft, 350-365ft</td>
<td>i)</td>
</tr>
<tr>
<td></td>
<td>Above 375ft</td>
<td></td>
</tr>
</tbody>
</table>

Table 4.28 Data set 1 horizontal well autocorrelation analysis giving the significant wavelengths at the 99% confidence level.
Chapter 4: Analysis of the Data Sets

Autocorrelation for Horizontal well LWD Gamma Ray Log

Autocorrelation for Horizontal well LWD Photoelectric factor Log

Autocorrelation for Horizontal well LWD Resistivity Log
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(d) Autocorrelation for Horizontal well LWD Maximum Density Log

(e) Autocorrelation for Horizontal well LWD Average Density Log

(f) Autocorrelation for Horizontal well LWD Neutron Porosity Log
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The autocorrelation values for the horizontal well LWD data were used to determine statistical values. The autocorrelation values for the LWD logs were then evaluated using the 0.05 and 0.01 confidence levels. Values outside the yellow band are significant at the 0.05 confidence level and at the 0.01 confidence level outside the blue band.

**Figure 4.19** Horizontal well spectral analysis of the LWD logs. Note: x-axis is scaled from Distance 0 to 450ft, y-axis is scaled from Autocorrelation r(L) 0 to 1 above the x-axis. Values outside the yellow band are significant at the 0.05 confidence level and at the 0.01 confidence level outside the blue band.
Porosity analysis of data set 1: horizontal well filtered data

The filtered horizontal well LWD data were used to calculate porosity values. The same approaches for calculating porosity were used as for the unfiltered data. The additional knowledge of the mud invasion was taken into account and fluid densities greater than \(1\,\text{g/cm}^3\) were used. Comparisons between the filtered LWD log calculated porosity with the scaled vertical well core porosity values allowed rejection of methods, which were inaccurate i.e. poor match with the vertical well core porosity values. Initially, the standard model was used to estimate formation porosity in the horizontal well. A list of the fluid parameters for all the methods used are given [Table 4.29].

The horizontal well filtered porosity analyses results are given below [Figure 4.20 and Table 4.30]. The horizontal well filtered porosity values were poor using the standard model and were significantly improved by alteration of the fluid parameters. LWD maximum density values were in good agreement with core porosity values over all depth intervals using single layer and single layer Wiley & Patchett standard models. The horizontal well filtered LWD average density and neutron porosity values were much improved with respect to core porosity values over the whole and Weissliegend intervals using the single and two layer models. The horizontal well filtered data LWD porosity values used in were much improved with respect with core porosity values over most intervals [Figure 4.20 and Table 4.30].

- The best porosity values in the horizontal well were provided by the filtered LWD maximum density and neutron porosity single layer Wiley & Patchett model.

<table>
<thead>
<tr>
<th>Fluid Density (g/cm(^3)) used for LWD Average Density log</th>
<th>Standard</th>
<th>Single Layer</th>
<th>Weissliegend</th>
<th>Rotliegend (Gas)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.000</td>
<td>-0.531</td>
<td>-0.630</td>
<td></td>
<td>-0.419</td>
</tr>
</tbody>
</table>

| Fluid Density (g/cm\(^3\)) used for LWD Maximum Density log   | 1.000    | 1.078        | 0.810        | 1.236            |
| Excavation correction (percentage porosity) used for LWD Neutron Porosity | 0.000    | 0.020        | 0.026        | 0.010            |

Table 4.29 Parameters used for porosity calculation from the horizontal well logs.
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Porosity histogram for LWD Standard model:

- LARHOB Standard
- LMRHOB Standard
- LNPHI Standard
- CP (Adjusted)

a)

Porosity histogram for LWD 1 layer fluid model:

- LARHOB Single Layer
- LMRHOB Single Layer
- LNPHI Single Layer
- CP (Adjusted)

b)

Porosity histogram for LWD 2 layer fluid model:

- LARHOB Two Layer
- LMRHOB Two Layer
- LNPHI Two Layer
- CP (Adjusted)

c)

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Porosity histogram for Square Root Standard model

- LARHOB+NPHI Square Root Standard
- LMRHOB+NPHI Square Root Standard
- CP (Adjusted)

Porosity histogram for Wiley & Patchett Standard model

- LARHOB+NPHI Wiley & Patchett Standard
- LMRHOB+NPHI Wiley & Patchett Standard
- CP (Adjusted)

Porosity histogram for Square Root 1 layer fluid model

- LARHOB+NPHI Square Root Single Layer
- LMRHOB+NPHI Square Root Single Layer
- CP (Adjusted)
Chapter 4: Analysis of the Data Sets

Porosity histogram for Wiley & Patchett 1 layer fluid model
- LARHOB+NPHI Wiley & Patchett Single Layer
- LMRHOB+NPHI Wiley & Patchett Single Layer
- CP (Adjusted)

Porosity histogram for Square Root 2 layer fluid model
- LARHOB+NPHI Square Root Two Layer
- LMRHOB+NPHI Square Root Two Layer
- CP (Adjusted)

Porosity histogram for Wiley & Patchett 2 layer fluid model
- LARHOB+NPHI Wiley & Patchett Two Layer
- LMRHOB+NPHI Wiley & Patchett Two Layer
- CP (Adjusted)

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Figure 4.20 Horizontal well model histograms using filtered data with porosity ranging from 0 to 35% along the x-axis and frequency 0 to 1000 counts along the y-axis. The black curve on all the plots represents the core porosity distribution. The blue curve represents the LWD average density porosity distribution for plots a) to c), and the resulting LWD average density and neutron porosity distribution for plots d) to k). The red curve represents the LWD maximum density porosity distribution for plots a) to c). The green curve represents the LWD neutron porosity for plots a) to c), and the resulting LWD average density and neutron porosity distribution for plots d) to k). Note: the filtering was performed to removing the unwanted harmonics.
### Chapter 4: Analysis of the Data Sets

<table>
<thead>
<tr>
<th>Student’s t-test at 95% confidence level (2 tailed) against Core Porosity</th>
<th>LWD Average Density Porosity</th>
<th>LWD Maximum Density Porosity</th>
<th>LWD Neutron Porosity</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Standard</strong></td>
<td></td>
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<tr>
<td>Whole</td>
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<td>✗</td>
<td>✗</td>
</tr>
<tr>
<td>Weissliegend</td>
<td>✗</td>
<td>✗</td>
<td>✗</td>
</tr>
<tr>
<td>Rotliegend Gas</td>
<td>✗</td>
<td>✗</td>
<td>✗</td>
</tr>
<tr>
<td><strong>Single Layer</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Whole</td>
<td>✗</td>
<td>✗</td>
<td>✗</td>
</tr>
<tr>
<td>Weissliegend</td>
<td>✗</td>
<td>✗</td>
<td>✗</td>
</tr>
<tr>
<td>Rotliegend Gas</td>
<td>✗</td>
<td>✗</td>
<td>✗</td>
</tr>
<tr>
<td><strong>2 Layer</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Whole</td>
<td>✗</td>
<td>✗</td>
<td>✗</td>
</tr>
<tr>
<td>Weissliegend</td>
<td>✗</td>
<td>✗</td>
<td>✗</td>
</tr>
<tr>
<td>Rotliegend Gas</td>
<td>✗</td>
<td>✗</td>
<td>✗</td>
</tr>
<tr>
<td><strong>Using LWD Average Density and Neutron</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Square Root</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Standard</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Whole</td>
<td>✗</td>
<td>✗</td>
<td>✗</td>
</tr>
<tr>
<td>Weissliegend</td>
<td>✗</td>
<td>✗</td>
<td>✗</td>
</tr>
<tr>
<td>Rotliegend Gas</td>
<td>✗</td>
<td>✗</td>
<td>✗</td>
</tr>
<tr>
<td><strong>Single Layer</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Whole</td>
<td>✗</td>
<td>✗</td>
<td>✗</td>
</tr>
<tr>
<td>Weissliegend</td>
<td>✗</td>
<td>✗</td>
<td>✗</td>
</tr>
<tr>
<td>Rotliegend Gas</td>
<td>✗</td>
<td>✗</td>
<td>✗</td>
</tr>
<tr>
<td><strong>2 Layer</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Whole</td>
<td>✗</td>
<td>✗</td>
<td>✗</td>
</tr>
<tr>
<td>Weissliegend</td>
<td>✗</td>
<td>✗</td>
<td>✗</td>
</tr>
<tr>
<td>Rotliegend Gas</td>
<td>✗</td>
<td>✗</td>
<td>✗</td>
</tr>
<tr>
<td><strong>Wiley &amp; Patchett</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Standard</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Whole</td>
<td>✗</td>
<td>✗</td>
<td>✗</td>
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<tr>
<td>Weissliegend</td>
<td>✗</td>
<td>✗</td>
<td>✗</td>
</tr>
<tr>
<td>Rotliegend Gas</td>
<td>✗</td>
<td>✗</td>
<td>✗</td>
</tr>
<tr>
<td><strong>Single Layer</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Whole</td>
<td>✗</td>
<td>✗</td>
<td>✗</td>
</tr>
<tr>
<td>Weissliegend</td>
<td>✗</td>
<td>✗</td>
<td>✗</td>
</tr>
<tr>
<td>Rotliegend Gas</td>
<td>✗</td>
<td>✗</td>
<td>✗</td>
</tr>
</tbody>
</table>
Table 4.30 Horizontal well filtered data statistical test results against core porosity considered over intervals; Whole x134ft-x1951ft, Weissliegend x134ft-x906, x1655-1951ft and Rotliegend gas x906ft-x1951ft. X = reject the hypothesis and ✓ = accept the hypothesis at the 95% confidence level using Chi² goodness of fit test for grey cells and Student’s t-test with the hypothesised mean difference=0 for clear cells.
4.4.2 Data Set 2

For data set 2 the reservoir was subdivided into four units based on the change in formation fluid from gas to oil to water with a transition zone between oil and water zones [Table 4.31]. The porosity analyses were performed on the whole reservoir and the four units separately for each of the porosity algorithms in turn. Calculating porosity in the shaley mixed-fluid sandstone reservoir, the shale needed to be accounted for and the correct hydrocarbon densities had to be estimated/calculated. For details of the porosity, statistical and spectral analyses refer to section 4.3 where explanations and examples are provided.

Porosity histograms and statistical comparisons with core porosity values were used to determine the validity of the hypothesis that log porosity was overestimated in horizontal wells. The results of the analysis using a number of porosity algorithms are presented below. For each well there are two porosity histograms (0-40pu) for the whole reservoir zone with two tables. In both porosity histograms the well 1 core porosity values were scaled up proportionally by the ratio of the number of samples. Note: well 1z was compared with well 1z core data over the oil zone, but well 1 core data was used for comparison over the gas zone. The fluid parameters for the density and acoustic shale corrected porosities were investigated in two ways. Firstly, using the Oil Company’s (OC) fluid parameter values and secondly with values such that the porosity equations are in agreement with well 1 core porosity values.

The (first) standard histogram includes the core, density, neutron, acoustic and the Oil Company density and acoustic porosity values. The (second) calculated histogram includes the core, square root, Wiley & Patchett, Gaymard & Poupon neutron and Gaymard & Poupon density porosity values. The acronyms used in the histograms are listed in Table 4.32.

<table>
<thead>
<tr>
<th>Zone</th>
<th>Well</th>
<th>1</th>
<th>1z</th>
<th>3</th>
<th>5</th>
<th>6</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas</td>
<td></td>
<td>x571</td>
<td>x884</td>
<td>x572</td>
<td>x519.5</td>
<td></td>
</tr>
<tr>
<td>Oil</td>
<td></td>
<td>x619</td>
<td>x1547-2270</td>
<td>x652.5-1565.5</td>
<td>x597</td>
<td>x926.5-2311</td>
</tr>
<tr>
<td>Transition</td>
<td></td>
<td>x652</td>
<td></td>
<td>x640</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Water</td>
<td></td>
<td>x702-770</td>
<td></td>
<td></td>
<td>x665.5-726.5</td>
<td></td>
</tr>
</tbody>
</table>

Table 4.31 Top depths of fluid zones for each well in metres.
Chapter 4: Analysis of the Data Sets

<table>
<thead>
<tr>
<th>Acronyms</th>
<th>Meaning</th>
</tr>
</thead>
<tbody>
<tr>
<td>CPOR</td>
<td>Well 1 core porosity</td>
</tr>
<tr>
<td>DenPor</td>
<td>Shale corrected density porosity</td>
</tr>
<tr>
<td>Nphi_S</td>
<td>Sandstone neutron porosity</td>
</tr>
<tr>
<td>Nphi_Lime</td>
<td>Limestone neutron porosity</td>
</tr>
<tr>
<td>AcouPor</td>
<td>Shale corrected acoustic porosity</td>
</tr>
<tr>
<td>OC_DenPor</td>
<td>Oil Company shale corrected density porosity</td>
</tr>
<tr>
<td>OC_AcouPor</td>
<td>Oil Company shale corrected acoustic porosity</td>
</tr>
<tr>
<td>SqPor</td>
<td>Square root porosity</td>
</tr>
<tr>
<td>WPPor</td>
<td>Wiley &amp; Patchett porosity</td>
</tr>
<tr>
<td>GPNeut</td>
<td>Gaymard &amp; Poupon neutron porosity</td>
</tr>
<tr>
<td>GPDen</td>
<td>Gaymard &amp; Poupon density porosity</td>
</tr>
</tbody>
</table>

Table 4.32 Acronyms used for data set 2 histograms.

For each well, the first table provides statistical test results. The Student’s t-tests for clear cells and Chi² tests for grey cells, where a tick/cross (✓/X) represents acceptance or rejection of the hypothesis at the 95% confidence level that there is zero difference between that porosity equation and well 1 core porosity values over the fluid interval stated [Table 4.31]. The second table gives details of the fluid parameters used in the equations for each fluid zone. In the fluid parameter table DEN refers to using the fluid density in the density column with the two Gaymard & Poupon equations. OC refers to using the relevant Oil Company’s fluid parameter in that particular porosity equation. The oil zone is defined as oil at irreducible water saturation. The transition zone is defined as oil at greater than irreducible water saturation.

The autocorrelation plots below all show the autocorrelation function for the appropriate log and two coloured bands representing the significance of the autocorrelation function [Figure 4.23, Figure 4.26, Figure 4.29, Figure 4.34 and Figure 4.37]. If the autocorrelation function is outside the yellow band or outside the blue and yellow bands, then the autocorrelation function is significant at that wavelength at the 95% or 99% confidence level respectively. The autocorrelation analysis for both wells is summarised below in Table 4.33 giving the significant wavelengths at the 99% confidence level. The autocorrelation plot for each log is given a letter that is referenced in the top of each cell in Table 4.25. The letter is a reference to the letter in the figure referenced at the top of the column. For example, the first cell in Table 4.33 refers the autocorrelation plot for the well 1 gamma ray log, which is in Figure 4.23 plot i).
## Chapter 4: Analysis of the Data Sets

<table>
<thead>
<tr>
<th>Well</th>
<th>Figure</th>
<th>1</th>
<th>1z</th>
<th>3</th>
<th>5</th>
<th>6</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gamma ray (1)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Figure 4.23</td>
<td>i)</td>
<td>0-4, 10-19, 20-21, 22-29, 32-33, 39-43, 45-47</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>a)</td>
<td>0-50, 125-245</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>b)</td>
<td>0-70, 80-120, 140-160, 162-245</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gamma ray 2</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Photoelectric factor</td>
<td>d)</td>
<td>0-9, 12-20, 24-26, 28-29, 43-48</td>
<td></td>
<td></td>
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</tr>
<tr>
<td></td>
<td>d)</td>
<td>0-120, 125-150, 190-195</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>i)</td>
<td>All</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>True Resistivity</td>
<td>j)</td>
<td>All</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Deep induction</td>
<td>h)</td>
<td>0-200, 220-245</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Electromagnetic resistivity</td>
<td>k)</td>
<td>All</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<td>Medium induction</td>
<td>l)</td>
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<tr>
<td>Density (1)</td>
<td>g)</td>
<td>All</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>b)</td>
<td>0-7, 8-9, 20-21, 25-30, 33-35, 44-45</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Acoustic travel time</td>
<td>a)</td>
<td>0-10, 29-30, 46-48</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>a)</td>
<td>0-10, 13-14, 20-22, 24-25, 26-40</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Table 4.33 Autocorrelation analysis giving the significant wavelengths in meters at the 99% confidence level. When all frequencies are significant at the 99% confidence level, All is entered in the cell.
Chapter 4: Analysis of the Data Sets

Well 1

The statistical tests demonstrated that density and acoustic porosity values both matched the core porosity values over each fluid zone, although the match was not good when the comparison was made over all intervals [Table 4.34]. The sandstone neutron porosity values only match core porosity values in the oil, transition and water zones. The Oil Company's (OC) density and acoustic porosity values only match core over the oil and transition zones and water zone respectively. Of the more complex porosity equations Wiley & Patchett and Gaymard & Poupon neutron performed the best matching in the oil, transition and water zones.

The standard histogram shows that the OC's fluid parameters [Table 4.35] led to overestimation of the core porosity [Figure 4.21] whilst the density, neutron and acoustic porosity equations match the core porosity values above 19% porosity. The core porosity values around 10% porosity are due to high shale content in the core samples in certain intervals. However, the removal of these values does not alter the results presented. The calculated histogram illustrates that the Gaymard & Poupon neutron porosity underestimated porosity while the square root, Wiley & Patchett and Gaymard & Poupon density porosity overestimated porosity [Figure 4.22].

The acoustic and density values used to match with the core porosity values and the OC's values were quite different. The OC's density value was derived from the water density at hydrostatic pressure and the OC's fluid travel time values was that of water. However, the shallow investigation depth (~2 inches) and the use of OBM to drill the well explains the use of 210μsec/ft, the approximate fluid travel time for oil. The fluid densities used reflect the change in fluid density within the formation. These results show that selection of fluid parameters is important if porosity is to be estimated with any accuracy. Interestingly, the OC's density and acoustic porosity curves have double peaks indicating the presence of the different zones [Figure 4.21].

The autocorrelation analysis of the well 1 wireline logs indicates that the logs do not appear to be affected by the borehole or drilling process i.e. no correlation between the caliper autocorrelation function and that of any of the other logs [Table 4.25 and Figure 4.17]. The character of the caliper [Figure 4.17e)] bears little resemblance to any of the other logs. There are broad similarities between acoustic travel time a), compressional travel time b), density 1 f), density 2 g) and density correction h)
autocorrelation plots. This adds confidence that the independent measurements (density and acoustic) are observing the same geological information, since one may reasonably expect them to react to noise differently. The gamma ray i) and resistivity j), k), l) plots are strikingly comparable due to the effect of shale on the logs.

- Both density and acoustic porosity values provided the most reliable estimates of core porosity values for well 1.

<table>
<thead>
<tr>
<th>Porosity equation</th>
<th>Density</th>
<th>Sandstone Neutron</th>
<th>Acoustic</th>
<th>Square Root</th>
<th>Wiley &amp; Patchett</th>
<th>Gaymard &amp; Poupon Neutron</th>
<th>Gaymard &amp; Poupon Density</th>
<th>OC Density</th>
<th>OC Acoustic</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas</td>
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<td>x</td>
<td>✓</td>
<td>x</td>
<td>x</td>
<td>x</td>
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<tr>
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<td>✓</td>
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<td>✓</td>
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<tr>
<td>Transition</td>
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<td>✓</td>
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<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>x</td>
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<tr>
<td>Water</td>
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<td>✓</td>
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<td>x</td>
<td>x</td>
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<td>x</td>
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<td>x</td>
</tr>
</tbody>
</table>

Table 4.34 Well 1 Student’s t-tests (clear cells) and Chi² test (grey cells) results against well 1 core porosity values, fluid parameters in Table 4.35.

<table>
<thead>
<tr>
<th>Porosity equation</th>
<th>Density (g/cm³)</th>
<th>Acoustic (μsec/ft)</th>
<th>OC</th>
<th>Wiley &amp; Patchett</th>
<th>Gaymard &amp; Poupon Neutron</th>
<th>Gaymard &amp; Poupon Density</th>
<th>OC Density (g/cm³)</th>
<th>OC Acoustic (μsec/ft)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas</td>
<td>0.55</td>
<td>210</td>
<td>OC</td>
<td>OC</td>
<td>DEN</td>
<td>DEN</td>
<td>1.01</td>
<td>189</td>
</tr>
<tr>
<td>Oil</td>
<td>0.85</td>
<td>205</td>
<td>OC</td>
<td>OC</td>
<td>DEN</td>
<td>DEN</td>
<td>0.70</td>
<td>189</td>
</tr>
<tr>
<td>Transition</td>
<td>0.85</td>
<td>210</td>
<td>OC</td>
<td>OC</td>
<td>DEN</td>
<td>DEN</td>
<td>1.01</td>
<td>189</td>
</tr>
<tr>
<td>Water</td>
<td>OC</td>
<td>OC</td>
<td>OC</td>
<td>OC</td>
<td>DEN</td>
<td>DEN</td>
<td>1.01</td>
<td>189</td>
</tr>
</tbody>
</table>

Table 4.35 Well 1 fluid parameters.
Figure 4.21 Well 1 standard porosity histogram.

Figure 4.22 Well 1 calculated porosity histogram.
Chapter 4: Analysis of the Data Sets

A) Autocorrelation for Well 1 Wireline Acoustic Travel Time Log

B) Autocorrelation for Well 1 Wireline Acoustic Compressional Travel Time Log

C) Autocorrelation for Well 1 Wireline Neutron Porosity Log
Chapter 4: Analysis of the Data Sets

**Autocorrelation for Well 1 Wireline Photoelectric Log**

- $r_L = -0.01$
- $r_L = 0.01$
- $r_L = 0.05$
- $PEF(r_L)$

**Distance (m)**

- $0$
- $10$
- $20$
- $30$
- $40$

**Autocorrelation for Well 1 Wireline Caliper Log**

- $r_L = -0.01$
- $r_L = 0.01$
- $r_L = 0.05$
- $CALI(r_L)$

**Distance (m)**

- $0$
- $10$
- $20$
- $30$
- $40$

**Autocorrelation for Well 1 Wireline Density Log 1**

- $r_L = -0.01$
- $r_L = 0.01$
- $r_L = 0.05$
- $RHOB(r_L)$

**Distance (m)**

- $0$
- $10$
- $20$
- $30$
- $40$
Chapter 4: Analysis of the Data Sets

Autocorrelation for Well 1 Wireline Density Log 2

- Distance (m)

Autocorrelation for Well 1 Wireline Density Correction Log

- Distance (m)

Autocorrelation for Well 1 Wireline Gamma Ray Log

- Distance (m)
Figure 4.23 Well 1 autocorrelation analysis of the wireline logs. Note: x-axis is scaled from Distance 0 to 45m, y-axis is scaled from Autocorrelation r(L) 0 to 1 above the x-axis. Values outside the yellow and blue bands are significant at the 0.05 and 0.01 confidence levels respectively.
Chapter 4: Analysis of the Data Sets

Well 1z

The statistical tests demonstrated that LWD density porosity values matched both the well 1 and well 1z core porosity values over the gas, oil and the whole reservoir [Table 4.36]. This was only possible by use of unrealistic density values in the oil zone and the whole reservoir [Table 4.37]. The limestone neutron porosity values matched core porosity values in the oil zone. Note: limestone neutron porosity is approximately 4% porosity lower than sandstone neutron porosity in sandstone. The OC’s density and complex porosity equations porosity values did not match core over any interval. The standard histogram showed that the OC’s density porosity overestimated the core porosity [Figure 4.24] whilst the limestone neutron porosity equation matched the core porosity values. The calculated histogram illustrated that all the complex porosity equations overestimated porosity [Figure 4.25].

The 4% porosity needed to match the core and LWD neutron porosity was assumed to be a result of standoff, >1½ inches of effective standoff was needed to move the values by 4% porosity. At >1½ inches standoff, density values are unusable. If the standoff was constant along the entire well, then ‘limestone’ neutron porosity values may be valid since the match with well 1z core porosity values is good in the oil zone. Neutron porosity logs are also more robust than density logs in the case of standoff due to their relative depths of investigation. However, it was difficult to foresee a physical situation in which the LWD tool parallel standoff could be as large as 1½ inches in such a well. It was possible that the LWD porosity tools were running skew across the wellbore increasing the effective standoff observed by these dual detector tools.

The autocorrelation analyses of the well 1z LWD logs indicated that the logs did not appear to be effected by the borehole or drilling process i.e. no correlation between the rate of penetration autocorrelation function e) and any of the other logs [Table 4.25 and Figure 4.26]. In fact, there was little similarity between any of the autocorrelation plots, hence the problematic porosity values were likely to be a result of tool orientation/position whilst logging.

- Unrealistic fluid parameters were required to match the core porosity values [Table 4.37], therefore no reliable log porosity values could be calculated for well 1z.
- These results show that there is no substitute for good quality log data.
Chapter 4: Analysis of the Data Sets

Figure 4.24 Well 1z standard porosity histogram with well 1z core porosity values.

Figure 4.25 Well 1z calculated porosity histogram with well 1z core porosity values.
### Table 4.36
Well 1z Student’s t-tests (clear cells) and Chisq test (grey cells) results against well 1z core porosity values, fluid parameters in Table 4.37.

<table>
<thead>
<tr>
<th>Porosity equation</th>
<th>Density</th>
<th>Limestone Neutron</th>
<th>Square Root</th>
<th>Wiley &amp; Patchett</th>
<th>Gaynard &amp; Poupon Neutron</th>
<th>Gaynard &amp; Poupon Density</th>
<th>OC Density</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas</td>
<td>✓</td>
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<td>x</td>
<td>✓</td>
<td>x</td>
<td>x</td>
<td>x</td>
</tr>
<tr>
<td>Oil</td>
<td>✓ ✓</td>
<td>✓</td>
<td>x</td>
<td>✓</td>
<td>x</td>
<td>x</td>
<td>x</td>
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<td>x</td>
<td>✓</td>
<td>x</td>
<td>x</td>
<td>x</td>
</tr>
</tbody>
</table>

### Table 4.37
Well 1z fluid parameters.

<table>
<thead>
<tr>
<th>Porosity equation</th>
<th>Density (g/cm³)</th>
<th>Square Root</th>
<th>Wiley &amp; Patchett</th>
<th>Gaynard &amp; Poupon Neutron</th>
<th>Gaynard &amp; Poupon Density</th>
<th>OC Density (g/cm³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas</td>
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<td>OC</td>
<td>OC</td>
<td>DEN</td>
<td>DEN</td>
<td>1.01</td>
</tr>
<tr>
<td>Oil</td>
<td>0.0</td>
<td>OC</td>
<td>OC</td>
<td>DEN</td>
<td>DEN</td>
<td>0.70</td>
</tr>
</tbody>
</table>
Chapter 4: Analysis of the Data Sets

A) Autocorrelation for Well 1z LWD Gamma Ray Log 1

B) Autocorrelation for Well 1z LWD Gamma Ray Log 2

C) Autocorrelation for Well 1z LWD Pressure Log
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Autocorrelation for Well 1z LWD Neutron Porosity Log

Distance (m)

Autocorrelation $r(L)$

Distance (m)

Autocorrelation for Well 1z LWD Rate of Penetration Log

Distance (m)

Autocorrelation $r(L)$

Distance (m)

Autocorrelation for Well 1z LWD Density Correction Log

Distance (m)

Autocorrelation $r(L)$

4-97
Figure 4.26 Well 1z autocorrelation analysis of the LWD logs. Note: x-axis is scaled from Distance 0 to 240m, y-axis is scaled from Autocorrelation r(L) 0 to 1 above the x-axis. Values outside the yellow and blue bands are significant at the 0.05 and 0.01 confidence levels respectively.
Chapter 4: Analysis of the Data Sets

Well 3

The statistical tests demonstrated that only the square root and Wiley & Patchett porosity values matched both the core porosity values over all the units [Table 4.38]. Of the other porosity equations, only the OC’s density and Gaymard & Poupon density porosity values matched core over the oil zone [Table 4.39]. The wireline neutron porosity values matched core over the whole reservoir. The histogram showed that the square root and Wiley & Patchett matched the core, whilst the other methods overestimated the core porosity except the Gaymard & Poupon neutron which underestimated core porosity [Figure 4.27 and Figure 4.28].

The results show that the only change of fluid parameters required to match the core and density porosity values was the oil zone fluid density [Table 4.39]. No reason for this could be found from the drilling information. The heavy value of fluid density required in the oil zone was due to the large number of doggers encountered in this well providing outlying data points. It was possible that a cuttings bed was lifting the porosity tools from the floor of the borehole, although poor tool application to the borehole would provide this effect.

- Despite the apparently poor logs, the square root and Wiley & Patchett methods provided good and reliable porosity values.

These results demonstrated that porosity in poor well conditions could be achieved. Although the importance of good quality density values in horizontal wells should not be ignored as this would have further improved the results.

The autocorrelation analysis of the well 3 logs showed similarities between all the logs below 20m lag indicating that the logs were affected by the borehole conditions [Table 4.25 and Figure 4.29]. The majority of the energy being in the first few metres of lag. The gamma ray a) and rate of penetration b) plot were characteristically the same, the shale content controlling the drilling speed.
Figure 4.27 Well 3 standard porosity histogram.

Figure 4.28 Well 3 calculated porosity histogram.
Table 4.38 Well 3 Student's t-tests (clear cells) and Chi² test (grey cells) results against well 1 core porosity values, fluid parameters in Table 4.39.

<table>
<thead>
<tr>
<th>Porosity equation</th>
<th>Density</th>
<th>Sandstone Neutron</th>
<th>Square Root</th>
<th>Wiley &amp; Patchett</th>
<th>Gaymand &amp; Poupon Neutron</th>
<th>Gaymand &amp; Poupon Density</th>
<th>OC Density</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas</td>
<td>X</td>
<td>X</td>
<td>✓</td>
<td>✓</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Oil</td>
<td>X</td>
<td>X</td>
<td>✓</td>
<td>✓</td>
<td>X</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
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<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
</tbody>
</table>

Table 4.39 Well 3 fluid parameters.

<table>
<thead>
<tr>
<th>Porosity equation</th>
<th>Density (g/cm³)</th>
<th>Square Root</th>
<th>Wiley &amp; Patchett</th>
<th>Gaymand &amp; Poupon Neutron</th>
<th>Gaymand &amp; Poupon Density</th>
<th>OC Density (g/cm³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas</td>
<td>OC</td>
<td>OC</td>
<td>OC</td>
<td>DEN</td>
<td>DEN</td>
<td>1.01</td>
</tr>
<tr>
<td>Oil</td>
<td>1.10</td>
<td>OC</td>
<td>OC</td>
<td>DEN</td>
<td>DEN</td>
<td>0.70</td>
</tr>
</tbody>
</table>
Chapter 4: Analysis of the Data Sets

Autocorrelation for Well 3 Wireline Gamma Ray Log

Autocorrelation for Well 3 Wireline Photoelectric Factor Log

Autocorrelation for Well 3 Wireline Neutron Porosity Log
Chapter 4: Analysis of the Data Sets

**Autocorrelation for Well 3 Wireline Rate of Penetration Log**

- $r^{-0.01}$
- $r^{0.01}$
- $r^{0.05}$
- $r^{-0.05}$
- $\text{ROPs}(r(L))$

**Autocorrelation for Well 3 Wireline Density Log**

- $r^{-0.01}$
- $r^{0.01}$
- $r^{0.05}$
- $r^{-0.05}$
- $\text{RHO}(r(L))$

**Autocorrelation for Well 3 Wireline Density Correction Log**

- $r^{-0.01}$
- $r^{0.01}$
- $r^{0.05}$
- $r^{-0.05}$
- $\text{DRHO}(r(L))$
Chapter 4: Analysis of the Data Sets

Autocorrelation for Well 3 Wireline Caliper Log

Autocorrelation for Well 3 Wireline True Resistivity Log

Autocorrelation for Well 3 Wireline Deep Induction Log
Figure 4.29 Well 3 autocorrelation analysis of the wireline logs. Note: x-axis is scaled from Distance 0 to 210m, y-axis is scaled from Autocorrelation r(L) 0 to 1 above the x-axis. Values outside the yellow and blue bands are significant at the 0.05 and 0.01 confidence levels respectively.

Well 3: filtered data

Well 3 and 6 data were filtered using a 19 point (~2m) moving average filter (10cm sampled data). The choice of this filter was determined by wishing to retain as much of the geological information in the logs whilst suppressing the noise as resulting from borehole damage. The filtered data were processed again to evaluate the effect of filtering upon the porosity estimation from the logs [log plot in the wallet at the back of the thesis].

The statistical tests demonstrated that the filtered density, square root and OC density porosity values matched the core porosity values over only the gas zones and the sandstone neutron porosity only over the whole reservoir [Table 4.40]. The histograms showed that the core porosity was overestimated except for the Gaymard & Poupon neutron that underestimated core porosity [Figure 4.30 and Figure 4.31]. However, an unrealistic fluid density was used [Table 4.41]. The filtering did not improve the accuracy of the results, but in fact, the opposite was true [compare Table 4.38 with Table 4.40] and again the large number of doggers may have been the cause of the bias in the data.
Figure 4.30 Well 3 standard porosity histogram with filtered data.

Figure 4.31 Well 3 calculated porosity histogram with filtered data.
Chapter 4: Analysis of the Data Sets

Table 4.40 Well 3 with filtered data Student's t-tests (clear cells) and Chi² test (grey cells) results against well 1 core porosity values, fluid parameters in Table 4.41.

<table>
<thead>
<tr>
<th>Porosity equation</th>
<th>Density</th>
<th>Sandstone Neutron</th>
<th>Square Root</th>
<th>Wiley &amp; Patchett</th>
<th>Gaymard &amp; Poupon Neutron</th>
<th>Gaymard &amp; Poupon Density</th>
<th>OC Density</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas</td>
<td>✓</td>
<td>x</td>
<td>✓</td>
<td>x</td>
<td>x</td>
<td>x</td>
<td>✓</td>
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<tr>
<td>Oil</td>
<td>x</td>
<td>x</td>
<td>x</td>
<td>x</td>
<td>x</td>
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<td>x</td>
<td>x</td>
<td>x</td>
<td>x</td>
</tr>
</tbody>
</table>

Table 4.41 Well 3 filtered data fluid parameters.

<table>
<thead>
<tr>
<th>Porosity equation</th>
<th>Density (g/cm³)</th>
<th>Square Root</th>
<th>Wiley &amp; Patchett</th>
<th>Gaymard &amp; Poupon Neutron</th>
<th>Gaymard &amp; Poupon Density</th>
<th>OC Density (g/cm³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas</td>
<td>OC</td>
<td>OC</td>
<td>OC</td>
<td>DEN</td>
<td>DEN</td>
<td>1.01</td>
</tr>
<tr>
<td>Oil</td>
<td>1.10</td>
<td>OC</td>
<td>OC</td>
<td>DEN</td>
<td>DEN</td>
<td>0.70</td>
</tr>
</tbody>
</table>

The results were merged into a single table showing the cross correlation between the core porosity values and fluid parameters. The data was used for further analysis to determine the impact of fluid types on core porosity. The analysis showed a significant correlation between fluid types and core porosity, indicating that different fluids can affect the porosity in different ways. This information is crucial for understanding the reservoir characteristics and optimizing production strategies.
Chapter 4: Analysis of the Data Sets

Well 5

The statistical tests demonstrated that the wireline density porosity values matched the core porosity values over the oil, transition and water zones [Table 4.42]. The sandstone neutron porosity values matched core porosity values over the oil and water zones, the acoustic only over the oil zone. The OC’s density porosity values matched core over the oil, water zones and the whole reservoir and OC’s acoustic only over the whole reservoir. Gaymard & Poupon neutron and Gaymard & Poupon density porosity values matched core only in the water zone. The square root and Wiley & Patchett porosity equations were poor, but matched core in the gas zone and, in the oil and water zones respectively. The histograms showed that the OC’s fluid parameters [Table 4.43] led to overestimation of the core porosity [Figure 4.32] whilst the density and acoustic porosity equations were a closer match with the core porosity values. The other porosity equations overestimated porosity [Figure 4.33].

The 169μsec/ft fluid travel time suggested that the acoustic measurement was affected by cycle slipping, with p-wave suppression as gas would increase the travel time required. The fluid density used in the gas zone being greater than the oil and transition zones is thought to be due to the particularly shaley nature of the gas zone although mud invasion was a possible cause. If the gamma ray values from well 1 are compared with well 5, the well 5 gamma ray values are significantly greater (~20 API). Increased shale would indicate possibly lower permeability which would lead to deeper invasion and therefore the tool seeing less gas. However, the shallow investigation depth (~2 inches) of the acoustic measurement and the use of OBM to drill the well explained the 210μsec/ft acoustic fluid travel time, the approximate fluid travel time for oil. The fluid densities used reflect the change in fluid density within the formation observed by the density tool, however the fluid densities used in the oil and transition zones appear to be unrealistically low. Typical in-situ oil densities for North Sea Tertiary aged reservoirs are 0.65 to 0.75g/cm³, 0.70g/cm³ was used by the Oil Company.

The autocorrelation plots of the well 5 wireline logs indicated that the logs all had the same basic appearance. The plots gradually taper to approximately 30m, then flatten to 55m lag. It was concluded that there was no borehole effect in the spectra of the logs [Table 4.25 and Figure 4.34].
Chapter 4: Analysis of the Data Sets

Well 5: Standard Porosity Histogram

Figure 4.32 Well 5 standard porosity histogram.

Well 5: Calculated Porosity Histogram

Figure 4.33 Well 5 calculated porosity histogram.
Table 4.42 Well 5 Student's t-tests (clear cells) and Chi² test (grey cells) results against well 1 core porosity values, fluid parameters in Table 4.43.

<table>
<thead>
<tr>
<th>Porosity equation</th>
<th>Density (g/cm³)</th>
<th>Acoustic (μsec/ft)</th>
<th>Square Root</th>
<th>Wiley &amp; Patchett</th>
<th>Gaymard &amp; Poupon Neutron</th>
<th>Gaymard &amp; Poupon Density</th>
<th>OC Density (g/cm³)</th>
<th>OC Acoustic (μsec/ft)</th>
</tr>
</thead>
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<td>Gas</td>
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<td>X</td>
<td>X</td>
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<td>✓</td>
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<td>X</td>
<td>X</td>
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</tr>
</tbody>
</table>

Table 4.43 Well 5 fluid parameters.
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Autocorrelation for Well 5 Wireline Acoustic Travel Time Log

Autocorrelation for Well 5 Wireline Caliper Density Log

Autocorrelation for Well 5 Wireline Caliper Log 1

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**Autocorrelation for Well 5 Wireline Caliper Log 2**

- $r = -0.01$
- $r = 0.01$
- $r = 0.05$
- $r = -0.05$

- CAL2(r(L))

**Autocorrelation for Well 5 Wireline Neutron Porosity Log**

- $r = -0.01$
- $r = 0.01$
- $r = 0.05$
- $r = -0.05$

- NPHI(r(L))

**Autocorrelation for Well 5 Wireline Density Log**

- $r = -0.01$
- $r = 0.01$
- $r = 0.05$
- $r = -0.05$

- RHOB(r(L))
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Autocorrelation for Well 5 Wireline Density Correction Log

-0.01  r0.01  r0.05  r-0.05  DRH0 r(L)

Distance (m)

Autocorrelation for Well 5 Wireline Gamma Ray Log

-0.01  r0.01  r0.05  r-0.05  GR r(L)

Distance (m)

Autocorrelation for Well 5 Wireline Photoelectric Factor Log

-0.01  r0.01  r0.05  r-0.05  PEF r(L)

Distance (m)
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Autocorrelation for Well 5 Wireline Array Induction 90inch Log

**Figure 4.34** Well 5 autocorrelation analysis of the wireline logs. Note: x-axis is scaled from Distance 0 to 55m, y-axis is scaled from Autocorrelation r(L) 0 to 1 above the x-axis. Values outside the yellow and blue bands are significant at the 0.05 and 0.01 confidence levels respectively.
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Well 6

The Chi² tests demonstrate that acoustic and OC’s acoustic porosity values did not match the core porosity values through the well [Table 4.44]. The standard histogram showed that the fluid parameters [Table 4.45] were inadequate to match the core porosity values due to the spread in the values [Figure 4.35]. These results show that selection of acoustic tool for porosity was not good, due to the noisy acoustic log. The choice of the acoustic tool was likely to be because of operational concerns over nuclear sources in the well and the relative unimportance of porosity data in this well. Often the acoustic data is used for correlation with other wells and perforation zones are selected on this basis.

The autocorrelation analysis of the well 6 logs showed similarities between all the logs below 15m lag indicating that the logs were effected by the borehole conditions [Table 4.25 and Figure 4.37]. The majority of the energy being in the first few metres of lag. The gamma ray a) and Stoneley travel time c) plot were characteristically similar below 200m lag demonstrating the influence of lithology on Stoneley waves. The resistivity plots e) and f) were flat due to the near constant resistivity through the well.

<table>
<thead>
<tr>
<th>Porosity equation</th>
<th>Acoustic</th>
<th>OC Acoustic</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil</td>
<td>X</td>
<td>X</td>
</tr>
</tbody>
</table>

Table 4.44 Well 6 Chi² test (grey cells) results against well 1 core porosity values, fluid parameters in Table 4.45.

<table>
<thead>
<tr>
<th>Porosity equation</th>
<th>Acoustic (µsec/ft)</th>
<th>OC Acoustic (µsec/ft)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil</td>
<td>210</td>
<td>189</td>
</tr>
</tbody>
</table>

Table 4.45 Well 6 fluid parameters.
Chapter 4: Analysis of the Data Sets

Figure 4.35 Well 6 standard porosity histogram.

Figure 4.36 Well 6 standard porosity histogram with filtered data.
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Well 6: filtered data

The \( \chi^2 \) tests demonstrate that the filtered acoustic and OC’s acoustic porosity values did not match the core porosity values through the well [Table 4.46]. The standard histogram showed that the fluid parameters [Table 4.47] were inadequate to match the core porosity values due to the spread in the values [Figure 4.36]. These results showed that filtering the data had not improved the porosity estimate, mainly relating to poor acoustic log data. Improving the acoustic log would have required extensive reprocessing of the acoustic waveform data that was not available. The filtered log plot can be found in the wallet at the back of the thesis.

<table>
<thead>
<tr>
<th>Porosity equation</th>
<th>Acoustic</th>
<th>OC Acoustic</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil</td>
<td>\text{x}</td>
<td>\text{x}</td>
</tr>
</tbody>
</table>

Table 4.46 Well 6 filtered data \( \chi^2 \) test (grey cells) results against well 1 core porosity values, fluid parameters in Table 4.47.

<table>
<thead>
<tr>
<th>Porosity equation</th>
<th>Acoustic (( \mu \text{sec/ft} ))</th>
<th>OC Acoustic (( \mu \text{sec/ft} ))</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil</td>
<td>210</td>
<td>189</td>
</tr>
</tbody>
</table>

Table 4.47 Well 6 filtered data fluid parameters.
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**Autocorrelation for Well 6 Wireline Gamma Ray Log**

- $r^{-0.01}$
- $r^{0.01}$
- $r^{0.05}$
- $r^{-0.05}$
- GR $r(L)$

**Distance (m)**

**Autocorrelation for Well 6 Wireline Acoustic Compressional Travel Time Log**

- $r^{-0.01}$
- $r^{0.01}$
- $r^{0.05}$
- $r^{-0.05}$
- DTCO $r(L)$

**Distance (m)**

**Autocorrelation for Well 6 Wireline Acoustic Stoneley Travel Time Log**

- $r^{-0.01}$
- $r^{0.01}$
- $r^{0.05}$
- $r^{-0.05}$
- DTST $r(L)$

**Distance (m)**

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Figure 4.37 Well 6 autocorrelation analysis of the wireline logs. Note: x-axis is scaled from Distance 0 to 340m, y-axis is scaled from Autocorrelation $r(L)$ 0 to 1 above the x-axis. Values outside the yellow and blue bands are significant at the 0.05 and 0.01 confidence levels respectively.
4.5 Mud Invasion

Estimations of the depths of mud invasion for the three logging runs (vertical well wireline, LWD and horizontal well LWD) were required to validate the statements made in the previous sections regarding porosity calculations and photoelectric factor anomalies. By modifying Harris’s equation [Equation 3.5] to give depth of symmetrical invasion from borehole wall, $d_i$, assuming that no mudcake exists, at $t=0$,

$$d_i = \sqrt{\frac{2(P_b - P_f)K_f t}{\mu_{mf} \phi S_{xo}}} \left( \ln \left( \frac{r_f}{r_b} \right) - 1 \right),$$

Equation 4.1

where $t = \text{time passed}$, $\mu_{mf} = \text{mud filtrate viscosity}$, $K_f = \text{formation permeability}$, $r_b = \text{borehole radius}$, $r_f = \text{distance to limit of reservoir}$, $P_b = \text{borehole fluid pressure}$ and $P_f = \text{formation fluid pressure}$, $\phi = \text{porosity}$ and $S_{xo} = \text{water saturation of invaded zone}$. The values used for the calculations are given below in Table 4.48.

| $\mu_{mf}$ | 64 cP |
| $r_b$      | 8.5 inches |
| $r_f$      | 538560 inches (2 miles). Reservoir compartmentalised by sealing faults (Dorn et al. 1996). |
| $P_b$      | 6374 psi calculated from depth and mud weight |
| $P_f$      | 4980 psi average of the repeat formation tester pressure data |
| $\phi$     | From calculated porosity |
| $K_f$      | From porosity/permeability relationship using the horizontal permeability for the vertical well and the vertical permeability for the horizontal well [Figure 4.10]. |
| $S_{xo}$   | Calculated from porosity using the Oil company a, m and n values. |

Table 4.48 Values used to estimate the depth of mud invasion during logging.

The vertical well wireline mud invasion profile was calculated using a constant time after circulation of 36 hours. The vertical well LWD mud invasion profile was calculated using time after circulation of 80 hours plus the rate of penetration multiplied by the distance behind the bit of the density/neutron tool. Figure 4.38 shows a schematic of the hypothesised invasion profile. The horizontal well LWD mud invasion profile was calculated using the rate of penetration multiplied by the distance behind the
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bit of the density/neutron tool. Note: This method of mud invasion depth estimation assumes no mudcake and therefore mud invasion is likely to be shallower than indicated by these calculations, although relative comparisons are informative.

The results are presented in Figure 4.39 for the vertical well and Figure 4.40 for the horizontal well and demonstrate that in the vertical well the depth of invasion was large for both wireline and LWD logging runs. Note: Some depth discrepancies are apparent between the logs largely due to poor LWD depth data. The vertical well mud invasion was typically >40 inches and similar for both runs [Figure 4.39]. The depth of invasion was far greater than the depths of investigation of either of the porosity tools [Table 4.49]. The resistivity tools demonstrated little separation suggesting that the invasion was either very shallow or greater than their depths of investigation. The wireline deep induction resistivity measured slightly greater resistivity values than the other resistivity tools in the vertical well because it was measuring a greater volume [Table 4.49 and Table 4.1]. However, the wireline and LWD porosity tools were affected by the presence of gas. The LWD porosity logs being affected to a greater extent than the wireline porosity logs due to re-invasion of gas into the invaded formation around the borehole. Gas is highly mobile and can travel miscibly through the invaded mud. The LWD logs were affected more than the wireline logs because the LWD logs were run some 2 days after the wireline tools.

The mud invasion in the horizontal well was typically 4-10 inches [Figure 4.40]. This explained why the LWD resistivity logs were very similar in value, with low invasion therefore little influence on the resistivity [Table 4.1]. The maximum density measured higher densities (lower porosity) than in the vertical well possibly due to better flushing of the gas from the near borehole region. The mud invasion profile could also explain why the neutron porosity values were much lower than in the vertical well [Table 4.1]. The depth of invasion being 4-10 inches would effectively remove the gas effect from the density due to flushing, but gas would still affect the neutron due to its' 10 inch depth of investigation.

The photoelectric factor logs may be explained by analogy with the mud invasion profiles [Figure 4.39 and Figure 4.40], since the wireline and LWD caliper logs agree well. The barite fines invaded into the formation with the mud, but due to their density travelled more slowly than the mud invasion front creating a second barite rich front. This barite rich front being time dependant and the shallow depth of investigation of the photoelectric factor measurement resulted in high initial
concentrations of the barite (high PEF) close to the borehole [Table 4.49]. The concentration of barite and therefore PEF values decreased as depth of invasion increased. Alternatively, a more likely cause was that the LWD caliper log was incorrectly indicating an in-gauge borehole and thus disguising the presence of a mudcake during LWD logging. Although mudcake could have been scraped off whilst drilling as the stabilisers covering the detector are intended to do leaving poor formation contact as the cause.

**Figure 4.38** Schematic of the mud invasion and tool positions.
Figure 4.39 Vertical well invasion profiles for LWD and wireline logging times.
Figure 4.40 Horizontal well invasion profile for LWD logging times.
<table>
<thead>
<tr>
<th>Tool</th>
<th>Depth of investigation (Inches) [cm]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wireline deep induction</td>
<td>60 [152]</td>
</tr>
<tr>
<td>Wireline medium induction</td>
<td>40 [102]</td>
</tr>
<tr>
<td>LWD amplitude resistivity</td>
<td>48 [122]</td>
</tr>
<tr>
<td>LWD phase resistivity</td>
<td>24 [61]</td>
</tr>
<tr>
<td>Wireline and LWD density</td>
<td>4 [10]</td>
</tr>
<tr>
<td>Wireline and LWD neutron porosity</td>
<td>.10 [25]</td>
</tr>
<tr>
<td>Wireline and LWD photoelectric factor</td>
<td>½ [1]</td>
</tr>
</tbody>
</table>

Table 4.49 Tool depths of investigation.
4.6 Summary

4.6.1 Data Set 1

Factors affecting porosity calculations in the vertical well

The porosity analyses showed that for the vertical well the wireline density porosity values were most reliable for predicting formation porosity values and had the highest correlation with the core porosity values. The wireline neutron porosity values were not as accurate as the wireline density porosity values, but in combination in more complex porosity algorithms, their calculated porosity values were in good agreement with core. The wireline acoustic porosity values were possibly affected by gas through the Rotliegend gas interval. Alternatively, preferential acoustic energy propagation along low porosity dipping beds encountered from the alternating dune slip face/lee sands reduced the recorded travel times. By changing the fluid parameter the LWD porosity values were improved by changes in fluid parameters to be in good agreement with core porosity values over all the intervals expect for the LWD neutron porosity in the Rotliegend gas interval.

- Square root single layer model using the LWD average density and neutron porosity values provides best LWD derived porosity values in the vertical well.

Accepted practice is that the LWD maximum density is preferred, as its density measurement is more valid and reliable with the LWD tools used (Rider 1996). The difference between LWD maximum and average density complex porosity values were small though tests showed closer match with core using LWD average density values.

The vertical well was logged with LWD (LAD) 2 days AFTER the wireline tools. LWD porosity values were greater than their respective wireline porosity values due to gas remigration towards the borehole decreasing the hydrogen index and fluid density of the formation. The fluid parameters used indicated the effect of the gas. There was increased borehole rugosity/enlargement and thus worse formation to detector contact than the wireline run indicated by the LWD caliper values.

Note that the standard method for obtaining fluid parameters is by crossploting the core against log porosity values [Figure 4.41a, b and c]. The values derived from the
crossplots compare well with the porosity values derived from the single layer model. Principally the two methods are in essence the same, one graphical, the other numerical.

**Vertical Well Core Porosity v. Density**

```
Core Porosity (m^3/m^3)

- WIRELINE DENSITY (G/CC)
- LWD MAXIMUM DENSITY (G/CC)
- LWD AVERAGE DENSITY (G/CC)

Linear (WIRELINE DENSITY (G/CC))
Linear (LWD MAXIMUM DENSITY (G/CC))
Linear (LWD AVERAGE DENSITY (G/CC))
```

Calculated Fluid Densities (g/cm^3)
- Wireline: 1.032
- LWD Maximum: 0.768
- LWD Average: 0.643

**Vertical Well Core Porosity v. Acoustic Travel Time**

```
Core Porosity (m^3/m^3)

- WIRELINE ACOUSTIC TRAVEL TIME (USEC/FT)
- Linear (WIRELINE ACOUSTIC TRAVEL TIME (USEC/FT))
```

Calculated Fluid Acoustic Travel Time
- Wireline: 185.85 us/sec

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Horizontal Well Core Porosity v. Density

Core Porosity (m³/m³)

<table>
<thead>
<tr>
<th>Density (g/cm³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.5</td>
</tr>
<tr>
<td>0</td>
</tr>
<tr>
<td>1</td>
</tr>
<tr>
<td>1.5</td>
</tr>
<tr>
<td>2</td>
</tr>
<tr>
<td>2.5</td>
</tr>
</tbody>
</table>

- LWD MAXIMUM DENSITY (g/cc)
- LWD AVERAGE DENSITY (g/cc)
- Linear (LWD MAXIMUM DENSITY (g/cc))
- Linear (LWD AVERAGE DENSITY (g/cc))

\[ y = -2.7817x + 2.65 \]
\[ R^2 = 0.07 \]
\[ y = -1.3398x + 2.65 \]
\[ R^2 = 0.05 \]

Calculated Fluid Densities (g/cm³):
- LWD Maximum: 1.310
- LWD Average: -0.132

Figure 4.41 Standard method of core porosity against porosity log crossplots for calculation of fluid parameters.

Factors affecting spectral analysis in the vertical well

The autocorrelation analyses of the vertical well logs indicated that the logs appeared to be largely unaffected by the borehole or drilling process. The only exception was the wireline PEF log that correlated with the LWD caliper log, which displayed resonance features. The cause may have been that mudcake filled the spirals, tool wobble or preferential mudcake build up on the more porous facies (dune slip faces). The LWD density correction log was also affected and explained why the LWD PEF and density logs were not similarly affected. The LWD density correction had removed these features from the LWD PEF and density logs.

- The vertical well wireline and LWD data was not filtered because this resulted in only marginal improvement in the porosity calculations.
Factors affecting porosity calculations in the horizontal well

LWD average density values were very low and LWD caliper values were large which suggested that the borehole was enlarged and rugose. The values were large enough to mean that both measurements were unreliable for any quantitative use and cast doubts on the reliability of all the other horizontal well LWD measurements. Although it was possible using the LWD average density values to achieve good agreement with core over some intervals the fluid densities used required for agreement were unrealistic.

The absence of core porosity data complicated the determination of which method(s) were appropriate to calculate accurate horizontal well porosity values. Comparison of LWD log calculated porosity with the scaled vertical well core porosity values over the relevant facies allowed the rejection of methods that were inaccurate.

- The standard Wiley & Patchett LWD maximum density and neutron porosity values provided the best LWD derived porosity values in the horizontal well.

This was not the same model as the vertical well (standard square root model) suggesting that reliable and consistent porosity calculation from these LWD porosity tools was not viable in this horizontal well and possibly all horizontal wells in this field.

The horizontal well LWD neutron and maximum density porosity values were lower than their respective measurements in the vertical well. The horizontal well LWD measurements were recorded approximately 18 hours after penetration and the vertical well wireline measurements 36 hours were after penetration. The volume of mud invasion was similar in both cases when compared with the volume of investigation of the porosity tools. The horizontal well LWD neutron porosity measurements were recorded approximately 84 hours after penetration and therefore mud invasion was more extensive. This was possibly due to barite mud invasion and mudcake increasing concentration of barite close to the borehole walls in the formation and mudcake at the time of logging compared with the vertical well. This would effectively have increased the formation fluid density to greater than 1g/cm³ reducing the calculated porosity values. The increased effect of the barite is indicated by the very large LWD PEF values in the horizontal well. The PEF measurement is only sensitive to the first ½ inch
in front of the short spaced detector indicating that the barite concentration is much greater than in vertical well measurements.

Incorrect LWD tool position within the borehole whilst logging i.e. "riding the borehole" leads to the possibility of non-parallel standoff. This non-parallel standoff can lead to either light or heavy bulk density values with no indication from the density correction curve. Thus in a situation where the short spaced detector reads light (poor contact) and the long spaced detector reads correctly (good contact) then the bulk density would read too heavy. This situation is possible since the long spaced detector leads the short spaced detector and the source down the borehole; the reverse of a wireline tool.

Factors affecting spectral analysis in the horizontal well

The autocorrelation analysis of the horizontal well LWD logs indicated that most of the logs were affected by the borehole or drilling process with only the LWD resistivity log unaffected. The LWD density correction algorithm appeared to be unable to correct sufficiently for the standoff encountered. The horizontal well LWD caliper log demonstrated that spiralling was evident at a number of wavelengths. The most damaging wavelengths appeared to be the short wavelengths between 8-10 ft. The logs were filtered accordingly to remove all wavelengths below 10 ft inclusively. The porosity calculations were then repeated on the filtered horizontal well LWD data. The additional knowledge of the mud invasion was taken into account and fluid densities greater than 1 g/cm$^3$ were used.

Factors affecting filtered data porosity calculations in the horizontal well

The horizontal well filtered data LWD porosity values used were much improved with respect core porosity values over most intervals.

• The best porosity values in the horizontal well were provided by the filtered LWD maximum density and neutron porosity Wiley & Patchett single layer model.
Factors affecting mud invasion in both wells

The vertical (1) and horizontal (1z) well demonstrated that in the vertical well the depth of invasion was larger for both wireline and LWD logging runs. The vertical well mud invasion was calculated to be >40 inches and similar for both runs. The wireline and LWD porosity tools appear to be gas affected and the LWD porosity logs being affected to a greater extent than the wireline porosity logs. This was because of remigration of gas into the mud invaded formation around the borehole. The LWD logs were affected more than the wireline logs because the LWD logs were run some 2 days after the wireline tools. This was despite the calculated invasion since it was unlikely that the mud invasion prevented gas migration towards the borehole (Woodhouse et al. 1991).

The mud invasion in the horizontal well was typically 4-10 inches, which explained why the LWD maximum density measured higher densities (lower porosity) than in the vertical well. However, the mud invasion profile could not explain why the neutron porosity values were much lower than in the vertical well. The depth of invasion would have had to have been greater than, but close to 10 inches throughout the whole horizontal well to explain this situation.

The LWD photoelectric factor logs were explained by barite fines invading into the formation with the mud, but travelled more slowly than the mud due to their density. The slow moving barite rich mud resulted in high initial concentrations of the barite (high PEF) close to the borehole. The concentration of barite and therefore PEF values decreased as depth of invasion increased. Alternatively, a more likely cause was that the LWD caliper log was incorrectly indicating an in-gauge borehole and thus disguising the presence of a mudcake during LWD logging.
4.6.2 Data Set 2

Porosity estimation in the two vertical wells (1 and 5) was aided by the core porosity data available. Improving the porosity estimate compared with standard fluid parameters only required a linear shift by adjusting the fluid parameters for the density and acoustic logs. The sandstone neutron porosity was affected by shale, but the shale correction used was ineffective. The use of the more complex porosity equations (square root and Wiley & Patchett) were shown to be useful for wells 1 and 3 and to a lesser extent well 5. One possible reason was the shale content of the sandstones was not adequately estimated by the gamma ray volume shale transformation; for example non-radioactive clays were encountered in well 5. Another is that the complex porosity equations were designed for clean sands and their use was inappropriate. Autocorrelation analysis demonstrated that there was little perturbation to the logs from the borehole conditions, since the conditions were good in well 1, 1z and 5.

- Both density and acoustic porosity values provided the most reliable estimates of core porosity values for well 1.

Horizontal well 1z porosity estimation was only possible due to the core porosity data in well 1z. The LWD log quality was poor especially the density that used alone the logs would not have been any use for porosity estimation. The standoff estimated at >1½" rendered the LWD density log invalid. Porosity estimation was only possible because the core porosity data allowed in-situ calibration of the neutron porosity log, the neutron tool having a greater depth of investigation than the density tool. As a result of the poor porosity logs, the more complex porosity equations were unsatisfactory as porosity estimators principally due to the poor bulk density data. Autocorrelation analysis demonstrated that there was little perturbation to the logs from the borehole conditions. This is not surprising if the tools were effectively stoodoff by >1½" initially, the log responses will be relatively insensitive to further small additional perturbations in standoff. The effective standoff was probably due to the LWD tools running skew across the borehole axis i.e. non-parallel standoff causing the large effective standoff and poor data quality. Another alternative is that the stabilisers
nearest the bit were down cutting into the rock, "keyseating" the borehole and resulting in the large standoff observed by the LWD porosity tools.

- Unrealistic fluid parameters were required to match the core porosity values, therefore no reliable log porosity values could be calculated for well 1z.

Porosity estimation in the horizontal wells 3 and 6 was not supported by core porosity data. Well 3 shale corrected density porosity was a poor match with well 1 core porosity values. It was possible that a cuttings bed was lifting the porosity tools from the floor of the borehole, although poor tool application to the borehole would also create this effect. The presence of numerous doggers in well 3 compared with wells 1, 1z and 5 may have influenced the results. Filtering data from well 3 did not improve porosity estimation - in fact the results were considerably worse possibly due to inappropriate use of the filtering in this case.

- Despite the apparently poor logs, the square root and Wiley & Patchett methods provided good and reliable porosity values.

Well 6 acoustic data was of poor quality (noisy) presumably due to the nature of the pipe conveyed logging run used. The poor acoustic travel time values may result from the tool being tilted (non-parallel) and/or the acoustic energy short cutting through fast beds (doggers). Autocorrelation analysis has shown the effect of borehole conditions on the logs. Filtering data from well 6 did not improve porosity estimation.

These results demonstrated that porosity in poor well conditions could be achieved (Well 3) although good well conditions are obviously preferable where they can be achieved. Although the importance of good quality density values in horizontal wells should not be ignored as this would have further improved the results.
4.7 Conclusions

4.7.1 General data quality criticisms

For data set 1, data from only one vertical well and its horizontal sidetrack well was made available. This meant that checking data quality with other comparable wells in this field was not possible. The data set 1 LWD data from the horizontal well was a splice of eight runs, however the overlapping sections of data were not available to evaluate repeatability. For data set 2, data from three horizontal wells were available from the field analysed with LWD data from one horizontal well and wireline pipe conveyed data in the other two wells run with different toolstrings.

Only the product logs were available for the wells analysed because the data was provided "as is" by Service Companies to Oil Companies. Little public domain information is accessible regarding the detailed processing techniques used for the wireline and LWD porosity tools employed, as this information is proprietary. This includes filtering techniques, some of which are merely cosmetic and can obscure poor quality data. However, if the 'raw' measurements were available, for example count rates, the potential for developing alternative processing techniques would have been possible. Oil Companies do double check the environmental corrections applied to porosity product logs. This does not involve working from the "raw" count rates, but from a "base" log that may itself be affected by incorrect processing.

A direct comparison of porosity values between wells is not necessarily valid. Ideally, core porosity data would have been available for all the wells for comparison with the log data. There was substantial scope for altering the position of the core porosity values in depth with respect to the horizontal well porosity data and thereby changing the match achieved. A number of different approaches were tested and the best comprise was to evenly distribute the core porosity values in depth. However, some immunity was achieved by binning the porosity values into 1pu bins prior to Chi² testing. Note that log porosity values are accepted to be reliable to ±1pu. The lack of core porosity data was problematic for accurate determination of which method(s) were appropriate to calculate accurate horizontal well porosity values. However, comparison of log calculated porosity with scaled vertical well core porosity values over the relevant units allowed rejection of methods that were certainly inaccurate. A decision was made to use data set 1 vertical well and data set 2 well 1 core porosity data for the
statistical comparisons. Data set 2 well 1z used well 1z core porosity values because the large number of core samples permitted their use. In addition, for data set 2 there was little reason to assume that porosity was laterally constant, since the sands were shaley and turbiditic with several doggers. However, without additional core porosity data no conclusive assessment of porosity homogeneity could be made.

A further complication in the horizontal wells was that the borehole and formation conditions differ from the vertical wells. Also calculating porosity was problematic because the horizontal wells were not logged with the same class of tools (wireline/LWD) or the same suite of tools (different measurements).

Details of the time-depth processing and the actual time-depth data are also critical for good LWD data quality control, but were not available. Obviously, data may be placed incorrectly with depth, a situation that becomes worse as the errors build as the size of the time-depth file increases and the manner in which the calculations are performed. In processing time-depth data it is possible, depending on if the porosity processing technique uses data combined from several depths, that the porosity calculations could be altered by different time-depth processing techniques. It is also possible to dramatically alter the interpretation of the data depending on the time-depth data. Bed boundaries and fluid contacts may be incorrectly located and the depth-derived logs will be simply incorrect. The time-depth processing will also have the effect of altering the effective volumes of investigation of the porosity tools making comparisons between LWD and wireline tools more complex and probably invalid. Wireline data is often on-depth to better than 1ft in 1000ft. LWD data is seldom so well depth aligned, the author is aware of LWD data off-depth by more than 20ft in 100ft and highly variable within a given 100ft section. Although absolute depth was not particularly important for the research presented here, the relative depths were necessary for matching core, wireline and LWD data prior to statistical comparison. In addition, pipe conveyed log data are well known to suffer from poor depth control due to the difficulties in maintaining cable tension during logging. This can render the tension log useless as a means of checking data quality.

The LWD service company operations summary was available for the data set 1 horizontal well, but other operational information was not accessible. The operations summary was available for all the data set 2 wells. Although the Oil Companies in question applied strict quality control procedures problems still occurred, as was the case for the data set 1 horizontal well, data set 2 wells 1z, 3 and 6. There is no substitute
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to talking directly with the logging engineers involved at the time. One quality control technique is to compare histograms of the data through the reservoir section from all the wells in the field. This enables rapid identification of inconsistent data, unfortunately this information was not available for data set 1.

Differences from previous work

The validity of the porosity calculations in both vertical and horizontal wells was tested against core porosity values from the vertical wells using Students’ t and Chi² tests. This has not been presented in such a manner previously for horizontal well comparisons allowing significance or otherwise of the porosity transforms to be evaluated.

The approach used in this chapter using numerous different porosity transforms was based on the approach detailed in Cowan and Wright (1997). This approach had not been applied to data in any published article known to the author. The techniques used for dealing with shale/clay were standard.

Tool orientation considerations have been more seriously considered here than in published papers particularly Cuddy et al. (1994) and Bedford et al. (1997). The author feels that full consideration of the effects of tool positioning has not been rigorously examined within the public domain. One clear indication of the deficiencies of the particular LWD density and neutron tool used here was the introduction of the azimuthal LWD density and neutron tools.

With respect to data set 1, horizontal wells drilled in this field after those analysed in this thesis confirmed that the main source of error was the LWD tool “riding the borehole” by the use of azimuthal LWD tools. The use of azimuthal LWD tools enabled the Oil Company to design an algorithm to search for the maximum bulk density in a more rigorous manner using the previous generations of LWD porosity tools. Simultaneous maximum bulk density and neutron porosity values were calculated to ensure their depth alignment. However, the techniques used within this chapter are useful for the examination of historical horizontal well LWD data.

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4.7.2 Porosity equations

The use of square root and Wiley & Patchett methods provided good porosity estimation in the Data set 1 horizontal gas well with poor borehole conditions (spiralled) using the LWD maximum density filtered data. The data set 1 horizontal LWD average density measurements were found to be unreliable as was the data set 2 horizontal well 1z LWD density measurement. These logs were not suitable for any quantitative use and cast doubts on the reliability of all the other horizontal well LWD measurements.

- The use of the LWD average density measurement for porosity calculation is strongly discouraged.

Spiralling of wells in both data sets led to further degradation of the porosity measurements. The use of numerical filtering and careful selection of the fluid parameters enabled the final porosity calculations to be improved significantly for data set 1. Data set 2 would require the raw measurements for filtering to be investigated as the porosity should be calculated from filtered count rates (Betts et al. 1990) and travel times.

The quality of wireline and LWD log data in horizontal wells was generally poor compared with vertical well log data. Standoff, borehole condition and noise generated by the conveyance of the tools was of greater magnitude. The result was poor quality data input into porosity equations. Data set 2 well 1z LWD density measurement was found to be unreliable for any quantitative use and the neutron porosity was ~4pu too high. This cast doubts on the reliability of the LWD horizontal well measurements. Well 3 wireline logs were noisy, but considered valid for porosity estimation. Porosity estimation was still problematic due to the abundance of doggers encountered. Without further study of other wells in the field, it would be difficult to conclude whether the doggers are localised or continuous across the field. The vertical well logs may not be resolving all the doggers whereas the relative angle of the beds to the horizontal wells may be increasing the likelihood of observing the doggers. Well 6 acoustic porosity estimation was poor. The spread in the acoustic travel time values demonstrated that the
log was too noisy to be reliable for porosity estimation in this horizontal well due to
downhole noise from drill pipe and tool movement.

Filtering did not significantly improve the porosity estimation of wells 3 and 6
from data set 2. Although, the effect of spiralling of the well was thought to be a
secondary effect compared with incorrect shale volume estimation and poor tool
positioning within the borehole. The use of filtering may well be fruitful once shale and
standoff has been sufficiently accounted for.

For data set 2, the use of Gaymard & Poupon density and neutron methods were
not generally found to be useful for the horizontal wells, even using the filtered data.
These methods were designed for different situations to those found in the wells
examined above, due to the shale content. Accounting for shale using the gamma ray
log was insufficient for these methods. Neutron-density crossplot methods for shale
corrections were not considered as this has the potential of using the data for cross­
purposes and involve a degree of subjectivity. The shale corrected density porosity
provided the most reliable porosity in the wells considered in this chapter. However,
fluid densities were chosen to fit the expected porosity distribution rather than direct
use of vertical well fluid densities to predict porosity in horizontal wells.

Computer modelling could provide a family of Wiley & Patchett type equations
to meet the need for improved porosity and water saturation calculations in a broader
variety of mixed lithologies. Explicit use of lithology indicators such as gamma ray and
photoelectric factor log measurements and core mineralogy could enhance the quality
of porosity estimation, although good geochemical logging data would be preferable if
such a tool existed, as could the inclusion of invasion as suggested by Wiley & Patchett
(Patchett and Wiley 1994). At present the range of neutron-density porosity transforms
is limited to clean sandstone, limestone and dolomite although, accounting for shale in
calculations by the use of the volume shale calculations is often sufficient. There are
many cases where this is not so. The gap could be filled using Wiley & Patchett type
equations.
Chapter 4: Analysis of the Data Sets

Recommended porosity calculation practices

The following procedure is strongly recommended for porosity calculations for horizontal wells:

- Check the logs for cyclicity (any repeated feature in the logs), especially the caliper, photoelectric factor and porosity logs. If cyclicity is present, filter the logs before porosity calculations are performed.
- The use of fluid densities, travel times and excavation constants from vertical wells are likely to be incorrect for the horizontal well. Do try to match the porosity values in the same interval/zone in the horizontal well as in the vertical wells, by adjusting the fluid densities, travel times and excavation constants.
- The square root and Wiley & Patchett method provide good porosity values.
- Be aware that there are geological reasons for different porosity values in horizontal wells that are in the same interval/zone as in the vertical wells. The closer the well is physically to the vertical well(s) the more likely the porosity values are to be similar.
- The use of the LWD average density measurement for porosity calculation is strongly discouraged.
- Where shale content is an issue gamma ray logs need to be calibrated in known beds to provide consistent and reliable volume shale estimation between wells and differing tool types especially when wireline and LWD are used.
- Careful inspection of logs is required to identify what shifts are required by justifying shifts from measured parameters e.g. standoff.
Chapter 4: Analysis of the Data Sets

Suggested Practical Remedies

- All raw measurements should be preserved for future use.
- Time-depth data should be preserved and rigorously checked for inconsistencies.
- If porosity, and therefore water saturation, are important in a horizontal well then use wireline rather than LWD tools because the log quality is generally superior.
- The density tool must be included in the toolstring.
- Azimuthal LWD density and neutron tools should be used and run within the correct rate of penetration range specified by the Service Company.
- LWD caliper measurement independent of the density measurements is essential. This is now addressed by the introduction of an ultrasonic caliper.
- Sidewall core plug porosity would be a useful constraint on porosity derived from logs run in horizontal wells.
- A shallow resistivity tool run in both wells would have provided evidence for anisotropic mud invasion as a cause of the apparent porosity decreases.
- Improved clay/shale content information could be gained by the use of a reliable geochemical logging tool or core mineralogy, especially when non-radioactive clays are present.
- Drill smoother horizontal wells by the use of two stabilisers. One stabiliser within say 10ft of the bit and a second one drill collar behind the first. The borehole may become spiralled with only one stabiliser as a single stabiliser can act as a pivot.

Additional comments

- Down cutting of the first stabiliser could be forming a ledge enabling the LWD tools to standoff leading to poor LWD density and possibly LWD neutron values.
- Ultrasonic caliper, wireline dipmeter or image logs in horizontal wells would verify the state of the borehole. The improved borehole size values could be included in the correction algorithms of the porosity tools to improve porosity estimation.
- Acoustic measurements in horizontal wells are likely to be noisy and unreliable for porosity estimation or rock strength calculations.
- Redesign the porosity tools to improve tracking of the horizontal wells as tools are often run in conditions for which they were not designed for.
Chapter 5: Conclusions and Further Work

This chapter draws together the conclusions from previous chapters and is divided into the following sections: recommended porosity calculation practices, porosity equations, suggested practical remedies and further work.

Validation of hypotheses

1. Log derived porosity values give poor estimates of formation porosity in horizontal wells, regardless of tool type.
   
   Data set 1 horizontal well (LWD) and data set 2 horizontal well 3 (wireline) log porosity values both provided good agreement with the vertical well core porosity values. However, data set 2 horizontal wells 1z (LWD) and 6 (wireline) log porosity values were not in agreement with the core porosity values as a result of poor quality log data.

2. LWD density-derived porosity provides the best LWD porosity tool estimate of the true formation porosity in horizontal wells.
   
   Data set 1 horizontal well LWD maximum density porosity values were in the best agreement with the vertical well core porosity values. Though this can only be shown to be case specific since only one well demonstrated this agreement.

3. Rugose and washed-out wellbore conditions in horizontal wells increases porosity log values to a greater extent than in vertical wells.
   
   The three vertical wells were all in good condition and so no conclusion can be drawn on the relative effects of the severity of the wellbore conditions between vertical and horizontal wells.

   The intention was to investigate all the hypotheses, but data was not available to assess hypotheses 4, 5 and 6.

4. Formation fluid affects the magnitude of porosity anomalies in horizontal wells to a greater extent than in vertical wells.
   
   No shallow resistivity logs were available demonstrate the degree of invasion.
Chapter 5: Conclusions and Further Work

5. In horizontal gas wells, anisotropic mud invasion increases density derived porosity values and decreases neutron porosity values, without increasing the apparent variability in the measurements.

*No azimuthal porosity and shallow azimuthal resistivity logs were available to measure the effects of anisotropic mud invasion on the recorded values.*

6. Bedding and relative dip affect porosity calculations in wells.

*No dipmeter, resistivity or acoustic imaging logs were available to measure the dips and to evaluate the subsequent change or otherwise in response of the porosity values.*

**Differences from previous work**

The validity of the porosity calculations in both vertical and horizontal wells were tested against core porosity values from the vertical wells using Students' t and Chi$^2$ tests. This has not been presented in such a manner previously for horizontal well comparisons allowing significance or otherwise of the porosity transforms to be evaluated. The approach used in this thesis using numerous different porosity transforms was based on the approach detailed in Cowan et al. (1997). This approach had not been applied to well data in any published article known to the author.

Tool orientation considerations have been more seriously considered here than in published papers particularly Cuddy et al. (1994) and Bedford et al. (1997). The author feels that full consideration of the effects of tool positioning has not been rigorously examined within the public domain. In data set 1, horizontal wells in this field, drilled after those analysed in this thesis the Oil Company, confirmed that the main source of error was the LWD tool “riding the borehole” by the use of azimuthal LWD tools. The use of azimuthal LWD tools enabled the Oil Company to design an algorithm to search for the maximum bulk density in a more rigorous manner using the previous generations of LWD porosity tools. Simultaneous maximum bulk density and neutron porosity values were calculated to ensure their depth alignment. However, the techniques used within this thesis are useful for the examination of historical horizontal well LWD data.
5.1 Recommended porosity calculation practices

The following procedure is strongly recommended for porosity calculations in horizontal wells:

- Check the logs visually for cyclicity, especially the caliper, photoelectric factor and porosity logs. If cyclicity is present filter the logs from the raw measurements before porosity calculations are performed.
- Use of the square root and Wiley & Patchett method provide good porosity values.
- The use of the LWD average density measurement for porosity calculation is strongly discouraged.
- Where shale content is an issue gamma ray logs need to be calibrated in known beds to provide consistent and reliable volume shale estimation between wells and differing tool types especially when wireline and LWD are used.
- The use of fluid densities, travel times and excavation constants from vertical wells are likely to be incorrect for the horizontal well. Do try to match the porosity values in the same interval/zone in the horizontal well as in the vertical wells, by adjusting the fluid densities, travel times and excavation constants.
5.2 Porosity equations

Data quality

The quality of wireline and LWD log data in horizontal wells was generally poor compared with vertical well log data. Standoff, borehole condition and noise generated by the conveyance of the tools were often of greater magnitude. The result was poor quality data input into porosity equations.

LWD logs are intended to record data within a few hours after penetration avoiding poor borehole conditions and invasion effects [see Chapter 2]. LWD logs are affected to a greater extent by perturbations than wireline logs are, possibly to the point that the potential benefits of LWD log quality are often lost. Notably, the principal porosity tool, density, is at a disadvantage in the LWD situation due to tool rotation and the stiff tool length (20ft [6m] the effective stiff tool length could be much greater). Wireline tools are able to conform to the borehole wall shape with only a 1m pad and caliper pushing the pad against the wall and reducing the effects of perturbations.

Direct comparison of porosity values between wells was not necessarily valid since core porosity data (assumed to be true formation porosity) was not available for all the wells for comparison with the log data. There was substantial scope for altering the position of the scaled vertical well core porosity values in depth with respect to the horizontal well porosity data and thereby changing the match achieved. The best compromise was to evenly distribute the core porosity values in depth, though some immunity was achieved by binning the porosity values into 1pu bins prior to Chi$^2$ testing. Note that log porosity values are accepted by the Oil Industry to be reliable to ±1pu. The lack of core porosity data was problematic for accurate determination of which method(s) were appropriate to calculate accurate horizontal well porosity values. However, comparison of log calculated porosity with scaled vertical well core porosity values over the relevant units allowed rejection of methods that were certainly inaccurate.
Assessment of porosity equations

- Shale corrected density porosity provided the most reliable porosity in the dataset 2 vertical and horizontal wells.
- Wiley & Patchett method provided the most reliable porosity in the dataset 1 horizontal gas wells using the filtered LWD maximum density and neutron data.
- Gaymard & Poupon methods were not found to provide good porosity estimation in horizontal wells, even when using filtered data.
- LWD average density was found to be unreliable for any quantitative use and its use for porosity calculation is strongly discouraged.
- Spiralled horizontal wells resulted in the degraded porosity measurements.
- Filtering significantly improved porosity estimation for data set 1, but not data set 2.
- Careful selection of fluid parameters enabled porosity calculations to be improved for data set 1 and most wells for data set 2.
- Poor shale volume estimation and doggers significantly degraded the porosity calculation for data set 2.
- Sonic logs are prone to downhole noise from drill pipe and tool movement in horizontal wells.

Porosity equations

Data set 1 LWD average density logs were not suitable for any quantitative use and cast doubts on the reliability of all the other horizontal well LWD measurements. The data set 1 horizontal well LWD maximum density and neutron Wiley & Patchett method were demonstrated to be useful for porosity estimation. The quality of wireline and LWD log data in horizontal wells was generally poor compared with vertical well log data. Standoff, borehole condition and noise generated by the conveyance of the tools was of greater magnitude. The result was poor quality data input into porosity equations.

Data set 2 well 1z LWD density measurement was found to be unreliable for any quantitative use and the neutron sandstone porosity was ~4pu too high. This cast
doubts on the reliability of the LWD horizontal well measurements. Well 3 wireline logs were noisy, but considered valid for porosity estimation. Porosity estimation was still problematic due to the abundance of doggers encountered. Well 6 acoustic porosity estimation was poor. The spread in the acoustic travel time values demonstrated that the log was too noisy to be reliable for porosity estimation in this horizontal well due to downhole noise from drill pipe and tool movement.

Filtering did not significantly improve the porosity estimation of well 3 and 6 from data set 2. Although, the effect of spiralling of the well was thought to be a secondary effect compared with incorrect shale volume estimation and poor tool positioning within the borehole. The use of filtering may well be fruitful once shale and standoff has been sufficiently accounted for (requiring the raw measurements).

For data set 2, the use of Gaymard & Poupon density and neutron methods were not generally found to be useful for the horizontal wells considered in this chapter even using the filtered data. These methods were designed for different situations to those found in the wells examined above due to the shale content. Accounting for shale using the gamma ray log was insufficient for these methods. Neutron-density crossplot methods for shale corrections were not considered as this has the potential for using the data for cross-purposes and involves a degree of subjectivity. The shale corrected density porosity provided the most reliable porosity in the wells considered in this thesis.
5.3 Suggested practical remedies

- All raw measurements should be preserved and readily available for future use.
- Time-depth data should be preserved and rigorously checked for inconsistencies.
- Filtering methods used by Service Companies should be made more transparent.
- If porosity and therefore water saturation are important in a horizontal well then use wireline rather than LWD tools because the log quality is generally superior.
- A density tool must be included in the toolstring, LWD or wireline.
- Azimuthal LWD density and neutron tools should be used when using LWD tools and run within the correct rate of penetration range specified by the Service Company.
- Redesign the porosity tools to improve tracking in the horizontal wells.
- Ultrasonic caliper, dipmeter or image logs in horizontal wells would verify the state of the borehole. The improved borehole size values could be included in the correction algorithms of the porosity tools to improve porosity estimation.
- An LWD caliper measurement independent of the density measurements is essential. This is now addressed by the introduction of an ultrasonic caliper measurement.
- Sidewall core plug porosity would be a useful constraint on porosity derived from logs run in horizontal wells.
- A shallow resistivity tool run in both wells would have provided evidence for anisotropic mud invasion as a cause of porosity anomalies.
- Improved clay/shale content information could be gained by the use of a reliable geochemical logging tool, especially when non-radioactive clays are present.
- Sonic measurements in horizontal wells are likely to be noisy and unreliable for porosity estimation or rock strength calculations.
- Drill smoother horizontal wells by the addition of two stabilisers. One stabiliser within 10ft of the bit and a second one drill collar behind the first. Inserting only one stabiliser results in the borehole becoming more spiralled than without as a single stabiliser will act as a pivot.
Chapter 5: Conclusions and Further Work

5.4 Suggestions for further work

The scope for further work in horizontal well log analysis is near endless, some techniques have only been touched on here. An important note is that formation properties can appear to change only very gradually or not at all in horizontal wells. Often one of the most revealing techniques is to plot depth and on a compressed scale (e.g. 1:1200/1:1000 normally 1:240/1:200 is used). Likewise log data on compressed scales can draw attention to features that may otherwise be overlooked.

Four topics that deserve further investigation from the data presented above are:

- Computer modelling could provide a family of Wiley & Patchett type equations to meet the need for improved porosity and water saturation calculations in a broader variety of mixed lithologies. Explicit use of lithology indicators such as gamma ray and photoelectric factor measurements could enhance the quality of porosity estimation. As could the inclusion of invasion as suggested by Patchett and Wiley (1994). At present the range of neutron-density porosity transforms is very limited, (clean sandstone, limestone and dolomite), although shale is accounted for in calculations by the use of the volume and is often sufficient. There are many cases where this is not so. The gap could be filled using Wiley & Patchett type equations.

- Sonic measurements in horizontal wells. Dataset 2 well 6 sonic travel time values in the sandstones were approximately 10μsec/ft slower than in the vertical wells. Given this observation and evidence of slow sonic travel time values in the southern North Sea (Austin et al. 1994), there appears to be further work in this line of study. This is especially when the use of nuclear logs are unacceptable for operational reasons, the sonic log may be the only porosity log available since NMR is not often run in horizontal wells. Analysis of the full waveforms may shed light on the causes of these anomalous horizontal sonic logs.

- Time lapse log analysis is possible with LWD and wireline tools and may provide values of formation properties such as permeability.

- Zonation of log data. Concerns over the gamma ray for volume shale estimation and the use of differing fluid zones raises the suggestion that the rather crude methods employed above could be significantly refined. There is a substantial amount of
published work regarding log zonation and automatic techniques for log evaluation. However, no technique is yet able to cope with log data without user input. Horizontal wells allow the subtle aspects of log evaluation to be put to the test. The cut off between one ‘zone’ and another can be very diffuse.

Additional comments

Greater involvement with the Service and Oil Companies involved would have provided more information regarding detailed porosity processing techniques. Increased knowledge of the procedures and common practices involved in porosity and log analyses of horizontal wells would have been beneficial. Planning of the data acquisition needs to involve the Service and Oil Companies with specific aims set out from the start. This includes the availability of “raw” measurements and processing algorithms, and an agreement to share the results between all involved. Much of the initial effort in this thesis involved the acquisition of data and the definition of the project.

In addition the effect of trajectory and mud properties on horizontal log data warrants closer examination. With subtle changes in formation properties in horizontal wells changes to the borehole environment become ever more critical to log evaluation.

Resistivity tool response (induction and laterolog) in horizontal wells is a vast topic in which the oil industry is only just starting to understand the problems involved. New resistivity tools are being developed or in early field use with azimuthal discrimination capabilities. Computer modelling of horizontal well and 3D resistivity responses is also in its early stages.

Azimuthal versions of the current logging tools are becoming available. The data from such tools such as the LWD azimuthal density neutron, azimuthal laterolog and 3D induction tools are aiding (horizontal) log interpretation and also uncovering previously unknown log features.

A common theme throughout the push to understand horizontal well logs is imaging. Not only the use of tools that provide 3D and 4D (time lapse) data, but developments in log presentation and incorporation with other oilfield disciplines (core analysis, seismics, well testing, reservoir modelling...) requires consideration for the future of horizontal well log interpretation.
Appendix 1: Geology of Data Set 1

The southern North Sea has been an area of active hydrocarbon exploration and production since the early 1960s. This area covers what is known as the southern Permian basin and stretches from the mid North Sea high in the west of the basin to the Polish-Russian border in the east [Figure 1.1]. The hydrocarbon fields of the offshore UK sector of the southern North Sea are predominantly gas producing [Figure 1.2].

The North Sea was formed as a result of tectonic stresses in the Hercynian foreland during the late Carboniferous/early Permian (Walker and Cooper 1987). At the end of the Hercynian orogeny, a period of uplift effected the North Sea resulting in erosion and accompanied by volcanism. The well data originate from a field in the Sole Pit sub-basin which formed during the early Permian and lies off the North coast of East Anglia, England [Figure 1.3].

The Sole Pit basin suffered inversion during the Late Jurassic/Early Cretaceous that stripped away most of the Upper Jurassic sediments and again in the mid-Tertiary as a result of the Alpine orogeny. The gas was derived from devolatilised coal from the underlying Carboniferous coal measures (Walker and Cooper 1987). The reservoir rocks are predominantly Permian Rotliegend aeolian/fluvial sands. Generally, the aeolian sand members have greater porosity than the fluvial members. Rotliegend (Leman) sands were formed on the southern North Sea basin margins. The primary sediment source was erosion of the Carboniferous coal measures (Westphalian) from the nearby London-Brabant massif that lay to the south [Figure 1.3](Ziegler 1975; Glennie 1990). Ephemeral fluvial channels carried the sediment into the basin, and on the flood plain the sediment was acted on by the strong trade winds from the North to Northeast to form aeolian deposits. The Permian Zechstein mudstone (Kuperschiefer) and the overlying evaporite sequences form the cap rocks.

Immediately overlying the Rotliegend is the basal mudstone of the Zechstein. An initial rapid marine transgression led to an increase in moisture allowing a covering of vegetation that later provided the basal mudstone of the Zechstein (Jenyon and Cresswell 1987). Subsequently, the basin became extremely dry with intermittent recharging of the basin that provided the source for the deposition of evaporites.
Figure 1.1 Southern Permian basin (Plate 1 Brooks and Glennie 1987).
Figure 1.2 Map of North Sea oil and gas fields (Inside Cover of Brooks and Glennie 1987).
Appendix 1: Geology of Data Set 1

There are five main cycles of evaporites known, indicating at least five marine transgressions during the Zechstein. Owing to the thickness of the evaporites (ignoring later thickening due to halokinesis), the basin must have been regularly recharged with saline water as indicated by numerous interbedded thin evaporites (Taylor 1990).

The data set used was from a 100-250ft (30-76m) thick Rotliegend gas reservoir. In the vertical well, the 120ft (36.6m) Leman sands are underlain by the Westphalian coal measures and overlain by a thin 2ft (0.6m) mudstone and dolomitic limestone 1ft (0.3m) [Figure 1.4]. Above the dolomitic limestone were 146ft (44.5m) of anhydrite with some thin dolomite interbeds. The anhydrite was capped by a minor gas reservoir consisting of 29ft (8.8m) of dolomite. Above the dolomite, 8ft (2.4m) of anhydrite is followed by a substantial thickness of halite/polyhalite.

Figure 1.3 Field location map redrawn (Figure 1 Bulat and Stoker 1987).
Appendix 1: Geology of Data Set 1

- Halite
- Anhydrite 8 ft (2m)
- Dolomite 30 ft (10m)
- Anhydrite 40 ft (12m) with dolomitic interbeds
- Dolomitic Limestone 1 ft (0.3m)
- Mudstone 2 ft (0.6m) [Zechstein, Kuperschiefer]
- Sandstone 120ft (36.6m) [Rotliegend, Leman Sands]
- Carboniferous Muds, Silts and Sands

Figure 1.4 Stratigraphic column based on the vertical well logs used.

Figure 1.5 Schematic lithology cross section through the reservoir (Figure 2 Dorn et al. 1996). Note: scale is only for guidance and is not necessarily representative.

The Rotliegend Leman sands are dominantly dune and interdune sands overlying poorer quality fluvial sands (Dorn et al. 1996). Thin cemented to partially cemented Weissliegend overlies the Rotliegend dune sands. The reservoir thickens from northwest to southeast with most of the thickening occurring in the low quality fluvial sands [Figure 1.5]. The geological descriptions from core and/or cuttings from the well
Appendix 1: Geology of Data Set 1

completion logs of the vertical and horizontal wells are given below [Table 1.1]. Reservoir quality varies rapidly laterally due to facies changes and compartmentalisation resulting from fault related diagenesis (fault sealing) (Dom et al. 1996). The reservoir is transgressed by two northwest-southeast en-echelon fault zones linked by a transfer zone consisting of discontinuous and variably oriented faults. Several phases of reactivation have occurred leading to (possibly extensive) structural controlled cementation (anhydrite/quartz). The wells have been positioned away from these faults (potential flow barriers) as much as possible (identified using 3D seismics) (Dom et al. 1996).

| Vertical Well | Sandstone: Poor to fair gas show, quartz sublitharenite becoming quartz arenite, light brown to brown, black and white speckled, hard, fine to medium grained, subrounded, well sorted, moderate to high sphericity, grain supported, lithic clasts, finely laminated with finer grained laminae, trace heavy mineral grains, rare chlorite near top and base, trace dark pyrobitumen stains near base, locally well cemented by siliceous cement, poor visible porosity at top, good visible porosity at base. |
| MD x14-x236ft (232ft 70m) | TVD x811-x931ft (120ft 36m) |
| MD x134-x906ft (772ft 235m) | Sandstone: Poor to fair gas show, quartz sublitharenite to arenite, off white, light grey, pale grey brown, fine to medium grained, moderately sorted, sub-angular to sub-rounded, moderate sphericity, loose to friable, poor anhydritic or rare dolomitic cement, anhydritic/argillaceous matrix, occasional red/black lithic clasts, poor to fair visible porosity. |
| TVD x802-x835ft (33ft 10m) | MD x906-x1655ft (749ft 228m) |
| TVD x835-x857ft (22ft 6m) | Sandstone: Moderate to good gas show, quartz arenite, light grey brown, fine to medium grained, moderately sorted, sub-angular to sub-rounded, moderate sphericity, loose to friable, poor dolomitic or rarely siliceous cement, rare argillaceous matrix, occasional red/black lithic clasts, fair to good visible porosity. |
| MD x1655-x2060ft (405ft 123m) | Sandstone: Poor to fair gas show, quartz sublitharenite to arenite, off white, light grey, light grey brown, fine to medium, predominately fine grained, moderately sorted, sub-angular to subrounded, moderate sphericity, loose to friable, poor dolomitic cement, argillaceous or dolomitic matrix, rarely slightly anhydritic, rare red/black lithic clasts, poor to fair visible porosity. |
| TVD x857-x846ft (11ft 3m) | Table 1.1 Well completion log geological descriptions based on Oil Company data. MD = measured depth, TVD = true vertical depth. |
Appendix 2: Geology of Data Set 2

The Palaeocene

The Palaeocene was initiated by the onset of spreading in the Labrador Sea leading to the Maureen terrigenous sediment deposition in the northern North Sea [Figure 2.2](Liu et al 1993). Subsequent uplift of the Scottish highlands and East Shetland platform resulted with an uplift (effective sea level fall) of 375-525m, followed by collapse of half that magnitude. Initial spreading of the Norwegian-Greenland Sea and associated reorganisation of the Labrador Sea spreading influenced the termination of the late Palaeocene sediment supply.

The Palaeocene sedimentation of the northern North sea was controlled by the presence of three radiating basins of the Moray Firth, Viking Graben and Central Graben [Figure 2.3](Mitchell et al 1986). These grabens were formed as a result of volcanic updoming at their junction in Mid-Jurassic times. The early Palaeogene sediments achieve a maximum thickness of 1200m over the Witch Ground Graben, dipping and thinning in a wedge shape to less than 200m in the southern Central Graben to the southeast (Stewart 1987). As the early Palaeogene sediments are traced to the Inner Moray Firth, they thin and rise towards the Scottish coast.

Initiation of the Palaeocene saw the rejuvenation of faulting, inversion and regional uplift of the sandstone rich Shetland and Scottish source areas [Figure 2.6](Galloway et al. 1993). An initial peak of the intrusive activity in western England and Ireland occurred in the early Thanetian, coincident with the maximum sediment supply during the deposition of the Andrew formation [Figure 2.4](Liu et al 1993). Coincident with the deposition of the Andrew tuff was a sea level rise and followed by the deposition of the Balmoral sequence [Figure 2.5].

The primary control on sedimentation was the progressive tilting and migration of the uplift axis to the east with eustatic sea level changes playing an important secondary control. The sedimentation of the first Palaeocene formation, Danian, resulted in the reworking of the underlying Cretaceous Chalk (Ekofisk formation) followed by the input of coarse siliciclasts through the Moray Firth (Maureen formation) [Figure 2.7] (Galloway et al. 1993).
Figure 2.1 Field map with well locations (provided by the Oil Company).

Top Palaeocene Reservoir & Well Locations

- Gas cap: Initial GOC = 1496 mTVDSS
- Oil leg: Initial OWC = 554 mTVDSS
- Aquifer
- Fault
- Appraisal well
- Well trajectory
- Horizontal oil producer
- Gas injector
- OWC monitoring
- Proposed

Appendix 2: Geology of Data Set 2
Appendix 2: Geology of Data Set 2

Figure 2.2 Sketch map of the northern North Sea (Figure 14.13 Mitchell et al 1986).

Figure 2.3 Simplified palaeography of northern Britain and the North Sea in Middle Jurassic times. The volcanics occur at the junction between the three radiating basins, the Moray Firth basin (MFB), Viking Graben (VG) and Central Graben (CG). Sediments are derived both longitudinally from the updomed triple junction and from lateral, possibly fault-bounded, margins (Figure 14.15 Mitchell et al 1986).
Appendix 2: Geology of Data Set 2

Figure 2.4 Stratigraphic scheme for the Early Tertiary of the central North Sea/Moray Firth area (Figure 2 Banner et al. 1992).

Figure 2.5 Early depositional sequences, central North Sea (Figure 2 Stewart 1987). See Figure 2.7 for the definition of the numbers.

Continuation of siliclastic deposition followed during the Thanetian with a progressive increase in source areas from the East Shetland platform, but the Moray Firth remained the focus of deposition. Three depositional episodes are known during the Thanetian; lower Andrew, upper Andrew and Forties. Initially sand was deposited onto the East Shetland platform from the highlands [Figure 2.8]. The coarse sands formed steep sloped (3-5°) prograding-braided deltas that built out to the southeast. The
sands were transferred into the basin from high relief via steep slopes in high viscosity turbidite flows. Mudstones were deposited in the distal parts of the basin (Lista formation). The end of the Palaeocene was a result of the Hebridean volcanism and the opening of the Norwegian-Greenland sea causing the collapse of the Shetland platform. This was marked by the deposition of Balder tuff.

Halokinesis in the northern North Sea was initiated during the Triassic and Jurassic because of thermal subsidence and sediment accumulation (Hodgson et al. 1992). Salt walls and ridges were formed. The high sedimentation rate and reduction in the supply of salt to the salt walls and ridges during the Cretaceous and early Tertiary resulted in the salt ridges reforming into domes/diapirs spaced at approximately 8km intervals along NE-SW Caledonian transfer fault systems and north-south Jurassic and Permian fault trends.

During the Palaeocene, the salt diapir crests were condensed, but the flanks were thickened leading to the development of peripheral rim-synclines. The result of these salt movements was to effect the topography of the sea floor and therefore the sedimentation during the Palaeocene. The Palaeocene turbidites were fed from the Witch Ground Graben/Moray Firth basin (Hodgson et al. 1992). The salt related topography provided the sediment with deposition sites on all flanks of the diapirs, but the detailed deposition was controlled by the sediment influx direction, rate and the position of the diapir.

The sea-floor topography dip was low, but the energy loss would be capable of forcing high-density turbidite deposition. Another possibility is that the increased turbulence when the flow hits a break of slope causes the flow to terminate [Figure 2.9]. Larger topography would cause the lower clastic-rich part of the turbidite flow to deflect around the topographic high, while the muddier part continued over the top. The energy imbalance caused by the flow separation resulting in the deposition of the clastic part of the flow around the diapir [Figure 2.10]. Note that previous turbidite deposition would also provide additional topographic features that would be capable of forcing the same processes. The presence of the salt diapir topography and/or the continued formation of the diapir as the sedimentation continued lead to the large four way dip closed structures ideal for hydrocarbon accumulation e.g. a dome.
Figure 2.6 Synthetic palaeostress curve derived from the generalised sea-level curve for the north-western European basins. Stresses are plotted relative to an arbitrary present day stress level. Comparison with columns on the right-hand side with the timing of tectonic events in north-western Europe shows correlation with tectonic phases in the Atlantic, the north-western European rift system and the Alpine domain. Thick and thin wavy lines denote major and minor rifting phases respectively. Major and minor folding phases are indicated by thick and thin saw-tooth lines; stars denote phases of anorogenic volcanism (Figure 4 Cloetingh et al. 1987).
Figure 2.7 Composite chronostratigraphic diagram for the early Palaeogene of the central North Sea (Figure 18 Stewart 1987).
Figure 2.8 Coastal onlap curve for the early Palaeogene of the central North Sea. The diagram shows the relative onlap position of each of the ten described depositional sequences and depositional systems operating within each. The terms 'highstand' and 'lowstand' refer only to the relative position of sea level (Figure 19 Stewart 1987).
Appendix 2: Geology of Data Set 2

SAND RICH SYSTEMS (Low efficiency)

Flow Direction

Palaeogene
Chalk
Rapid Turbulence Decay
Sea Bed
Cut Fill
Sand concentrated on upstream side of salt high

MUD RICH SYSTEMS (High efficiency)

Muds and Silts in Turbulent Suspension
Basal traction carpet dominated by coarser grained clastics
Flow Stripping
Salt Swell
Turbidity Current

Sand deposition concentrated on leeward side of salt diapir

Figure 2.9 Turbidite-salt dome interaction; central North Sea (Figure 16 Hodgson et al. 1992).
### Appendix 2: Geology of Data Set 2

#### SALT TECTONICS/GEOMETRIES

<table>
<thead>
<tr>
<th>PERIOD</th>
<th>AGE</th>
<th>BASIN EVOLUTION</th>
</tr>
</thead>
<tbody>
<tr>
<td>TERTIARY</td>
<td></td>
<td><strong>EASTERN TROUGH CENTRAL GRABEN</strong></td>
</tr>
<tr>
<td>PRE RIFT II</td>
<td>-10</td>
<td>Major period of clastic basin fill following thermal uplift of Scotland - continued salt withdrawal from synclines driving widespread diapir growth.</td>
</tr>
<tr>
<td>POST RIFT II</td>
<td>-20</td>
<td>Creation of large salt withdrawal synclines in major depocentres. Formation of salt ridges on the margins of remnant half-graben.</td>
</tr>
<tr>
<td>POST RIFT I</td>
<td>-30</td>
<td>Decoupling of basement and cover during late Jurassic rifting. Inherited salt wall/sediment pod geometries reactivated.</td>
</tr>
<tr>
<td>PRE RIFT I</td>
<td>-40</td>
<td>Salt withdrawal/dissolution creating accommodation space for Triassic/Mid Jurassic continental sediments.</td>
</tr>
<tr>
<td>PRE RIFT II</td>
<td>-50</td>
<td>Zechstein salt deposition as post rift fill of Permian extensional basins. Initial period of gravity creep.</td>
</tr>
</tbody>
</table>

**Figure 2.10** Salt controls on basin evolution; central North Sea (Figure 18 Hodgson et al. 1992).
Appendix 2: Geology of Data Set 2

The Andrew formation

The Andrew submarine fan is channellized with the channels persistent close to the fan edges (Den Hartog Jager et al. 1993). The very high sedimentation rate reached a maximum soon after the initiation of fan deposition. The sediment source was from the northwest via the Fergus/Dornoch delta within the Moray Firth [Figure 2.11].

The channels lack cohesive levees due to the high sand volume of the turbidites and therefore, the initial sand/shale distribution was erratic. However, as the sediment supply waned, the levee and channel definition increased as the mud fraction of the sediment increased [Figure 2.12]. This enabled the aggradation of the massive sand units in the stable channels. The channels were up to 5m thick prior to amalgamation forming a sheet-like fan. These massive channel sands are also interbedded with mudstones from unconfined density flows. In addition, frequent local occurrences of slump deposits are seen resulting from abrupt breakthrough of levees during channel switching [Figure 2.13, Figure 2.14 and Figure 2.15].

The Andrew formation [58.5-59.5Ma] (Reynolds 1994) consists of amalgamated fine to coarse grained mid fan lithic sands with mud clasts and carbonaceous fragments. The beds within the formation show upward thickening cycles due to lobe switching. The sediment is sourced from the East Shetland platform from three principal lobes [Figure 2.16]. Note, the Andrew submarine fan sandstones have relatively constant high acoustic velocity logs [Figure 2.16](Stewart 1987).

One particular example, the Andrew field [Figure 2.17], the Andrew submarine fan sandstones are subdivided into a lower unit of thin bedded fine to medium grained outer fan turbidites (Stewart 1987). The lower unit progrades into an upper unit of medium and course grained channellized sandstones showing upward mid fan thickening. The upper unit consists of thin-bedded fine-grained interlobe sandstones with reworked sandy basaltic tuff at the top. Below are sands and muds with thin reworked chalk and tuff layers (Knox et al. 1981). The lower unit comprises of massive fine to medium grained poorly sorted sands with occasional coarse grains (Knox et al. 1981). The sands are relatively texturally uniform but with internal deformation structures such as dish structures and at the shale contacts load structures. Some thin beds show graded bedding and in the upper part cross lamination.
Figure 2.11 Palaeogeographic map of the Andrew formation (Plate 1 Panel 2 Reynolds 1994).

Figure 2.12 Schematic changes in fan geometry through the Palaeocene and Eocene (Figure 12 Den Hartog Jager et al. 1993).
Figure 2.13 Block diagrams of the (A) lowstand fan, (B) early lowstand wedge (channel-levee complex), and (C) late lowstand wedge (prograding complex). An axial section (D) through the canyon and onto the slope illustrates the stratal geometric relationships between the three units. The lowstand fan is deposited where there is a break in slope beyond the mouth of the canyon. The early lowstand wedge is deposited within the canyon and downlaps onto the lowstand fan. The late lowstand wedge is also deposited within the canyon and downlaps onto the early lowstand wedge (Figure 10.1 Posamentier and Erskine 1991).
Appendix 2: Geology of Data Set 2

Figure 2.14 Forties formation submarine fan depositional model (Figure 6 Whyatt et al. 1992).

Figure 2.15 Schematic diagrams for the depositional systems (Figure 6 Armentrout et al. 1993).
Appendix 2: Geology of Data Set 2

Figure 2.16 Sequence 3 summary (Figure 8 Stewart 1987). Gamma ray logs are on the left and sonic logs on the right-hand side of the logs shown.

In a second example, the Cyrus field [Figure 2.17], the Andrew formation consists of a fining upward interbedded sequence passing into the Andrew mudstone indicating the waning of the supply and fan abandonment (Mound 1991). The beds are thin channel-like sandstones (0.5-2.5m) of limited lateral extent with interbedded mudstones with a total thickness over reservoir of 10-15m thinning to the southeast and thickening to the northwest. The upper unit porosities range from 12-18%, 50% water saturation and permeability 50mD with 39-64% net/gross reservoir.

The lower unit is massive channelized mid-fan sandstone interspersed by thin mud and limestones, but is vertically and laterally extensive throughout the reservoir (Mound 1991). The lower unit has average porosities of 20%, water saturation 35% and permeability 200mD with 90% net/gross reservoir based on the top 30m reservoir.
Figure 2.17 Palaeocene play map. The shaded area shows the combined distribution of the Paleogene and lower Eocene sandstones, mainly derived from the uplifted area of the basin axis. Note that in many cases fields are not directly underlain by mature source rocks (Figure 14 Pegrum et al. 1990).
Appendix 3: Excel Macro Listings

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Appendix 3: Excel Macro Listings

--------------- Porosity Macro ---------------

1. This macro calculates porosity from an ascii log data file using a number of formulae.
2. Porosity is calculated using density and/or neutron tool porosity data only.
3. The porosity is calculated assuming a sandstone matrix in all cases.
4. Solver is used iteratively to optimise the calculated porosity in some cases.
5. Where code has not been written by myself, I have endeavoured to reference the code to the relevant textbook or more often website.

---------------

Option Explicit ' Means all variables must be declared. Make finding error easier.
Option Compare Text' Means that text operations are case in-sensitive for SELECT CASE

Start: Start of process time
Finish: End of process time
Msg : Message to say it's finished and how long it took.

Dim i%, j%, k%, l%, m%, s%, R%, a%, sta%, stb%, std%, c%
Dim ResColumn%, NeutColumn%, DenColumn%, ResXoColumn%
Dim DepColumn%, CporColumn%
Dim NeutStartRow%, NeutFinRow%, DenStartRow%, DenFinRow%, ResStartRow%, ResFinRow%
Dim ResXoStartRow%, ResXoFinRow%, CorStartRow%, CorFinRow%, FinRow%, StartRow%
Dim SwFinRow%, SwStartRow%, NumNeut%, NumDen%, NumRes%, NumResXo%, NumCalcPoints%, NumCalcSw%
Dim ws$, ps$, ips$, contents, msg$, mins%, secs!
Dim Finish!, Start!, Depth!, RhobM!, WeightM!
Dim Mud_Unit$, TempUnitS, Dep_Unit$
Dim Sal_Mud!, RW!, RwTemp!, SalWatTemp!, WatTempRhob!, ResPres!, ResTemp!
Dim ResRw!, RMFI!, ResWatRhob!, ResSal_wat!, MaxCpor!, Numcor%
Dim NumSheets%, SourceDataSheet$
Dim DenVal(20000), WPNeutVal(20000), NeutVal(20000), ResVal(20000), ResValXo(20000) As Single
Dim Dep(20000), Cpor(20000), DenPor(20000), SqrtPor(20000), WPor(20000) As Single
Dim ArchieSw(20000), NeutSw(20000), SqrtArchieSw(20000), WPArchieSw(20000) As Single
Dim GPPor(20000), GPArchieSw(20000), GPNSw(20000), GPNWat(20000) As Single
Dim GPNeutSh(20000), GPDenSh(20000) As Single
Dim startcol%, histstop!
Dim ColData1, ColData2, dr As Range

---

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Appendix 3: Excel Macro Listings

Dim Mean1!, Mean2!, SD1!, n1%, n2%, SD2!, Correlation!, Critical!, Prob!, test!, cumul!
Dim p%, q%, plow!, phigh!
Dim comp$, all$, wks$
Dim Initial_choice, Input_Data As Object
Dim Iter, Plot, Stat, ItPlot, ItPlot2, ItStat As Boolean
Dim NeutColFor!, CporColFor!
Dim NameIndex(100) As String
Dim histogram As Boolean
Dim ran, dan, ban As String

Const RhobH! = 0.5
Const WPCon! = 1.916
Const WPNeut1! = 0.4253
Const WPNeut2! = 0.001828
Const WPNeut3! = 0.00001885
Const WPDen1! = 0.4903
Const WPDen2! = 0.003882
Const WPDen3! = 0.004397
Const GPCon1! = 1.07
Const GPCon2! = 1.11
Const GPCon3! = 0.65
Const GPCon4! = 0.4
Const RhobSS! = 2.65
Const RhobW% = 1
Const RhobSS_W! = 1.65
Const CsrRhobSS! = 2.650019

Sub Porosity()
' Use Dialog Boxes to obtain information.
' I. Let the user set up the program with their choice of calculations, stats and
' plotting.

Set Choose_Data_Sheet = New Choose_Data_Sheet
NumSheets = Sheets.count
For R = 1 To NumSheets
    Sheets(R).Select
    wks = ActiveSheet.Name
    With Choose_Data_Sheet.Controls("OptionButton" & R)
        .Visible = True
        .Caption = wks
    End With
Next
Load Choose_Data_Sheet
Choose_Data_Sheet.Show
For i = 1 To NumSheets
    If Choose_Data_Sheet.Controls("OptionButton" & i).Value = True Then
        ws = Worksheets(i).Name
    End If
Next

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Appendix 3: Excel Macro Listings

Else
    Unload Choose_Data_Sheet
End If
Next
Unload Choose_Data_Sheet
Set Choose_Data_Sheet = Nothing

Set Initial_Choice = New Initial_Choice
Load Initial_Choice
Initial_Choice.Show
    If Initial_Choice.Controls("Iter_Calc_Poro").Value = True Then
        Iter = True
    Else
        Iter = False
    End If
    If Initial_Choice.Controls("Calculate_Stats").Value = True Then
        Stat = True
    Else
        Stat = False
    End If
    If Initial_Choice.Controls("Plot_Results").Value = True Then
        Plot = True
    Else
        Plot = False
    End If
Unload Initial_Choice
Set Initial_Choice = Nothing

Set Input_Data = New Input_Data
Load Input_Data
With Input_Data
    .MudUnits.AddItem "(lb/gal)"
    .MudUnits.AddItem "(g/cm3)"
    .MudUnits.AddItem "(lb/cu ft)"
    .MudUnits.ListIndex = 1
    .DepthData.Value = 2600
    .Depth_Unit.AddItem "(ft)"
    .Depth_Unit.AddItem "(m)"
    .Depth_Unit.ListIndex = 1
    .Temp_Unit.AddItem "F"
    .Temp_Unit.AddItem "C"
    .Temp_Unit.ListIndex = 0
    .Rw_Value.Value = 0.118
    .RmfValue.Value = 10
    .RwTemp.Value = 60
    .BHT.Value = 216
    .MudWeight.Value = 1.415
    .MudSalinity.Value = 144000
End With
Input_Data.Show

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Appendix 3: Excel Macro Listings

```vba
RW = Input_Data.Rw_Value.Value
RMF = Input_Data.RmfValue.Value
RwTemp = Input_Data.RwTemp.Value
ResTemp = Input_Data.BHT.Value
TempUnit = Input_Data.Temp_Unit.Text
WeightM = Input_Data.MudWeight.Value
Mud_Unit = Input_Data.MudUnits.Text
Sal_Mud = Input_Data.MudSalinity.Value
Dep_Unit = Input_Data.Depth_Unit.Text
Depth = Input_Data.DepthData.Value
Unload Input_Data
Set Input_Data = Nothing

If TempUnit = "C" Then
    RwTemp = 1.8 * RwTemp + 32
End If
If Mud_Unit = "(g/cm3)" Then
    WeightM = WeightM / 8.345
ElseIf Mud_Unit = "(lb/cu ft)" Then
    WeightM = WeightM / 7.48113
End If
If Dep_Unit = "(m)" Then
    Depth = Depth * 0.3048
End If

' Insert a sheet for the calculations
Sheets.Add
ActiveSheet.Name = "Porosity"
p = ActiveSheet.Name
Sheets(ws).Select

' Define name of data sheet. Find the columns containing density and neutron data.
For i = 1 To 30
    contents = Cells(1, i)
    Select Case contents
    Case Is = "NPHI", "NPHI (%)", "NPHI (M3/M3)", "NPHI (PU)"
        NeutColumn = i
    End If
Next i
```

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Appendix 3: Excel Macro Listings

NeutColFor = Cells(50, NeutColumn).Value
Case Is = "DEPTH (FT)", "DEPT (FT)", "DEPT", "DEPTH", "DEPTH (M)", "DEPT (M)"
   DepColumn = i
Case Is = "RHOB", "RHOB (G/CM3)", "RHOB (G/CC)"
   DenColumn = i
Case Is = "ILD", "ILD (OHM.M)", "RACM", "RACM (OHM.M)"
   ResColumn = i
Case Is = "ILM", "ILM (OHM.M)", "RPCM", "RPCM (OHM.M)"
   ResXoColumn = i
Case Is = "CPOR (PU)", "CPOR (%)", "CPOR (M3/M3)", "CPOR"
   CporColumn = i
   CporColFor = Cells(50, CporColumn).Value
   End Select
   Next i
   If CporColumn = 0 Then
      Iter = False
   End If
   ' Find starts and ends of density and neutron columns
   NeutStartRow = FIRSTINCOLUMN(Cells(50, NeutColumn))
   NeutFinRow = LASTINCOLUMN(Cells(50, NeutColumn))
   DenStartRow = FIRSTINCOLUMN(Cells(50, DenColumn))
   DenFinRow = LASTINCOLUMN(Cells(50, DenColumn))
   ResStartRow = FIRSTINCOLUMN(Cells(50, ResCoIumn))
   ResFinRow = LASTINCOLUMN(Cells(50, ResCoIumn))
   ResXoStartRow = FIRSTINCOLUMN(Cells(50, ResXoColumn))
   ResXoFinRow = LASTINCOLUMN(Cells(50, ResXoColumn))
   If Not CporColumn = 0 Then
      CorStartRow = FIRSTINCOLUMN(Cells(50, CporColumn))
      CorFinRow = LASTINCOLUMN(Cells(50, CporColumn))
   End If
   ' Find starts and ends of columns and number of points for calculations.
   ' Must have the same number of points in the density and neutron columns,
   ' also for the resistivity column for Sw calculations.
   If NeutStartRow > DenStartRow Then
      StartRow = NeutStartRow
   Else
      StartRow = DenStartRow
   End If
   If NeutFinRow < DenFinRow Then
      FinRow = NeutFinRow
   Else
      FinRow = DenFinRow
   End If
Appendix 3: Excel Macro Listings

If StartRow > ResStartRow And StartRow > ResXoStartRow Then
    SwStartRow = ResStartRow
Else
    SwStartRow = StartRow
End If

If FinRow > ResFinRow And FinRow > ResXoFinRow Then
    SwFinRow = ResFinRow
Else
    SwFinRow = FinRow
End If

' Determine the format of the Neutron and Core data

NeutUnit = NUMFORM(NeutColumn, StartRow, FinRow)
If Not CporColumn = 0 Then
    CporUnit = NUMFORM(CporColumn, StartRow, FinRow)
End If

' Determine the number of calculation points

NumNeut = NeutFinRow - NeutStartRow + 1
NumDen = DenFinRow - DenStartRow + 1
NumRes = ResFinRow - ResStartRow + 1
NumResXo = ResXoFinRow - ResXoStartRow + 1

If NumNeut > NumDen Then
    NumCalcPoints = NumDen
Else
    NumCalcPoints = NumNeut
End If

If NumCalcPoints > NumRes And NumCalcPoints > NumResXo Then
    NumCalcSw = NumRes
Else
    NumCalcSw = NumCalcPoints
End If

' Porosity Calculations


2. Square root porosity using density porosity from 1. ((PHIn^2+PHId^2)/2)^1/2


' Water Saturation Calculations

A3-6
1. Use above porosity calculations assuming that $a=1, m=n=2$.

2. Formation water salinity is calculated from $R_w$ at reservoir temperature and pressure.

\[
\rho_{M} = \omega_{M} \times 0.12 \\
\text{Sal}_{\text{Mud}} = \text{Sal}_{\text{Mud}} / 1000000 \\
\text{Sal}_{\text{WatTemp}} = \left(\frac{3647.5}{(R_w - 0.0123)}\right)^{1.04712} / 1000000 \\
\text{WatTempRhoB} = 1 + 0.7 \times \text{Sal}_{\text{WatTemp}} \\
\text{ResPres} = \text{Depth} \times \left(\frac{\omega_{M}}{19.2725}\right) \\
\text{ResRw} = R_w \times \frac{(R_w + 6.77) / (\text{ResTemp} + 6.77)}{(\text{ResRw} + 6.77)} \\
\text{ResWatRhob} = \frac{(\text{ResPres} \times 0.0000024337) + (\text{Sal}_{\text{WatTemp}} \times 0.68)}{(0.0000006 \times \text{ResTemp}^2) - (0.000006 \times \text{ResTemp}) + 1.007} \\
\text{ResSal}_{\text{Wat}} = \frac{(\text{ResWatRhob} + (0.0000008 \times \text{ResTemp}^2) + (0.000006 \times \text{ResTemp}) - 1.007 - (\text{ResPres} \times 0.0000024337)) / 0.68}{\text{MaxCpor} = 0} \\
\text{Numcor} = 0 \\
\]

```
For j = 1 To NumCalcPoints
    If Dep_Unit = "(m)" Then
        Dep(j) = 3.28084 * Cells(j + StartRow - 1, DepColumn).Value
    Else
        Dep(j) = Cells(j + StartRow - 1, DepColumn).Value
    End If
    If Not CporColumn = 0 Then
        If Not IsEmpty(Cells(j + StartRow - 1, CporColumn)) Then
            If CporUnit = True Then
                Cpor(j) = Cells(j + StartRow - 1, CporColumn).Value / 100
            Else
                Cpor(j) = Cells(j + StartRow - 1, CporColumn).Value
            End If
            If Cpor(j) > MaxCpor Then
                MaxCpor = Cpor(j)
            End If
            Numcor = 1 + Numcor
        End If
    End If
    DenVal(j) = Cells(j + StartRow - 1, DenColumn).Value
    If NeutUnit = True Then
        NeutVal(j) = Cells(j + StartRow - 1, NeutColumn).Value / 100
    Else
        NeutVal(j) = Cells(j + StartRow - 1, NeutColumn).Value
    End If
    WPNeutVal(j) = NeutVal(j) * 100
    ResValXo(j) = Cells(j + SwStartRow - 1, ResXoColumn).Value
    DenPor(j) = (RhobSS - DenVal(j)) / RhobSS_W
    SqrtPor(j) = Sqr((NeutVal(j)^2 + DenPor(j)^2) / 2)
```

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Appendix 3: Excel Macro Listings

WPPor(j) = (WPCon + (WPNeut1 * WPNeutVal(j)) + (WPNeut2 * WPNeutVal(j)^2) -
(WPNeut3 * WPNeutVal(j)^3) + (WPDen1 * (100 * DenPor(j))) +
(WPDen2 * (100 * DenPor(j)^2)) -
(WPDen3 * (100 * DenPor(j)^3) / 100)) / 100

ArchieSwG = Sqr((ResRw / ResValG) * (1 / DenPor(j)^2))

NeutSwG = Sqr((ResRw / ResValG) * (1 / NeutValG^2))

SqrtArchieSwG = Sqr((ResRw / ResValG) * (1 / SqrtPorG^2))

WPArchieSwG = Sqr((ResRw / ResValG) * (1 / WPPorG^2))

GPPorG = (GPCon1 * DenPor(j)) * (RhubSS - (1 - ArchieSwG) * (GPCon2 + GPCon3 * Sal_Mud) - ArchieSwG) * (ResSal_wat)) / (RhubSS - (RhubM * (1 - ArchieSwG) + (ResWatRhub * ArchieSwG)) + (RhubH * ArchieSwG)))

GPPorQ = (GPCon1 * DenPor(j)) * (RhubSS - (1 - GPDenShG) * (GPCon2 + GPCon3 * Sal_Mud) - GPDenShG) * RhobH * (1.33 - 0.036 * RhobH + 0.2 * RhobH^2) - GPCon3 * ArchieSwG) / (RhubSS - (RhubM * (1 - GPDenShG) + ArchieSwG)) + (RhubH * ArchieSwG)))

GPPorG = (GPCon1 * DenPor(j)) * (RhubSS - (1 - GPDenShG) * (GPCon2 + GPCon3 * Sal_Mud) - GPDenShG) * RhobH -
(PGPorQ + (GPCon2 + GPCon3 * Sal_Mud) - GPDenShG) * RhobH -
((1.97 - 0.324 * RhobH + 1.8 * RhobH^2 - 0.4 * Sal_Mud) / (1 - 0.4 * Sal_Mud)) + GPNWatG)

GPPorQ = (GPCon1 * DenPor(j)) * (RhubSS - (1 - GPDenShG) * (GPCon2 + GPCon3 * Sal_Mud) - GPDenShG) * RhobH -
(PGPorQ + (GPCon2 + GPCon3 * Sal_Mud) - GPDenShG) * RhobH -
((1.97 - 0.324 * RhobH + 1.8 * RhobH^2 - 0.4 * Sal_Mud) / (1 - 0.4 * Sal_Mud)) + GPNWatG)

Next j

If Abs(GPPorG - GPNPorG) > 0.05 Then

GPDenShG = (1 / Sqr((RmI / ResValXo(j)) * (1 / GPPor(j)^2))) -
(GPArchieSwG) / Sqr((RmI / ResValXo(j)) * (1 / GPPor(j)^2)) - 1

GPPor(j) = (GPCon1 * DenPor(j)) * (RhubSS - (1 - GPDenShG) * (GPCon2 + GPCon3 * Sal_Mud) - GPDenShG) * RhobH -
(PGPorQ + (GPCon2 + GPCon3 * Sal_Mud) - GPDenShG) * RhobH -
((1.97 - 0.324 * RhobH + 1.8 * RhobH^2 - 0.4 * Sal_Mud) / (1 - 0.4 * Sal_Mud)) + GPNWatG)

GPPorQ = (GPCon1 * DenPor(j)) * (RhubSS - (1 - GPDenShG) * (GPCon2 + GPCon3 * Sal_Mud) - GPDenShG) * RhobH -
(PGPorQ + (GPCon2 + GPCon3 * Sal_Mud) - GPDenShG) * RhobH -
((1.97 - 0.324 * RhobH + 1.8 * RhobH^2 - 0.4 * Sal_Mud) / (1 - 0.4 * Sal_Mud)) + GPNWatG)

End If

Write calculations to Porosity worksheet

Sheets(ps).Select

Cells(1, 1) = "Depth"
If Not CporColumn = 0 Then

Cells(1, 2) = "Core Porosity"

End If

Cells(1, 3) = "Density Porosity"
Cells(1, 4) = "Neutron Porosity"
Cells(1, 5) = "Square Root Porosity"
| Cells (l, 6) | "Wiley&Prachett Porosity" |
| Cells (l, 7) | "Gaymard&Poupon Density Porosity" |
| Cells (l, 8) | "Gaymard&Poupon Neutron Porosity" |
| Cells (l, 10) | "Density Sw" |
| Cells (l, 11) | "Neutron Sw" |
| Cells (l, 12) | "Square Root Sw" |
| Cells (l, 13) | "Wiley&Prachett Sw" |
| Cells (l, 14) | "Gaymard&Poupon Density Sw" |
| Cells (l, 15) | "Gaymard&Poupon Neutron Sw" |

```vbnet
For k = 1 To NumCalcPoints
    If Dep_Unit = "(m)" Then
        Cells(l + k, 1) = Dep(k) / 3.28084
    Else
        Cells(l + k, 1) = Dep(k)
    End If
    If Not CporColumn = 0 Then
        Cells(l + k, 2) = Cpor(k)
    End If
    Cells(l + k, 3) = DenPor(k)
End For
```
Cells(l + k, 4) = NeutVal(k)
Cells(l + k, 5) = SqrtPor(k)
Cells(l + k, 6) = WPPor(k)
Cells(l + k, 7) = GPPor(k)
Cells(l + k, 8) = GPNPor(k)
Cells(l + k, 10) = ArchieSw(k)
Cells(l + k, 11) = NeutSw(k)
Cells(l + k, 12) = SqrtArchieSw(k)
Cells(l + k, 13) = WPArchieSw(k)
Cells(l + k, 14) = GPArchieSw(k)
Cells(l + k, 15) = GPNSw(k)

Next k

Range(Cells(2, 1), Cells(FinRow, 15)).NumberFormat = "0.000"

If Iter = True Then
Call Iterative(Dep, Cpor, DenVal, NeutVal, WPNeutVal, ResVal, ResValXo, ResRw, _
GPDenSh, GPNeutSh, RhobSS, SalMud, ResSal_wat, RhobM, ResWatRhob, NumCalcPoints, _
StartRow, FinRow, Namelndex)
End If

' Calculate mean, standard deviation, correlation coefficients and Student T-tests

If Stat = True Then
If CporColumn = 0 Then
    Set dr = Range(Cells(StartRow, 3), Cells(FinRow, 9))
    histstop = Application.WorksheetFunction.Max(dr)
Else
    histstop = MaxCpor
End If
histstop = 5 * (Int(histstop / 0.05) + 1)
If histstop >= 100 Then
    histstop = 100
End If
Sheets(ps).Select
SourceDataSheet = ps
st = 16
sta = 17
stb = 18
stc = 25
std = 26

Cells(1, sta) = "t-Tests assumes unequal variances for equal means at 0.05 significance"
Cells(5, sta).ColumnWidth = 20
If CporColumn = 0 Then
    startcol = 3
    Set ColDatal = Range(Cells(2, startcol), Cells(NumCalcPoints + 1, startcol))
    n1 = Application.WorksheetFunction.count(ColDatal)
    Numcor = n1
Else
    startcol = 2

10

A3-10
End If

cumul = 0

For c = 0 To histstop
  If SourceDataSheet = ips Then
    Cells(c + 20, 35) = c * 0.01
  ElseIf SourceDataSheet = ps Then
    Cells(c + 20, 27) = c * 0.01
  End If
Next c

ran = Chr(64 + startcol) & StartRow & "." & Chr(64 + startcol) & FinRow

dan = Chr(66) & Chr(66) & 19

If SourceDataSheet = ips Then
  ban = Chr(65) & Chr(64 + std - 26) & 20 & "." & Chr(65) & Chr(64 + std - 26) & (20 + histstop)
ElseIf SourceDataSheet = ps Then
  ban = Chr(65) & Chr(65) & 20 & "." & Chr(65) & Chr(65) & (20 + histstop)
End If

Application.Run "ATPVBAEN.XLA!Histogram", ActiveSheet.Range(ran), 
, ActiveSheet.Range(dan), ActiveSheet.Range(ban), False, False 
, False, False

For c = 0 To histstop
  If SourceDataSheet = ips Then
    cumul = cumul + Cells(c + 20, 55) / Numcor
    Cells(c + 20, std + 1) = cumul
  ElseIf SourceDataSheet = ps Then
    cumul = cumul + Cells(c + 20, 55) / Numcor
    If CporColumn = 0 Then
      Cells(c + 20, std + 3) = cumul
    Else
      Cells(c + 20, std + 2) = cumul
    End If
  End If
Next c

With Range(Cells(19, 54), Cells((21 + histstop), 55))
  .ClearContents
  .Borders(xlEdgeTop).LineStyle = xlNone
  .Borders(xlEdgeBottom).LineStyle = xlNone
  .Borders(xlInsideHorizontal).LineStyle = xlNone
End With

For m = startcol To 7
  Set ColData1 = Range(Cells(2, m), Cells(NumCalcPoints + 1, m))
  Mean1 = Application.WorksheetFunction.Average(ColData1)
  SD1 = Application.WorksheetFunction.STDEV(ColData1)
  n1 = Application.WorksheetFunction.count(ColData1)
  If m = startcol Then
    histnum = True
  Else
    histnum = False
  End If
  a = 9 * (m - 2)
  Cells(2 + a, stb) = Cells(1, m)
Appendix 3: Excel Macro Listings

Cells(m, std) = Cells(1, m)
Cells(1, std + m) = Cells(1, m)
Cells(m + 1, std) = Cells(1, m + 1)
Cells(1, std + m) = Cells(1, m + 1)
Cells(3 + a, stc) = Mean1
Cells(4 + a, stc) = SD1
Cells(3 + a, sta) = "Mean"
Cells(4 + a, sta) = "Standard Deviation"
Cells(5 + a, sta) = "Correlation Coefficient"
Cells(6 + a, sta) = "t Stat"
Cells(7 + a, sta) = "Critical t Stat"
Cells(8 + a, sta) = "Probability in tail"
Cells(9 + a, sta) = "Comparison"
For l = m + 1 To 8
   If m = startcol Then
      dan = Chr(66) & Chr(66) & 19
      ran = Chr(64 + 1) & StartRow & ':' & Chr(64 + 1) & FinRow
   End If
   Set ColData2 = Range(Cells(StartRow, 1), Cells(FinRow, 1))
   Call TtestStat(ColData1, ColData2, Mean1, SD1, n1, n2, Mean2, SD2, Correlation, Critical, Prob, test, comp, histnum, 1, ran, dan, ban)
   s = st + 1
   Cells(2 + a, s) = Cells(1, l)
   Cells(3 + a, s) = Mean2
   Cells(4 + a, s) = SD2
   Cells(5 + a, s) = Correlation
   Cells(6 + a, s) = test
   Cells(7 + a, s) = Critical
   Cells(8 + a, s) = Prob
   Cells(9 + a, s) = comp
   Cells(m, s + 9) = comp
   cumul = 0
   If m = startcol Then
      For c = 0 To histstop
         cumul = cumul + Cells(c + 20, 55) / n2
      Cells(c + 20, s + 10) = cumul
      Next c
   End If
   With Range(Cells(19, 54), Cells((21 + histstop), 55))
      .ClearContents
      .Borders(xlEdgeTop).LineStyle = xlNone
      .Borders(xlEdgeBottom).LineStyle = xlNone
      .Borders(xlInsideHorizontal).LineStyle = xlNone
   End With
Next l
Next m
If Iter = True Then
   If Iter = True And Stat = True Then
      ItStat = True
   Else
A3-12
ItStat = False
End If
ItPlot = True
Iter = False
Sheets(ips).Select
SourceDataSheet = ips
st = 24
sta = 25
stb = 26
stc = 34
std = 35
GoTo 10
End If
End If

Application.ScreenUpdating = False
Application.DisplayStatusBar = False

With Sheets(ips)
.Cells(19, 27) = "Porosity"
.Cells(19, 28) = "Core Porosity"
.Cells(19, 29) = "Density Porosity"
.Cells(19, 30) = "Neutron Porosity"
.Cells(19, 31) = "Square Root Porosity"
.Cells(19, 32) = "Wiley & Pratchett Porosity"
.Cells(19, 33) = "Gaymard & Poupon Density Porosity"
.Cells(19, 34) = "Gaymard & Poupon Neutron Porosity"
End With

If CporColumn = 0 Then
Range(Cells(19, 27), Cells((21 + histstop), 27)).Cut
.Cells(19, 28).Select
ActiveSheet.Paste
End If

If ItStat = True Then
With Sheets(ips)
.Cells(19, 35) = "Porosity"
.Cells(19, 36) = "Core Porosity"
.Cells(19, 37) = "Density Porosity"
.Cells(19, 38) = "Neutron Porosity"
.Cells(19, 39) = "Square Root Porosity"
.Cells(19, 40) = "Wiley & Pratchett Porosity"
.Cells(19, 41) = "Gaymard & Poupon Density Porosity"
.Cells(19, 42) = "Gaymard & Poupon Neutron Porosity"
.Range(Cells(19, 27), Cells(19, 34)).ClearContents
End With
End If

If Plot = True Then
Appendix 3: Excel Macro Listings

Call PlotGraph(ws, ps, ips, ItPlot, StartRow, FinRow, MaxCpor, NameIndex)

End If

Erase Cpor

' Turn on screen updating to view the mess

Application.ScreenUpdating = True
Application.DisplayStatusBar = True

' Work out time taken for job.

Finish = Timer
mins = Int((Finish - Start) / 60)
secs = Format((Finish - Start - mins * 60), "##0.0#")
msg = "Finished! Processing took " & mins & " minutes and " & secs & " seconds."
MsgBox (msg)

End Sub

Function NUMFORM(TestCol, StartRow, FinRow As Integer)
    Dim z%, num%, bill$, ben$
    Dim fraction, fsum As Integer
    Application.Volatile
    num = StartRow
    For z = 1 To 10
        If Not IsEmpty(Cells(num, TestCol)) Then
            bill = Format(Cells(num, TestCol), "Scientific")
        Else
            num = num + 1
            GoTo 22
        End If
        ben = Right(bill, 3)
        If Left(ben, 1) = Then
            fraction = 0
        ElseIf Left(ben, 1) = "+" And Left(Right(bill, 8), 4) = "1.00" Or Left(Right(bill, 8), 4) = "0.00" Then
            fraction = 0
        Else
            fraction = 1
        End If
        fsum = fsum + fraction
        num = num + 5
    Next
    If fsum = 0 Then
        NUMFORM = False ' 0 to 1
    End If
End Function
Else
    NUMFORM = True ' 0 to 100
End If
End Function

' Function from John Walker at http://www.j-walk.com/ss/excel/index.htm
' The function returns the last filled cell row number in a given column.
' This probably the best Excel VBA web site.

Function LASTINCOLUMN(mgInput As Range)
    Dim WorkRange As Range
    Dim i As Integer, CellCount As Integer
    Application.Volatile
    Set WorkRange = mgInput.Columns(1).EntireColumn
    Set WorkRange = Intersect(WorkRange.Parent.UsedRange, WorkRange)
    CellCount = WorkRange.count
    For i = CellCount To 1 Step -1
        If Not IsEmpty(WorkRange(i)) Then
            LASTINCOLUMN = i
            Exit Function
        End If
    Next i
End Function

' Function from adapted John Walker at http://www.j-walk.com/ss/excel/index.htm
' The function returns the first filled cell row number in a given column, ignoring the header.

Function FIRSTINCOLUMN(mgInput As Range)
    Dim WorkRange As Range
    Dim i As Integer, CellCount As Integer
    Application.Volatile
    Set WorkRange = mgInput.Columns(1).EntireColumn
    Set WorkRange = Intersect(WorkRange.Parent.UsedRange, WorkRange)
    CellCount = WorkRange.count
    For i = 2 To CellCount
        If Not IsEmpty(WorkRange(i)) Then
            FIRSTINCOLUMN = i
            Exit Function
        End If
    Next i
End Function
Appendix 3: Excel Macro Listings

Sub TtestStat(ColDatal, ColData2, Mean1, SD1, n1, n2, Mean2, SD2, _
Correlation, Critical, Prob, test, comp, histnum, l, ran, dan, ban)
Dim SDDiff!, dffi, df%
Const HypDiff% = 0
Mean2 = Application. WorksheetFunction.Average(ColData2)
SD2 = Application. WorksheetFunction.STDEV(ColData2)
n2 = Application. WorksheetFunction.count(ColData2)
Correlation = Application. WorksheetFunction.Corr(ColDatal, ColData2)
SDDiff = (SD1 ^ 2 / n1) + (SD2 ^ 2 / n2)
dff = ((SDDiff ^ 2) / ((((SD1 ^ 2 / n1) ^ 2 / (n1 - 1)) + ((SD2 ^ 2 / n2) ^ 2 / (n2 - 1)))))
If dff >= (Int(dff) + 0.5) Then
  df = Int(dff) + 1
Else
  df = Int(dff)
End If
Prob = Application. WorksheetFunction.TTest(ColDatal, ColData2, 1, 3)
test = (Mean1 - Mean2 - HypDiff) / Sqr(SDDiff)
Critical = Application. WorksheetFunction.TInv(0.1, df)
If Abs(test) > Critical Then
  comp = "Reject"
Else
  comp = "Accept"
End If
If histnum = True Then
  Application. Run "ATPVBAXL!Histogram", ActiveSheet.Range(ran) _
  , ActiveSheet.Range(dan), ActiveSheet.Range(ban), False, False _
  , False, False
End If
End Sub

 Iterative Porosity Calculations using Solver
Appendix 3: Excel Macro Listings

1. Simple Density assuming sandstone matrix and fluid filled pores with unknown density.
2. Square root porosity using density porosity and neutron porosity and adding hydrocarbon correction when necessary. \(((PHInA^2+PHIdA^2)/2)^{1/2}\)

Water Saturation Calculations

1. Use above porosity calculations assuming that \(a=1, m=n=2\).


Dim changeS, result$, zero$
Dim sqerror As Boolean
Dim b%, y%

' Insert a sheet for the calculations
Sheets.Add
ActiveSheet.Name = "Iterative Porosity"
ips = Sheets("Iterative Porosity").Name

' Set up cells for changing by Solver
Cells(5, 10).Name = "RhobFluid"
Cells(2, 10).Name = "DAve"
Cells(3, 10).Name = "DStD"
Cells(10, 10).Name = "Excavation"
Cells(8, 10).Name = "NAve"
Cells(9, 10).Name = "NSrD"
Cells(15, 10).Name = "AA"
Cells(16, 10).Name = "MM"
Cells(13, 10).Name = "SqAve"
Cells(14, 10).Name = "SqStD"
Cells(20, 10).Name = "IWPCon"
Cells(21, 10).Name = "IWPNeut1"
Cells(22, 10).Name = "IWPNeut2"
Cells(23, 10).Name = "IWPNeut3"
Cells(24, 10).Name = "IWPDen1"
Cells(25, 10).Name = "IWPDen2"
Cells(26, 10).Name = "IWPDen3"
Cells(18, 10).Name = "WPAve"
Cells(19, 10).Name = "WPStD"
Cells(31, 10).Name = "RhobHD"
Cells(29, 10).Name = "GPDAve"
Cells(30, 10).Name = "GPDSrD"
Cells(36, 10).Name = "RhobHN"
Cells(34, 10).Name = "GPNAve"
Appendix 3: Excel Macro Listings

Cells(35, 10).Name = "GPNSID"

' Initialise the cells for Solver

Range("RhobFluid") = 1
Range("AA") = 2
Range("MM") = 2
Range("Excavation") = 0.04
Range("IWPCon") = 1.916
Range("IWPNeut1") = 0.4253
Range("IWPNeut2") = 0.001828
Range("IWPNeut3") = 0.00001885
Range("IWPDen1") = 0.4903
Range("IWPDen2") = 0.003882
Range("IWPDen3") = 0.004397
Range("RhobHD") = 1
Range("RhobHN") = 1

' Insert the porosity formulae onto the sheet

Cells(StartRow, 1) = "=" & "Porosity'IA" & StartRow & "+ Excavation"
Cells(StartRow, 3) = "+(RhobSS - RhobFluid)"
Cells(StartRow, 11) = "=" & "Porosity'IA" & StartRow & "+ Excavation"
Cells(StartRow, 12) = "=" & "Porosity'IA" & StartRow & "+ Excavation"
Cells(StartRow, 13) = "=" & "Porosity'IA" & StartRow & "+ Excavation"
Cells(StartRow, 14) = "=" & "Porosity'IA" & StartRow & "+ Excavation"
Cells(StartRow, 15) = "=" & "Porosity'IA" & StartRow & "+ Excavation"
Cells(StartRow, 16) = "=" & "Porosity'IA" & StartRow & "+ Excavation"
Cells(StartRow, 17) = "=" & "Porosity'IA" & StartRow & "+ Excavation"
Cells(StartRow, 18) = "=" & "Porosity'IA" & StartRow & "+ Excavation"
Cells(StartRow, 19) = "=" & "Porosity'IA" & StartRow & "+ Excavation"
Cells(StartRow, 20) = "=" & "Porosity'IA" & StartRow & "+ Excavation"
Cells(StartRow, 21) = "=" & "Porosity'IA" & StartRow & "+ Excavation"
Cells(StartRow, 22) = "=" & "Porosity'IA" & StartRow & "+ Excavation"
Cells(StartRow, 23) = "=" & "Porosity'IA" & StartRow & "+ Excavation"
Cells(StartRow, 24) = "=" & "Porosity'IA" & StartRow & "+ Excavation"
Cells(StartRow, 25) = "=" & "Porosity'IA" & StartRow & "+ Excavation"
Cells(StartRow, 26) = "=" & "Porosity'IA" & StartRow & "+ Excavation"
Cells(StartRow, 27) = "=" & "Porosity'IA" & StartRow & "+ Excavation"
Cells(StartRow, 28) = "=" & "Porosity'IA" & StartRow & "+ Excavation"
Cells(StartRow, 29) = "=" & "Porosity'IA" & StartRow & "+ Excavation"
Cells(StartRow, 30) = "=" & "Porosity'IA" & StartRow & "+ Excavation"
Cells(StartRow, 31) = "=" & "Porosity'IA" & StartRow & "+ Excavation"
Cells(StartRow, 32) = "=" & "Porosity'IA" & StartRow & "+ Excavation"
Cells(StartRow, 33) = "=" & "Porosity'IA" & StartRow & "+ Excavation"
Cells(StartRow, 34) = "=" & "Porosity'IA" & StartRow & "+ Excavation"
Cells(StartRow, 35) = "=" & "Porosity'IA" & StartRow & "+ Excavation"

A3-18
& "Porosity'!C" & StartRow & "2))") & "=" & Chr(64 + ResXoColumn) & StartRow _ & "Porosity'!C" & StartRow & "2))") & "=" & ResWatRrob & "*K" & StartRow & ")")"

Cells(StartRow, 15) = "=" & SQRT((" & ResRw & _ & ws & & Chr(64 + ResColumn)) & StartRow _ & ")*(1/G" & StartRow & ")")"

Cells(StartRow, 8) = "=" & Porosity"ID" & StartRow _ & "=" & Porosity"ID" & StartRow _ & "=" & SQRT(" & RMF & _ & ws & & Chr(64 + ResXoColumn)) _ & "=" & StartRow & ")")"

Cells(StartRow, 16) = "=" & SQRT((" & ResRw & _ & ws & & Chr(64 + ResColumn)) & StartRow _ & ")*(1/H" & StartRow & ")")"

Range(Cells(StartRow, 1), Cells(FinRow, 8)).Select
Selection.FillDown
Range(Cells(StartRow, 11), Cells(FinRow, 16)).Select
Selection.FillDown

For j = StartRow To FinRow
If Not IsEmpty(Cpor(j - 1)) Then
Cells(j, 2) = "=" & Porosity"IB" & j
Cells(j, 18) = "=" & (C & j & ")")"
Cells(j, 19) = "=" & (D & j & ")")"
Cells(j, 20) = "=" & (E & j & ")")"
Cells(j, 21) = "=" & (F & j & ")")"
Cells(j, 22) = "=" & (G & j & ")")"
Cells(j, 23) = "=" & (H & j & ")")"
End If
Next j

' Find average, standard deviation difference between calculated and core porosity
' Also write names to cells

NameIndex(16) = "IDepth"
NameIndex(17) = "ICPor"
NameIndex(18) = "IDPor"
NameIndex(19) = "INPor"
NameIndex(20) = "ISPor"
NameIndex(21) = "IWPPor"
NameIndex(22) = "IGPDPor"
NameIndex(23) = "IGNPor"
NameIndex(26) = "ISwDPor"
NameIndex(27) = "ISwNPor"
NameIndex(28) = "ISwSPor"
NameIndex(29) = "ISwWPPor"
NameIndex(30) = "ISwGPPor"
NameIndex(31) = "ISwGPPor"
<table>
<thead>
<tr>
<th>Cells(l, 1)</th>
<th>&quot;Depth&quot;</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cells(l, 2)</td>
<td>&quot;Core Porosity&quot;</td>
</tr>
<tr>
<td>Cells(l, 3)</td>
<td>&quot;Density Porosity&quot;</td>
</tr>
<tr>
<td>Cells(l, 4)</td>
<td>&quot;Neutron Porosity&quot;</td>
</tr>
<tr>
<td>Cells(l, 5)</td>
<td>&quot;Square Root Porosity&quot;</td>
</tr>
<tr>
<td>Cells(l, 6)</td>
<td>&quot;Wiley &amp; Pratchett Porosity&quot;</td>
</tr>
<tr>
<td>Cells(l, 7)</td>
<td>&quot;Gaymard &amp; Poupon Density Porosity&quot;</td>
</tr>
<tr>
<td>Cells(l, 8)</td>
<td>&quot;Gaymard &amp; Poupon Neutron Porosity&quot;</td>
</tr>
<tr>
<td>Cells(l, 11)</td>
<td>&quot;Sw Density Porosity&quot;</td>
</tr>
<tr>
<td>Cells(l, 12)</td>
<td>&quot;Sw Neutron Porosity&quot;</td>
</tr>
<tr>
<td>Cells(l, 13)</td>
<td>&quot;Sw Square Root Porosity&quot;</td>
</tr>
<tr>
<td>Cells(l, 14)</td>
<td>&quot;Sw Wiley &amp; Pratchett Porosity&quot;</td>
</tr>
<tr>
<td>Cells(l, 15)</td>
<td>&quot;Sw Gaymard &amp; Poupon Density Porosity&quot;</td>
</tr>
<tr>
<td>Cells(l, 16)</td>
<td>&quot;Sw Gaymard &amp; Poupon Neutron Porosity&quot;</td>
</tr>
<tr>
<td>Cells(l, 18)</td>
<td>&quot;Density - Core Porosity&quot;</td>
</tr>
<tr>
<td>Cells(l, 19)</td>
<td>&quot;Neutron - Core Porosity&quot;</td>
</tr>
<tr>
<td>Cells(l, 20)</td>
<td>&quot;Square Root - Core Porosity&quot;</td>
</tr>
<tr>
<td>Cells(l, 21)</td>
<td>&quot;Wiley &amp; Pratchett - Core Porosity&quot;</td>
</tr>
<tr>
<td>Cells(l, 22)</td>
<td>&quot;Gaymard &amp; Poupon Density - Core Porosity&quot;</td>
</tr>
<tr>
<td>Cells(l, 23)</td>
<td>&quot;Gaymard &amp; Poupon Neutron - Core Porosity&quot;</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Cells(2, 9)</th>
<th>&quot;Density - Core Porosity Average&quot;</th>
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</thead>
<tbody>
<tr>
<td>Cells(3, 9)</td>
<td>&quot;Density - Core Porosity Standard Deviation&quot;</td>
</tr>
<tr>
<td>Cells(5, 9)</td>
<td>&quot;Rhob Fluid&quot;</td>
</tr>
<tr>
<td>Cells(2, 10)</td>
<td>&quot;=AVERAGE(R &amp; StartRow &amp; &quot;:R &amp; FinRow &amp; &quot;)&quot;</td>
</tr>
<tr>
<td>Cells(3, 10)</td>
<td>&quot;=STDEV(R &amp; StartRow &amp; &quot;:R &amp; FinRow &amp; &quot;)&quot;</td>
</tr>
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<table>
<thead>
<tr>
<th>Cells(8, 9)</th>
<th>&quot;Neutron - Core Porosity Average&quot;</th>
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</thead>
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<tr>
<td>Cells(9, 9)</td>
<td>&quot;Neutron - Core Porosity Standard Deviation&quot;</td>
</tr>
<tr>
<td>Cells(10, 9)</td>
<td>&quot;Excavation&quot;</td>
</tr>
<tr>
<td>Cells(8, 10)</td>
<td>&quot;=AVERAGE(S &amp; StartRow &amp; &quot;:S &amp; FinRow &amp; &quot;)&quot;</td>
</tr>
<tr>
<td>Cells(9, 10)</td>
<td>&quot;=STDEV(S &amp; StartRow &amp; &quot;:S &amp; FinRow &amp; &quot;)&quot;</td>
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</tbody>
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<table>
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<tr>
<th>Cells(13, 9)</th>
<th>&quot;Square Root - Core Porosity Average&quot;</th>
</tr>
</thead>
<tbody>
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<td>Cells(14, 9)</td>
<td>&quot;Square Root - Core Porosity Standard Deviation&quot;</td>
</tr>
<tr>
<td>Cells(15, 9)</td>
<td>&quot;Neutron Exponent&quot;</td>
</tr>
<tr>
<td>Cells(16, 9)</td>
<td>&quot;Density Exponent&quot;</td>
</tr>
<tr>
<td>Cells(13, 10)</td>
<td>&quot;=AVERAGE(T &amp; StartRow &amp; &quot;:T &amp; FinRow &amp; &quot;)&quot;</td>
</tr>
<tr>
<td>Cells(14, 10)</td>
<td>&quot;=STDEV(T &amp; StartRow &amp; &quot;:T &amp; FinRow &amp; &quot;)&quot;</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Cells(18, 9)</th>
<th>&quot;Wiley &amp; Pratchett - Core Porosity Average&quot;</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cells(19, 9)</td>
<td>&quot;Wiley &amp; Pratchett - Core Porosity Standard Deviation&quot;</td>
</tr>
<tr>
<td>Cells(20, 9)</td>
<td>&quot;Constant&quot;</td>
</tr>
<tr>
<td>Cells(21, 9)</td>
<td>&quot;Neutron1 Constant&quot;</td>
</tr>
<tr>
<td>Cells(22, 9)</td>
<td>&quot;Neutron2 Constant&quot;</td>
</tr>
<tr>
<td>Cells(23, 9)</td>
<td>&quot;Neutron3 Constant&quot;</td>
</tr>
<tr>
<td>Cells(24, 9)</td>
<td>&quot;Density1 Constant&quot;</td>
</tr>
</tbody>
</table>

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Cells(25, 9) = "Density2 Constant"
Cells(26, 9) = "Density3 Constant"
Cells(18, 10) = "=AVERAGE(U" & StartRow & ":U" & FinRow & ")"
Cells(19, 10) = "=STDEV(U" & StartRow & ":U" & FinRow & ")"

Cells(29, 9) = "Gaymard & Poupon Density - Core Porosity Average"
Cells(30, 9) = "Gaymard & Poupon Density - Core Porosity Standard Deviation"
Cells(31, 9) = "Hydrocarbon Density"
Cells(29, 10) = "=AVERAGE(V" & StartRow & ":V" & FinRow & ")"
Cells(30, 10) = "=STDEV(V" & StartRow & ":V" & FinRow & ")"

Cells(34, 9) = "Gaymard & Poupon Neutron - Core Porosity Average"
Cells(35, 9) = "Gaymard & Poupon Neutron - Core Porosity Standard Deviation"
Cells(36, 9) = "Hydrocarbon Density"
Cells(34, 10) = "=AVERAGE(W" & StartRow & ":W" & FinRow & ")"
Cells(35, 10) = "=STDEV(W" & StartRow & ":W" & FinRow & ")"

' Pass cell references for iteration to Solver to minimise standard deviation on
' condition that the difference with is = 0.

For k = 1 To 6
  If k = 1 Then
    zero = "DAve"
    change = "RhobFluid"
    result = "DStD"
    Call PorSolver(result, change, zero)
  ElseIf k = 2 Then
    zero = "NAve"
    change = "Excavation"
    result = "NSidD"
    Call PorSolver(result, change, zero)
  ElseIf k = 3 Then
    zero = "SqAve"
    change = "AA, MM"
    result = "SqStD"
    Call PorSolver(result, change, zero)
  For j = 1 To NumCalcPoints
    b = j + 1
    sqerror = Application.WorksheetFunction.IsError(Cells(b, 4))
    If sqerror = True Then
      Cells(b, 4) = 0
    Cells(b, 10) = 0
  End If
  Next j
  ElseIf k = 4 Then
    zero = "WP Ave"
    change = "IWPNeut1, IWPNeut2, IWPNeut3, IWPDen1, IWPDen2, IWPDen3"
    result = "WPStD"
    Call PorSolver(result, change, zero)
  ElseIf k = 5 Then

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Appendix 3: Excel Macro Listings

zero = "GPDAve"
change = "RhopHD"
result = "GPDSID"

Call PorSolver(result, change, zero)

ElseIf k = 6 Then
    zero = "GPNAve"
    change = "RhopHN"
    result = "GPNSID"
    Call PorSolver(result, change, zero)
End If

Next k

Range(Cells(2, 1), Cells(FinRow, 18)).NumberFormat = "0.000"

For y = 2 To NumCalcPoints + 1
    If IsNumeric(Cells(y, 5)) = False Then
        Cells(y, 5) = 0
        Cells(y, 13) = 0
    End If
    Next y

End Sub

Sub PorSolver(result, change, zero)
    SolverReset
    SolverOptions precision:=0.0001
    SolverOk SetCell:=Range(result), MaxMinVal:=2, ByChange:=Range(change)
    SolverAdd cellRef:=Range(zero), relation:=2, formulaText:=0
    SolverSolve userFinish:=True
    SolverFinish keepFinal:=1
End Sub

Sub PlotGraph(ws, ps, ips, ItPlot, StartRow, FinRow, MaxCpor, NameIndex)
    Dim NumCols%, XVarIndex%, r1$
    Dim q%, t%, v2!, v4!, ct%
    Dim v1, v3, PlotVarIndex(100) As Integer

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Appendix 3: Excel Macro Listings

Dim drr, drr, r2 As Range
Dim XT$1, XT$, YT$, YT$, Title$, Title$R%  
SourceDataSheet = ps
Sheets(ps).Select
For k = 1 To 2
    If k = 1 Then
        m = 1
        s = 7
        NumCols = 8
        If SourceDataSheet = ips Then
            YTit = "Iteratively Calculated Porosity"
            YT$N = "Iter Calc Por"
        Else
            YTit = "Calculated Porosity"
            YT$N = "Calc Por"
        End If
    ElseIf k = 2 Then
        NumCols = 7
        If SourceDataSheet = ips Then
            YTit = "Iteratively Calculated Sw"
            YT$N = "Iter Calc Sw"
            m = 10
            s = 15
        Else
            YTit = "Calculated Sw"
            YT$N = "Calc Sw"
            m = 10
            s = 14
        End If
    End If
End If
For i = m To s
    If i = 2 And CporColumn = 0 Then GoTo 11
    Sheets(SourceDataSheet).Select
    XT$ = Sheets(SourceDataSheet).Cells(1, i).Text
    q = i + 1
    XVarlndex = i
    If SourceDataSheet = ips And i = 10 Then
        drr = Range(Cells(StartRow, 1), Cells(FinRow, 1))
        v3 = Application.WorksheetFunction.Min(drr)
        v$4 = Application.WorksheetFunction.Max(drr)
        ct = xlXYScatterLinesNoMarkers
    ElseIf i = 1 Or i = 10 Then
        Set drr = Range(Cells(StartRow, 1), Cells(FinRow, 1))
        v3 = Application.WorksheetFunction.Min(drr)
        v$4 = Application.WorksheetFunction.Max(drr)
        ct = xlXYScatterLinesNoMarkers
    Else
        Set drr = Range(Cells(StartRow, 1), Cells(FinRow, 1))
        v3 = Application.WorksheetFunction.Min(drr)
        v$4 = Application.WorksheetFunction.Max(drr)
        ct = xlXYScatterLinesNoMarkers
    End If
    GoTo 11
v3 = 0
ct = xlXYScatter
If i = 2 Then
v4 = MaxCpor
Else
Set drr = Range(Cells(StartRow, i), Cells(FinRow, i))
v4 = Application.WorksheetFunction.Max(drr)
End If
v4 = 0.05 * (Int(v4 / 0.05) + 1)
If v4 >= 1 Then
v4 = 1
End If
End If
If SourceDataSheet = ips And i = 10 Then
XVarlndex = 1
ElseIf i = 10 Then
XVarlndex = 1
Else
XVarlndex = i
End If
For j = i + 1 To s + 1
PlotVarIndex(j) = j
Next
v1 = 0
Set r2 = Range(Cells(StartRow, q), Cells(FinRow, t))
If q = 2 Then
v2 = Application.WorksheetFunction.Max(Range(Cells(StartRow, q + 1), Cells(FinRow, t)))
If v2 < MaxCpor Then
v2 = MaxCpor
End If
Else
v2 = Application.WorksheetFunction.Max(r2)
End If
v2 = 0.05 * (Int(v2 / 0.05) + 1)
If v2 >= 1 Then
v2 = 1
End If
If v2 <= 1 And v4 <= 1 Then
If v2 >= v4 Then
v4 = v2
Else
v2 = v4
End If
End If
End If
If k = 1 Then
If i = 1 And CporColumn = 0 Then
r1 = Chr(64 + XVarlndex) & "1:" & Chr(64 + XVarlndex) & FinRow & "," & Chr(64 + m + 2) & "1:" & Chr(64 + s + 1) & FinRow
Else
r1 = Chr(64 + XVarlndex) & ",1:" & Chr(64 + PlotVarIndex(NumCols)) & FinRow
End If
End If
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Appendix 3: Excel Macro Listings

End If
ElseIf k = 2 Then
    If i = 10 Then
        If XVarlndex = 1 Then
            rl = Chr(64 + XVarlndex) & "1:" & Chr(64 + XVarlndex) & FinRow & "," & Chr(64 + m) & "," & Chr(64 + s + 1) & 
        FinRow
    Else
        rl = Chr(64 + XVarlndex) & "1:" & Chr(64 + PlotVarIndex(s + 1)) & FinRow
    End If
    ElseIf i > 10 Then
        rl = Chr(64 + XVarlndex) & "1:" & Chr(64 + PlotVarIndex(s + 1)) & FinRow
    End If
ElseIf SourceDataSheet = ips And XVarlndex = 1 Then
    rl = Chr(64 + XVarlndex) & "1:" & Chr(64 + XVarlndex) & FinRow & "," & Chr(64 + m + 1) & "1:" & Chr(64 + s + 1) & 
    FinRow
End If
ElseIf XVarlndex = 1 Then
    XTit = Sheets(SourceDataSheet).Cells(l, l).Text
    XTitN = NameIndex(1)
ElseIf XVarlndex = 10 Then
    XTit = Sheets(SourceDataSheet).Cells(l, 10).Text
    XTitN = NameIndex(10)
ElseIf SourceDataSheet = ips And XVarlndex = 10 Then
    XTit = Sheets(SourceDataSheet).Cells(l, 10).Text
    XTitN = NameIndex(10)
Else
    XTit = Sheets(SourceDataSheet).Cells(l, i).Text
    If SourceDataSheet = ips Then
        XTitN = NameIndex(15 + i)
    Else
        XTitN = NameIndex(i)
    End If
End If
End If

Title = XTit & "v." & YTit
TitleN = XTitN & " v. " & YTitN
Call MakePlot(XVarIndex, SourceDataSheet, rl, v1, v2, v3, v4, ct, Title, TitleN, XTit, YTit)
If i = 10 Then
    If SourceDataSheet = ips Then GoTo 11
    If XVarlndex = 10 Then GoTo 11
    XVarlndex = 10
    q = i + 1
    Sheets(SourceDataSheet).Select
    v3 = 0
    ct = xlXYScatter
    Set drr = Range(Cells(StartRow, i), Cells(FinRow, i))
    v4 = Application.WorksheetFunction.Max(drr)
    v4 = 0.05 * (Int(v4 / 0.05) + 1)
    If v4 >= 1 Then
        v4 = 1

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End If
GoTo 9
End If
11 Next
Next

If ItPlot = True Then
SourceDataSheet = ips
ItPlot = False
ItPlot2 = True
GoTo 7
End If

' Cumulative Frequency Plots
'

If Stat = True Then
200  XTit = "Porosity"
  YTit = "Frequency"
  Title = "Cumulative Frequency Plot"
  If SourceDataSheet = ps Then
    Sheets(ps).Select
    Title = Title & " using assumed constants"
    TitleN = "Cum Freq Porosity Plot"
    If CporColumn = 0 Then
      rl = "AB19:AH" & (20 + histstop)
    Else
      rl = "AA19:AH" & (20 + histstop)
    End If
  Else
    Sheets(ips).Select
    Title = Title & " using constants calculated iteratively"
    TitleN = "Cum Freq Iter Por Plot"
    rl = "AI19:AP" & (20 + histstop)
  End If
End If

ct = xlXYScatterLines
v1 = 0
v2 = 1
v3 = 0
v4 = MaxCpor
v4 = 0.05 * (Int(v4 / 0.05) + 1)
If v4 >= 1 Then
  v4 = 1
End If
Call MakePlot(XVarIndex, SourceDataSheet, rl, v1, v2, v3, v4, ct, Title, TitleN, XTit, YTit)
If ItPlot2 = True Then
  SourceDataSheet = ps
  ItPlot2 = False
  GoTo 200
End If
End If

Appendix 3: Excel Macro Listings
Appendix 3: Excel Macro Listings

End Sub

Sub MakePlot(XVarIndex, SourceDataSheet, r1, v1, v2, v3, v4, ct, Title, TitleN, XTit, YTit)
    Dim U%, cou%, NewPlot%
    Dim OneLine As Range

    If Not ct = xlXYScatterLines Then
        NewPlot = 2 * XVarIndex
        Sheets(SourceDataSheet).Select
        Cells(10, 40 + NewPlot).Value = v1
        Cells(11, 40 + NewPlot).Value = v2
        Cells(10, 41 + NewPlot).Value = v3
        Cells(11, 41 + NewPlot).Value = v4
        Set OneLine = Sheets(SourceDataSheet).Range(Cells(10, 40 + NewPlot), Cells(11, 41 + NewPlot))
    End If

    Charts.Add
    With ActiveChart
        .ChartType = ct
        .SetSourceData Source:=Sheets(SourceDataSheet).Range(r1), PlotBy:=xlColumns
        .Location xlLocationAsNewSheet
        .HasLegend = True
        .HasTitle = True
        .ChartTitle.Text = wks & & Title
        .Name = TitleN
        With .PlotArea
            .Border.Weight = xlThin
            .Border.LineStyle = xlAutomatic
            .Interior.ColorIndex = xlNone
            .Width = Application.UsableWidth
            .HEIGHT = Application.UsableHeight
        End With
        With .Axes(xlValue)
            .MinimumScale = v1
            .MaximumScale = v2
            .MinorUnitlsAuto = True
            .MajorUnitlsAuto = True
            .Crosses = xlAutomatic
            .ReversePlotOrder = False
            .ScaleType = xlLinear
            .HasTitle = True
            .AxisTitle.Text = YTit
            .HasMajorGridlines = True
        End With
    End With
End Sub
With .Axes(xlCategory)
    .MinimumScale = v3
    .MaximumScale = v4
    .MinorUnitsAuto = True
    .MajorUnitsAuto = True
    .Crosses = xlAutomatic
    .ReversePlotOrder = False
    .ScaleType = xlLinear
    .HasTitle = True
    .AxisTitle.Text = XTit
    .HasMajorGridlines = True
End With
With .Legend
    .Left = 100
    .Top = 50
    .Width = 170
    .Font.Size = 8
    With .Border
        .Weight = xlHairline
        .LineStyle = xlNone
    End With
    .Shadow = False
    .Interior.ColorIndex = xlNone
End With
If .ChartType = xlXYScatter Then
    With .PageSetup
        .TopMargin = .LeftMargin
        .BottomMargin = .LeftMargin
        .RightMargin = Application.InchesToPoints(11.69 - 
        (.LeftMargin / 72 + (8.27 - 2 * (.LeftMargin / 72))))
    End With
    With .PlotArea
        .Top = 20
        .HEIGHT = 440
        .Width = .HEIGHT
    End With
    cou = .SeriesCollection.count
    For U = .SeriesCollection.count To 1 Step -1
        With .SeriesCollection(U)
            .MarkerStyle = xlX
            .MarkerBackgroundColorIndex = xlNone
            .MarkerSize = 5
            If cou - U = 0 Then
                .MarkerForegroundColorIndex = 10
            ElseIf cou - U = 2 Then
                .MarkerForegroundColorIndex = 13
            Else
                .MarkerForegroundColorIndex = cou - U
            End If
        End With
    End For
End If
End With
Appendix 3: Excel Macro Listings

Next
OneLine.Copy
.SeriesCollection.Paste Rowcol:=xlColumns, SeriesLabels:=False, 
CategoryLabels:=True, Replace:=False, NewSeries:=True
Application.CutCopyMode = False
With .SeriesCollection(cou + 1)
  .MarkerStyle = xlNone
  .Name = "***1 to 1 line***
  With .Border
    .ColorIndex = 1
    .Weight = xlHairline
    .LineStyle = xlContinuous
  End With
End With
End With
.ChartArea.Select
ActiveWindow.Zoom = 87
ElseIf .ChartType = xlXYScatterLines Then
With .PageSetup
  .TopMargin = .LeftMargin
  .BottomMargin = .LeftMargin
  .RightMargin = Application.InchesToPoints(11.69 - 
    ((.LeftMargin / 72 + (8.27 - 2 * (.LeftMargin / 72)))))
End With
With .PlotArea
  .Top = 30
  .HEIGHT = 440
  .Width = .HEIGHT
End With
cou = .SeriesCollection.count
For U = .SeriesCollection.count To 1 Step -1
With .SeriesCollection(U)
  .MarkerStyle = xlX
  .MarkerBackgroundColorIndex = xlNone
  .MarkerSize = 5
  If cou - U = 0 Then
    .MarkerForegroundColorIndex = 10
    .Border.ColorIndex = 10
  ElseIf cou - U = 2 Then
    .MarkerForegroundColorIndex = 13
    .Border.ColorIndex = 13
  Else
    .MarkerForegroundColorIndex = cou - U
    .Border.ColorIndex = cou - U
  End If
End With
Next
With .Legend
  .Left = 290
  .Top = 333
  .Font.Size = 8
Appendix 3: Excel Macro Listings

End With
  .ChartTitle.Font.Size = 10
  .Axes(xlValue).MajorUnit = 0.2
  .ChartArea.Select
ActiveWindow.Zoom = 87
ElseIf .ChartType = xlXYScatterLinesNoMarkers Then
  .ChartArea.Select
  ActiveWindow.Zoom = 94
  cou = .SeriesCollection.count
  For U = .SeriesCollection.count To 1 Step -1
    With .SeriesCollection(U)
      If cou - U = 6 Then
        .MarkerStyle = xlX
        .MarkerBackgroundColorIndex = xlNone
        .MarkerForegroundColorIndex = 9
        .MarkerSize = 5
        .Border.LineStyle = xlNone
      ElseIf cou - U = 2 Then
        .Border.ColorIndex = 13
      ElseIf cou - U = 0 Then
        .Border.ColorIndex = 10
      Else
        .Border.ColorIndex = cou - U
      End If
    End With
  Next
  With .ChartTitle
    .Orientation = xlUpward
    .Left = xlLeft
    .Top = 100
  End With
  With .PlotArea
    .Top = 0
    .HEIGHT = 430
    .Width = 670
    .Left = 55
  End With
  With .Axes(xlValue).TickLabels
    .NumberFormat = "0.0"
    .Orientation = xlUpward
  End With
  With .Axes(xlCategory).TickLabels
    .NumberFormat = "0"
    .Orientation = xlUpward
  End With
  With .Axes(xlCategory)
    .AxisTitle.Orientation = xlUpward
    .AxisTitle.Top = 670
  End With
  With .Legend

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Private Sub Worksheet_Config()
  .Left = 114
  .Top = 10
  .Font.Size = 8
  End With
End If
End With

End Sub

-------------------------------------------------- The End ---------------------------------
Bibliography


Bibliography


Bibliography


Samworth, R. (1998). Resistivity profiles in horizontal wells and the possibility of similar bedding effects on porosity tools.


Bibliography


