Ternary Rock Typing: A Novel Solution to Multi-Scale Multi-Discipline Rock Typing for Carbonate Rocks

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This thesis is dedicated to my father Nazih, a great man and a pioneer geoscientist. To my mother Shahira, and my dearest wife Dina for her endless love and support.
ABSTRACT

The static and dynamic characteristics of carbonate reservoirs are very challenging to sedimentologists, geologists, petrophysicists, and reservoir engineers. The multi-scale and multi-discipline nature of carbonate characterization complicates any global rock typing workflow that aims to satisfy all disciplines and datasets. The heterogeneity of pore space and pore network systems obscures the understanding of the interaction between rock, pore and fluid, and hence there is no simple relationship between pore type distribution and depositional environment for carbonate reservoirs. The challenge is to accurately assign the complex pore system properties to their sedimentological rock container for vertical and lateral predictability.

In this thesis, a novel Ternary Rock Typing (TRT) application and workflow combines depositional facies, wireline logs, routine core analysis, capillary pressure data and relative permeability curves from three parameters representing rock, pore and fluid interaction. The three parameters proposed are porosity, permeability and irreducible water saturation represented in the shape of a 3D ellipsoid. The complex interaction of rock, pore and fluid affect the location, shape, orientation and relative position of the three-parameter ellipsoid. The quality control of derived rock types by saturation height functions becomes an integral part of defining a Ternary Rock Type (TRT).

A Ternary Rock Typing (TRT) methodology using TRT software was developed as part of this thesis was tested against a synthetic data set. It was then tested on 1D and 3D domains using 6 cored wells from an actual carbonate field. The data included sedimentological core description, wireline logs, routine core analysis, and SCAL data. The utilization of TRT is subdivided into several applications: rock typing scheme, concept, workflow, plot and software. All of the previous applications can be adapted to work with TRT or accompanied by any of the other rock typing methods. The TRT proved to perform well in 1D and 3D static modelling environments where it proved to predict the oil in place for the limestone and dolostone of the highest storage and flow capacity rock types compared to the reference based model.
The TRT technique can be used as a raw unguided solely data driven approach (rTRT) or as a guided "sedimentologically" data driven approach (gTRT). The guided TRT (gTRT) uses seed points from the centre of ellipsoids representing "sedimentological facies" for the ternary rock typing algorithm to predict the likelihood for rock typing clusters and thus paves a link between sedimentological facies, wireline logs, RCA and SCAL data.

The TRT was also tested against two simulation models, the first of which is an active water drive and the second is an injector/producer scheme with no water drive. The TRT model also proved to accurately model barriers, baffles and flow units. Thus, it gave the best fluid movements compared to other rock typing schemes. This affects the production and completion strategy. It also affects water breakthrough, fingering, channelling, and by passed oil. The impact of changing rock typing scheme on static and dynamic models is seldom quantified, as it creates too great a number of realizations often not feasible to dynamically simulate. A subset is usually chosen for the simulation testing. The TRT workflow disregards rock typing schemes that are not satisfying the static and dynamic interrelationships, and hence minimizes the effort of simulating unnecessary models.
List of Papers/Presentations

- Lessons Learned From Modeling A Mature Carbonate Field. Rock Typing and Facies Distribution of The Miocene Synrift Oil Bearing Carbonate Reservoirs, Analogue For Calibration For 3D Static Model Building.  
  Presentation at AAPG/SEG Barcelona (April, 2016)

  Presentation at EAGE London (June, 2019)
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CHAPTER ONE
INTRODUCTION

1.1 Introduction

Carbonate rocks’ modelling and their relationship to the complex pore structure is a challenging task for all geoscientists. Carbonate reservoir rocks exhibit a long process of alteration, from deposition, diagenesis and fracturing, where secondary processes often mask the original depositional texture. The superposition of these processes results in a heterogeneous rock and a complex pore system. The rock and pore characterization is approached differently based on the technical background. Geological and sedimentological classifications define lithology, rock fabric, texture, grain size, and morphology to define the depositional environment. Petrophysical classifications are grouped based on one phase properties such as: porosity, permeability, water saturation, pore size and pore throat size characteristics to quantify pore space, pore network and fractional saturation. Reservoir engineers, on the other hand, focus on quantifying the two phase properties affecting storage and flow capacity of reservoirs for optimal flow unit identification, well productivity, maximizing recovery and monitoring fluid distribution in the reservoir during primary, secondary and tertiary recoveries.

Rock typing is the process used to classify rocks based on pore system and their related properties, wireline log signature, routine and special core analysis response, static and dynamic properties. Geological and sedimentological rock typing (GRT) involve rock characterization from a geological perspective that include age dating, biostratigraphy, depositional environment, sequence stratigraphy, diagenesis and fracture mechanism identification. Petrophysical rock typing (PRT) involves the determination of rock types through their one-phase properties to determine fractional fluid saturation, storage and flow capacity. Static rock typing (SRT) focuses on rock system, pore space and their associated petrophysical properties in 3D static model building through pixel and object based distribution algorithms to populate facies to their petrophysical properties in the 3D space. It is evident that static rock types become very informative as the container carrying geological and petrophysical information needed to build a static model with vertical buildup and lateral extension.
However, side wall cores, trimmed core plugs and whole cores used for static modelling correspond to only a small volume of the reservoir and are not always a good representation of the overall reservoirs, baffles and barriers. In addition, in a certain depositional environment, several pore types exist and any one pore type can exist in different depositional environments. There is no simple relationship between pore type distribution and depositional environment. Only through a robust rock typing workflow, can a relationship between rock system and pore complex be achieved. Another drawback of static rock typing schemes is that they do not include two-phase flow characteristics.

Populating facies in a dynamic simulation environment imposes two phase flow properties on facies derived from static rock type distribution in the background. However, reservoir flow based characteristics such as: capillary pressure curves, pore size distributions, wettability changes, interfacial tensions, contact angles and relative permeability end points are not part of static rock typing. It is misleading to use SRT's to distribute dynamic properties of multiphase origin. Data with two phase characteristics like special core analysis is used for dynamic rock typing to initialize dynamic simulation models, model saturation height functions and fluids distribution relevant to their location above the free water level. Dynamic rock types, however, lack the predictability vertically and laterally that is available in SRT's.

Saturation height functions are a direct indication of the link between static and dynamic rock types. They include facies, porosity, permeability, water saturation and wettability effect. They can be modelled using wireline logs, routine and special core analysis data. Saturation height functions model aquifers, transition zones and dry oil limit zones at irreducible water saturation with great accuracy and hence can be used for quality control of any proposed rock typing scheme. This leads to the validation of static rock types through the quality control of their drainage characteristics and hence their geological and petrophysical measurements can be confirmed. This results in a robust association between static and dynamic rock types and establishes an accurate saturation height function and fluid distribution across the reservoir.

The dynamic behaviour of a reservoir can be correlated to DST's, production logs, well tests and others. These data are usually limited to a specific number of wells due to associated costs or operational restrictions. When available, they are indispensable
complementary information to reservoir modelling. Routine and special core analyses, on the other hand, are the primary source for rock and fluid characterisation for one-phase and two-phase properties.

A unique static rock type (SRT) is assumed to have a similar depositional environment, similar diagenetic history, same wireline log responses and a defined porosity and permeability relationship. Integrating SRT with dynamic data such as wettability, tortuosity, capillary pressure and relative permeability paves the way for the integration of dynamic rock typing concept (DRT).

Rock typing becomes a multi-scale and multi-discipline problem as stated by Skalinski, (2013) in a paper reviewing various rock typing techniques, where he stated that existing rock typing to date falls short in representing oil in place and fluid flow in carbonate models.

In this thesis a novel application for carbonate rock typing; namely Ternary Rock Typing (TRT) will be introduced. This method intends to use depositional facies, wireline logs, routine core analysis, and special core analysis all in one scheme. This new concept is extended to represent a comprehensive workflow for carbonate rock typing that includes geological, petrophysical and engineering disciplines with the integration of sedimentological facies, wireline logs, RCA and SCAL. The workflow emphasises on the separation of various pore types and their one-phase and two-phase properties and their diagenetic and fracturing characteristics.

The TRT concept allows for a seamless jump between data types and disciplines and narrows bias of any one-sided concept to a more global approach and application. This novel concept results in the integration of all rock typing disciplines, scales and data types into one robust rock typing approach that can be used in static as well as in dynamic modelling. Proper initialization narrows the gap between static and dynamic model hydrocarbon in place volume calculations. It leads to the modelling of fractional fluid saturation more accurately in the 3D space. The proper prediction of rock and pore relationship enhances IOR and EOR predictions and thus becomes more economically feasible.
This thesis comprises eight chapters divided into three main sections, in addition to the appendix. The first section is the theoretical background and review from chapters 2 to 4. The second section contains chapter 5, which presents the novel Ternary Rock Type (TRT) concept and workflow. The last section contains chapters 6 and 7, which present a comprehensive carbonate rock typing workflow developed in 1D and 3D space for improved application of rock typing to enhance reservoir characterisation and minimize the uncertainty of reservoir simulation.

Chapter 2 explains how geologists and sedimentologists are able to predict rock distribution vertically and laterally through the understanding of the depositional environment and associated energy level. This is achieved by understanding the rock system elements such as: texture, packing, grain size, fabric, composition, and sedimentary structures. The focus on the rock system at the expense of the voidage space and pore network system made geological and sedimentological carbonate classification schemes less appealing to petrophysicists and reservoir engineers but have the advantage and importance of being able to be predicted over vast distances.

Chapter 3 focuses on one phase static rock and reservoir property interaction based methods utilizing wireline logs and routine core analysis through the examination of storage and flow capacity’s effect on rock volume and its associated pore network.

Chapter 4 focuses on the concepts and techniques used for dynamic rock typing of two phase flow. The dynamic/hydraulic rock typing concept includes rock/fluid interaction and is affected by the scale of pore throat aperture radius and pore network connectivity. The primary tools used are routine and special core analysis.

Chapter 5 elaborates on proper integration of SRT with DRT and quality controlled by saturation height function to become an integral part of defining a novel Ternary Rock Type (TRT) concept. This novel concept results in the integration of all rock typing disciplines, scales and data types into one robust rock typing approach that can be used in static as well as in dynamic modelling.

Chapter 6 tests the Ternary Rock Typing (TRT) concept and the global comprehensive workflow against actual carbonate reservoir data in 1D space. The
data set used from a carbonate field located of Miocene age of restricted lagoonal environment.

Chapter 7 tests the applicability of the Ternary Rock Typing (TRT) concept, workflow, plot and software in a real field scale scenario. The effect of rock typing on static and dynamic conditions is presented and tested. The models were generated and simulated using Petrel RE and Eclipse.

Finally, chapter 8 summarises the main results and conclusions derived from the previous chapters and provides recommendations for future work.
CHAPTER TWO
REVIEW OF GEOLOGICAL AND SEDIMENTOLOGICAL ROCK TYPING

2.1 Introduction

Carbonate rocks are important oil and gas targets for both exploration and production. Carbonate reservoirs hold more than 40% of the oil and gas reserves in more than 60 basins worldwide (Sun et al., 2012). The static and dynamic characteristics of carbonate reservoirs are very challenging to all geoscientists, whether they are sedimentologists, geologists, petrophysicists or reservoir engineers. Each discipline approaches the rock and pore network characterization aspect from a different perspective. Geological and sedimentological classifications look at cores, thin section petrography, and 3D Digital Imaging to define lithology, rock fabric, texture, grain size, and morphology. This leads to an understanding of the relative position of the producing reservoir depositional environment within the overall sedimentological framework. The relative reservoir position with regard to the energy level affects reservoir characteristics and changes laterally with lateral variation of energy. Petrophysical classifications, on the other hand, are grouped based on porosity, permeability, pore size and pore throat size characteristics making them very appealing as a quantitative description of pore space and pore network. Finally, reservoir engineers focus on the dynamic interaction between rock and fluid and direct their efforts towards quantifying the storage and flow capacity of reservoirs for optimal flow unit identification, well productivity, maximizing recovery and monitoring fluid distribution in the reservoir during primary, secondary and tertiary recoveries.

A review of geological/sedimentological rock typing concepts and their application is discussed in this chapter as well as a critical review of the various methods presented. Chapter 3 focuses on one phase static rock and reservoir property interaction based methods utilizing wireline logs and routine core analysis, while chapter 4 emphasizes the dynamic and hydraulic rock/fluid two phase relationships including wettability, relative permeability, capillary pressure and saturation height functions. Assumptions, constraints, successes, failures and lessons learnt applying the different
classifications and techniques are scrutinized to pave the road for the development of an optimally integrated workflow for carbonate rock typing to be applied in 1D and 3D static and dynamic modelling using different data sources, disciplines and techniques.

2.2 Concept of Sedimentological Rock Typing

The sedimentological and depositional environmental framework perspective of carbonate reservoirs is an important descriptive model on the outcrop scale and an analytical one on the pore scale (Figure 2.1). The larger scale concentrates on the depositional environment and energy level affecting genetic units comprising the building blocks of the overall environmental model. The smaller scale, on the other hand, deals with pore throat characterization, fracturing mechanisms, and stylolitization affecting fluid flow, while pore/vein filling minerals, dissolution, and secondary porosity affect storage capacity.

![Figure 2.1: Carbonate facies variation of a carbonate ramp depositional model with change of water depth and lateral change of energy level (Moore and Wade, 2013).](image)

The stratigraphic sequence of any succession is dominated by siliciclastics and carbonates comprising a sedimentary package. These packages are composed of numerous rock types, which are related in sedimentological aspects and diagenetic
controls directing reservoir properties. The time boundaries between these sequences are classified and distinguished based on high resolution biostratigraphy and age dating techniques. The lithologic and facies aspects are analyzed using ditch-cuttings and core descriptions while the grain to grain relation and associated mineralogy, texture and diagenesis is interpreted using thin section petrography from cores and ditch cuttings. The sedimentological depositional systems and their associated facies change over time by post diagenesis and epigenesis. This change controls the rock to pore interaction and interrelation. The compound effect of all these parameters on the carbonate rock entails how much hydrocarbon can be stored and produced from its related pore spaces and pore network (Figure 2.2).

Figure 2.2: Sequence stratigraphy can provide useful information on depositional environment, structures, texture and composition, which directly control the diagenetic processes and patterns (modified after Morad et al., 2012).

The geological and sedimentological investigation of outcrops, cores, ditch cuttings, thin sections and FMI logs from previous authors led to classification schemes
covering a broad spectrum, but can be divided into the following main categories (Figure 2.3):

- Texture
  - Grain Size
  - Fabric
- Composition
- Sedimentary Structures
- Detrital Carbonates
- Reef Rocks
- Genetic Classification
- Digital Image Analysis

Figure 2.3: Categorization of geological and sedimentological rock typing and associated authors.
2.3 Review of Geological and Sedimentological Rock Typing Schemes

2.3.1 Classification According to Texture

Texture is described by the arrangement and sorting of the detrital grains in a sedimentary rock together with the grain size and shape (Pettijohn, 1975). In detrital carbonates, the effect of depositional grain to grain relation is prominent. The shape, size, packing, and orientation of the grains affect the pore geometry, which in turn affect porosity, permeability and irreducible water saturation. The original texture can be altered after deposition by diagenetic and/or fracturing mechanisms.

2.3.1.1 Classification According to Grain Size

Grain size variation is described by sedimentologists and geologists using a scale developed by the petrologist Udden (1898) and modified by Wentworth (1922). The scale (Figure 2.4) classifies the average grain diameters to be gravel, sand or mud representing sizes of >2mm, between 2mm and 1/16mm and <1/16mm respectively. The Udden-Wentworth scale is a geometric scale in nature. Unconsolidated and lithified carbonate grain size measurements can be made using pipettes, sieves, settling chambers and thin sections (Tucker and Wright, 1990).
Krumbein (1934) proposed an alternative to the millimetre grain size Wentworth scale in which he adopted a phi (Φ) scale conversion. The phi (Φ) size values convert the different millimetre sizes to phi units using a negative logarithmic transformation. Small grain sizes have positive phi values, while large grain sizes have negative values.

$$\Phi = -\log_2 d$$  \hspace{1cm} (Eq. 2.1)

where

- $d$ is the grain size diameter in mm
- $\Phi$ is phi unit scale transformation proposed by Krumbein (1934).

The Wentworth grade scale was originally applicable to clastic sediments. However, Leighton and Pendexter (1962), modified it to be applicable to carbonate rocks (Figure 2.5). They characterized limestones by the relative amounts of four textural
groups; namely grains, lime mud, cement and pores (Chilingar et al., 1967). The textural terminology is used mainly by petrologists and petrographers.

![Grade-size scale (mm) vs. Textural Terms](image)

Figure 2.5: Leighton and Pendexter’s (1962) modification on Wentworth scale (1922) for application to carbonate rocks (redrafted after Chilingar et al., 1967).

Earlier attempts by Grabau (1904, 1913) were made to characterize limestone rocks. The classification scheme used a genetic approach based on the original process of establishment, where he classified carbonates into hydroclastic, bioclastic, and biogenic. The processes describe the mechanism of breaking by water, mechanical action of organisms, and physiological activities of organisms (Chilingar et al., 1967). Grabau (1913) also characterized limestones according to the size of the calcareous components. He used terms such as calcilutite, calcisiltite, calcarenite and calcirudite, which indicate clay, silt, sand and gravel size of the calcareous particles respectively. These terms are used in some sedimentological studies but rarely used among practical geoscientists.

Folk (1959, 1962) pioneered a practical petrographic classification of limestone using a detailed descriptive and quantitative scheme, where he separated the main constituents of limestones into allochem, matrix and sparite; terms denoting grains, micrite and cement, respectively. He also related the volumetric ratios of the
components to depositional environmental origin and setting. Folk added some terms to Grabau’s scheme for detrital carbonate such as micrite and intraclast. The naming convention of the scheme uses suffixes for matrix description, and prefixes for the non-matrix components (Figures 2.6 and 2.7).

The advantages of using Folk’s scheme are evident for thin section petrographic studies. However, the scheme is too complicated to be used for practical reservoir characterization studies. It is also not applicable to the description of reef rocks.

Figure 2.6: Carbonate rock classification after Folk, (1959) (redrafted after Moore and Wade, 2013).
Tucker (1988) and Tucker and Wright (1990) used thin section petrography to address the importance of determining the grain size measurements of carbonate rocks. They highlighted the importance of point counting of thin sections for identifying the relative percentages of grains to matrix ratio. This method also comes with limitations especially when no supporting matrix material is present in the examined thin section slide such as in some grainstone reservoirs. However, Tucker and Wright's (1990) book provided thorough illustrations on carbonate environments, diagenesis, and sedimentation through time.

From the previous review, it is evident that grain size classifications give a representation of the rock system rather than the pore voidage network, which determines porosity and permeability. It is a description of the rock but lacks the representation of the voidage space. In conclusion, grain size in carbonate rocks alone is not a direct indicator of rock type as can be depicted in sandstone environments.

2.3.1.2 Classification According to Fabric

The rock fabric of carbonate rocks according to Ahr (2008) can be classified according to the process of origin that created the fabrics. The processes are depositional, diagenetic, and biogenic (Figure 2.8). Depositional fabrics involve the alignment of detrital grains composing the carbonate rocks. Diagenetic fabrics
embrace the diagenesis effect on the original depositional fabrics after deposition. This can have a positive or negative effect on reservoir properties. Biogenic fabrics include reefs, buildups and skeletal grains (Ahr, 2008).

Figure 2.8: Depositional, diagenetic, and biogenic rock fabrics of carbonate rocks (redrafted after Ahr, 2008).

Depositional fabric of carbonate rocks is a direct indicator of paleo-reservoir properties. However, post deposition diagenesis and fracturing often mask the original fabric and hence fabric alone cannot be related directly to petrophysical or engineering properties but remains a direct indicator for the depositional environment.

2.3.2 Classification According to Composition

In sedimentological terms, carbonate composition typically relates percentages of grain type components and not their mineral composition (Ahr, 2008). Bathurst (1971, 1975) wrote an important book which details carbonate constituents and carbonate diagenesis. He used sixteen fabric criteria from various authors describing cement processes (Larsen and Chilingar, 1979). He also applied the micritization terminology of Folk for the process of grain surface to micrite alteration caused by microborings filled with micrite precipitates (Hopley, 2011). He linked his work to modern limestone accumulations. Milliman (1974) characterized carbonate cements and coined matrices terminology (Table 2.1). Purser (1980), Scoffin (1980, 1987) and Tucker and Wright (1990) highlighted compositional constituents found in carbonates covering different geological frameworks and depositional environments.
Carbonate composition can be a key to understanding the depositional environment and associated reservoir quality. Cementation, recrystallization, and lithification, among other processes, explain the rapid change of carbonate reservoir quality along small distances vertically and laterally.

Table 2.1: Terminologies of various carbonate cements and matrices *(after Milliman, 1974)*

<table>
<thead>
<tr>
<th>Terminology</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Acicular</td>
<td>long, thin crystal, usually oriented normal to grain surface; usually aragonite</td>
</tr>
<tr>
<td>Blocky</td>
<td>massive, equant grains</td>
</tr>
<tr>
<td>Cryptocrystalline</td>
<td>Light brown to opaque tiny crystals, less than 4 microns in diameter</td>
</tr>
<tr>
<td></td>
<td><em>(Purdy, 1963); similar to microcrystalline</em></td>
</tr>
<tr>
<td>Dentate</td>
<td>drusy cement with jagged, tooth-like edges</td>
</tr>
<tr>
<td>Drusy</td>
<td>a type of sparry cement; crystalline to subhedral crystals, coarser than about 10 microns, generally forming in voids (drusy mosaic) or as thin coatings <em>(Bathurst, 1958)</em>; In drusy mosaic, cement crystals increase in size away from the component grains</td>
</tr>
<tr>
<td>Fibrous</td>
<td>similar to acicular</td>
</tr>
<tr>
<td>Granular</td>
<td>general term for cement crystals coarser than about 10 microns, but smaller than about 60 microns; overlaps with drusy</td>
</tr>
<tr>
<td>Micrite</td>
<td>microcrystalline calcite, less than 4 microns in diameter <em>(Folk, 1959)</em>; less than 30 microns <em>(Leighton and Pendexter, 1962)</em></td>
</tr>
<tr>
<td>Microcrystalline</td>
<td>subtranslucent crystals less than 4 microns in diameter <em>(Folk, 1959)</em>; Between 4 and 30 microns <em>(Macintyre, 1967a)</em></td>
</tr>
<tr>
<td>Microspar</td>
<td>recrystallized matrix <em>(Folk, 1965)</em></td>
</tr>
<tr>
<td>Pelletal</td>
<td>cement and matrix composed of numerous small pellets, 20 to 60 microns in Diameter; the pellets are composed of cryptocrystalline grains</td>
</tr>
<tr>
<td>Submicrocrystalline</td>
<td>less than 4 microns in diameter <em>(Macintyre, 1967a)</em></td>
</tr>
<tr>
<td>Sucrosic</td>
<td>sugary cement, common in dolomites</td>
</tr>
<tr>
<td>Sparry</td>
<td>clear, coarse crystals, generally coarser than 10 microns <em>(Folk, 1959)</em></td>
</tr>
</tbody>
</table>

2.3.3 Classification According to Sedimentary Structures

According to Allen (1982), sedimentary structures arise in immediate or close association with the transport of sedimentary materials. He attributed the creation of sedimentary structures to chemical, biological and physical agents. These might be lamination, beddings, borings, burrows, or fenestral fabrics. Features are recorded from outcrop, core and thin section petrography indicating the depositional environment *(Reineck and Singh, 1973; Wilson, 1975; Scholle et al., 2003; and Reading, 1996).*
Understanding the sedimentary structures can improve the interpretation of depositional environments. Facies within a certain environmental setting can be predicted laterally and vertically for long distances making the prediction of geological facies in the three dimensional space reliable.

2.3.4 Classification of Detrital Carbonates

Detrital carbonates are calcium carbonate grains composed of broken fragments of older rocks, broken down by mechanical processes or by weathering agents and transported to the site of deposition. They are derived from inland by fluvial action or by marine erosion. They are also often found in sedimentary packages alternating and inter-fingering with siliciclastic terrigenous derived materials. The thickest detrital carbonate accumulation is found filling palaeo-lows. Since detrital carbonates are an accumulation of different origins, it is very challenging to come up with a unified descriptive classification.

Folk (1959, 1962) classified detrital carbonates based on mud to grain percentages. Dunham (1962), on the other hand, focused on the textural aspect and grain size of the detrital carbonate material. He distinguished recognizable depositional texture into mud-supported and grain-supported carbonates. Then, based on the carbonate mud percentage, four main categories were determined namely; grainstone, packstone, wackestone and mudstone (Figure 2.9). He also added boundstone representing reefs and crystalline rock with unrecognizable depositional texture. The mud to grain ratio gives an indication of the energy level of the depositional environment (Scholle et al., 2003).
Dunham’s classification is easy to use by geologists and sedimentologists. However, it focuses on the depositional textural aspects of the rock with no reference to the voidage and pore network association. This is why it is hard to relate it directly to the petrophysical properties of the rock. It also ignores post depositional diagenesis and fracturing which is a key property of carbonate rocks.

Dunham's classification is most applicable to core description utilizing the detailed textural characteristic of the rocks, while Folk's terminology is used at its best by thin section petrography determining diagenetic influence on the rock.

Kerans et al. (1994) modified Dunham’s classification to distinguish between mud-dominated and grain-dominated packstones. The distinction relates the absence of mud in intergranular areas in packstones to have petrophysical characteristics like those of grainstones. On the other hand, packstones with intergranular areas filled with mud behave like wackestones and mudstones (Figure 2.10). Kerans et al. also studied the characterization of facies and permeability patterns in carbonate reservoirs based on outcrop analogs. Including outcrop models in carbonate characterization can greatly enhance the interchange of information between hydrocarbon model building since depositional models repeat within various geological times and geographical locations.

![Depositional Texture Recognized Table](image)

Figure 2.9: Dunham’s Classification according to depositional texture (1962), (redrafted after Dunham, 1962, modified by Embry & Klovan, 1971).
2.3.5 Classification of Reef Rocks

Tucker and Wright (1990) classified biologically influenced carbonate accumulation into skeletal (frame-built) reefs and reef mounds. Skeletal reefs possess a rigid calcareous frame, while reef mounds lack a skeletal framework. Organic reef rocks are in place calcareous deposits created by sessile organisms (Riding, 2002). Embry and Klovan (1971), and Riding (2002) developed detailed reef descriptions featuring the heterogeneity observed in reef sedimentary components and physical structure. They modified Dunham’s textural scheme to take into account the biological process of building the reefal accumulation (Figure 2.11).
Embry and Klovan (1971) divided autochthonous limestones into three rock types based on the way organisms bind the sediments; namely framestone, bindstone, and bafflestone. For allochthonous limestones associated with reefs, they used the term rudstone equivalent to the term grainstone/packstone and the term floatstone equivalent to wackestone (Figure 2.12). Embry and Klovan’s classification is most applicable to reefs with a stiff framework.

Figure 2.11: Modification of Embry and Klovan’s (1971) scheme to the Dunham classification (1962).

Figure 2.12: The Riding classification for reefs and build-ups (redrafted after Riding, 2002).
Riding (2002) classified reef rocks according to the supporting agent holding the rock. He used the terms skeletal support, matrix support, and cement support to define frame reefs, cluster/segment reefs and cement reefs (Figure 2.12). Riding’s nomenclature is especially useful for mudstone and cementstone reefs (Ahr, 2008).

<table>
<thead>
<tr>
<th>Allochthonous</th>
<th>Autochthonous</th>
</tr>
</thead>
<tbody>
<tr>
<td>Matrix supported</td>
<td>By organisms that act as baffles</td>
</tr>
<tr>
<td>Supported by &gt;2mm component</td>
<td>By organisms that encrust and bind</td>
</tr>
<tr>
<td>&gt; 10% grains &gt; 2mm</td>
<td>By organisms that build a rigid framework</td>
</tr>
</tbody>
</table>

Figure 2.13: The skeletal reef classification of Embry and Klovon (1971) (redrafted after an illustration in Tucker and Wright, 1990).

### 2.3.6 Classification According to Genetic Classification

The geological processes of carbonate rocks demonstrate a complex imprint on the final rock fabric, pore space and pore network. This begins from deposition, sedimentation, post depositional digenesis and fracturing. The compound effect of these processes explains the heterogeneous carbonate rock and multi-modal pore type behaviour.
Wright (1992) adapted a genetic approach to explain the geological processes affecting carbonate rocks. He modified the depositional textural classification of Dunham (1962), the biological classification of Embry and Klovan (1971) and added syn-sedimentary and post-depositional diagenetic terminologies (Figure 2.15). Wright’s genetic classification (1992) is mainly used for limestone. As with other purely geological based schemes, concentration is based on the rock system and does not approach the voidage and pore network characteristics.

![Figure 2.14: Ternary porosity plot classification (redrafted after Flügel, 2004).](image1)

![Figure 2.15: Wright’s genetic classification (1992) (redrafted after an illustration in Scholle, 2003).](image2)
Ahr and Hammel (1999) and Ahr et al. (2005) enhanced the genetic approach classification of Wright to include porosity as part of the class categorizing process. Porosity creation depends on depositional, diagenetic, and fracture processes (Figure 2.16). This approach is a great enhancement as it includes a geological approach as well as porosity: a property with a multi-disciplinary importance.

![Figure 2.16: A genetic classification of porosity in carbonate rocks (after Ahr et al., 2005).](image)

2.3.7 Pore Type Classifications Using Digital Image Analysis

Weger et al. (2009) introduced a Digital Image Analysis (DIA) method that produced quantitative pore-space parameters, which are linked to physical properties in carbonates, in particular sonic velocity and permeability. The DIA parameters derived from thin sections, captured two-dimensional pore size roundness, aspect ratio, and pore network complexity. They showed that estimates of permeability from porosity can be improved when pore geometry information is incorporated.

Mishra et al. (2012) used CT and micro CT scan techniques to carry out pore to core scale characterization of carbonate rocks. They concluded that the digital rock physics technology was still in the development stage and that the cost was still too high compared to other characterization techniques. Amabeoku et al. (2013) applied Digital Rock Physics (DRP) techniques to predict Special Core Analysis in a
carbonate formation. They concluded that DRP provided equivalent special core analysis data much more quickly than traditional laboratories. They computed porosity, absolute permeability, electrical properties, capillary pressure, and relative permeability. The estimation of these properties was within the bands of traditional laboratory experimental measurements.

Al-Ratrout et al. (2014) applied Digital Rock Physics to different scales of interrogation from nano to micro metres to define microporosity. They showed DRP to be an excellent tool to assess microporosity and to quantify microporosity effectively in a 3D pore network. Natarajan et al. (2014) presented a case study, which illustrated how to compute relative permeability curves in Middle Eastern carbonates using Digital Rock Physics. The computed relative permeability curves compared very well with the laboratory-derived curves for similar rock types.

Figure 2.17: Digital Rock Imaging showing rock and flow properties computed directly from 3D images of the rock (after Kalam et al.’s, 2013).

The advances of digital imaging and relating these to routine and special core analysis and hydrodynamic flow is an emerging science but digital imaging still lacks the global standards, sufficient case studies and consistent techniques (Figure 2.17).
2.4 Critical Review and Concluding Remarks

The characterization process of carbonates has been tackled by different authors from a geological and sedimentological perspective. Dunham and Folk's schemes are based on mud to grain ratios depicting original energy levels. Dunham's classification is most applicable to core description utilizing the detailed textural characteristics of the rocks, while Folk's terminology is used by thin section petrography. They both lack the description of reef rocks and fracturing mechanisms. The abundance of mud content according to their interpretation is an indication of areas with low energy environment while higher grain content is a sign of higher energy environment. High mud content lowers reservoir quality dramatically if not affected by post depositional processes.

Embry and Klovan (1971), and Riding (2002) developed detailed reef description methods featuring the heterogeneity observed in reef sedimentary components and physical structure. They modified Dunham’s textural scheme to take into account the biological process of building the reefal accumulation. This remains the most adopted scheme for reef classification.

Wright (1992) adopted a genetic scheme for the geological processes affecting carbonate rocks from deposition to post-deposition. Following Wright’s work (1992), Ahr and Hammel (1999) and Ahr et al. (2005), included porosity to be depositional, diagenetic, or fracture porosity. This genetic superposition approach is a great enhancement to the classification process as it includes a rock based geological approach and a reservoir-based property thus approaching a multi-disciplinary scheme.

Table 2.2: Table showing a brief summary of advantages and limitations of geological and sedimentological rock typing techniques:

<table>
<thead>
<tr>
<th>Geological / Sedimentological Rock Typing</th>
<th>Advantages</th>
<th>Limitations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Relating rock/texture to depositional environment</td>
<td>- New drill core, side wall core, drill cuttings and outcrops</td>
<td></td>
</tr>
<tr>
<td>Cement, diagenesis, fracture effect on pore space and pore network</td>
<td>- Qualitative more than quantitative classification</td>
<td></td>
</tr>
<tr>
<td>Micro-scale to Mega-Scale Modeling</td>
<td>- Classified genetic units with great overlaps</td>
<td></td>
</tr>
<tr>
<td>Actual pore throat measurements not just pore size</td>
<td>- Fracture incorporation is usually moderate</td>
<td></td>
</tr>
<tr>
<td>Lateral prediction of environment and related properties</td>
<td>- When superimposed to Phi crossplot usually no common trend arises</td>
<td></td>
</tr>
<tr>
<td>Prediction of Pore Network if a relation between rock and pore systems can be found</td>
<td>- Dynamic/Hydraulic incorporation is poor</td>
<td></td>
</tr>
<tr>
<td></td>
<td>- Upscaling problem to actual dynamic simulation grid size</td>
<td></td>
</tr>
<tr>
<td></td>
<td>- Grouping of sedimentological facies to manageable representative dynamic rock types is subjective</td>
<td></td>
</tr>
</tbody>
</table>
Geological and sedimentological classification techniques for rock typing of carbonate rocks are excellent tools for understanding the origin, mechanism and depositional environment of rock types, porosity types and pore network characteristics (Table 2.2). On a micro scale, the compound effect of depositional, diagenetic and fracturing processes on porosity, permeability and pore size characteristics can only be explained through geological and sedimentological investigations. On a mega scale, the lateral prediction and vertical buildup of the depositional environment can be achieved through biostratigraphic, geological and sedimentological interpretations. These, however, fail to quantify petrophysical and reservoir engineering parameters as we will investigate in chapters 3 and 4. A robust carbonate classification scheme has to link sedimentological facies to petrophysical and dynamic properties. Linking pore space and pore network to sedimentological facies and the depositional environment allows for the prediction of the pore system since rocks can be mapped and predicted for longer distances.
CHAPTER THREE

REVIEW OF STATIC ROCK AND RESERVOIR PROPERTY
ROCK TYPING

3.1 Introduction

Chapter 2 explained how geologists and sedimentologists are able to predict rock distribution vertically and laterally through the understanding of the depositional environment and associated energy level. This is achieved by understanding the rock system elements such as: texture, packing, grain size, fabric, composition, and sedimentary structures. The focus on the rock system at the expense of the voidage space and pore network system made geological and sedimentological carbonate classification schemes less appealing to petrophysicists and reservoir engineers.

In this chapter, we will investigate static rock and reservoir property interaction through the examination of storage and flow capacity’s effect on rock volume and its associated pore network using routine core analysis and wireline logs.

3.2 Concept of Static Rock/Reservoir Property Rock Typing

The geological and sedimentological rock typing (GRT) involves the characterization of rocks from a purely geological point of view. Petrophysical rock typing (PRT), on the other hand, involves wireline logs and routine core analysis techniques. When integrating geological rock typing (GRT) and petrophysical rock typing (PRT), the end result is a static rock typing concept (SRT) (Asgari and Sobhi, 2006; Salman and Sameer, 2009; Ghedan et al., 2012; Skalinski et al., 2005, 2009, 2013; Rebelle and Lalanne, 2014; Agar and Geiger, 2014; Skalinski and Kenter, 2015; Jin et al., 2016). A unique static rock type is assumed to have a specific depositional environment and diagenetic history with a defined poro/perm relationship. Integrating SRT with dynamic data such as wettability, capillary pressure and relative permeability, paves the way to a dynamic rock typing perception (DRT).
The porosity in the carbonate system can be categorized into two: effective porosity, which is responsible for fluid transmission and non-effective porosity, which is responsible for isolated pores and does not affect fluid flow. In terms of pore network, these are related to connected pores and non-connected pores respectively. The isolated vuggy porosity in carbonates is usually the non-transmitting portion of the fluid flow unless it overlaps through fractures. Matrix and fracture porosity, on the other hand, are typically responsible for most of the flow capacity of the reservoir. Multiple porosity systems are evident through progressive geological processes affecting permeability values. For the same porosity, differences in permeability values of many orders of magnitude are often found. Absolute permeability resembles pressure drop through a pore space fully saturated with a one-phase fluid. The relationships between $k$, $\phi$ and $S_w$ become more complicated than a simple linear function (Figure 3.1).

Figure 3.1: Permeability and porosity trends for various carbonate rock types and textures (after Corelab, 1983).
The static rock/reservoir property rock typing investigation of geological fabric, routine core analysis and wireline log data from various authors led to classification schemes that can be divided into the following categories (Figure 3.2):

- k and \( \Phi \) techniques
- \( S_w \) and \( \Phi \) techniques
- \( S_w \) and \( k \) techniques
- Wireline Clustering
- Integrated Approach

Figure 3.2: Categorization of static rock/reservoir property rock typing and associated authors.
3.3 Review of Static Rock/Reservoir Property Rock Typing

3.3.1 G. E. (Gus) Archie, 1942, 1947, 1950, 1952

Archie (1952) pioneered a scientific discipline and named it "Petrophysics". This new discipline covered rock and fluid interaction. In spite of the fact that he was a reservoir engineer, he established the link between geology and reservoir engineering. His revolutionary paper “Classification of Carbonate Reservoir Rocks and Petrophysical Considerations” was one of the early applications used to quantify reservoir properties and fluid quantities. Fluid flow was linked to pore structure in terms of porosity, permeability, relative permeability, fluid resistivity, irreducible water saturation and capillarity. This concept revolutionized the well-established geological classification adapted by his predecessors who concentrated mainly on the rock system and depositional mechanisms more than the pore network and relative voidage space. The term "Rock Type" (1950) was introduced for a rock with a certain effective pore-size distribution, a particular group of capillary pressure curves, porosity, permeability and irreducible water saturation.

Archie classified carbonates based on textural matrix aspects into three types, namely, I, II, and III. Type I represent compact crystalline carbonates, type II are characterized by a chalky texture, and type III are granular/saccharoidal carbonates. He also classified porosity into visible and non-visible with varying pore size diameters size (Classes A, B, C and D) (Table 3.1).

<table>
<thead>
<tr>
<th>Class</th>
<th>Porosity and Pore size diameter</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>No visible porosity, Pore size diameter less than 0.01 mm</td>
</tr>
<tr>
<td>B</td>
<td>Visible porosity, Pore size diameter between 0.01-0.1 mm</td>
</tr>
<tr>
<td>C</td>
<td>Visible porosity, Pore size diameter between 0.1-2 mm</td>
</tr>
<tr>
<td>D</td>
<td>Visible porosity, Pore size diameter &gt;2 mm</td>
</tr>
</tbody>
</table>

Archie related the electrical resistivity of the fluids in the porous reservoir system to their porosity and proposed a quantitative equation relating the fluid saturation to reservoir parameters (Eq. 3.1 and Eq. 3.2).
Archie defined the formation factor $F$ as:

$$F = \frac{R_o}{R_w} = \frac{a}{\Phi^m}$$  \hspace{1cm} (Eq. 3.1)

where

- $R_o$ is resistivity of a porous rock at 100% water saturation
- $R_w$ is formation water resistivity in the pores at formation temperature
- $F$ is Archie formation factor
- $\Phi$ is reservoir porosity
- $a$ is tortuosity factor (varies from 0.62 to 1.2). Archie assumes $a$ to be 1.
- $m$ is cementation factor (varies from 1.0 to 4.0) but normally is 2.0

The Archie equation can be expressed as follows:

$$S_w^n = \frac{a R_w}{(\Phi^m * R_t)}$$  \hspace{1cm} (Eq. 3.2)

where

- $S_w$ is water saturation of the un-invaded zone
- $n$ is saturation exponent, varies from 1.8 to 4.0 but normally is 2.0, depending on wettability
- $R_t$ is true resistivity of the formation, corrected for invasion, borehole, thin bed, and other effects

The cementation factor, $m$, is an indication of the pore geometry of the rock. The variation of $m$ in carbonate rocks denotes the heterogeneity and complex nature of these rocks. The average value is usually taken as 2 for intergranular porosity with well connected pores, while for vuggy/moldic porosity where the tortuosity leads to poor connectivity, $m$ is greater than 2.5, and in fractured rocks $m$ will be near 1 (Figure 3.3). In the literature, bi-modal and poly-modal pore types were observed in carbonate rocks and reported by various authors (Corbett 2004, 2010, 2012; Hayat et al., 2014; Al Ameri et al. 2011; and Hulea 2013). Multi pore and void systems exist
in carbonates due to the fact that sequential depositional, diagenesis, and fracturing processes superimpose and overlap pore space and pore networks.

![Figure 3.3: Cementation factor, m, variation with porosity type (redrafted after Rodolfo et al., 2012; SPE 152872).](image)

Focke et al. (1987) recognized that Archie's classification did not include a genetic porosity classification and hence was insufficient for general rock classification. The relationship between pore type and rock origin is important to be able to predict extensions laterally and vertically away from the borehole, and this is not achieved in Archie’s classification.

### 3.3.2 Buckles, 1965

Buckles (1965), a petroleum engineer, investigated hydrocarbon reservoirs particularly Devonian carbonates and Cretaceous clastics from Alberta, Canada. He showed that, above the transition zone for a given rock type, an equilateral hyperbola equation (Eq. 3.3) fits porosity and irreducible-water-saturation data (Figure 3.4).

\[
\Phi \ast S_w = C \quad \text{(Eq. 3.3)}
\]

where

- \( C \) is a constant for a given rock
The correlation factor C is known as Bulk Volume Water (BVW) and is controlled by pore size distribution in a particular rock type. If the water saturation is at irreducible saturation, the term is denoted Bulk Volume Water Irreducible (BVI) or Buckles Number above the transition zone.

![Figure 3.4: Bulk Volume Water for different rock types](redrafted after Xu et al., 2013; SPE 166082).

Reservoirs with large pore size will have a smaller correlation factor C, while reservoirs with small pore size will have higher values. The lower the value of the constant, the better the performance of the reservoir. The value of C ranges from 0.02 to 0.10 for Sandstone, 0.01 to 0.06 for intergranular carbonates and 0.005 to 0.06 for vuggy carbonates (Holmes et al., 2009). The Buckles Number is sometimes used for the prediction of water free producing zones after proper calibration from producing Drill Stem Test (DST) and perforations. Values higher than 0.04 will tend to have low permeabilities and are likely to produce water (Asquith, 1985).

Buckles’ method is a pioneering concept that relates irreducible water and porosity to pore size, but only works above the transition zone. In carbonate reservoirs, especially in low porosity and/or permeability limestones long transition zones are common and the method becomes non-applicable.
3.3.3 Choquette and Pray, 1970

Choquette and Pray’s (1970) classification is termed utilizing the integration of sedimentological facies and porosity types and involves 15 porosity forms (Figure 3.5).

They considered four essentials elements:

- Basic porosity types and potential for fabric selection
- Original porosity timing and secondary genetic modification of porosity
- Pore shape and size
- Pore abundance

![Figure 3.5: Choquette and Pray’s (1970) carbonate porosity classification. Left: Basic fabric selective porosity types. Right: Basic non-fabric selective and variably fabric selective porosity types (redrafted after Scholle, 2003).](image)

This classification method divides pore space into three main categories. The first category is fabric selective where porosity pore system coincides with the original depositional and diagenetic rock fabric. The second category is not fabric selective where the porosity pore system crosses the original rock fabric such as in fractures and vugs. The third category includes animal and plant processes that cannot be related to the rock fabric such as borings and burrowings.
They also divided pore size into three categories:

- Megapore (4 to 256 mm)
- Mesopore (1/16 to 4 mm)
- Micropore (< 1/16 mm)

The Choquette-Pray method is a very comprehensive sedimentological description to characterize carbonate porosity and this is the reason it is widely used by well site geologists and modellers. However, it lacks the petrophysical and reservoir engineering characteristics of porosity quantification and associated permeability.

### 3.3.4 Schlumberger SPI™, 1972, 1974

Schlumberger devised an indicator in 1972 and 1974 to draw attention to secondary porosity (e.g., vugs, and fractures). The theory behind it is that sonic transit time is not affected by isolated vugs and fractures because the propagation of sonic waves travels through the faster path in the medium and thus is sensitive to the primary intergranular porosity. This is why sonic derived porosity is less than the total porosity, and the difference is attributed to the presence of secondary porosity. Sonic porosity can be determined using the Wyllie time-average equation, while total porosity is derived from a neutron density crossplot.

**Secondary (Vuggy) Porosity = Total Porosity - Sonic Porosity**  \(\text{(Eq. 3.4)}\)

The secondary porosity indicator is still used in reservoir characterization studies, but only qualitatively and not quantitatively especially when calibrated with cores and thin section petrography in the absence of bore hole image tools.

### 3.3.5 Schlumberger’s 1979, M-N plot

Schlumberger utilized a graphical method (Figure 3.6) in order to characterize various rock types first introduced by Burke et al. (1969). The M-N plot removes the fluid effect by projection from the neutron, density and sonic data. This leads to a porosity independent plot that can be used to determine lithology. The M value is calculated from sonic and density logs, while the N value is determined from neutron and density logs.
This method was used in older reservoir characterization studies but has lost its momentum over the years because M and N values have no physical meaning. In part, this method might be attributed to an early attempt of Principle Component Analysis (PCA).

**3.3.6 Schlumberger’s 1979, MID plot**

The Matrix Identification Plot (MID) used three porosity logs to determine apparent matrix parameters. The apparent matrix parameters were plotted on a MID chart and major rock types were evaluated (Figure 3.7).
Figure 3.7: Schlumberger’s MID plot from Slb, Chart Book, (1979).

A problem encountered using the MID plot is that the centre points of dolomite, calcite and quartz lie very close to each other on the plot and minute separation is achieved thus making mixed lithologies hard to identify. The MID technique lost its momentum with the introduction of the neutron-density cross plot.

3.3.7 Wooddy-Wright-Johnson (WWJ) approach

A combined approach from Wooddy and Wright (1955) and Johnson (1987) using capillary pressure data was illustrated (Rebelle and Lalanne, 2014). The derived water saturation and permeability pairs from capillary pressure data are plotted on a log-log plot (Eq. 3.5 and Figure 3.8).

\[ \log S_w = -a \log k + b \]  
(Eq. 3.5)

where
- \( k \) is permeability (mD)
- \( a \) and \( b \) are fitting parameters

The plot reveals linear parallel lines with constant slope "a". Different lines represent different rock types.
Water saturation from core plugs is usually measured using the Retort or Dean-Stark methods. The first method quantifies evaporation of the fluids in the pores, while the second quantifies leaching of fluids in the pores. Detailed pros and cons are discussed further in chapter 5. $S_w$ measured on core plugs always assumes no filtrate displacement, which is not always the case.

![Figure 3.8: Left: Water saturation versus permeability on a semi-log plot. Right: Water saturation versus permeability on a log-log plot with distinctive linear and parallel lines representing different rock types.](image)

Plotting water saturation versus permeability is a valuable technique especially for reservoir engineers due to the fact that the two parameters are readily available from routine and special core analysis. However, there is no theoretical basis for the technique and geological and petrophysical integration is not part of it. A linear trend is not always achieved between water saturation and permeability especially for carbonate rocks and particularly for polymodal pore systems.

### 3.3.8 Ebanks 1987, 1992

Ebanks et al. (1992) defined the flow unit concept as part of the reservoir that can be mapped with similar geological and petrophysical properties. The flow unit is correlatable between wells, recognizable from wireline logs, has a common capillary pressure relation and a unique porosity/permeability relationship.
Figure 3.9: Separation of flow units is indicated with an obvious change in lithology, pore type, porosity/permeability relationship, capillary pressure and wireline log behaviour (after Ebanks et al., 1992).

The flow unit concept of Ebanks et al. (1992) is a valid concept and is still being used today. However, he used lithofacies as a rock representative classifier. It is preferable to use a sedimentological approach where the original fabric, diagenesis and epigenesis are included in the geological classification. This will allow for easier prediction of flow units laterally and vertically. The concentration of flow units is of importance but an emphasis on baffles and barriers is also needed since they also affect the hydrodynamic movements of the fluids.

3.3.9 Amaefule et al., 1993

Amaefule et al. (1993) proposed a method using core plug measurements of porosity and permeability adopting the concept of a modified Kozeny-Carman equation (Section 4.3.1). The core porosity and permeability measurements were used to determine Reservoir Quality Index (RQI) and Flow Zone Indicator (FZI). They suggested that the same hydraulic unit of a reservoir rock is controlled by similar pore throat geometry and will have similar FZI values (Eq. 3.6-3.8).
Reservoir Quality Index (RQI) can be expressed as:

\[
\text{RQI (µm)} = 0.0314 \sqrt{\frac{k}{\Phi_e}} 
\]  
(Eq. 3.6)

where

- \(\Phi_e\) is defined as the effective porosity

\[
\Phi_z = \frac{\Phi_e}{1 - \Phi_e} 
\]  
(Eq. 3.7)

where

- \(\Phi_z\) is defined as the pore volume to grain volume ratio

Flow Zone Indicator (FZI) is given by:

\[
\text{FZI (µm)} = \frac{1}{\sqrt{F_s \tau S_{gv}}} = \frac{\text{RQI}}{\Phi_z} 
\]  
(Eq. 3.8)

where

- \(F_s\) is the shape factor
- \(\tau\) is the tortuosity
- \(S_{gv}\) is the surface area per unit grain volume

RQI vs. \(\Phi_z\) can be plotted on a log-log plot as a straight line with equal slope for constant FZI values (Eq. 3.9 and Figure 3.10). Core samples with different FZI values lie on parallel lines corresponding to different rock types.

\[
\log \text{RQI} = \log \Phi_z + \log \text{FZI} 
\]  
(Eq. 3.9)

The note to consider here is that the Kozeny-Carman equation was derived for rounded spherical particles. The deviation of carbonate rocks from the theoretically perfect rounded hypothesis explains why the FZI technique sometimes fail to
represent carbonate reservoirs accurately where secondary porosity and fracture permeability prevail.

Figure 3.10: Flow zone indicator variation along porosity and permeability cross-plot.

Figure 3.11: Capillary pressure curves for different flow units with FZI comparison (redrafted after Udegbunam & Amaefule, 1996).

The RQI/FZI methodology is widely used especially in reservoir engineering studies as it is easily applied across different disciplines. The technique has a theoretical derivation using the Kozeny-Carman equation and correlates well with irreducible
water saturation. However, Al-Farisi et al. (2013) indicated that FZI does not correlate with irreducible water saturation especially for poly pore rock types.

Table 3.2: Hypothetical FZI values from two obviously different rock types

<table>
<thead>
<tr>
<th>Kh (md)</th>
<th>Phi (Dec)</th>
<th>FZI (μm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>0.05</td>
<td>3</td>
</tr>
<tr>
<td>1000</td>
<td>0.35</td>
<td>3</td>
</tr>
</tbody>
</table>

The FZI method is a petrophysical grouping approach and does not consider any rock texture, diagenesis or fracture effect on pore space and pore network. Thus, for complementing porosity and permeability values, similar FZI values (Table 3.2) might be wrongly grouped together as one rock type but in reality, have completely different depositional environments making lateral and vertical prediction misleading. The FZI bounds for each rock type are subjectively taken and thus cannot be transferred across similar field studies.


Lucia (1983, 1995, 1999, 2007) integrated Archie and Dunham’s schemes in an attempt to include depositional fabrics with a petrophysical property classification from several carbonate datasets. The scheme attempted to classify the pore space that created the pore network as well as the grains/crystals that created the rock volume. He separated pore space porosity into interparticle and vuggy. The interparticle porosity is then distinguished depending on the rock-grain to rock-mud relationship being grain-dominated or mud-dominated. The vuggy porosity, on the other hand, is distinguished based on the relationship between the connectivity of the vugs being separated vugs or touching vugs (Figure 3.12).
Lucia related interparticle porosity and permeability directly to describe different rock type classes. The classes were assigned Rock Fabric Numbers (RFN) attributed to the depositional fabric and petrophysical data (Figure 3.13):

- **Class 1**, RFN (0.05-1.5), large grains (larger than 100 µm), Displacement Pressure < 15 psia: Grainstone fabric
- **Class 2**, RFN (1.5-2.5), medium particle size (20 < particle size < 100 µm), Displacement Pressure ranging from 15-70 psia: Grain-dominated Packstone fabric
- **Class 3**, RFN (2.5-4.0), fine particle size (less than 20 µm), Displacement Pressure > 70 psia: Mud-dominated fabric

This classification attempted to group classes according to depositional fabric, porosity, permeability, grain size, and MICP displacement pressure.
Lucia (1999) tested out his work on Winland (Kolodzie, 1980) and Pittman’s (1992) published papers and concluded that for carbonate rocks there is no direct relationship between pore size and rock fabric.

Figure 3.13: Left: Depositional facies and associated RFN number behaviour on a porosity/permeability crossplot of non-vuggy limestone. Right: Rock fabric numbers of various classes (Redrafted after Lucia, 2007).

Lucia (2007) showed that the Buckles number and Rock Fabric Number (RFN) give the same trend of porosity and water saturation relationship for lower values of porosity indicating small pore sizes but vary for higher porosity values (Fig. 3.14).

Figure 3.14: Comparison between Lucia's Class Classification and Buckles numbers (redrafted after Lucia, 2007).
Lucia’s scheme is an integrated approach combining geological rock fabric and petrophysical pore space and is an excellent approach for static rock typing. This scheme is appropriate in explaining the significance of the presence and architecture of vugs, as distinct from interparticle pore fabrics. Rebelle et al. (2014) also commented on the non-applicability of Lucia's approach for reservoirs dominated by micro porosity.

3.3.11 Martin et al., 1997, 1999

Martin et al. (1997) used Winland's R35 method to characterize carbonates with regard to pore sizes and dominant types of porosity in the reservoir. They distinguished five categories of pore sizes:

- Megaport - R35 above a threshold of 10 μm
- Macroport - R35 ranging between 2–10 μm
- Mesoport - R35 ranging between 0.5–2 μm
- Microport - R35 ranging between 0.5–0.1 μm
- Nanoport - R35 of less than 0.1 μm

They classified porosity depending on the type of open space to be intergranular, intercrystalline, vuggy/moldic and fracture. For each category of pore size and porosity they proposed a type curve for capillary pressure and relative permeability (Figure 3.15).

They emphasized on the integration between different disciplines especially for water saturation modelling by looking at Pickett plots, Buckles’ plots and saturation height functions in order to understand the hydrocarbon distribution in the reservoir and fluid contacts.
Figure 3.15: Pore geometry classification including typical capillary pressure, pore throat profiles and relative permeability curves (redrafted after Martin et al., 1999 and Hartmann and Beaumont, 1999).

Martin et al.’s approach is petrophysical in nature in spite of the fact that the classification is related to geological porosity. It is a good integrative approach especially for water saturation modelling, but inherits the limitation of using a fixed number (R35) as a carbonate representative value, which many authors agreed changes with facies for a particular reservoir. Another limitation is the assumption that only one dominant pore throat size is representative for carbonate facies. R35 is not consistent within the same facies and varies within the same flow unit. These inconsistencies pose limitations in using R35 for lateral and vertical prediction for uncored wells.

3.3.12 Gunter et al., 1997

Gunter et al. (1997) described a graphical method for rock typing and flow unit identification following the mathematical concept of Max Lorenz, an economist, and its modification to the oil industry by Craig (1972). They plotted a continuous crossplot between cumulative flow capacity and cumulative storage capacity and named it the Stratigraphic Modified Lorenz Plot (SMLP) method. The slope and
inflection points identify flow units for a specific reservoir (Figure 3.16). The results were combined with Winland's R35 method and reservoir process speed (k/Φ). This method revealed the highest producing intervals, number of flow units and rock types to be characterized.

Figure 3.16: Stratigraphic Modified Lorenz Plot for a well showing flow units for a specific reservoir (From Chekani and Kharrat, 2009, SPE 123703).

Gunter et al.’s (1997) petrophysical method is easily applied using available routine core porosity and permeability data. However, it has no geological or sedimentological input in relating the observed porosity and permeability to their original depositional environment. It has the advantage of being able to quantify the number of flow units and their relative contribution in terms of storage and flow capacities.

3.3.13 Aguilera R., 2002

Aguilera (2002) used Pickett plots to characterize carbonate reservoirs. Pickett plots were obtained by plotting effective porosity versus true reservoir resistivity to calculate reservoir process speed, which is equal to k/Φ (Figure 3.17). Capillary pressure data, pore-throat apertures and Winland R35 value analyses were also included in their study to define hydraulic flow units.
Aguilera (1990b) showed that using Pickett plots could result in a straight line for intervals of constant permeability at irreducible water saturation. The straight line also represented intervals with constant capillary pressure and constant pore throat aperture radii. Aguilera’s method is a good classification technique when no core data is available.

Aguilera (2002), using data published by Kwon and Pickett (1975), developed \( r_{p35} \) referring to the size of pore throats at 35\% non-wetting phase saturation. It provided similar results to Winland R35 even though it was developed from different data sets than Winland.

![Pickett plot incorporating formation permeability and pore throat aperture radii; data from a well with high-porosity (From Aguilera, 2002).](image)

Formulation of \( r_p \) from different authors:

\[
 r_{p\,Winland} = 5.395 \left( \frac{k^{0.588}}{\Phi^{0.864}} \right) 
\]  
(Eq. 3.10)

\[
 r_{p\,Pittman} = 0.0534 \left( \frac{k^{0.8439}}{\Phi^{1.3729}} \right) 
\]  
(Eq. 3.11)

\[
 r_{p\,Aguilera} = 2.665 \left( \frac{k}{\Phi} \right)^{0.45} 
\]  
(Eq. 3.12)
where

- \( r_p \) is pore throat radius (microns)
- \( \Phi \) is porosity

It is worth noting that \( R_{35} \) values are calculated using a specific dataset and a correlation was achieved for that particular dataset. This means that the correlation value might be variable for different rock types and it is misleading to take the 35% as a fixed value for all reservoir rock types.

### 3.3.14 Corbett and Potter, 2004

Corbett and Potter (2004) used more than 3000 measurements of porosity and permeability from 24 wells and pioneered a global technique that could be universally applied. The technique was coined the “Petrotyping Approach”. Petrotyping uses a systematic series of FZI values that allow the determination of Hydraulic Unit boundaries to define ten Global Hydraulic Elements (GHEs) that can be applied to any reservoir (Figure 3.18). The definition of these boundaries was arbitrarily chosen in order to obtain a wide range of possible combinations of porosity and permeability in a manageable number of Global Hydraulic Elements (Corbett et al., 2003; Corbett and Potter, 2004).

Table 3.3: Hydraulic unit lower boundaries (shown as FZI values) for 10 Global Hydraulic Elements (GHEs) (*From Corbett and Potter, 2004*).

<table>
<thead>
<tr>
<th>FZI</th>
<th>GHE</th>
</tr>
</thead>
<tbody>
<tr>
<td>48</td>
<td>10</td>
</tr>
<tr>
<td>24</td>
<td>9</td>
</tr>
<tr>
<td>12</td>
<td>8</td>
</tr>
<tr>
<td>6</td>
<td>7</td>
</tr>
<tr>
<td>3</td>
<td>6</td>
</tr>
<tr>
<td>1.5</td>
<td>5</td>
</tr>
<tr>
<td>0.75</td>
<td>4</td>
</tr>
<tr>
<td>0.375</td>
<td>3</td>
</tr>
<tr>
<td>0.1875</td>
<td>2</td>
</tr>
<tr>
<td>0.0938</td>
<td>1</td>
</tr>
</tbody>
</table>
The method is easy and efficiently applied to carbonate and siliciclastic reservoirs. This was one of the early attempts to use a type curve methodology that could be transferred globally between carbonate fields.

### 3.3.15 Lønøy, 2006

Lønøy (2006) used some of Lucia’s (1983, 1995) definitions and Choquette and Pray’s (1970) classification to come up with a porosity scheme. He used thin section images for some of the pore system classifications and identified 20 pore types in this pore system classification according to the size and relative distribution of pores to the matrix (Table 3.4). Lønøy’s scheme takes into account spatial variability (patchy vs uniform) at the thin section scale and this needs to be upscaled to the
stratigraphic/reservoir scale. Perhaps the Stratigraphic Modified Lorenz Plot could be used to see patchy vs uniform Rock Type distributions.

Table 3.4: Lønøy’s Porosity Classification System (*From Lønøy, 2006*).

<table>
<thead>
<tr>
<th>PORE TYPE</th>
<th>PORE SIZE</th>
<th>PORE DISTRIBUTION</th>
<th>PORE FABRIC</th>
</tr>
</thead>
<tbody>
<tr>
<td>Interparticle</td>
<td>Micropores (10-50 µm)</td>
<td>Uniform</td>
<td>Interparticle, uniform micropores</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Patchy</td>
<td>Interparticle, patchy micropores</td>
</tr>
<tr>
<td>Mesopores (50-100 µm)</td>
<td>Uniform</td>
<td>Patchy</td>
<td>Interparticle, uniform micropores</td>
</tr>
<tr>
<td>Macropores (&gt;100 µm)</td>
<td>Uniform</td>
<td>Patchy</td>
<td>Interparticle, patchy micropores</td>
</tr>
<tr>
<td>Intercrystalline</td>
<td>Micropores (10-20 µm)</td>
<td>Uniform</td>
<td>Intercrystalline, uniform micropores</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Patchy</td>
<td>Intercrystalline, patchy micropores</td>
</tr>
<tr>
<td>Mesopores (20-60 µm)</td>
<td>Uniform</td>
<td>Patchy</td>
<td>Intercrystalline, uniform micropores</td>
</tr>
<tr>
<td>Macropores (&gt;60 µm)</td>
<td>Uniform</td>
<td>Patchy</td>
<td>Intercrystalline, patchy micropores</td>
</tr>
<tr>
<td>Interparticle</td>
<td></td>
<td>Interparticle</td>
<td></td>
</tr>
<tr>
<td>Molding</td>
<td>Micropores (&lt;10-20 µm)</td>
<td>Uniform</td>
<td>Moldic micropores</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Patchy</td>
<td>Moldic micropores</td>
</tr>
<tr>
<td>Vuggy</td>
<td></td>
<td>Vuggy</td>
<td></td>
</tr>
<tr>
<td>Mudstone microporosity</td>
<td>Micropores (&lt;10 µm)</td>
<td>Uniform</td>
<td>Tertiary chalk</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Patchy</td>
<td>Cretaceous chalk</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Chalky micropores, uniform</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Chalky micropores, patchy</td>
</tr>
</tbody>
</table>

Lønøy’s (2006) scheme is valuable however; it does not fill the gap of predicting how the flow units and barriers are distributed laterally and vertically. The rock fabric and depositional environment are not fully integrated in this scheme.

3.3.16 Mousavi et al., 2013

Mousavi et al. (2013) provided a new carbonate classification system where rocks were divided into three groups on the basis of their carbonate content: grain, cement, and mud. These rock types were defined as muddy rocks (with only mud and porosity), grainy rocks (grains, cement, and porosity) and mixed rocks (grain, mud, cement, and porosity). Each rock type was subdivided on the basis of pore geometries, as defined by other researchers (Table 3.5). Pore-size distribution (Lønøy, 2006) was used to define the size of pores in each subtype.
Table 3.5: New Carbonate-Rock Classification for Pore-Scale Modelling By Mousavi, 2013 (From SPE 163073).

<table>
<thead>
<tr>
<th>TYPE</th>
<th>SUBTYPE</th>
<th>MICROPORES (µm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Type I (Muddy rock) (only matrix &lt;20 µm)</td>
<td>Subtype I (interparticle porosity or Microporosity)</td>
<td>Micropores (&lt;10µm)</td>
</tr>
<tr>
<td></td>
<td>Subtype II (Touching-vug porosity)</td>
<td></td>
</tr>
<tr>
<td>Type II (Grainy rock) (Grains &gt;20 µm) (only grains and cement)</td>
<td>Subtype I (Interparticle porosity)</td>
<td>Micropores (10–50µm) Mesopores (50–100µm) Macropores (&gt;100µm)</td>
</tr>
<tr>
<td></td>
<td>Subtype II (Intercrystalline porosity)</td>
<td>Micropores (10–20µm) Mesopores (20–60µm) Macropores (&gt;60µm)</td>
</tr>
<tr>
<td></td>
<td>Subtype III (Interparticle porosity)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Subtype IV (Molding porosity)</td>
<td>Micropores (10–20µm) Macropores (&gt;20–30µm)</td>
</tr>
<tr>
<td></td>
<td>Subtype V (Touching-vug porosity)</td>
<td></td>
</tr>
<tr>
<td>Type III (Mixed rock) (Matrix &lt;20µm and Grains &gt;20µm) (Grains, Matrix and cement)</td>
<td>Subtype I (interparticle porosity)</td>
<td>Micropores (10–50µm) Mesopores (50–100µm) Macropores (&gt;100µm)</td>
</tr>
<tr>
<td></td>
<td>Subtype II (Intercrystalline porosity)</td>
<td>Micropores (10–20µm) Mesopores (20–60µm) Macropores (&gt;60µm)</td>
</tr>
<tr>
<td></td>
<td>Subtype III (Interparticle porosity)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Subtype IV (Molding porosity)</td>
<td>Micropores (10–20µm) Macropores (&gt;20–30µm)</td>
</tr>
<tr>
<td></td>
<td>Subtype V (Touching-vug porosity)</td>
<td></td>
</tr>
</tbody>
</table>

Mousavi et al.’s approach (2013) links rock fabric to porosity and type of associated pores. It is evident from the scheme that characterizing carbonates is not an easy task. Three geological rock types led to the identification of five porosity based rock types and 17 engineering pore based rock types. A one to one correlation between geological, petrophysical and engineering rock types is hard to achieve in carbonate reservoirs.
3.3.17 Wibowo et al., 2013

Wibowo et al. (2013) applied an integrated approach using data from eight carbonate reservoirs with complete core analysis data of 1,838 core plugs. They applied the Kozeny-Carman model and a comprehensive analysis was then carried out by plotting pore geometry against pore structure (PGS) on log-log graphs to come up with the Pore Geometry Structure (PGS) cross-plot (Figure 3.19). The PGS plot plots $\sqrt{(k/\Phi)}$ for y-axis against $(k/\Phi^3)$ for x-axis on a log-log graph. Straight lines indicate a similarity of both pore geometry and structure. This type of curve can be used for rock type differentiation.

Figure 3.19: Pore geometry-Pore structure crossplot and Rock Type Curves (redrafted from Wibowo, 2013).

Wibowo et al.’s (2013) method has not been fully tested by case studies and so it will be one of the methods verified in the present thesis. Wibowo’s method implies 23 rock types, which is too high a number to be used in a practical dynamic simulation model.

3.3.18 Log Clustering and Electrofacies

Log clustering and the concept of electrofacies is based on using wireline logs alone or integrated with other data sets to come up with groupings/clusters representing similar rocks with similar wireline log responses.
Serra and Abbot (1982) used the term electrofacies to represent different lithofacies predicted from wireline logs. They defined electrofacies as "the set of log responses that characterize a sediment and permit the sediment to be distinguished from others". The segmentation of intervals to electrofacies was achieved by zonation and clustering. This method was an early attempt to use computer technology and the advances in digital petrophysics to help in rock typing but it was difficult to implement. Wolff and Pellissier-Combesoure (1982) attempted one of the early trials to automate rock typing using wireline log signatures. A software was developed to characterize facies from the continuous well log data. Principal component and modal distribution analyses were used as a multi-dimensional space for points clustering. Shin-Ju and Rabiller (2000) investigated the dimensionality problem of wireline logs and the geological framework surrounding it. The wireline log space is not equivalent to the geological space, and two points that are close to each other in log space may not always be similar geologically. They developed a two-step method for facies analysis. The first step is to choose a large number of clusters for automatic clustering. The second step involves manually merging small clusters into electrofacies with common geological characteristics. They used Multi-Resolution Graph-based Clustering to determine the optimal number of clusters for electrofacies definition.

Xu et al. (2012) introduced a new method for petrophysical rock classification in carbonate reservoirs that honors multiple well logs and emphasizes the signature of mud-filtrate invasion. An inversion-based algorithm was implemented to simultaneously estimate mineralogy, porosity, and water saturation from well logs. Rock types derived from the new method were in good agreement with lithofacies described from core samples. Smith et al. (2014) used and summarized NMR response for log characterization of carbonate reservoirs.

Electrofacies clustering is a great tool when integrated with other log types. If properly integrated with the core description, thin section petrography, bore hole image logs and routine core analysis then it becomes a powerful tool for places with uncored intervals. Multi regression analysis, neural networks and principle component analysis, among others, are methods used to predict continuous log from other available sources.
3.4 Critical review and concluding remarks

Static rock typing (SRT) is an integrated approach combining geology and petrophysics. Geological rock typing (GRT) emphasizes the depositional, diagenetic and fracture processes on the rocks. On the other hand, petrophysical rock typing (PRT) uses wireline and routine core analysis to quantify reservoir petrophysical parameters. Applying the static rock typing concept on cored intervals allows for the integration of petrophysical parameters such as porosity, permeability, water saturation, pore throat radius with geological rock types including depositional fabric, diagenesis and fracturing mechanisms.

Table 3.6: A brief summary of the advantages and limitations of static rock typing techniques:

<table>
<thead>
<tr>
<th>Advantages</th>
<th>Limitations</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Good match between routine core and wireline data</td>
<td>• Geological/Sedimentological incorporation is poor</td>
</tr>
<tr>
<td>• Moderate incorporation of special core analysis</td>
<td>• Petro-facies are statistically driven</td>
</tr>
<tr>
<td>• Prediction using advanced techniques like neural networks, multi-linear</td>
<td>• Number of Petro-facies is subjective</td>
</tr>
<tr>
<td>regressions, principle component analysis</td>
<td>• No lateral predictability</td>
</tr>
<tr>
<td>• Good separation between Petro-facies with minimal overlap</td>
<td>• Micro fractures might be beyond wireline resolution</td>
</tr>
<tr>
<td>• Easy to implement</td>
<td>• Cutoffs used have a dramatic effect on reservoir/no-reservoir and pay/no-pay identification</td>
</tr>
<tr>
<td></td>
<td>• Wireline tool acquisition artefacts</td>
</tr>
<tr>
<td></td>
<td>• Wettability changes with depth is seldom truly understood but rather globally extrapolated</td>
</tr>
</tbody>
</table>

SRT categories can be divided into:

- k and Φ techniques
  - (e.g. Amaefule FZI, Corbett GHE, etc.)
- S_w and Φ techniques
  - (e.g. Archie, Buckles, Aguilera, etc.)
- S_w and k techniques
  - (e.g. WWJ, etc.)
- Wireline Clustering
  - (e.g. Ebanks, etc.)
- Integrated Approach
  - (e.g. Lucia RFN, etc.)
k and Φ techniques are easy to use because of the direct application of routine core analysis. The major drawback in k and Φ techniques is assuming that the same rock type can represent a continuous porosity/permeability relationship from the low porosity/low permeability to the extremely high porosity/high permeability. Sedimentologically, this is seldom the case and banding of porosity and/or permeability solves this constraint. Porosity and permeability in carbonate rocks are not directly proportional, especially when they deviate from the intergranular, intragranular, interparticle, intercrystalline and intracrystalline porosities and approach vuggy, moldic and fracture behaviours.

Sw and Φ techniques are very insightful because of the use of water saturation, which is a quantitative measure that can be derived from analytical, petrophysical, and engineering sources using core analysis, wireline logs and saturation height functions respectively. To minimize the uncertainty of water saturation modelling the three mentioned quantities should be verified with each other. However, water saturation is one of the most uncertain quantities to measure. A slight change in clay content, wettability, or mineral composition will have a great impact on the outcome.

Sw and k techniques are even more attractive to use for rock typing, but the assumption that a linear relationship between both parameters exists in carbonate rocks is not always the case. In addition, the relationship can only be derived reliably from routine and special core analysis data. Permeability is even much harder to obtain than water saturation.

Wireline logs, however, are not a direct indicator of facies and rock types. They possess problems derived from acquisition, bore hole, and drilling mud. Conventional wireline logs have problems with bed effect, mud filtrate invasion, cavings and breakouts. They perform with less accuracy for thin bedded reservoirs, minerals effect, wettability change and clay effect. NMR and bore hole image tools yield a better resolution, but still possess part or all of these problems.

The integrated approaches of static rock typing are the backbone of any reliable rock typing methodology since they integrate rock and pore space. They only lack the rock
to fluid interaction which affects the dynamic movements of fluids within the pore system.

Diagenetic effects, fracture identification and poly pore sizes are only part of the problem that complicates the characterization problem since one effect might be seen by one data source but missed by another. For example, it is often found that vuggy porosity rock types as well as very high permeability rock types are seldom represented in routine core analysis because they are harder to acquire. Also, there is always a tendency to choose the sample in the better reservoir rock types missing the baffles thus over estimating reservoir performance.

The prediction of SRT’s for un-cored intervals utilizes the integration of cores, wireline logs and routine core analysis.
CHAPTER FOUR
REVIEW OF DYNAMIC/HYDRAULIC RESERVOIR AND FLUID
PROPERTY ROCK TYPING

4.1 Introduction

As stated before in previous chapters, carbonate reservoir rocks undergo a long process of alteration from deposition to diagenesis. The original depositional texture is often masked by secondary diagenesis and fracturing processes. The superposition of these processes results in a heterogeneous rock and a complex pore system. The heterogeneity of the pore space and pore network systems can be assessed by understanding the interaction between rock and fluid. Porosity, permeability, irreducible water saturation and specific surface area give a static snapshot of the static behaviour of reservoir rocks, while pore throat, pore size distribution, wettability, capillary pressure and relative permeability give another perspective of the dynamic behaviour of the rock-fluid interaction.

Chapters 2 and 3 highlighted depositional, rock and property reservoir aspects concerning fabrics, voids and pores from a static behavioural point of view. This, however, does not address the dynamic rock-fluid interaction which can only be deciphered through the understanding of multi-phase flow characteristics from rock-fluid relations represented by relative permeability, capillary pressure data (SCAL) and saturation height function (Masalmeh and Jing, 2004). This chapter focuses on the concepts and techniques used for Dynamic Rock Typing (DRT).

One of the important outcomes of a proper rock typing scheme is achieving a robust fluid distribution under static conditions. The hydrocarbon/water profile changes with regard to the rock type and distance from the free water level (Figures 4.1 and 4.2). It is often found that flow units having various rock properties will belong to different associated capillary pressure curves. The units might have a barrier at well locations, but be connected through a common aquifer away from the well bore. This will determine the saturation profile for each rock unit and allow for the possibility of multiple hydrocarbon water contacts. The possible hydrocarbon contact for each rock unit is related to the reservoir characteristics and threshold pressure. Above the
transition zone for each unit the saturation is at irreducible water saturation where only hydrocarbon is produced.

Figure 4.1: Multiple oil water contacts and free water level concept (modified after Archer and Wall, 1986).
4.2 Concept of Dynamic/Hydraulic Rock Typing Property

Classical static modelling requires populating reservoir grid cells with four major properties: facies, porosity, permeability and saturation. These properties are populated with the understanding of the impact of sedimentological, depositional, digenetic, and petrophysical processes. This concept however, fails to be robust as soon as the model is simulated dynamically because rock/fluid interaction is not included in the classification process. The static concept alone does not take into account wettability, capillarity and fluid distribution. This is the reason why the dynamic/hydraulic rock typing concept arose to include the rock/fluid interaction in the rock typing scheme (Gomes et al., 2008). The dynamics of rocks are affected by...
the scale of pore throat aperture radius and pore network connectivity. The primary tools used are routine and special core analysis.


Integrating static and dynamic rock typing techniques has been the focus of several authors over the years. Hamon (2003) showed that petrophysical parameters and wettability indices were able to model changes in relative permeability curves and recommended that relative permeability curves be used for the generation of multiphase flow rock types. Some trials included relative permeability in the classification process (Dernaika et al., 2013 and Compan et al., 2016). This was impractical on its own because of the scarcity in the number of relative permeability data, which did not cover all available reservoir/non-reservoir rock types (Skalinski and Kenter, 2013). Asgari and Sobhi, (2006) adapted a sequential approach, where they defined static rock types and then re-assigned them to dynamic rock types based on SCAL data. The effect of wettability was demonstrated on the characteristics of the relative permeability and capillary pressure curves of carbonate rocks to include multi-phase flow characteristics and wettability variation with depth (Masalmeh, 2002, Masalmeh et al. 2007, James et al., 2014). Ghedan (2007) approached this concept with a hierarchal alternative by imposing wettability to the classified static rock types.

Data sources with dynamic characteristics, such as NMR logs to determine T2 relaxation time, were used to fill the gap between static and dynamic concepts. Xu and Torres-Verdin (2012), proposed a new dynamic technique where they simulated a
mud-filtrate invasion process for each rock type and integrated the results with routine petrophysical analysis. They tried to simultaneously honour the saturation profile vertically and mud-filtrate invasion laterally.

Well tests and production logging tools, in combination with Stratigraphic Modified Lorenz Plots, have been also used to partition producing zones but are often only available over specific zones (Ellabad et al., 2001 Ellabad, 2003, Cortez and Corbett, 2005).

Digital rock typing is an emerging physical method using high resolution scanning and simulation techniques, which tries to mimic laboratory measurements and special core analysis with documented successes but is still not widely used (Grader et al., 2010, Amabeoku et al., 2013, Natarajan et al., 2014, Rahimov et al., 2016).

Dynamic rock typing is evaluated by calculating the saturation dependent capillary pressure versus the saturation achieved from wireline logs in pre-production initial wells. The physical parameters affecting dynamic rock typing include capillarity, pore size distribution and wettability are highlighted in the next section.

4.2.1 Balance of Forces

Hydrocarbon and water phase allocation is considered one of the most challenging and crucial tasks for geoscientists and reservoir engineers. Before production, a static system ensures an equilibrium between forces. The differential pressure across hydrocarbon and water phases is stabilized by the weight of water above the free water level. The static trapping mechanism is based on the equilibrium between the upward driving forces due to adhesion tension acting against a downward force due to the weight of the fluids.

Adhesion forces act between a solid and a liquid, while cohesion forces hold the liquid molecules together. In static conditions, the adhesion forces between solids and water are stronger than the cohesion forces and thus water sticks to the solid surface. In a narrow tube, and because of the effect of capillarity, the adhesion forces are so strong that water actually defies gravity and rises above the flat free water level.
The curved surface in the capillary tube is called the meniscus and can be a concave meniscus between water and air or a convex meniscus between mercury and air. The convex meniscus between air and mercury is due to the fact that the cohesion forces of mercury are stronger than the adhesion forces between mercury and glass. A convex boundary exists between the immiscible fluid phases in the pore space, where the non-wetting phase pressure is greater than the wetting phase pressure (Amyx et al., 1960).

Surface tension is defined as the cohesion forces between the molecules of a liquid along the contact surface between two immiscible fluids. Arps (1964) defined capillary pressure as the pressure drop in a reservoir system across the interface between two fluid phases under static conditions. Capillary pressure is characterized by the variation in pressure between non-wetting and wetting immiscible fluids occupying the pore space in a reservoir rock.

Mercury Injection Capillary Pressure (MICP) and relative permeability data reveal a great deal about the rock and fluid interaction in both static and dynamic conditions. Porosity, permeability, irreducible water saturation, wettability and pore throat distribution are all parameters that affect the shapes of the capillary pressure and relative permeability curves.

The oil phase starts to become moveable when reaching a specified saturation, which is governed by the shape of the relative permeability curve (Figure 4.3). The same saturation reveals the transition zone above the free water level attained from capillary curves. This defines the location of the hydrocarbon water free one-phase production versus commingled water/hydrocarbon two-phase production.
Physically, capillary pressure can be expressed as the pressure variation between non-wetting and wetting phases (Amyx et al., 1960, Eq. 4.1). Simplifying the actual reservoir behaviour, the pore throat radius of a capillary tube in the lab can be modelled to be inversely proportional to capillary pressure as can be shown by the Washburn equation (1921, Eq. 4.2, Figure 4.4).
\[ P_c = P_{nw} - P_w \quad \text{(Eq. 4.1)} \]

\[ P_c = \frac{2\sigma \cos \theta}{r} \quad \text{(Eq. 4.2)} \]

where
- \( P_c \) is capillary pressure (psia)
- \( \sigma \) is interfacial tension (dyn/cm)
- \( \cos \theta \) is contact angle (degrees)
- \( r \) is pore throat radius (microns)

The capillary pressure is inversely proportional to the pore throat radius. Purcell (1949) related laboratory conditions of capillary pressure to reservoir conditions based on the following relationship:

\[ P_{c_{res}} = \frac{P_{c_{lab}} \sigma_{res} \cos(\theta_{res})}{\sigma_{lab} \cos(\theta_{lab})} \quad \text{(Eq. 4.3)} \]

where
- \( \text{res} \) is reservoir condition
- \( \text{lab} \) is lab condition

The static hydrocarbon trapping mechanism is based on the equilibrium between two forces acting against each other. The upward driving force due to adhesion tension is acting against the downward force from the weight of the fluids.

\[ \text{Upward Force} = 2\pi r A_T \quad \text{(Eq. 4.4)} \]

where
- \( A_T \) is Adhesion tension (N/m)
- \( r \) is radius of capillary tube (m)
\textit{Downward Force} = \pi r^2 H (\rho_l - \rho_a) \quad (\text{Eq. 4.5})

where

- \( H \) is height of capillary rise (ft)
- \( \rho_l, \rho_a \) is liquid and air density (lbm/ft³)
- \( g \) is gravity acceleration (ft/s²)

\[ 2\pi r A_T = \pi r^2 H (\rho_l - \rho_a) \quad (\text{Eq. 4.6}) \]

\[ H = \frac{2A_T}{r \left( \rho_l - \rho_a \right) g} \quad (\text{Eq. 4.7}) \]

where

- \( A_T \) is \( \sigma \cos \theta \)

\[ P_c = P_a - P_l \quad (\text{Eq. 4.8}) \]

\[ P_c = g (\rho_l - \rho_a) \left( \frac{2\sigma \cos(\theta)}{2g(\rho_l - \rho_a)} \right) = \frac{2\sigma \cos(\theta)}{r} \quad (\text{Eq. 4.9}) \]

These equations represent the background for most of the models highlighted in this chapter.

4.2.2 Wettability Effect

Carbonate rocks exhibit changes in wettability along the hydrocarbon column because of their complex and heterogeneous mineralogical nature (Table 4.1). This variation in wettability along the hydrocarbon column is common in carbonate reservoirs (Figure 4.5). There are some preferential wettability towards some rock types (Table 4.1) and some hydrocarbon mixtures (Figure 4.6). Some measures were devised for measuring wettability; e.g. Corey exponent and wettability indices. It has been observed that some carbonate reservoirs may exhibit a strong oil wet nature at the top.
of the reservoir and a strong water wet nature at the bottom of the reservoir. This might also be complicated when mixed or alternating wettability is observed.

Figure 4.5: Variation in wettability for a carbonate reservoir with respect to Free Water Level (FWL) (redrafted after Marzouk et al., 1995).

Table 4.1: Probable Wettabilities of Different Reservoir Minerals (after Worden and Morad, 2000)

<table>
<thead>
<tr>
<th>Oil Wet Minerals</th>
<th>Water Wet Minerals</th>
</tr>
</thead>
<tbody>
<tr>
<td>Calcite</td>
<td>Quartz</td>
</tr>
<tr>
<td>Dolomite</td>
<td>Kaolinite Single Crystal</td>
</tr>
<tr>
<td>Ferroan dolomite</td>
<td>Unweathered Feldspar</td>
</tr>
<tr>
<td>Kaolinite booklets</td>
<td></td>
</tr>
<tr>
<td>Fe-rich smectite</td>
<td></td>
</tr>
<tr>
<td>Haematite</td>
<td></td>
</tr>
<tr>
<td>Weathered Feldspar</td>
<td></td>
</tr>
<tr>
<td>Fe-rich chlorite</td>
<td></td>
</tr>
</tbody>
</table>

For strongly water wet reservoirs, the water fills the small pores and adheres to the walls of the grains. Mixed wettability is encountered when there is no preference for being water or oil wet or when the smaller pores are water wet and the larger pores are oil wet. On the other hand, fractional wettability is observed in heterogeneous reservoirs where some grains are oil wet and others are water wet. For strongly oil
wet reservoirs, the complete opposite occurs, where the small pores are dominated by oil and there is a tendency for the rock to be filmed by a layer of oil (Figures 4.7 & 4.8).

Figure 4.6: Conceptual wettability changes with regard to reservoir mineralogy and hydrocarbon fluid type (redrafted after Worden and Morad, 2000).

Figure 4.7: Wettability changes and fluid/rock grain interaction (after Pourmohammadi, 2009).
Figure 4.8: Changes of capillary pressure curve shapes with respect to changing the contact angle (redrafted after Kwon and Pickett, 1975).

4.2.3 Pore Throat and Pore Size Distribution

Just as carbonate rocks are highly affected by the superposition of processes from the time of deposition to diagenetic alteration, so are the pores and pore structures. Lønøy (2006) realized that pore size distributions are more important than grain size distributions when it comes to the classification of carbonate rocks. Pore structure is defined as the spatial and size distribution, shape and interconnection of pores. Several models represented pore structure as a packing of spheres, bundles of capillary tubes, or networks of capillary tubes (Kwon and Pickett, 1975). Complex pore system modality in carbonate rocks is common. It can be mono-modal, bi-modal, tri-modal or poly-modal. Lucia (1999) concluded that no relationship between porosity and permeability could be modelled without a factor for pore size distribution.

Mercury injection experiments are used to determine the effective interconnected pore size distributions. Measurements reach high pressures (>50000 psi), however older
measurements reached only 2000 psi and hence only large pores could be deciphered. Injected mercury volume increment is a result of the increment in pressure and represents a specific contribution of pore throat size limits. Some smaller pore sizes are not occupied by mercury until their displacement pressure is reached (Figure 4.10).

Figure 4.9: A schematic indicating pore size influence on capillary pressure measurements (modified after Dandekar, 2013).

Pore size distribution influences the amount of irreducible water saturation and height of the transition zone (Harrison and Jing, 2001). Five basic flow unit sizes were classified (after Martin et al., 1997):

- Megaport (>10 μm)
- Macroport (2-10 μm)
- Mesoport (0.5-2 μm)
- Microport (0.1-0.5 μm)
- Nanoport (<0.1 μm)
Pittman (1992) defined a pore throat radius that separates effective porosity from non-
effective porosity and assigned the value to be 0.5 μm. A continuous mercury film in
the pore system was investigated by Swanson (1981), where he defined a point on the
capillary pressure curve that represented the continuous interconnected pore system.

Figure 4.10: Pore throat size contributing to capillary pressure behaviour (modified
after Beaumont and Foster, 1995).
4.2.4 Entry, Threshold and Displacement Pressure

In most practical applications of reservoir engineering, the following pressures are usually considered: threshold pressure, displacement pressure and entry pressure (Figure 4.11). They differ in their physical behaviour as follows:

- **Entry pressure** is the minimum pressure where the non-wetting phase primarily enters the pores of the rock. This point is related to the largest pore throat size in the sample attributed to the first flow (Pittman, 1992). However, an irregularity of the sample surface disturbs proper identification of this point.

- **Threshold pressure** is determined by the inflection point where mercury forms a connected path and where the mercury injection curve becomes convex upwards (Katz and Thompson, 1987). Swanson (1977) determined this point as corresponding to the apex of a hyperbola on a log-log plot. Pittman (1992) drew a 45 degree line as a tangent to a hyperbola representing the same apex point. He also created a more accurate plot to define the inflection point as the point where mercury fills most of the population of pores sizes representing the main fraction of porosity in the rock. Values between 3-10% of the total mercury saturation were chosen by many investigators.

- **Displacement pressure** is defined as the extrapolated displacement pressure from a log-log plot of capillary pressure and mercury saturation (Thomeer, 1960). Schowalter (1979) chose it to be close to 10% mercury saturation (defined as the extrapolation of mercury pressure curve when the non-wetting phase is displacing the wetting phase to enter the sample).
The injection pressure is affected firstly by the largest pores, thus allowing the capillary pressure to rise. This rise allows the non-wetting fluid to invade the medium sized pores until the pressure is high enough to enter the smallest pores depending on the wettability. The modal pore throat size in this example is the highest occurrence of pore throat size available (Figure 4.12).
Table 4.2: Pore Size Classifying Parameters (after Davies et al., 1999)

<table>
<thead>
<tr>
<th>Pore Size Classifying Parameters</th>
<th>Definition/Determination Methodology</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pore Size and Shape</td>
<td>Determined via scanning electron work</td>
</tr>
<tr>
<td>Pore Throat Size</td>
<td>Determined via scanning electron work and capillary tests</td>
</tr>
<tr>
<td>Aspect Ratio</td>
<td>Ratio of pore body to throat size</td>
</tr>
<tr>
<td>Characterization Number</td>
<td>The number of pore throats intersecting each pore</td>
</tr>
<tr>
<td>Pore Arrangement</td>
<td>Pore distribution is analyzed</td>
</tr>
</tbody>
</table>

4.2.5 Effect of Permeability

The pore system of a rock is closely linked to permeability. The shape and relative position of the capillary pressure curve on a saturation vs. pressure plot is a direct sign of overall rock permeability (Figure 4.13). The shape of the flat portion of the capillary curve is an indication of the dominant pore size contributing to permeability (Figure 4.14).

Figure 4.13: Sorting effect on permeability of three carbonate samples (after Wu, 2004).
Figure 4.14: Relationship between permeability and capillary pressure.

Figure 4.15: Plot showing the effect of permeability change on the shape of the profile of water saturation vs. capillary pressure.

Capillary pressure shape variation is linked to pore throat size distribution describing permeability pore network system. Uni-modal and multi-modal pore systems change the shape of the profile dramatically. The increase in permeability and pore throat
size sorting shifts the profile to the lower left of a water saturation versus capillary pressure plot.

For a water-oil two phase system, when the capillary pressure is less than the entry pressure only one phase exists. For water-wet reservoirs this represents the water aquifer. As the capillary pressure increases, representing the central portion of the profile, a two-phase system exists representing the transition zone, where two-phase production is imminent. As the capillary pressure increases further, the wetting phase will decrease to a minimum value that cannot be decreased further even with an increase in pressure. At this point, capillarity forces take over gravitational forces and this might represent irreducible water saturation, where only one phase oil will flow.

![Carbonate Classification based on Dynamic/Hydraulic Rock Typing](image)

Figure 4.16: Categorization of dynamic/hydraulic reservoir and fluid rock typing methods and associated authors.
The methods of dynamic/hydraulic reservoir and fluid rock typing can be grouped based on:

- Statistical Clustering
- Simulating Flow
- Wireline Log Based Saturation Height Function
- Capillary Pressure Modelling
- Integrating SCAL and Wireline Data
- Pore Throat Size

These classification schemes were grouped according to various disciplines into the following main categories:

- Kozeny (1927)-Carman (1937, 1956)
- Leverett’s J-function (1939, 1941)
- Guthrie and Greenberger’s Polynomial (1955)
- Thomeer's Hyperbola Model (1960, 1983)
- Brooks and Corey (1964, 1966)
- Lambda Function
- Heseldin (1974)
- Kwon and Pickett (1975)
- Winland’s R35 (Kolodzie, 1980)
- Swanson (1981)
- Wells and Amaefule (1985)
- Pittman (1992)
- Ibrahim et al. (1992)
- Johnson - “Pseudo-Permeability” (1987)
- Cuddy et al.’s BVW, FOIL Function (1993)
- El-Khatib’s Modified J-function (1995)
- Skelt & Harrison (1995)
- Shedid Characterization Number (2003, 2013)
- Wu (Modified Thomeer) (2004)
4.3 Review of Dynamic Property Rock Typing

4.3.1 Kozeny (1927)-Carman (1937, 1956)

Kozeny (1927) developed a theory for estimating the velocity of a fluid for a sequence of capillary tubes with identical length. Carman (1937) verified Kozeny's equation and added variables representing the hydraulic radius and specific surface per unit mass of solid (Eq. 4.10).

\[ v = \gamma \left( \frac{I}{\mu} \right) c \left( \frac{\Phi^2}{\sigma_1^2} \right) \]  
(Eq. 4.10)

where

- \( v \) is the Darcy velocity
- \( \gamma \) is the unit weight of the fluid
- \( I \) is the hydraulic gradient
- \( \mu \) is fluid viscosity
- \( c \) is a geometric constant
- \( \sigma_1 \) is its specific surface expressed in squared metres per unit bulk volume of the porous material

Although Kozeny (1927) and Carman (1937, 1956) never published their work jointly, their combined contribution is referred to as the Kozeny-Carman equation. The equation simulates a pressure drop through a porous media for a flowing fluid. It assumes the reservoir to behave like a collection of capillary tubes and relates it to Poisseuille's law and Darcy's law to derive a relationship between porosity and permeability.

The Kozeny–Carman equation is given by:

\[ \frac{\Delta P}{L} = \frac{180 \mu}{\Phi^2 D_p^2 \Phi_5^3} \nu_s \]  
(Eq. 4.11)
where

- $\Delta p$ is the pressure drop
- $L$ is the total height of the bed
- $\omega_s$ is the superficial or “empty-tower” velocity
- $\Phi_s$ is the sphericity of the particles in the packed bed
- $D_p$ is the diameter of the related spherical particle

There are many forms of this equation, but a general form demonstrates that permeability is dependent on the pore geometry, making permeability a function of porosity and specific surface area.

\[
k = \frac{\Phi_e^3}{(1-\Phi_e)^2} \left( \frac{1}{F_s \tau^2 S_{gv}} \right)
\]  
(Eq. 4.12)

where

- $\Phi_e$ is effective porosity
- $F_s$ is shape factor (2 for circular cylinder)
- $S_{gv}$ is the surface area per unit grain volume
- $(F_s \tau^2)$ is named Kozeny's constant

In some publications and applications by different authors, $S_{gv}$ is ignored in the equation. Kozeny's constant $(F_s \tau^2)$ is uniform within a particular hydraulic unit but varies between distinctive flow units (Amaefule et al., 1993).

$(F_s \tau^2)$ and $S_{gv}$ values are also hard to determine and thus limit the direct use of the Kozeny-Carman equation. Kozeny’s constant is an empirical constant that depends on the cross sectional shape of the flow paths. Aguilera (2004) presented one form for deciphering Kozeny’s constant $(F_s \tau^2)$ to be written according to the following equation:
\[
F_s \tau^2 = 114.14 (k/\Phi)^{-0.1} = 89.543 \, r_{p35}^{-0.2222} \quad \text{(Eq. 4.13)}
\]

where \(r_{p35}\) is the size of pore throats at 35% non-wetting phase saturation, which indicates that the constant is a function of porosity and permeability and consequently \(r_{p35}\). According to Rose and Bruce (1949), the value of \((F_s \tau^2)\) ranges between 5 and 200.

Berryman and Blair (1986, 1987) used image analysis to estimate the constants presented in the Kozeny–Carman equation. They concluded that estimating the specific surface is problematic as it cannot be predicted with accuracy. The accuracy of the equation was also questioned especially where deposits have a high percentage of clayey material (Urumovic et al., 2014).

The Kozeny-Carman equation is accepted among reservoir engineers because of its theoretical basis and the fact that it is derived from Darcy’s law. The equation works well for rocks with dominant depositional porosity. It also proved to work well when permeability could be directly related mathematically to porosity. However, it fails where permeability is not dependent on porosity as is the case in vuggy and fracture permeability reservoirs.

4.3.2 Leverett, 1939, 1940, 1941

The definition of capillary pressure, as stated earlier, is the pressure difference across the interface between two immiscible fluids arising from capillary forces. These capillary forces are surface tension and interfacial tension. In a porous hydrocarbon-water system, this capillary pressure can be defined as:

\[
P_c = \frac{2 \sigma \cos \theta}{r} \quad \text{(Eq. 4.14)}
\]
Leverett pioneered laboratory work which was conducted to measure capillary pressure saturation experiments. He used six unconsolidated samples with different mesh sizes to obtain drainage and imbibition capillary curves. His concept involved applying thermodynamic and physical concepts statically and dynamically. In 1941, he formulated a dimensionless expression for capillary pressure grouping. The dimensionless function (J-function) is achieved by the normalization of core capillary pressure data. By plotting J-function versus water saturation (Figures 4.17 and 4.18), an average capillary pressure curve was obtained from the regression plot using a power function representing a given rock type (Leverett 1939, 1941) (Eq. 4.15).

\[
J = a (S_w)^b \tag{Eq. 4.15}
\]

where

- \( J \) is dimensionless function

Leverett related the average pore radius (\( r_p \)) to porosity and permeability:

\[
r_p = \sqrt{\frac{8k}{\phi}} \tag{Eq. 4.16}
\]

A dimensionless function can be written as:

\[
J(S_w) = \frac{p_c}{\sigma} \sqrt{\frac{k}{\phi}} \tag{Eq. 4.17}
\]
Some authors added the contact angle (Rose and Bruce, 1949) to include the effect of wettability:

\[ J(S_w) = \frac{P_c}{\sigma \cos(\theta)} \frac{\sqrt{k}}{\sqrt{\Phi}} \]  

(Eq. 4.18)

Other authors found that using the J-function without the contact angle term yielded better results (Anderson, 1987).

Figure 4.17: Typical behavior of dimensionless J-function versus water saturation from special core analysis.
The relationship between porosity and permeability is referred to by some authors as Leverett’s Reservoir Quality Index and is given by (Eq. 4.19 and Figure 4.19):

\[
(RQI) = \sqrt{\frac{k}{\Phi}}
\]  

(Eq. 4.19)

Figure 4.18: Illustration using Leverett’s dimensionless function versus water saturation showing drainage and imbibition curves (Leverett, 1941).

Figure 4.19: Core based Leverett’s RQI in North Sea field case showing various rock types (redrafted after Xu & Torres-Verdin, 2012).
Leverett's Reservoir Quality Index can be derived from $P_c$ and water saturation ($S_w$), irreducible water saturation ($S_{wirr}$), and using the J-function model as follows (Xu and Torres-Verdín, 2012):

$$S_w = S_{wirr} + af^b \Rightarrow J(S_w) = \left(\frac{S_w - S_{wirr}}{a}\right)^{\frac{1}{b}} \quad \text{(Eq. 4.20)}$$

$$\sqrt[\Phi]{\frac{k}{P_c}} = \frac{J(S_w)}{P_c} \cdot \sigma \cos \theta = \left(\frac{S_w - S_{wirr}}{a}\right)^{\frac{1}{b}} \cdot \frac{\sigma \cos \theta}{P_c} \quad \text{(Eq. 4.21)}$$

A modification to the J-function was proposed by El-Khatib (1995). He added a tortuosity factor to the equation to include porosity, irreducible water saturation and permeability.

$$J^*(S_w) = \frac{P_c}{\sigma \cos(\theta)} \cdot \sqrt[\Phi]{\frac{k \tau}{(1 - S_{wirr})}} \quad \text{(Eq. 4.22)}$$

where

- $J$ is modified dimensionless J-function
- $S_{wirr}$ is irreducible water saturation (fraction)

By plotting $P_c$ versus normalized water saturation $\frac{S_w - S_{wirr}}{1 - S_{wirr}}$ on a log-log plot, the intercept will yield an estimation of tortuosity ($\tau$).
Several case studies tested the J-function concept such as the one carried out by Stolz and Graves (2003) where they compared seven methods of flow unit through a reservoir simulation study. They stated that the use of the J-Function gave the most similar dynamic reservoir performance to the fine scale simulation model. Sarwaruddin et al. (2001) realized that changing the irreducible water saturation and saturation exponent had a significant effect on the capillary pressure profile, which meant that the J-function by itself could not be used as a grouping criterion for carbonate rock typing. They proposed a modified version of the J-function, where the pore size distribution effect was included in the form of a saturation exponent, irreducible liquid saturation and tortuosity.

From the previous discussion, we conclude that the J-function is correctly used to evaluate a single rock type with a similar pore structure. As the function simulates averaging the connectivity of the effective pore network, the model concept assumes a uni-modal pore throat size distribution. It works well with homogeneous reservoirs having a mono-modal pore network system. This is unusually attributed to the normal increase in permeability with the increase of grain size and inter/intra pore system. It fails where the micro and/or secondary porosity dominates the voidage space. The use of the J-function to group heterogeneous rock types in one function will yield erroneous results. Banding of poro-perm groups has given better results, where for each group a separate J-function is used (Wiltgen et al., 2003).

### 4.3.3 Guthrie and Greenberger Polynomial, 1955

Guthrie and Greenberger (1955) tried to statistically analyze a correlation dependency between porosity, permeability and irreducible water saturation. The method required analyzing capillary pressure data in order to derive a correlation between the three parameters (k, phi, S_{wirr}) for a given capillary pressure data set grouping (Figures 4.20 and 4.21).

They established a linear formulation of the correlation between water saturation, porosity and logarithm of porosity in the form of (Eq. 4.23):

$$S_w = a_1 \Phi + a_2 \log(k) + c$$  
(Eq. 4.23)
Then they tried different quadratic formulations which gave better results. These were in the form of:

\[
S_w = a_1 \Phi + a_2 \log(k) + a_3 (\log(k))^2 + c
\]  

(Eq. 4.24)

\[
S_w = a_1 \Phi + a_2 \Phi^2 + a_3 \log(k) + a_4 (\log(k))^2 + c
\]  

(Eq. 4.25)

\[
S_w = a_1 \Phi + a_2 \Phi^2 + a_3 \log(k) + a_4 (\log(k))^2 + a_5 \frac{k}{\phi} + c
\]  

(Eq. 4.26)

where

- \(a_1, a_2, a_3, a_4, a_5, c\) are constants from the data fitting
Wooddy and Wright (1955) applied the Guthrie-Greenberger concept to compare capillary pressure profiles with different permeabilities and assigned constant porosity. Pletcher (1994) suggested the use of the Guthrie-Greenberger approach to construct an average capillary pressure curve corresponding to average k and Φ from a series of capillary pressure curves of different k and Φ from the same reservoir (El-Khatib, 1995). The set of equations could be used to estimate connate water saturation for a specific reservoir when porosity and permeability are known. If a statistical correlation between the three parameters cannot be achieved then the method cannot be used. It, however, shows clearly that porosity, permeability and water saturation are three independent variables and any attempt to correlate one with respect to the other will always be an approximation and not an exact estimation.
4.3.4 Thomeer's Hyperbola Model (1960, 1983)

Thomeer (1960) tested 144 samples and presented a mathematical hyperbolic representation of capillary pressure data. He plotted a log-log plot where the x-axis represented the volume of injected mercury and the y-axis represented the pressure applied. He demonstrated that the shape of the capillary pressure curve characterized the pore structure and its interconnectivity in the rock. The formulation included pore geometric factor (G), displacement pressure ($P_d$), and interconnected pore volume ($V_b$). The process imitated the drainage process where the non-wetting phase displaces the wetting phase.

\[
\frac{(V_b)_{P_c}}{(V_b)_{P_\infty}} = e^{-\frac{G}{\log(P_c/P_d)}} \tag{Eq. 4.27}
\]

where
- $(V_b)_{P_c}$ is Fractional bulk volume occupied by mercury at pressure $P_c$
- $(V_b)_{P_\infty}$ is Fractional bulk volume occupied by mercury at infinite pressure
- $P_c$ is mercury/air capillary pressure (psia)
- $P_d$ is mercury/air extrapolated displacement pressure (psia)
- $G$ is pore geometrical factor (dimensionless)

or in terms of saturation:

\[
\frac{(S_b)_{P_c}}{(S_b)_{P_\infty}} = e^{-\frac{G}{\log(P_c/P_d)}} \tag{Eq. 4.28}
\]

where
- $(S_b)_{P_c}$ is Mercury saturation at capillary pressure $P_c$ (fraction)
- $(S_b)_{P_\infty}$ is Mercury saturation at infinite capillary pressure (fraction)

The pore geometric factor ($G$) is a positive number and ranges from zero to 10, where high values indicate poor quality reservoirs and low values indicate higher quality reservoirs (Figure 4.22). $G$ represents the curvature at the apex of the capillary pressure. Lucia (2007) indicated that entry capillary pressure correlated quite well with porosity, while there was no correlation between porosity and $G$ factor.
Figure 4.22: Thomeer (1960) plot showing the relationship between fractional bulk volume occupied by mercury, mercury/air capillary pressure and (G) the pore geometrical factor.

For multimodal pore systems, several hyperbolas can be superimposed to replicate the complex carbonate pore network system (Clerke, 2009).

Figure 4.23: Superposition of multiple Thomeer hyperbolas allows parameterization of complex pore systems and accounts for micro-macro porosity modes (redrafted after Smart et al., 2016).
Thomeer’s parameters are insightful where they correspond to physical properties of the rock ($S_{wi}$ and $P_d$). Thomeer (1983) continued his work and constructed a relationship between permeability and pore network parameters. He used 279 rock samples (165 siliciclastic rock sample and 114 carbonates) from 54 fields. He produced an empirical formulation as follows:

$$k = 3.8068 G^{-1.3334} \left( \frac{S_{b}\infty}{P_d} \right)^{2.0}$$

(Eq. 4.29)

Figure 4.24: Correlation between Leverett's RQI and Thomeer's G factor (redrafted after C. Xu and C. Torres-Verdin, 2012).
Figure 4.25: Correlation between $G$, $k/\Phi$ and $S_{wi}$ (redrafted after Wu, 2004 based on data from Petty, 1988).

\[
\log(P_c) = \left( \frac{G}{\ln 10} \right) \times \left( \frac{1}{\log S_{Hg}} \right) + \log(P_d) \quad \text{(Eq. 4.30)}
\]

Thomeer’s parameters can be obtained using a linear plot where the x-axis is $1/\log(S_{HG})$ and the y-axis represents the $\log(P_c)$. The linear trend will have a slope of $(-G/\ln 10)$, while the intercept will represent $\log(P_d)$ (Figure 4.26).

Figure 4.26: Thomeer’s parameters fitting criteria (redrafted after Rebelle and Lalanne, 2014).
Ghorayeb et al. (2011) used the Thomeer function in terms of height above free water level in the following form:

\[
S_w = S_{w_{irr}} + (1 - S_{w_{irr}}) \left\{ 1 - e^{\frac{g}{Pe \ln(HAFWL / RCF)}} \right\} \tag{Eq. 4.31}
\]

where

- \( S_{w_{irr}} \) is Irreducible water saturation (fraction)
- \( HAFWL \) is height above free water level
- \( P_e \) is Entry Pressure (psi)
- \( RCF \) is Reservoir Conversion Factor

Clerke (2003, 2008, 2009) demonstrated examples of using the Thomeer fitting in the Ghawar field in Saudi Arabia including dual porosity models and pointed out that permeability is most affected by the largest pores corresponding to the entry pressure and showed that Thomeer’s method can generate synthetic capillary pressure curves where no SCAL data is available.

Figure 4.27: 3D clustering of Thomeer parameters \((G, P_d, (V_b)_{P_{\infty}})\) to define petrophysical rock typing (Clerke, 2008).

Several advantages were highlighted by Calvert and Ballay (2011) using Thomeer’s parameterization such as: independency of permeability, superposition of hyperbolas, representation of texture, separation of facies clusters, and predictability of irreducible
water saturation. Thomeer’s method can thus reliably predict free water level even in transition zones (Wiltgen et al., 2003). For a specific rock type and known range of porosity, permeability, water saturation and FWL, if three of these parameters are known then the fourth can be predicted (Haynes, 1995). Thomeer’s application is widely used and accepted in the oil industry especially among reservoir engineers.

4.3.5 Brooks and Corey 1964, 1966

Brooks and Corey (1964, 1966) developed a theoretically solid correlation between effective water saturation ($S_e$, sometimes denoted $S^*$) and capillary pressure ($P_c$) as a function of threshold pressure ($P_{th}$) (sometimes replaced by $P_e$, entry pressure) and a dimensionless pore size distribution index ($\lambda$).

$$S_e = \left( \frac{P_c}{P_{th}} \right)^{-\lambda} \quad \text{(Eq. 4.32)}$$

$$S_e = \frac{S_w - S_{w_{irr}}}{1 - S_{w_{irr}}} \quad \text{(Eq. 4.33)}$$

$$S_w = S_{w_{irr}} + (1 - S_{w_{irr}}) * \left( \frac{P_{th}}{P_e} \right)^{\frac{1}{\lambda}} \quad \text{(Eq. 4.34)}$$

or in terms of free water level:

$$S_e = \left[ \frac{(FWL - TVD)}{(FWL - DTh)} \right]^{-\lambda} * \left( 100 - S_{w_{irr}} \right) + S_{w_{irr}} \quad \text{(Eq. 4.35)}$$

where

- $P_{th}$ is threshold pressure (psia)
- $\lambda$ is pore size distribution (dimensionless)
- $S_{w^*}, S_e$ is effective water saturation (fraction)
- **FWL** is free water level
- **TVD** is true vertical depth
- **DTh** is depth where \( P_c = P_e \)

Figure 4.28: Illustration showing the relationship between pore geometry index and permeability (after Lala, 2013).

The pore size distribution (\( \lambda \)) value is directly proportional to permeability and an increase in (\( \lambda \)) corresponds to enhancement of rock reservoir quality. It is proportionally correlated with FZI. \( \lambda \) is a positive number with larger values indicating homogeneous reservoirs with good sorting, large particle size, while smaller values indicate more heterogeneous reservoirs, smaller pore sizes, bad sorting and smaller particle size. \( \lambda \) of 2 is used for the matrix porosity based reservoirs, while values of 0.2-1.0 are used for fracture dominated reservoirs (Belayneh, 2009).

It is practical to represent \( S_w^* \) versus \( P_c \) on log-log plot, where the resultant straight line will have a slope of -\( \lambda \) and the intercept at \( S_w^* = 1 \) will represent the threshold pressure, \( P_{th} \) (Figure 4.29).
Brooks and Corey’s method in carbonate fields represent both long and short transition zones with accurate results (Lian et al., 2015). An advantage of the Brooks and Corey function is that the fitting parameters (λ and P_D) have a physical meaning corresponding to rock and fluid interaction. The function has a solid theoretical background and its application is widely used and accepted in the oil industry. However, the function cannot be used in dominantly fractured reservoirs (Li and Horne, 2004).

### 4.3.6 Lambda Function

One form relating capillary pressure to saturation is the lambda function. It has several forms, one of which being the following:

\[
S_w = aP_c^{-\lambda} + b \tag{Eq. 4.36}
\]

If b is substituted for \(S_{w_{irr}}\) then the function will be:

\[
S_w - S_{w_{irr}} = \frac{c}{P_c^x} \tag{Eq. 4.37}
\]
\( \lambda \) can be correlated with effective porosity as the main dependency for water saturation (Wiltgen et al., 2003).

\[
\lambda = e^{a + b \ln(\phi_e/100)}
\]  
(Eq. 4.38)

\[
S_w = a + bP_c^{d \phi_e + f}
\]  
(Eq. 4.39)

where

- \( a, b, c, d \) and \( f \) are fitting parameters

The Lambda function is a simple approximation of capillary pressure and water saturation modeling with statistical fitting parameters. However, the parameters do not have any physical meaning. The Lambda function is a single curve with no discrimination of facies. Attempting to describe the reservoir with one facies involving one value for irreducible water saturation might be misleading in a heterogeneous reservoir (Wiltgen et al. 2003). This however, can be overcome using porosity banding.

4.3.7 Heseldin, 1974

Heseldin (1974) presented correlations between bulk volume of hydrocarbon and porosity at different values of capillary pressure. This method assumes a relationship between porosity and water saturation can be established. The correlation is used graphically to determine hydrocarbon and water saturation at any location of the field knowing porosity and height above free water level.
Figure 4.30: Plot showing bulk volume of hydrocarbon (BVH) versus porosity with variation of capillary pressure values (after Heseldin, 1974).

\[
V_{bh} = \Phi (1 - S_w)
\]  
(Eq. 4.40)

where

- \(V_{bh}\) is BVH, bulk volume of hydrocarbon

Figure 4.31: Plot showing saturation versus capillary pressure with variation of porosity (after Heseldin, 1974).
Alger et al. (1989), in a method called "Caplog", continued the work of Heseldin (1974) and applied a multi-linear regression function relating capillary pressure to porosity and permeability. They proposed the following relationship for bulk volume of hydrocarbon function (Eq. 4.41):

\[
V_{bh} = A + B \log(h) + C \Phi + D \log(k) \quad \text{(Eq. 4.41)}
\]

where
- \(H\) is height above free water level
- \(A, B, C, \text{ and } D\) are constants

Heseldin’s method is applicable using the correlation in low porosity carbonate reservoirs since the height curve versus capillary pressure for any porosity can be established. The method differs from FOIL (bulk volume of water function) functions as it relates porosity to hydrocarbon bulk volume instead of water saturation. The advantages of plotting porosity at constant capillary pressure lines is that results can be obtained at any part of the reservoir. The use of bulk volume of hydrocarbon instead of fractional pore volume of hydrocarbon minimizes the inconsistent water saturation values at low porosities (Alger et al., 1989).

### 4.3.8 Kwon and Pickett, 1975

Kwon and Pickett (1975) investigated MICP data from 2500 samples representing sandstone and carbonate formations and developed an empirical correlation between permeability, porosity and capillary pressure at different water saturation values. They chose to represent the pore network system as a tapered angular intersecting model based on photomicrograph examination.

They presented the following function:

\[
P_c = A \left(\frac{k}{\Phi}\right)^{-B} \quad \text{(Eq. 4.42)}
\]
where

- $A$ is a function of $S_w$, and $B$ is approximately equal to 0.45

Aguilera (2002) suggested the following equation for $A$:

$$A = 19.5S_w^{-1.7} \quad \text{(Eq. 4.43)}$$

$$\log P_c = \log A - B \log (k/\Phi) \quad \text{(Eq. 4.44)}$$

Figure 4.32: shows the average curves obtained for saturation increments of 10% over the $S_w$ range from 100% to 10% (redrafted after Kwon and Pickett, 1975).

The plot is not universal. However, if it can be established for a specific reservoir, then an integrated single plot for porosity, permeability, water saturation and capillary pressure makes it easy to predict the fourth variable if the other three are known.

4.3.9 Winland’s R35 (Kolodzie, 1980)

Winland was evaluating the sealing potential of rocks by testing mercury injection capillary pressures curves of 82 samples (56 sandstone and 26 carbonate) with low
permeabilities that were corrected for gas slippage and 240 other samples with uncorrected permeabilities (Pittman, 1992).

Windland ran graphical analyses using regression techniques for mercury saturations using capillary pressure curves. The analysis revealed that the highest correlation coefficient between porosity and permeability matches 35% of the pore volume filled with mercury and is dominated by a pore throat radius (R35) of 0.5μm. R35 represents a point on the flat portion of the capillary pressure curve (Haro, 2004).

Figure 4.33: Capillary pressure curve and dominant pore throat radius by various authors (redrafted after Haro, 2004; SPE Paper 89516)

Figure 4.34: Winland Model pore throat size variation along porosity and permeability cross-plot (redrafted after Haro, 2004; SPE Paper 89516)
The Winland Equation is represented as:

\[
\log R_{35} = 0.732 + 0.88 \log k_a - 0.864 \log \Phi
\]  

(Eq. 4.45)

where

- \( R_{35} \) is in microns

The Winland \( R_{35} \) method works best in intergranular, interparticle, or intercrystalline pore systems (Hartmann and Beaumont, 1999). Spearing et al. (2001) used the \( R_{35} \) to determine the net pay threshold permeability for tight gas reservoirs.

![Figure 4.35: Plot of mercury porosity values versus pore-throat radius for determination of pore-throat radii (after Nabawy et al., 2009).](image)

The Winland methodology found great momentum in the oil industry because it was easy to use, integrated routine core analysis with capillary pressure and proved to give acceptable results in many cases. The setback in using the Winland equation is that there is no theoretical or physical justification for using 35% saturation. Various authors debated that \( R_{35} \) might not always be representative for all rocks and reservoirs. Rezaee et al. (2006) showed that \( R_{50} \) proved to be more appropriate for
their reservoir, while Pittman (1992) correlated R25 with his data set. Another particularization in the assumption made by Winland is that carbonate rocks can be represented by a unimodal pore throat distribution, however carbonate reservoirs are very heterogeneous in nature and can often exhibit bi-modal and multi-modal pore throat distribution (Choquette and Pray, 1970; Ahr, 2005, Corbett 2003, 2010).

4.3.10 Swanson, 1981

Swanson (1981) identified an apex point on a log/log plot of capillary pressure versus mercury saturation. The apex point is located at a forty-five degree line touching the capillary pressure curve. He devised a correlation between permeability and capillary pressure data by investigating sandstone and carbonate samples. The developed equation relates the capillary pressure and saturation at the apex point to permeability. The apex point is related to the dominant interconnected pores sizes contributing to the fluid flow.

For sandstone samples the permeability correlation is:

\[ k_w = 431 \left( \frac{S_b}{P_c} \right)^{2.109} \]  
(Eq. 4.46)

For carbonate samples the permeability correlation is:

\[ k_w = 290 \left( \frac{S_b}{P_c} \right)^{1.901} \]  
(Eq. 4.47)

For combined clean sandstone and carbonate samples the correlation is:

\[ k_w = 355 \left( \frac{S_b}{P_c} \right)^{2.005} \]  
(Eq. 4.48)

where
- \( k_w \) is brine permeability (md)
- \( S_b \) is mercury saturation in percent of bulk volume (fraction)
It is worth noting that the combined equation for sandstone and carbonate has an exponent of two, which correlates with Purcell's theoretical model using Poiseuille's equation.

The term \( \frac{S_b}{P_c} \) is calculated at various pressure values and the maximum value determined represents the effective connected pore space contributing to fluid flow and distinguishing it from the non-connected pore space. He related unstressed air permeability to stressed brine permeability using the following equation:

\[
k_w = 0.292 k_a^{1.186}
\]

(Eq. 4.49)

where

- \( k_w \) is stressed brine permeability
- \( k_a \) is unstressed air permeability

In a comparison study using 206 carbonate rock samples with SCAL data, Nooruddin et al. (2011) found that Swanson’s equations gave the best permeability estimation followed by the Winland R35 method.
When carbonate rocks are dominated only by inter-particle porosity, then particle size and particle sorting dominantly affect the permeability. However, when secondary porosity exists, then bi- and poly-modal pore throat sizes prevail. The Swanson method characterizes the entire pore size distribution with one representative point, which fails in poly-mode pore system "modality". Swanson (1981), in his work, used samples with permeabilities larger than 10 md and thus his equations cannot be used for tight reservoirs, where they perform with less accuracy in low permeability reservoirs. In addition, Swanson’s method cannot be used in simulation models since the parameters cannot be predicted laterally (Wiltgen et al., 2003).

### 4.3.11 Wells and Amaefule, 1985

Wells and Amaefule (1985) generated a modified correlation to Swanson's equations where they used low permeability capillary data from tight gas sand reservoirs with permeability values below 10 microdarcies. They modified Swanson's equation as follows (Eq. 4.50 & Figure 4.37):

\[
k = 30.5 \left( \frac{S_b}{P_c} \right)^{1.56}
\]

(Eq. 4.50)

where

- \( P_c \) is capillary pressure at the apex (psia)
- \( S_b \) is bulk volume occupied by mercury (percentage)
The method of Wells and Amaefule (1985) has the same disadvantages of Swanson's method, in that it cannot be used for fractured reservoirs when poly pore systems dominate.

4.3.12 Pittman, 1992

Pittman (1992) used the same concept as Winland in developing equations between porosity and permeability at different mercury saturation points. He found that the dominant pore throat radius is at 36% mercury saturation which was very close to the 35% confirmed by Winland. However, when looking at Pittman's paper, the highest correlation coefficient was between 20% and 25%.

Pitman followed Swanson's (1981) apex concept and analyzed the MICP curves for the entry pressure, displacement pressure, and threshold pressure. He tried to predict the percentile of mercury saturation for the threshold pressure. The work led to the
prediction of pore aperture radius at different mercury saturation percentiles from porosity and permeability.

Figure 4.38: Plot of mercury saturation versus mercury saturation divided by pressure showing an apex at a saturation of 28% (*redrafted after Haro, 2004*).

The use of pore aperture radius using regression analysis of uncorrected air permeability (k) and porosity (Φ) led to the definition of pore-throat size corresponding to the threshold pressure \( r_{thresh} \), the displacement pressure \( r_{PD} \), and the apex \( r_{apex} \) in sandstone by routine core analysis data as follows:

\[
\log r_{thresh} = 0.137 + 0.479 \log k - 0.143 \log \Phi \\
\text{ }(r=0.900)
\]

\[
\log r_{PD} = 0.459 + 0.500 \log k - 0.385 \log \Phi \\
\text{ }(r=0.901)
\]

\[
\log r_{apex} = -0.117 + 0.475 \log k - 0.099 \log \Phi \\
\text{ }(r=0.919)
\]
The data set that Pittman used was from sandstone reservoirs with porosity values ranging from 3.3% to 28.0% and permeability values ranging from 0.05 to 998 md. For low permeability data values no apex could be found and a suggestion was made that no predominate pore throat size exists in low permeability reservoirs. When looking at these ranges we see that they do not represent the heterogenous nature of carbonate reservoirs. The spectrum of hydrocarbon producing carbonate reservoirs ranges from extremely tight limestones to moldic, vuggy, and fractured dolomites. Nabawy et al. (2009), in a study of high permeability rocks, tested the $r_{35}$ of Winland and the $r_{25}$ of Pittman and found that derived permeabilities were extremely under estimating permeability for high porosity/permeability rock types.

4.3.13 Ibrahim et al., 1992

Ibrahim et al. (1992) proposed an empirical power law function for tight sands to represent the $J$-function and water saturation. He used water saturation from wireline log data to represent the transition zone. The empirical function representing tight sand correlates $P_c$ and $S_w$:

$$P_c = \frac{a}{(S_w)^b} \quad \text{(Eq. 4.54)}$$

where

- $S_w$ is water saturation (percent), in some papers normalized water saturation is used $S^*$
- $a$ and $b$ coefficients representing pore size distribution
$P_c$ is plotted on a log-log scale to yield a straight line:

![Figure 4.39: log/log plot showing water saturation versus capillary pressure and linear trends corresponding to different rock types](image)

Figure 4.39: log/log plot showing water saturation versus capillary pressure and linear trends corresponding to different rock types

The J-function is plotted on a log-log scale to yield a straight line:

![Figure 4.40: log/log plot showing water saturation versus J-function and linear trends corresponding to different rock types.](image)

Figure 4.40: log/log plot showing water saturation versus J-function and linear trends corresponding to different rock types.
The empirical function representing tight sand correlating $P_c$ and $S_w$:

$$J = \frac{\alpha}{(S_w)^\beta}$$  \hspace{1cm} (Eq. 4.55)

where
- $J$ is Leverett's J-function (dimensionless)
- $\alpha$ and $\beta$ are fitting parameters

or in terms of height above FWL:

$$H_{FWL} = 10.66 \frac{\alpha \sigma \cos \theta}{(S_w)^\beta (\rho_w - \rho_g) k \sqrt{\phi}}$$  \hspace{1cm} (Eq. 4.56)

where
- $H_{FWL}$ is height above free water level (ft)
- $\rho_w$ and $\rho_g$ are water and gas densities (gm/cm$^3$)

Ibrahim’s equation is commonly used in reservoir engineering studies with fitting parameters derived from special core analysis data.

### 4.3.14 Johnson - “Pseudo-Permeability” (1987)

Johnson (1987) developed a mathematical relationship relating water saturations, permeability and capillary pressure through the investigation of SCAL capillary pressure measurements. He found a better correlation between permeability and saturation than between porosity and water saturation. He generated empirical functions that related the parameters as straight lines at individual pressures then empirically related capillary pressure, water saturation and permeability on a log-log plot of saturation versus permeability. These functions could be used to generate sets of averaged capillary curves.

Johnson’s function can be generalized as follows:
\[ \log S_w = A \log k + B \]  
(Eq. 4.57)

where

- \( A \) is the slope of capillary pressure set
- \( B \) is the intercept with the Y-axis

A drawback of the log/log relationship between water saturation and permeability is the fact that it is purely empirical and does not have any theoretical foundation. Johnson’s technique is sometimes called the "pseudo permeability" technique or "permeability averaging" technique. \( B \) can be related to capillary pressure on a log-log plot between \( B \) versus \( P_c \) as follows:

\[ B = a P_c^{-b} \]  
(Eq. 4.58)

where

- \( a \) and \( b \) are fitting variables

This results in the following generalized form of the equation:

\[ \log(S_{wn}) = (a P_c^{-b}) - A \log k \]  
(Eq. 4.59)

where

- \( S_{wn} \) is normalized water saturation (percent)
- \( A, a \) and \( b \) are fitting variables
Figure 4.41: Johnson’s mathematical relationships relating water saturations, permeability and capillary pressure through the investigation of SCAL capillary pressure measurements (after Johnson, 1987).
Johnson’s method provides clues on water saturation and can be used for distinctly separating various rock types if different trends can be found (Rebelle and Lalanne, 2014). An advantage to Johnson’s method over others is that it does not need the estimation of irreducible water saturation beforehand.

Johnson’s model is a form of a best-fit regression equation and thus tends to average parameters. The process of linearizing the relationship between $S_w$, $k$ and $P_c$ is not universal and has no theoretical basis. If there is no relationship between water saturation and permeability, then the method cannot be used (Wiltgen et al., 2003). In addition, it is a time consuming process to build the parameters needed to create the equation and it overestimates water saturation values for small capillary pressure values (Harrison and Jing, 2001). Harrison and Jing also observed a higher estimation of water saturation directly above the free water level. Shortage of the method was also observed for low permeability reservoirs and short distances above the free water level (Biniwale, 2005).

4.3.15 Cuddy et al. (BVW, FOIL Function), 1993

Cuddy et al. (1993) presented a wireline log based method named "FOIL" where they reviewed a gas sand reservoir in the southern region of the North Sea. The process assumes that the Bulk Volume of Water (BVW) is dependent on the Height above the Free Water Level (FWL) above the transition zone. The product of porosity and water saturation is balanced to give a fixed value. When the porosity decreases, the water saturation increases and vice-versa. The assumption is that the change in the bulk volume of water depends only on height above the FWL. The bulk volume of water is used based on a porosity cutoff to eliminate non-reservoir rocks and only includes net reservoir thicknesses greater than 1m to resolve the problems with wireline acquisition resolution.
Figure 4.42: Left: Plot showing water saturation versus height above FWL. Right: Plot showing bulk volume of water saturation versus height above FWL (after Cuddy et al., 1993).

Figure 4.43: Plot showing the curve fitting of volume of water saturation versus height above FWL.

\[ BVW = 1 - A H^B \]  \hspace{1cm} (Eq. 4.60)

\[ BVW = S_w \Phi \]  \hspace{1cm} (Eq. 4.61)

where

- **BVW** is Bulk Volume of water
- **A** and **B** are constants
\[ \log_{10}(BVW) = B \log_{10}(H) + \log_{10}(A) \quad (Eq. \ 4.62) \]

A, B are constants for a specific field and can be obtained by plotting wireline data versus height above water level.

The equation leads to the following plot of height above FWL versus BVW:

![Figure 4.44: log-log plot of bulk volume of water versus height above FWL (after Cuddy et al., 1993).](image)

Cuddy et al.’s method (1993) does not need porosity banding. Another advantage to this method is that low porosity rock types are well represented as well as high porosity types. It only works above the transition zone and this is why it performs well with gas reservoirs having a clear Gas Water Content (GWC) and very small transition zone. It has been suggested that the FOIL application can relate flank wells relative to crestal wells and define free water level between faulted blocks.

However, there is no theoretical basis behind this methodology. Despite the fact that this method is easy to use, it ignores SCAL data. No lithology or rock typing is
performed and thus the curve fitting procedure focuses on the highest porosity parts of the reservoir, thus mismatching the lower quality reservoirs. This method cannot be used within the transition zone. Cuddy’s function also over estimates hydrocarbon saturation in low quality reservoirs rocks and that is why it tends to overestimate hydrocarbon in place (Harrison and Jing, 2001).

4.3.16 Skelt and Harrison (1995)

Skelt and Harrison (1995) established a non-linear regression function using capillary pressure data and refining the results using wireline log saturation data. The parameters formulating the function are related in a way to physical reservoir quality parameters. The parameters included are irreducible water saturation, contact angle, surface tension, threshold pressure, and fluid contacts.

They formulated the function with the following criteria:
- Saturation height function should perform well along and beyond the whole range of the data available
- Fitting data parameters should be flexible
- Log data and SCAL could be used jointly or independently
- The effect of changing the fitting parameters should be predictable
- Fitting parameters could be linked to physical properties not just numbers
- Ability to interchange between capillary pressure and height above FWL

Hydrocarbon saturation is expressed as follows:

\[
S_h = 1 - S_w = a \exp\left(\frac{-b}{P_c + d}\right)^c
\]

\[
S_w = 1 - a \exp\left(-\left(\frac{b}{H+d}\right)^c\right)
\]

(Eq. 4.63) 

(Eq. 4.64)

where
- \(S_h\) is hydrocarbon saturation (fraction)
- \(a, b, c\) and \(d\) are fitting coefficients
The coefficients are linked to physical parameters as follows:

- **a** is shifting the curve along the water saturation x-axis and honouring a predetermined irreducible water saturation
- **b** is shifting the curve along the pressure/height y-axis and has the same effect of converting pressure to height domains and also has the effect of changing the threshold pressure
- **c** changes the shape and curvature of the function. **b** and **c** are closely related to the available pore size network model
- **d** is a vertical bulk displacement to match the FWL

![Figure 4.45: Effect of altering parameter values of a, b, c, and d on the shape of hydrocarbon and height function (redrafted after Skelt & Harrison, 1995).](image)

The "b" coefficient defines the pressure entry with distinct separation and can be used for rock typing classification (Zahaf et al., 2014). A separate equation is performed for each plug to define the parameters. The final coefficients are grouped to the final
model by taking an average, a median or through linear regression versus a preferred attribute.

Zahaf et al. (2014), while modeling transition zones in a giant carbonate reservoir, found that Skelt and Harrison’s method (1995) provided the best fit for the modeling of MICP capillary pressure for each rock type. An obvious advantage of this method is that it can use SCAL and log data independently or jointly. It also surpasses other methods in that it does not simplify the relationships between parameters using linear approximation but preserves the non-linearity of the relationships and hence produces a more realistic approach (Harrison and Jing, 2001).

However, the method is very time consuming and labor intensive. Permeability is not clear in the formalization of the method, which is the key property for fluid flow (Biniwale, 2005). Also, there is no relation to geological or sedimentological rock or pore origin.

\[ \text{Eq. 4.65} \]

\[
CN = 1.0067 \times \left( \frac{\rho_o \sigma_{o-w}}{\mu_o \cos \theta} \right) \times \left( \frac{k_{ro}}{k_{rw}} \right) \times \sqrt{\frac{k}{\Phi}}
\]

where

- \( \sigma_{o-w} \) is oil-water interfacial tension (dyn/cm)
- \( \rho_o \) is oil density (kg/cm\(^3\))
- \( \mu \) is viscosity (centipoises)
- \( k_{ro} \) is relative permeability of oil
- \( k_{rw} \) is relative permeability of water

4.3.17 Shedid, 2003, 2013

Shedid and Almehaideb (2003) presented a new method for carbonate rock typing. The method was named Characterization Number (CN) and considered rock and fluid properties. The rock properties included porosity and permeability; the fluid properties included oil viscosity and density, while oil/water petrophyiscal properties included interfacial tension and wettability.
Plotting Reservoir Quality Index (RQI) versus Characterization Number (CN) yields separate rock typing clusters (Figure 4.46).

![Figure 4.46: Cross-plot of Reservoir Quality Index (RQI) versus Characterization Number (CN) indicating four separate rock types (after Shedid, 2013).]

There is insufficient documentation regarding the testing of the method in static and dynamic studies. The obvious drawback is that it needs Pressure, Volume Temperature (PVT), SCAL and routine core analysis data. In the absence of any of these data, the method cannot be applied.

### 4.3.18 Wu (Modified Thomeer), 2004

Wu (2004) proposed a capillary pressure model to predict permeability based on Thomeer’s equation and he included the cementation exponent (m). The assumption of most of the previous models was that capillary pressure data follows a hyperbolic or semi-hyperbolic shape. Extreme reservoirs that behave differently than normal, like low permeability or bi-modal pore throat reservoirs have extreme capillary pressure shapes (Wu, 2004).

Wu’s model tested 200 core samples, where he modified Thomeer's model by introducing a shape factor ($\beta$) to calculate the threshold pressure ($P_{th}$).
The shape factor ($\beta$) ranges from 1 to 3, where $\beta=1$ represents tight low permeability reservoirs.

Wu (2004) presented the following empirical equation to estimate threshold pressure:

$$P_c = P_{th} + \sigma \cos \theta \sqrt{\frac{\phi}{k}} \left(\frac{\ln 1}{S_e}\right)^\beta$$  \hspace{1cm} (Eq. 4.66)

$$\ln P_{th} = 5.458 - 1.255 \ln \sqrt{\frac{k}{\phi}} + 0.08 \left(\ln \sqrt{\frac{k}{\phi}}\right)^2$$  \hspace{1cm} (Eq. 4.67)

where

- $\beta$ is shape factor (dimensionless)
- $S_e$ effective water saturation (fraction)

Wu (2004) proposed a permeability correlation that relates to Archie's cementation exponent ($m$) and was based on Thomeer, Archie, Kozeny-Carman concepts:

$$k = CF_g^{-1.33} \left[\Phi \left(1 - S_{wirr}\right)/P_{th}\right]^m$$  \hspace{1cm} (Eq. 4.68)

$$\log \left(\frac{P_c}{P_{th}}\right) = \frac{F_g}{\ln(1-S_e)}$$  \hspace{1cm} (Eq. 4.69)

where

- $F_g$ is pore geometry
- $C$ is a fitting parameter
- $m$ is Archie's cementation exponent
Using m as a part of the rock classification scheme is proposed by many authors (e.g. Aguilera, 2004 and Corbett et al., 2017) and the addition of irreducible water saturation as part of the permeability equation is also accepted by many authors (e.g. Thomeer) indicating that irreducible water saturation together with other properties can be used as part of a rock typing scheme.

4.4 Critical review and concluding remarks

Dynamic rock typing (DRT) is an essential link of rock and fluid interaction by understanding multiphase flow characteristics that cannot be deciphered from geological and petrophysical disciplines. However, DRT fails to predict pore space and pore network laterally and vertically for simulation modeling purposes. If a proper rock typing scheme is established then the rock can be linked to its associated pore system. Then predictability of rocks through depositional model building can be applied and hence prediction of its associated pore system, (Table 4.3).

Table 4.3: Table showing a brief summary of advantages and limitations of dynamic rock typing techniques:

<table>
<thead>
<tr>
<th>Carbonate Classification based on Dynamic/Hydraulic Properties</th>
<th>Advantages</th>
<th>Limitations</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>• Excellent tool when integrated with Petro-facies</td>
<td>• Poor link with Geological/Sedimentological facies</td>
</tr>
<tr>
<td></td>
<td>• Saturation comparison between routine core analysis, special core analysis and wireline log data</td>
<td>• No lateral predictability</td>
</tr>
<tr>
<td></td>
<td>• Combines porosity, permeability, saturation and position from free water level (fluid distribution)</td>
<td>• Engineering discipline to overwhelm sedimentological/geological and petrophysical disciplines</td>
</tr>
<tr>
<td></td>
<td>• Directly linked to fluid simulation models</td>
<td>• Upscaling problem</td>
</tr>
<tr>
<td></td>
<td>• Excellent for thick reservoirs</td>
<td>• Sparse data points usually not covering all rock types</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Concentration on reservoir with less emphasis on baffles and barriers</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Poor for very thin reservoirs</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Require converting from lab to reservoir condition</td>
</tr>
</tbody>
</table>
DRT classification schemes were classified according to various disciplines into the following main categories:

- **Statistical Clustering**
  - (e.g. Guthrie and Greenberger)

- **Simulating Flow**
  - (e.g. Kozeny-Carman)

- **Wireline Log Based Saturation Height Function**
  - (e.g. Cuddy et al.)

- **Capillary Pressure Modelling**
  - (e.g. Leverett, Thomeer, Brooks and Corey, Lambda Function, Heseldin, Wu, Kwon and Pickett, Ibrahim et al., Johnson, El-Khatib, etc.)

- **Integrating SCAL and Wireline Data**
  - (e.g. Skelt & Harrison, Shedid)

- **Pore Throat Size**
  - (e.g. Winland (Kolodzie), Pittman, Swanson, Wells and Amaefule)

Statistical Clustering techniques have no theoretical background. However, because they are derived from a particular data set in a special reservoir setting they prove to be useful if a relationship between parameters can be found. If the mathematical relationship between parameters cannot be extracted from real data then the polynomials cannot be justified (Wiltgen et al., 2003).

Simulating flow equations like Kozeny-Carman have a solid theoretical basis but can only be applied within the limits of the application of Darcy’s law, especially for carbonate reservoirs. Some of the constants in the equation are also hard to quantify or measure, as is the case with specific surface area. Several authors chose not to use the simulation equation directly but an approximation using substitution constants with known parameters (e.g. Amaefule et al., Flow Zone Indicator). This, however, is not a reliable technique as it assumes that the substitution can be applied universally for all reservoirs. This defies the known heterogeneous nature of carbonate rocks.

Capillary pressure modelling techniques are a key part of any simulation study for initializing water saturation in the static model before production. A common use is
using Leverett J-function modelling. However, a unique J-function fails to model saturation properly when multi-modal pore throat distribution exists in a single rock type. Because of the averaging nature of the Leverett J-function, it was documented to have a conservative behaviour for high permeability rocks which have the best reservoir quality. It also underestimates water saturation for low quality reservoirs (Harrison and Jing, 2001, Dernaika et al., 2013). Harrison and Jing (2001) found that the J-function should not be used when the range in permeability difference is greater than two to three orders of magnitude. The J-function is a poor technique to identify flow units and to characterize carbonate reservoirs (Shedid 2013, Al-Farisi et al., 2013). The function gives good results when a standard Archie equation can be used in good quality reservoirs (Al-Amri, 2015). Banding of porosity and permeability groups has given better results, where for each group a separate J-function is used (Wiltgen et al., 2003).

Other functions for capillary pressure modelling are empirical like Johnson’s technique, where they assume a log/log relationship between water saturation and permeability with no theoretical foundation. A linear relationship between $S_w$, $k$ and $P_c$ is not universal and if there is no relationship between water saturation and permeability, then the method cannot be used (Wiltgen et al., 2003). An advantage of Johnson’s method over others is that it does not need the estimation of irreducible water saturation beforehand.

Wireline log based saturation height functions like the FOIL function of Cuddy et al. has an advantage in low porosity rock types that are well presented as well as high porosity types. It can be used without porosity banding but it ignores SCAL data and only works above the transition zone. In addition, there is no theoretical basis behind the methodology. Cuddy’s function also over estimates hydrocarbon saturation in low quality reservoir rocks and that is why it tends to overestimate hydrocarbon in place. It is also not suitable for long transition zones (Harrison and Jing, 2001).

Integrating SCAL and Wireline log data was achieved by Skelt and Harrison who established a non-linear regression function using capillary pressure data and refined these results using wireline log saturation data. An advantage of Skelt's function over other methods is that it does not simplify the relationship between parameters using
linear approximation but preserves the non-linearity of the relationships and hence produces a more realistic result (Harrison and Jing, 2001).

Pore throat size methods simplify the dynamic flow by assuming a dominant pore throat size (e.g. Winland, Pittman) attributing to fluid flow. This assumes a unimodal pore network, which is only applicable when depositional pore space dominates. A modal pore system prevails when superposition of post diagenesis and fracturing affects reservoir rocks and hence a unique pore throat size is not representative. This is evident by the change of the representative pore throat radius to be R20, R25, R35 and R50. Applying a porosity permeability relationship for rock typing derived from a specific dataset to another very different dataset is a common mistake because there is no evidence that both reservoirs share the same dominant pore throat and pore size distribution.
CHAPTER FIVE

TERNARY ROCK TYING (TRT)

5.1 Introduction

In the previous chapters, it has been shown how geological and sedimentological rock typing (GRT) involve rock characterization from a geological perspective, while petrophysical rock typing (PRT) involves the determination of rock types through their one-phase properties. The sedimentological and geological disciplines include age dating, biostratigraphy, depositional environment, sequence stratigraphy, diagenesis and fracture mechanism identification. The petrophysical discipline, on the other hand, involves the determination of fractional fluid saturation and one-phase reservoir properties. Integrating geological rock typing (GRT) and petrophysical rock typing (PRT) provides the framework for the static rock typing concept (SRT), which focuses on the rock system, pore space and their associated petrophysical properties. Static rock types are used primarily for 3D static model building, facies and reservoir property distribution. This is achieved by using pixel and object based distribution algorithms to populate facies to their petrophysical properties in the 3D space. Boundaries and vertical and lateral extensions of these facies are governed by the use of sedimentological maps and seismic inversion as a background controlled and supervised distribution.

Static rock types include concepts of biofacies, lithofacies, sedimentological facies, electrofacies, and petrofacies. Biofacies is determined by analyzing the flora and fauna of ditch cuttings/core chips to determine the age and environment of the analyzed intervals. Lithofacies concentrates on lithology from outcrops, ditch cuttings and core description and has the advantage of being predictable and correlatable for long distances. Sedimentological facies and environment are based on outcrops, core description, and bore hole image log interpretation to determine primary structure, diagenesis, cementation and fracturing features. Sedimentological modelling is the key concept for predicting the size, shape and extension of rock volumes. Electrofacies determination is based on wireline logs' interpretation using cluster analysis to group similar wireline log responses. Comparing core derived
facies to wireline facies shows that core derived facies are more detailed and precise than wireline based facies, have a higher vertical resolution and might include features not recognizable at the wireline log scale. However, core derived facies have the disadvantage of covering only a small portion of the reservoir. Electrofacies, on the other hand, have a consistent resolution over reservoir/non-reservoir intervals, have good lateral coverage as most of the drilled wells are logged, but tend to average reservoir properties, and hence facies are inferred rather than determined. There is no one to one relationship between electrofacies and core facies and hence upscaling or downscaling is used to achieve a relationship between both categories. Petrofacies uses both wireline logs and routine core analysis mainly for the clustering of porosity and permeability and representing reservoir single phase properties as discussed in chapter 3.

It is evident that static rock types become very informative as the container carrying geological and petrophysical information needed to build a static model with vertical buildup and lateral extension. However, side wall cores, trimmed core plugs and whole cores used for static modelling contribute only to a small volume of the reservoir and are not always a good representation of the overall reservoirs, baffles and barriers. Also, in a certain depositional environment, several pore types exist and any one pore type can exist in different depositional environments. There is no simple relationship between pore type distribution and depositional environment. Only through a robust rock typing workflow, can a relationship between rock system and pore complex be achieved. Another drawback of static rock typing schemes is that they do not include two-phase flow characteristics.

Populating facies in a dynamic simulation environment imposes two phase flow properties on facies derived from static rock type distribution in the background. However, reservoir flow based characteristics such as: capillary pressure curves, pore size distributions, wettability changes, interfacial tensions, contact angles and relative permeability end points are not part of static rock typing. It is misleading to use SRT's to distribute dynamic properties of multiphase origin. Data with two phase characteristics like special core analysis is used for dynamic rock typing to initialize dynamic simulation models, model saturation height functions and fluids distribution
relevant to their location above the free water level. Dynamic rock types, however, lack the predictability vertically and laterally that are available in SRT's.

Saturation height functions are a direct indication of the link between static and dynamic rock types. They include facies, porosity, permeability, water saturation and wettability effect. They can be modelled using wireline logs, routine and special core analysis data. Saturation height functions model aquifers, transition zones and dry oil limit zones at irreducible water saturation with great accuracy and hence can be used for quality control of any proposed rock typing scheme. This leads to the validation of static rock types through the quality control of their drainage characteristics and hence their geological and petrophysical measurements can be confirmed. This results in a robust association between static and dynamic rock types and establishes an accurate saturation height function and fluid distribution across the reservoir.

The dynamic behaviour of a reservoir can be correlated to DST's, production logs, well tests and others. These data are usually limited to a specific number of wells due to associated costs or operational restrictions. When available, they are indispensable complementary information to reservoir modelling. Routine and special core analyses, on the other hand, are the primary source for rock and fluid characterisation for one-phase and two-phase properties.

A unique static rock type (SRT) is assumed to have a similar depositional environment, similar diagenetic history, same wireline log responses and a defined porosity and permeability relationship (Figure 5.1). Integrating SRT with dynamic data such as wettability, tortuosity, capillary pressure and relative permeability paves the way for the integration of dynamic rock typing concept (DRT).

Integrating static and dynamic rock typing techniques has been the focus of several authors and software applications over the years. Geo2Flow software was tested during the writing of the thesis and proved to be an interdisciplinary tool that can be applied for 3D saturation modeling using Petrel. Hamon (2003) showed that petrophysical parameters and wettability indices were able to model changes in relative permeability curves and recommended that relative permeability curves be used for the generation of multiphase flow rock types. Some trials included relative
permeability and/or capillary pressure in the classification process (Dernaika et al., 2013 and Compan et al., 2016). This was often impractical on its own because of the scarcity in the number of relative permeability data, which did not cover all available reservoir/non-reservoir rock types (Skalinski and Kenter, 2013). Asgari and Sobhi, (2006) adapted a sequential approach, where they defined static rock types and then re-assigned them to dynamic rock types based on SCAL data. The effect of wettability was demonstrated on the characteristics of the relative permeability and capillary pressure curves of carbonate rocks to include multi-phase flow characteristics and wettability variation with depth (Masalmeh, 2002, James et al., 2014). Ghedan (2007) approached this concept with a hierarchal alternative by imposing wettability to the classified static rock types.
Figure 5.1: General pros and cons of Geological Rock Typing (GRT), Petrophysical Rock Typing (PRT), Static Rock Typing (SRT), and Dynamic Rock Typing (DRT).

- **Excellent tool when integrated with Petro-facies**
- Saturation comparison between routine core analysis, special core analysis and wireline log data
- Combines porosity, permeability, saturation and position from free water level (fluid distribution)
- Directly linked to fluid simulation models
- Excellent for thick reservoirs

- **Good match between routine core and wireline data**
- Moderate Incorporation of special core analysis
- Prediction using advanced techniques like neural networks, multi linear regressions, principle component analysis ... 
- Good separation between Petro-facies with minimal overlap
- Easy to implement

- **Geological/Sedimentological incorporation is poor**
- Petro-facies are statistically driven
- Number of Petro-facies is subjective drives
- No lateral predictability
- Micro fractures might be beyond wireline resolution
- Cutoffs used has a dramatic effect on reservoir/no-reservoir and pay/non-pay identification
- Wireline tool acquisition artefacts
- Wettability changes with depth is seldom truly understood but rather globally

- **Poor link with Geological/Sedimentological facies**
- No lateral predictability
- Engineering discipline to overwhelm sedimentological/geological and petrophysical disciplines
- Upscaling problem
- Sparse data points usually not covering all rock types
- Concentration on reservoir with less emphasis on baffles and barriers
- Poor for very thin reservoirs
- Require converting from lab to reservoir condition

- **Petrophysical incorporation is usually moderate**
- Qualitative more than quantitative classification
- Classified genetic units with great overlaps
- Dynamic/Hydraulic incorporation is poor
- Upscaling problem to actual dynamic simulation grid size
- Grouping of sedimentological facies to manageable representative rock types
- Needs core, side wall core or ditch cuttings
- When superimposed to $\Phi/k$ crossplot usually no common trend arises
The multi-scale and multi-discipline nature of carbonate characterization demands that any rock typing workflow be looked at from an integrated and global perspective and not from a single discipline approach. The multi-scale and multi-discipline rock typing approaches differ in (Figure 5.2):

- Emphasis on: Rock versus pore versus fluid
- Approach: Geological, petrophysical or engineering
- Data: Source of available data
- Scale: Scale and resolution
- Property: Description, inferred, or measured
- Rock Typing Focus: GRT, PRT, SRT or DRT
Figure 5.2: Factors affecting rock typing schemes being multi-scale and multi-discipline.
Common problems occurring due to the transfer across disciplines:

- Scale Difference: Upscaling from plugs or downscaling from logs is needed
- Qualitative versus quantitative analysis
- Lack of common tools (software) to transfer knowledge and test alternatives
- Interpretation goals not always aligned
- 1D versus 3D
- Measured properties versus inferred properties
- Lack of cross disciplinary understanding, tools and training in this area
- Deficiency of representative samples across disciplines
- Lack of published examples across disciplines
- Estimation vs. interpretation vs. extrapolation (uncertainty)

There is always a bias towards a specific discipline over others. The bias can be toward a certain data type like concentrating on special core analysis and ignoring geological environmental facies, or bias toward a certain scale through upscaling or downscaling, where geologists apply very high resolution models compared to reservoir engineers who tend to upscale these to a manageable size due to hardware and software requirements. However, the appropriate size is not discipline based but is the resolution needed to accurately model the fluid dynamics. Understanding how certain features change across disciplines and scales like modality of pore system, fractures, stylolites and change of wettability is often a problem. It is found that these features can be extracted from a certain data type or discipline but cannot be concluded from other data sources. These features might have an impact on the reservoir behaviour, but because it is only found in one data source it is hard to model and correlate across the field in the three dimensional space. Rock physics inversion has been used intensively over the last decade as it allows the prediction of reservoir rock properties through acoustic and elastic properties inferred from post and pre stack seismic data.

Skalinski and Kenter (2013) reviewed various rock typing techniques and stated that existing rock typing to date falls short in representing oil in place and fluid flow in carbonate models.
The heterogeneity of the reservoir properties changes vertically and laterally. The scale at which to capture these heterogeneities is important. If the measured property volume is too small it does not capture the variation of the rock/pore signature. The volume has to be large enough to capture a representative steady mean value of the rock/pore properties. Very fine geologic models capture reservoir heterogeneities at the expense of machine processing time and in some instances increase the modelling uncertainty by introducing artifacts due to the uncertainty in how the finer features are distributed in the 3D space. Very coarse models, on the other hand, decrease the accuracy of the hydrocarbon in place measurements and the predicted field performance. The optimal grid size at which to model static and hydrodynamic field performance is therefore an important decision.

The reservoir property mean and variance values are scale dependent. These values only hold at a specific volume and are only maintained for modelling purposes. It is a concept that is not inherited from nature but approached from practical application and discretization processes. This indicates that the mean and variance of any property vary with the change of the volume they are measured at. Understanding the limitations and constraints of applying data measurements at different scales is a key concept affecting static and dynamic modelling.

The volume at which there is a stable mean value of any measured property is noted as Representative Elementary Volume (REV). As the average volume at which the property is measured increases, the mean value of the property oscillates decreasingly until it reaches a stable plateau at the REV. Increasing the average volume beyond the REV may change the property mean based on the homogeneous or heterogeneous nature of that property (Figure 5.3).

The variance of the measured property is minimal at the REV and increases above and below the REV range. The first REV is reached at a small volume measurement where the grain/pore scale is identified. Increasing the measurement volume oscillates the property value until it reaches the second stabilized REV, which might be at the lamina/bed scale. However, by increasing the volume further, another property mean value is reached at a larger REV scale, that might be a para-sequence/flow unit scale (Corbett, 2006).
The change of average values of the different reservoir properties is accompanied by a change of REVs and thus points to the scale of heterogeneity necessary to be modelled. The model becomes a series of units each of which consists of several REVs. The grid size of the simulation model contains average values of the reservoir properties such as porosity, permeability, and water saturation. Hence, it is assumed that the individual 3D grid is a partial representation of a REV and is a reflection of petrophysical and engineering models. Data measurements have to be within the scale of the stable REV or they have to be up-scaled or down-scaled to a stable REV scale (Figure 5.4). Most rock typing methods are performed fundamentally at core plug scale. A 1D upscaling step is performed to link to wireline log scale. A subsequent 3D upscaling step is implemented from wireline scale to simulation grid. In this thesis, the simulation grid was modelled at the wireline log scale to minimize upscaling uncertainties.

Figure 5.4: Upscaling and downscaling of measurement scales and associated processes (https://www.nap.edu/read/25259/chapter/9, 2019).
From the review of previous methods and techniques conducted in the present thesis, it was found that a multi-scale and multi-disciplinary carbonate rock typing workflow should:

- match routine core analysis
- work well with clustered wireline logs
- have a clear separation between clusters
- match capillary pressure
- match relative permeability end points
- be able to predict facies and properties over intervals with no routine and special core analysis
- work well when RCA is not present
- work well above and below FWL
- be able to exclude non-reliable/representative points
- be able to be used when there is no SCAL
- differentiate between mono and poly pore types
- have a minimum number of clusters
- link to rock physics model
- differentiate/integrate depositional, diagenetic and fracture effect of rock to pore types
- provide a common platform to visualize different data sources and suggest alternative interpretations
- derive the equation constants from the concerned data set and not inherit them from other datasets

A proper integration of SRT with DRT and quality controlled by saturation height function becomes an integral part of defining a Ternary Rock Type (TRT) as will be shown in this chapter. This novel concept results in the integration of all rock typing disciplines, scales and data types into one robust rock typing approach that can be used in static as well as in dynamic modelling. Proper initialization narrows the gap between static and dynamic model hydrocarbon in place volume calculations. It leads to the modelling of fractional fluid saturation more accurately in the 3D space. The
proper prediction of rock and pore relationship enhances IOR and EOR predictions and thus becomes more economically feasible.

5.2 TRT Concept

This chapter introduces a novel application for carbonate rock typing; namely Ternary Rock Typing (TRT). This method intends to use depositional facies, wireline logs, routine core analysis, and special core analysis all in one scheme. This new concept is extended in subsequent chapters to represent a comprehensive workflow for carbonate rock typing that includes geological, petrophysical and engineering disciplines with the integration of sedimentological fabrics, wireline logs, RCA and SCAL. The workflow emphasises on the separation of various pore types and their one-phase and two-phase properties and their diagenetic and fracturing characteristics. The TRT concept allows for a seamless jump between data types and disciplines and narrows bias of any one-sided concept to a more global approach and application.

A global carbonate rock typing scheme must include the interaction of rock, pore and fluid characteristics with a clear representation of sedimentological facies and their one-phase and two-phase related properties. Ternary Rock Typing (TRT) focuses on sedimentological facies, wireline logs, routine core analysis, capillary pressure data and relative permeability curves from three parameters representing rock, pore and fluid interaction. The three parameters proposed take into consideration the petrophysical interrelation between porosity, permeability and irreducible water saturation in the shape of a 3D ellipsoid (Figure 5.3). The change of rock fabric and its post depositional diagenesis and fracturing changes the ellipsoid characteristics. The complex interaction of rock, pore and fluid affect the location, shape, orientation and relative position of the three-parameter ellipsoid. The three measurements are available from a combination of wireline logs, routine and special core analysis, and are associated with capillary pressure and relative permeability measurements. Hence, these parameters are a good representation of rock type from a static and dynamic point of view. The ellipsoid characteristics are derived from the particular data and not inherited from non-relevant data sets and non-representative depositional environment. The technique overlaps between different datasets and disciplines.
Porosity and permeability in carbonate rocks are not directly proportional, especially when rocks deviate from the intergranular, intragranular, interparticle, intercrystalline and intracrystalline porosities to be vuggy, moldic or fracture. Porosity is the storage capacity of a rock and distinguished to be total, effective and non-effective porosity. Total porosity includes all the pore systems in the rock. Effective porosity includes the connected pores that can permit fluid flow in primary recovery conditions. Non-effective porosity includes isolated pores and micro-porosity with micro pore throat. Secondary porosities are related to secondary processes affecting the pore system after deposition including vuggy and fracture porosity. Secondary porosity can be isolated or connected.

Absolute permeability is related to pressure drop through pore space fully saturated with a one-phase fluid. Like porosity, permeability can be classified into primary or secondary. Primary permeability is the result of connected space during deposition, while secondary permeability is post deposition affected by diagenesis and fracturing leading to enhancement or reduction in productivity. Carbonate reservoirs usually have preferential directional permeability because of their heterogeneous and
anisotropic nature. It is evident that the pore throat size distribution has the greatest impact on permeability.

A theoretically solid equation that relates porosity to permeability is the Kozeny-Carman equation, which relates permeability to porosity and specific surface area of the particles that constitute the rock. The specific surface area correlates inversely with the mean particle diameter, while it correlates positively well with irreducible water saturation ($S_{wirr}$). This makes $S_{wirr}$ a good indicator for rock type. Rocks with fine grained/particles/crystals have a high specific surface area and high $S_{wirr}$, while coarse grained/particles/crystals have a lower specific area and lower $S_{wirr}$.

Irreducible water saturation is the retainable water in a certain rock type with a specific porosity and permeability. Water is non-producible and is held to rocks by capillary forces. The capillary bound water resides on the grain surface of the rock and is trapped in some of the small pores with a minute pore throat radius, while the clay bound water is attached to the clay surface. $S_{wirr}$ is accurately derived from the drainage capillary pressure test as the pore volume of water that cannot be flushed out at very high pressures. In a relative permeability test, the critical water saturation is the value where the water phase starts to move. For most reservoirs, irreducible water saturation and critical water saturation are very close to each other. Irreducible water saturation is a petrophysical quantity that is an indicator of reservoir quality. It can be derived from wireline logs (above the transition zone), routine core analysis, capillary pressure curves, and relative permeability. Thus, it gives a direct association between petrophysical, static and dynamic data sets. Including $S_{wirr}$ in any rock typing scheme enhances the results of initialization as it is directly used in the estimation of the oil in place. It is a direct indicator of one-phase fluid flow in rocks as depicted by some authors (Morris-Biggs, 1967, and Timur, 1968), as it is proportionally correlated with porosity and inversely proportional to permeability (Eq. 5.9). The product of irreducible water saturation and porosity is evidence of reservoir rock quality as proven by Buckles (Section 3.3.2).

In several integrated studies using SCAL and wireline data, the resulting rock type included sub-division based on $S_{wirr}$. Ghedan (2012) found the need to divide the SCAL based rock types further to include sub-types based on $S_{wirr}$. Al-Otaibi et al.
(2012) found the need to divide the rock types derived from capillary pressure again based on porosity and permeability. Kalam et al.'s (2013) results of integration data of a giant carbonate field showed that matching of capillary data rock types resulted in banding of facies based on porosity and permeability. Zahaf et al. (2014) identified reservoir layers based on average water saturation from SCAL and wireline logs and then subdivided the rock types of limestone and dolomite based on R50 using Pittman's equation. Omeke (2014) classified rock types based on $S_{wirr}$ for better dynamic simulation and volumetric estimation. Rebelle and Lalanne (2014) investigated clustering methods for carbonate rock typing and their results included banding of porosity and permeability data for each representative capillary pressure group. Skalinski et al. (2015) investigated geological, petrophysical and SCAL data and the results showed porosity and permeability banding to satisfy the reservoir dynamic conditions.

Sedimentological facies include depositional, diagenetic and fracture rock types. A three dimensional association for each sedimentological facies property of porosity, permeability, and irreducible water saturation ensures that lithology, static and dynamic behaviour, pore throat characterization of various rock types is captured. The initialization parameters are derived from wireline logs, routine core analysis, capillary pressure data and relative permeability curves end points. Calibration from logs takes into consideration that irreducible water should be above the transition zone, whereas prediction can be made all along the well including the transition zone and at 100% water saturation by using saturation height modelling.
Figure 5.6: Conceptual Ternary Rock Typing (TRT) Plot showing generalized carbonate texture and fabric associated with the three TRT parameters; porosity, permeability and irreducible water saturation. Size, shape and orientation of the ellipsoids will vary based on variation in depositional environments’ fabric, diagenesis and fracture effect.

It can be seen from the TRT plot (Figure 5.4) that Mudstones exhibit low porosity, low permeability and high $S_{wirr}$ because of the small particle size. The increase in porosity and permeability for Wackstones and Packstones, and decrease in $S_{wirr}$ can be easily attributed to the increase in the grain to mud ratio. Isolated pores do not affect fluid flow but act as a container for storage capacity, while fractures are accountable for fluid transmission. Fractures might have storage capacity or they can merely act as conduits for fluid flow between pores with storage capacity. These completely different processes can be identified on the conceptual TRT plot and distinctive signatures for vuggs, dissolution and fractures can be distinguished. The three-part relationship between porosity, permeability and irreducible water saturation is a direct indicator of rock and pore type interaction.
The TRT plot can utilize most of the previous rock typing techniques discussed in chapters 3 and 4. The k and $\Phi$ techniques shown in red in Figure 5.4 (e.g. Winland/Kolodzie R35, Amaefule RQI/FZI, Lucia RFN, Corbett GHE, etc.) can be plotted in the (k, $\Phi$) domain. The $S_{\text{wirr}}$ and $\Phi$ methods shown in blue (e.g. Archie, Buckles, Aguilera, etc.) can be plotted in the ($S_{\text{wirr}}$, $\Phi$) domain. The $S_{\text{wirr}}$ and k methods shown in cyan (e.g. Timur, etc.) can be plotted in the ($S_{\text{wirr}}$, k) domain. The plot combines most sedimentological, geological, petrophysical and reservoir engineering concepts and measurements in one single plot.

5.3 Theoretical Background of TRT

One form of Kozeny-Carman Equation:

$$k = \frac{\phi_e^2}{(1-\phi_e)^2} \times \left( \frac{1}{F_s \tau^2 S_{gv}} \right)$$  \hspace{1cm} (Eq. 5.1)

where

- $\phi_e$ is the effective porosity
- $F_s$ is the shape factor (2 for circular cylinder)
- $S_{gv}$ is the specific surface area per unit grain volume
- $(F_s \tau^2)$ is referred to as Kozeny's constant

$(F_s \tau^2)$ is constant within a particular hydraulic unit but varies between different units (Amaefule et al., 1993). In some studies and applications, $S_{gv}$ is ignored.

$(F_s \tau^2)$ and $S_{gv}$ values are also hard to determine and thus set limitations for the use of the Kozeny-Carman equation. Some authors attempted to decipher these constants. Kozeny’s constant is an empirical constant that depends on the cross sectional shape of the flow paths. Aguilera (2004) stated that Kozeny’s constant $(F_s \tau^2)$ can be re-written according to the following equation:

$$F_s \tau^2 = 114.14 (k/\Phi)^{-0.1} = 89.543 r_p^{-0.2222}$$  \hspace{1cm} (Eq. 5.2)
This leads to:

\[ F_s \, \tau^2 = f(k, \Phi) \quad (\text{Eq. 5.3}) \]

which indicates that the constant is a function of porosity and permeability and consequently \( r_{p35} \). According to Rose and Bruce (1949) the value of \( (F_s \, \tau^2) \) ranges between 5 and 200.

Tiab and Donaldson (2004) related surface area per unit grain volume \( S_{gv} \) to \( S_{wirr} \) according to the following equation:

\[ S_{gv} = ae^{bS_{wirr}} \quad (\text{Eq. 5.4}) \]

This leads to:

\[ S_{gv} = f(S_{wirr}) \quad (\text{Eq. 5.5}) \]

The dynamic relationship of Kozeny-Carman is reduced to be a three dimensional relationship of:

\[ f(S_{wirr}, k, \Phi) \quad (\text{Eq. 5.6}) \]

The relationship becomes a function of permeability, porosity and irreducible water saturation and associated constants between the three parameters that vary with each rock-pore interaction. The non-linearity of the relationship between parameters (phi, k, \( S_{wirr} \)) is best deciphered from actual data (wireline logs, RCA and SCAL data) for each rock type rather than trying to derive an equation with constants that tries to account for all rock types. The above procedure has the advantage that it does not omit any of the pore type parameters like pore throat radius, tortuosity at the core plug volume, shape factor and specific surface area. Instead of trying to explicitly determine them individually, they are included implicitly in the three dimensional relationship of the above-mentioned parameters. The rock typing procedure becomes more robust since the data governs the relationship instead of trying to force data to follow a predefined equation or relationship.
5.4 TRT and Wireline Logs

Wireline logs have been used for decades, directly or indirectly, as a classification tool for lithology and rock typing. The TRT method uses three reservoir related parameters. The porosity is one of the most reliable measurements since it comes from more than three wireline tool sources (Sonic, Neutron, Density, etc.). There are wireline tools that infer permeability (e.g. NMR, CMR) and these can be used as a first run to assign TRT rock types. One limitation of the NMR tool is that it measures the pore body size distribution, while permeability is dependent on the pore throat. The industry standard for achieving a predicted permeability log still relies on the Poro/Perm cross plot relation methodology. Water saturation derived from wireline logs is the most challenging measurement due to the sensitivity of the tools and correction needed for saturation equations. In the TRT workflow, water saturation uses the irreducible part not the initial water saturation. Irreducible water saturation from logs has to be derived from initial wells not affected by water production or water injection and above the transition zone effect. The effect of initial water saturation has to be subtracted from the water saturation curve by using an appropriate modified J-function or by only using data well beyond the transition zone. In cases where wireline acquisition comes from different vendors and different tools then normalization of wireline logs has to be achieved to homogenize the effect of tools and borehole effects. The TRT method can be applied to un-cored intervals by inferring rock types by their wireline log signature using neural networks, K-nearest neighbours algorithm, multi linear regression, etc. The workflow can also work when no routine core analysis is available but several iterations will be required to come up with an acceptable model.

5.5 TRT and RCA

Routine core analysis (RCA) is used regularly for reservoir property extraction. An important aspect in core analysis is being able to adjust porosity and permeability to stress corrected values at reservoir conditions. Porosity and permeability core analysis measurements are usually reliable. However, it is often not a straightforward task. Bias in the selection of the samples towards 'easier to measure' sections, avoiding tight or loose rocks often result in a more optimistic data set and non-
representative samples for the lower quality rock types. Outlier measurement data points’ interpretation is difficult to assign as being authentic or artificial. Porosity and permeability rock typing techniques often fail to represent carbonates if used exclusively as most of them rely on the concept that a single relationship for a specific rock type can include low porosity/low permeability together with high porosity/high permeability as one single pore throat radius (or other similar parameter). This is sedimentologically not accurate as the dramatic change in porosity and permeability entails different diagenetic and fracture history. Adding irreducible water saturation as a third classifier minimise this problem. However, achieving a water saturation value from routine core analysis is usually taken as a qualitative rather than quantitative measure. The most common methods used for saturation estimation are: the Retort method and the Dean-Stark method. The Retort method uses fluid evaporation from the pore space and is fast but often over estimates water recoveries. The Dean-Stark method is based on leaching of fluids in the pore space and is more accurate but takes longer laboratory time. The TRT method can be applied easily using routine core analysis and differentiates between representative and non-representative data points.

5.6 Use of TRT for Core Based Dynamic Rock Typing

In previous chapters it was elaborated that the word dynamic or hydraulic relates to the dynamic movement of fluid in rock pore network and pore space. This can be deciphered by the capillary, wettability and relative permeability behaviour. The cluster analysis of routine core and wireline logs to achieve one-phase rock types and then trying to impose these rock types to relevant capillary pressure and relative permeability curves is a linear workflow that often fails. Another methodology uses SCAL data to determine dynamic rock types and then tries to upscale high resolution geological/petrophysical facies to these rock types. This is again a linear approach that often does not allow for looping back to achieve more consistent results between disciplines.

The approach in this thesis is a much more integrated approach between various disciplines. The sedimentological facies is plotted in a phi, k, Swirr domain using core description, thin section petrography and routine core analysis. A TRT prototype for
each sedimentological facies is achieved and an ellipsoid of phi, k, \( S_{wirr} \) parameters is assigned. Ellipsoids for each facies vary in size and orientation based on the depositional, diagenetic and fracturing history of that particular facies. It allows for proper understanding and investigation of outliers and overlaps. This also permits for the separation of representative points with outlier behaviour such as fractures and stylolites from the misrepresentative points which results in misleading readings.

Capillary Pressure profile identifies the prevailing pore throat and pore geometry affecting fluid flow depending on the plateau curvature, which relates to a specific sedimentological facies. This allows for the definition of mono and poly pore related facies. The relative permeability of the water phase differs from one rock type to the other based on its wettability and rock to fluid interaction affecting its irreducible water saturation. By adding capillary pressure and relative permeability points to the TRT plot, an integrated rock typing scheme is easily achieved (Figure 5.5).

Figure 5.7: Conceptual TRT plot and effect of rock typing quality change showing rock types ellipsoid centroids presented as cubes and associated effect on capillary pressure and relative permeability data.
5.7 TRT and Saturation Height Modelling as a Quality Control Tool

Saturation Height Modelling is a representation of FWL, water saturation, porosity, permeability, wettability, transition zone and dry oil limit. Hence, it will be used as a quality control tool. Since the TRT method uses capillary pressure, water saturation and permeability in the identification of rock types, it will give a better saturation profile than the techniques that only use porosity and permeability. Saturation modelling using J-function and other saturation height modelling functions will test wireline based saturation against core based saturation to test the validity of the TRT rock types. Since the J-function is related to FWL, porosity, permeability, wettability for each facies, if the resultant water saturation agrees with the core and wireline saturation it is evident that the rock type profile is correct. A TRT workflow is suggested (Figure 5.6) and will be updated based on results using 1D and 3D modelling of real carbonate reservoirs data in subsequent chapters.

TRT is innovative and differs from other methods in utilizing the static and dynamic rock typing and where quality control becomes part of the rock typing process.

Figure 5.8: A proposed Ternary Rock Typing (TRT) workflow to be updated based on testing against real data in subsequent chapters.
5.8 TRT Software

The pore space and pore network properties are not predictable over large distances away from the drilled well bore using related petrophysical and engineering clustering. Rocks, on the other hand, are part of the architectural building blocks of the sedimentological environment. Understanding the rock system relevant to its place in the environmental model, whether in a proximal or distal location or whether in a low energy versus high energy deposition, makes it predictable over long distances. Linking pore space and pore network to sedimentological facies and the depositional environment allows for the prediction of the pore system since rocks can be mapped and predicted away from well data. The rock type becomes a predictable sedimentological container with predefined clusters of pore space and pore network properties.

The number of clusters depends on the sedimentological processes that affect the reservoir properties. Any geologic processes (depositional, diagenetic and fracturing) that do not affect the petrophysical and engineering properties are ignored. For example, if fractures are closed and do not contribute to fluid flow or storage capacity, they are ignored in the rock typing process. However, if stylolization contributes to fluid flow with an obvious signature on permeability and can be predicted from core slabs, then it has to be included in the rock typing scheme. The other aspect of defining the number of clusters is a practical constraint where the range of each cluster has to have a property range. A common practical range for a cluster is within 10 porosity units, 10 water saturation units and one decade for permeability in millidarcys.

Quality control is achieved on several levels. Qualitative and quantitative levels are achieved using plots and measures. Qualitative measures are first performed in (k, \(\Phi\)), (\(S_{wirr}\), \(\Phi\)), (\(S_{wirr}\), k) domains. The centroid of each predicted rock typing cluster has to be located coherently in each domain. The best performance rock type should posses the highest reservoir storage and flow capacity. It should also hold the largest pore sizes and smallest specific surface area. The best rock type will have the lowest irreducible water saturation, the highest porosity and permeability centroid mean values. The same quality control is applied for all other gradation rock types where the lowest performance rock type will have the lowest porosity, permeability and the
highest irreducible water saturation. Upon inspection of the location of the centroids of the four data types (wireline logs, RCA, capillary pressure and relative permeability) in the three domains, a verification can be made if any of the data types are assigned to the correct rock typing class (Figure 5.9).

![Figure 5.9: Hypothetical centroids' response for rock types based on their quality assignment in the Phi, k, S_{wir} domains.](image)

Using the Ordered Lorenz Plot (OLP) gives yet another quality control on the predicted rock type. Since the OLP is ordered, it can be concluded that the contributing rock types should increase from highest to lowest quality rock types. In Figure 5.10, a lighter color indicates better quality rock types, while darker colors correspond to lower quality ones. Depending on the rock typing methodology used, the predicted rock type is assigned to its rock type quality irrespective of the Lorenz plot assignment. If the rock type is correctly assigned, the lighter colors will dominate the left section of the plot, while the lower quality will dominate the right section of the plot. If the rock type is erroneously assigned then the location will be variably located in the plot.
The first quantitative measure is applied using the predicted permeability for each rock typing methodology with respect to the core permeability and a Pearson coefficient is measured. The same is applied to predicted permeability and SCAL permeability. The rock typing methods with the highest Pearson coefficients are then candidates for the next quantitative measure.

The second measure is Pearson coefficient comparing water saturation from wireline logs and saturation derived from J-function. The J-function capillary pressure grouping changes with the change of each rock typing method assignment. The best Pearson coefficients give an indication of the best rock typing scheme to be used concerning this particular data set.
An investigation of different platforms and software found that there was no available tool to handle the testing of various rock typing models and data-sets as stated earlier in previous chapters. As part of this research, a tool needed to be programmed from scratch to be able to test the different techniques and data sets in a fast and objective manner. The tool must be able to quantify the difference between various techniques. The tool developed, as part of this thesis, has almost 12,000 lines of code programmed using Visual basic.

This new tool is able to:
- Read Las files
- Read RCA data
- Read SCAL data
- Cross plotting capability
- Clustering capability
- Data output capability

The following processes are performed using the TRT software on the fly:
- Performs rock typing using eight published methods
- Performs rock typing using TRT method (Guided and Un-Guided Approach)
- Performs automatic poro/perm relations and predicted permeability using all previously mentioned techniques per rock type
- Performs Stratigraphic Modified Lorenz Plot/Ordered Lorenz Plot (SMLP/OLP) for all rock typing techniques
- Quantifies the match of permeability for various rock typing techniques between core and predicted permeability
- Quantifies validity of rock typing techniques through the match of water saturation derived J-function and resistivity derived saturation
- Outputs of TRT provide the building blocks for 3D architectural models in Petrel & Eclipse (formats readable to Petrel and Eclipse).
The TRT tool performs rock typing using the following methods:

- Amaefule, FZI
- Winland, R35
- Wibowo, PGS
- Corbett, GHE
- Lucia, RFN
- Buckles, BVW
- Pittman, R50, R25
- Ternary Rock Typing (TRT)

Figure 5.12: A snapshot of the TRT tool programmed to test various rock typing techniques.
5.9 TRT Validation Through Predicted Data Set

In chapters 6 and 7, TRT is tested using realistic 1D and 3D data sets from actual carbonate reservoirs. However, before testing the real data sets with their associated uncertainties, a synthetic data set is created and tested based on the concepts provided by previous authors to assess the applicability of the ternary rock typing concept and software. The data set includes “sedimentological facies” and their associated porosity, permeability, water saturation and height above free water level values. Lucia's work proved to be extensively integrated among various disciplines and his work and method are well documented and tested. The porosity and permeability relationship used in the synthetic data set is based on a generic form of his results with a change of exponents and constants to represent different rock types and fabrics. As water saturation evaluation is one of the uncertain numbers to document, two different approaches are used for testing. The first approach uses the Lucia equation and the other uses the Timur equation. Lucia's method is based on porosity and height above free water level (Eq. 5.7 & 5.8), while Timur's is based on an empirical equation of porosity and permeability (Eq. 5.9).

Six carbonate rock types are tested covering different lithologies, fabrics, fracture and diagenetic history as follows (Table 5.1):

Table 5.1: Six carbonate rock types to be tested

<table>
<thead>
<tr>
<th>Rock type</th>
<th>Associated &quot;Sedimentologic Fabric&quot;</th>
</tr>
</thead>
<tbody>
<tr>
<td>1-3</td>
<td>Mud dominated, wackestone and packstone limestone and/or fine crystalline dolostones.</td>
</tr>
<tr>
<td>4-6</td>
<td>Grainstone and/or Large crystalline possibly fractured dolostone</td>
</tr>
</tbody>
</table>

The Lucia type equation of permeability takes on the following form:

\[ k = a \cdot b \cdot \Phi^c \]  

(Eq. 5.7)

where

- \( \Phi \) is effective porosity
- \( a, b \) and \( c \) are constants
Table 5.2: Six rock types to be tested and their permeability constant variation based on Lucia's equation

<table>
<thead>
<tr>
<th>Porosity Range</th>
<th>a</th>
<th>B</th>
<th>c</th>
</tr>
</thead>
<tbody>
<tr>
<td>RT 6</td>
<td>0.15-0.20</td>
<td>45.35</td>
<td>$10^8$</td>
</tr>
<tr>
<td>RT 5</td>
<td>0.10-0.15</td>
<td>45.35</td>
<td>$10^8$</td>
</tr>
<tr>
<td>RT 4</td>
<td>0.07-0.10</td>
<td>45.35</td>
<td>$10^8$</td>
</tr>
<tr>
<td>RT 3</td>
<td>0.23-0.30</td>
<td>2.04</td>
<td>$10^6$</td>
</tr>
<tr>
<td>RT 2</td>
<td>0.15-0.23</td>
<td>2.2</td>
<td>$10^5$</td>
</tr>
<tr>
<td>RT 1</td>
<td>0.07-0.15</td>
<td>2.4</td>
<td>$10^4$</td>
</tr>
</tbody>
</table>

The Lucia type equation of water saturation takes on the following form:

$$S_w = e \ast H^f \ast \Phi^g$$

(Eq. 5.8)

where

- $H$ is reservoir height in ft
- $e, f$ and $g$ are Lucia type equation constants

Table 5.3: Six rock types and their associated water saturation constants

<table>
<thead>
<tr>
<th>Porosity Range</th>
<th>e</th>
<th>f</th>
<th>g</th>
</tr>
</thead>
<tbody>
<tr>
<td>RT 6</td>
<td>0.15-0.20</td>
<td>0.02219</td>
<td>-0.316</td>
</tr>
<tr>
<td>RT 5</td>
<td>0.10-0.15</td>
<td>0.02219</td>
<td>-0.316</td>
</tr>
<tr>
<td>RT 4</td>
<td>0.07-0.10</td>
<td>0.02219</td>
<td>-0.316</td>
</tr>
<tr>
<td>RT 3</td>
<td>0.23-0.30</td>
<td>0.1404</td>
<td>-0.407</td>
</tr>
<tr>
<td>RT 2</td>
<td>0.15-0.23</td>
<td>0.25</td>
<td>-0.43</td>
</tr>
<tr>
<td>RT 1</td>
<td>0.07-0.15</td>
<td>0.35</td>
<td>0.45</td>
</tr>
</tbody>
</table>
The Morris-Biggs and Timur type equation of irreducible water saturation takes on the following form:

\[
S_{wirr} = \left( \frac{a}{k} \times \phi^b \right)^{1/c}
\]

(Eq. 5.9)

where

- \( a, b \) and \( c \) are Timur equation constants equal to 8581, 4.4 and 2 respectively and equal to 62500, 6 and 2 for Morris-Biggs equation.
Figure 5.13: Porosity and permeability calculated for different “sedimentological facies” for the synthetic test data set

Figure 5.14: Water saturation for the test data set derived by Lucia and Timur equation
Table 5.4: Six rock types and their associated average centre of ellipsoid

<table>
<thead>
<tr>
<th></th>
<th>Av. phi</th>
<th>Av. k</th>
<th>Av. Swi</th>
</tr>
</thead>
<tbody>
<tr>
<td>RT 6</td>
<td>0.175</td>
<td>1986.778</td>
<td>0.113</td>
</tr>
<tr>
<td>RT 5</td>
<td>0.123</td>
<td>118.888</td>
<td>0.172</td>
</tr>
<tr>
<td>RT 4</td>
<td>0.085</td>
<td>4.560</td>
<td>0.271</td>
</tr>
<tr>
<td>RT 3</td>
<td>0.261</td>
<td>447.501</td>
<td>0.109</td>
</tr>
<tr>
<td>RT 2</td>
<td>0.184</td>
<td>24.482</td>
<td>0.299</td>
</tr>
<tr>
<td>RT 1</td>
<td>0.117</td>
<td>1.289</td>
<td>0.696</td>
</tr>
</tbody>
</table>

In the following section (Figures 5.10 to 5.20) different snapshots from the TRT software represent prediction of various rock typing methods and their behaviour on log and porosity, permeability and saturation domains using the synthetic data set and comparing the results to the original data. The assigned "sedimentological facies" in the synthetic well and the properties are sampled statistically to represent local variability to give pseudo-natural like scenario.

Figure 5.15: Porosity and permeability crossplot, porosity and saturation crossplot, and OLP of the original rock types of the test data set.
Figure 5.16: Porosity and permeability crossplot, porosity and saturation crossplot, and OLP of the Flow Zone Indicator (FZI) derived rock types of the test data set.

Figure 5.17: Porosity and permeability crossplot, porosity and saturation crossplot, and OLP of Winland (R35) derived rock types of the test data set.
Figure 5.18: Porosity and permeability crossplot, porosity and saturation crossplot, and OLP of Wibowo (PGS) derived rock types of the test data set.

Figure 5.19: Porosity and permeability crossplot, porosity and saturation crossplot, and OLP of Corbett (GHE) derived rock types of the test data set.
Figure 5.20: Porosity and permeability crossplot, porosity and saturation crossplot, and OLP of Lucia (RFN) derived rock types of the test data set.

Figure 5.21: Porosity and permeability crossplot, porosity and saturation crossplot, and OLP of Buckles (BVW) derived rock types of the test data set.
Figure 5.22: Porosity and permeability crossplot, porosity and saturation crossplot, and OLP of Pittman (R25) derived rock types of the test data set.

Figure 5.23: Porosity and permeability crossplot, porosity and saturation crossplot, and OLP of Pittman (R50) derived rock types of the test data set.
Figure 5.24: Porosity and permeability crossplot, porosity and saturation crossplot, and OLP of unguided Ternary Rock Typing (rTRT) derived rock types of the test data set.

Figure 5.25: Porosity and permeability crossplot, porosity and saturation crossplot, and OLP of Guided Ternary Rock Typing (gTRT) derived rock types of the test data set using guided centres of ellipsoids.
The synthetic test data set has distinctive sedimentological fabrics and associated change in reservoir properties. The smaller grain/crystal size carbonate is represented by RT 1 to RT 3, while the larger grain/crystal size is represented by RT 4 to RT 6. RT 3 and RT 6 are responsible for most of the hydraulic flow as can be seen from OLP in Figure 5.10. They both possess the highest porosity and permeability relationship and the lowest irreducible water saturation. Distinct clusters are seen from the six rock types in terms of fabric, porosity, permeability and irreducible water saturation. The objective is to be able to correctly predict the proper sedimentological fabric and associated petrophysical properties from only porosity, permeability and irreducible water saturation.

Flow Zone Indicator and Corbett GHE methods performed well in assigning the highest rock type RT 6 (Figures 5.11 and 5.14). However, the high quality RT 3 was assigned incorrectly to the lower quality RT 4 giving a high hydraulic contribution to the wrong fabric. This can be seen from the poro/perm cross plot as RT 4 is assigned incorrectly to the highest porosity and permeability. From the water saturation porosity plot RT 4 was given the lowest irreducible water saturation and highest porosity. This is attributed to the fact that the same flow zone indicator value crosses between rock types that have different reservoir properties. The assumption is that one flow zone indicator value is representative for low porosity/low permeability and for high porosity/high permeability is non-representative.

Winland R35 performed well in assigning the highest quality RT 6 (Figure 5.12). However, the highest RT 3 was assigned to the wrong fabric of rock type (RT 5) minimizing the high hydraulic contribution of RT 3. This can be seen from the poro/perm cross plot as RT 5 is assigned incorrectly to the highest porosity and permeability replacing RT 3. RT 4 was incorrectly assigned the lowest $S_{wirr}$ instead of RT 3. It can be concluded that porosity and permeability rock typing schemes on their own are misleading for carbonate rock typing as the heterogeneity of carbonate rocks proves that irreducible water saturation cannot be implicitly predicted from porosity and permeability and hence $S_{wirr}$ has to be included explicitly in any carbonate rock typing method.
Wibowo (PGS) performed well in assigning the extreme high values of rock type RT 6 (Figure 5.13). However, the highest quality rock type of RT 3 was assigned to the wrong fabric of RT 6 minimizing the high hydraulic contribution of RT 3. The lowest reservoir quality rock type of RT 1 was assigned partly to RT 3 giving misleading information about recovery from lower and higher rock types.

Despite the fact that the synthetic data was generated by related equations from Lucia, the technique was unable to fully regenerate the original rock types (Figure 5.15). It, however, was able to assign all the fabric related rock types of RT 4-6 following a constant RFN. However, the rock type RT 3 was assigned to the rock type RT 4 minimizing the high hydraulic contribution of RT 3.

Buckles (BVW) performed well in assigning the high quality rock type RT 6 (Figure 5.16). However, the high quality rock type RT 3 was assigned to the wrong fabric RT 5 minimizing the high hydraulic contribution of RT 3. This can be seen from the poro/perm cross plot as RT 5 is assigned incorrectly to the highest porosity and permeability replacing RT 3. RT 4 was incorrectly assigned the lowest Swirr instead of RT 3. Buckles represents rock typing techniques using porosity and irreducible water saturation. It can be concluded that porosity and irreducible water saturation rock typing schemes, on their own, are misleading for carbonate rock typing.

Pittman (R50 and R25) performed well in assigning the high quality rock type RT 6 (Figures 5.18 and 5.17 respectively). However, the high quality rock type (RT 3) was assigned to rock type (RT 5) minimizing the high hydraulic contribution of RT 3. Un-guided TRT (rTRT) performed with similar results as the previous methods giving unsatisfactory results on (phi, k) and (phi, Swirr) domains.

The guided TRT (gTRT) using the centre of ellipsoids representing "sedimentological facies" as suggested in previous sections gave an almost perfect match to the original data as depicted in Figure 5.20. The predicted "sedimentological facies" are correct. The rock types from RT 1 to RT 6 are assigned properly on the depth domain with a minute mismatch of RT 5. The porosity and permeability assignment to rock fabrics is properly predicted. The porosity and irreducible water saturation assignment to rock types is also properly predicted. The hydraulic contribution of each rock type is
also correctly assigned. It can be concluded that using guided TRT (gTRT) gives the best results using the synthetic data set and is a candidate for further testing using realistic data as will be elaborated in the next chapters. The final TRT plot of the synthetic data set is illustrated in Figures 5.21 and 5.22.

Figure 5.26: TRT plot showing the synthetic data set rock types and ellipsoid centroids (C-RT) for each rock type.

Figure 5.27: TRT plot showing the projection of the synthetic data set rock types in the 2D domains of \((\phi, S_{wirr})\), \((\phi, k)\), and \((S_{wirr}, k)\) and the ellipsoid centres for each rock type in the 3D domain.
In the next chapters the Kernel of the TRT will be integrated to form a comprehensive workflow for carbonate rock typing to be used in static and dynamic modelling. This will be achieved using 1D and 3D data from a carbonate oil field. The objectives of the TRT global rock typing scheme to be presented in the next chapters are:

- To propose a novel Ternary Rock Typing approach (TRT) that utilizes wireline logs, routine core analysis, capillary pressure data and relative permeability curves by three dimensional clustering of porosity, permeability and irreducible water saturation.
- To show that TRT can be used as a vehicle that combines most sedimentological, geological, petrophysical and reservoir engineering concepts and measurements in one single plot.
- To show that TRT is able to distinctively capture facies, static and dynamic reservoir properties of various rock types and match wireline logs, routine and special core analysis
- To test TRT against other rock typing techniques
- To test the ability for prediction of rock types and reservoir properties of un-cored intervals
- To optimize of the initialization of static and dynamic models thus directly lowering the uncertainty in the calculated HIIP and dynamic behaviour
5.10 Conclusion

From a review of previous methods and techniques, it is concluded that a multi-scale and multi-disciplinary carbonate rock typing workflow should possess the following features:

- match routine core analysis
- work well with clustered wireline logs
- have a clear separation between clusters
- match capillary pressure
- match relative permeability end points
- be able to predict facies and properties over intervals with no routine and special core analysis
- work well when RCA is not present
- work well above and below OWC
- be able to exclude non reliable/representative points
- be able to be used when there is no SCAL
- differentiate between mono and poly pore types
- have a minimum number of clusters
- link to rock physics model
- differentiate/integrate depositional, diagenetic and fracture effect of rock to pore types
- provide a common platform to visualize different data sources and suggest alternative interpretations
- derive the equation constants from the concerned data set and not inherit them from other datasets

It was concluded that porosity and permeability rock typing schemes on their own are misleading for carbonate rock typing as the heterogeneity of carbonate rocks proves that irreducible water saturation cannot be implicitly predicted from porosity and permeability and hence $S_{wirr}$ has to be included explicitly in any carbonate rock typing method. Also it was shown that porosity and irreducible water saturation rock typing schemes on their own did not capture the carbonate fabric satisfactorily with their associated reservoir properties.
A novel Ternary Rock Typing (TRT) application was presented that focuses on the interrelation between porosity, permeability and irreducible water saturation in the shape of a 3D ellipsoid. The change of rock fabric and its post depositional diagenesis and fracturing changes the ellipsoid characteristics. The complex interaction of rock, pore and fluid affect the location, shape, orientation and relative position of the three-parameter ellipsoid. The three measurements are extracted from wireline logs, routine and special core analysis, and are associated with capillary pressure and relative permeability measurements. Hence, these parameters are a good representation of rock type from a static and dynamic point of view. The ellipsoid characteristics are derived from the particular data and not inherited from non-relevant data sets and non-representative depositional environment. The technique overlaps between different datasets and disciplines.

The TRT methodology has the advantage that it does not omit any of the pore type parameters like pore throat radius, tortuosity at the core plug volume, shape factor and specific surface area or even wettability. Instead of trying to explicitly determine them individually, they are included implicitly in the three dimensional relationship of the above-mentioned parameters. The rock typing procedure becomes more robust since the data governs the relationship instead of trying to force data to follow a predefined equation or relationship.

Saturation height modeling is used as part of the quality control of the TRT rock typing scheme. This leads to the validation of static rock types through the quality control of their imbibition characteristics and hence their geological and petrophysical measurements can be confirmed. This results in a robust association between static and dynamic rock types and establishes an accurate saturation height function and fluid distribution across the reservoir. TRT is innovative and differs from other methods in utilizing the static and dynamic rock typing and where quality control becomes part of the rock typing process as will be shown in chapter 6.

As part of this research, a TRT tool was programmed that is able to generate rock typing logs, 1D plots, crossplots and output data and quantifies the match of various reservoir properties using various rock typing techniques.
The guided TRT (gTRT) using the centre of ellipsoids representing "sedimentological facies" proved to be able to replicate the prediction of a perfect match of the original synthetic data set. The porosity and permeability assignment to rock fabrics is properly predicted. The porosity and irreducible water saturation assignment to rock types is also properly predicted. The hydraulic contribution of each rock type is also correctly assigned. It can be concluded that using guided TRT (gTRT) gives the best results using the synthetic data set and is a candidate for further testing using realistic data as will be elaborated in the next chapters.

Advantages of Ternary Rock Typing (TRT):

- Ability to incorporate sedimentological fabric, routine and special core analysis in one plot
- Uses cloud ellipsoid assignment concept rather than single cutoffs
- Integrated with RCA
- Integrated with capillary pressure irreducible water saturation
- Integrated with relative permeability critical water saturation
- Uses clustered wireline logs
- Ability to exclude unreliable/non-representative points (located outside the ellipsoids)
- Integrates (phi/k) techniques (Winland, Pittman, FZI, Corbett, etc.)
- Integrates (phi/S_w) techniques (Aguilera, Cuddy, etc.)
- Integrates (k/S_w) techniques (Timur, etc.)
- Possibility of differentiation between depositional, diagenetic and fracture effect on rock if a signature in (phi, k, S_wirr) domain can be found
- Narrows the gap of data scale differences as the workflow used is parallel rather than linear
- Eliminates the need for multi-scheme; same rock type is used from start of geological interpretation, petrophysical analysis, static and dynamic modelling
- Saturation height function modelling is part of the rock typing technique as a quality control (as presented in the subsequent chapters)
- The technique can be used as a data only driven approach (rTRT) or as a guided data driven approach (gTRT)
CHAPTER SIX

COMPARISON OF TRT WITH TRADITIONAL ROCK TYPING METHODS: 1-D EXAMPLE FROM THE GULF OF SUEZ

6.1 Introduction

This chapter continues the progress of the previous chapters to achieve a comprehensive workflow for carbonate rock typing that can be applied in static and dynamic modelling. In chapter 2, a review of geological/sedimentological rock typing concepts and their application was discussed. Chapter 3 focused on one phase static rock and reservoir property interaction based methods utilizing wireline logs and routine core analysis, while chapter 4 emphasized on two phase dynamic and hydraulic rock/fluid relationships including wettability, relative permeability, capillary pressure and saturation height functions. Chapter 5 introduced a proposed global carbonate rock typing methodology, namely Ternary Rock Typing (TRT) which proved through the application of TRT software using a synthetic data set that it is able to reduce some of the pitfalls of previous rock typing methodologies through the integration of sedimentological facies, porosity, permeability and irreducible water saturation.

In this chapter, the Ternary Rock Typing (TRT) concept is tested on actual carbonate reservoir data in 1D space. The data set used in this chapter is from a carbonate oil field located in the Gulf of Suez (G.O.S.). Lessons learned will be used progressively to develop a global and comprehensive workflow that can be used in 3D space for carbonate reservoir modelling utilizing sedimentological, petrophysical and reservoir engineering disciplines and datasets as will be shown in chapter 7.

The biostratigraphic and sedimentological results in this section are based on an internal report by EREX Petroleum Consultants and published presentations (Tawfik et al., 2016 and Darwish et al., 2016). The results of these studies will be used as a reference data set in chapters 6 and 7 including biostratigraphy, cyclo-sequence stratigraphy, thin section petrography, core description, and sedimentological modelling, where the results were calibrated using wireline log data as well as routine and special core analysis.
6.2 Regional Tectono-Stratigraphy of Field X

Field X is located in the southern part of the Gulf of Suez (G.O.S.), Egypt. The Suez Rift is a northwest extension of the Red Sea rift, which was initiated during the Oligocene time as a result of the separation of the Arabian and African plates. The Gulf of Suez rift basin proved to be a prolific petroleum province with the first oil well exploration discovered in 1886 and oil reserves equivalent to more than twelve billion barrels. The rift is up to 80 km wide and 300 km long and comprises a series of half-graben tilted fault blocks (Figure 6.1). Source rocks are Campanian and Eocene Limestones and a minor contribution of Miocene shales. Hydrocarbon bearing reservoirs range from Precambrian to Serravalian rocks with most of the reserves found within Cenozoic reservoirs.

![Location map of Gulf of Suez and the different structural dip provinces](image)

Figure 6.1: Location map of Gulf of Suez and the different structural dip provinces (after Younes and McClay, 2002).
The majority of the producing fields in the G.O.S are located along the crests of the tilted fault blocks and four-way dip closures. More than 1300 exploration wells have been drilled in the basin targeting structural and stratigraphic traps with thousands of more wells drilled as infill producers. The Gulf of Suez contains several oil fields that target Miocene carbonate facies for their hydrocarbon potentiality. The heterogeneous distribution of these carbonate reservoirs poses special challenges for the development, hydrocarbon volume assessment, and secondary/tertiary recovery processes.

Field X is a typical example of a Miocene carbonate oil field in the Gulf of Suez. The oil production is concentrated in Miocene carbonates and clastics, pre-Miocene clastics and Precambrian fractured basement complex. The multiple oil reservoirs are in complete hydraulic communication. It is evident that the oil reserves in the field are strongly controlled by their stratigraphic and sedimentologic interrelation. The syn-rift Miocene carbonates are volumetrically the largest hydrocarbon bearing reservoirs in the field, containing approximately 50% of the total reserves with initial production from about 800' oil column.

Field X’s stratigraphic succession is comprised of syn-rift Miocene strata which rest unconformably on the Lower Cretaceous sandstone with a major time gap. The missing of Upper Cretaceous-Oligocene successions may indicate that Field X tilted fault block was subject to deep erosion of the uplifted intra-basinal fault blocks (Figure 6.2). The stratigraphic framework of the field is distinguished, relative to the rifting stages, into pre-rift (Paleozoic-Lower Cretaceous Sandstones), syn-rift Miocene sequences (clastics, carbonates and evaporites) and Post Miocene sequences (clastics and evaporites) (Tewfik and Ayyad, 1982).

The Syn-rift successions are represented by two major groups; the lower succession is dominated by clastics and carbonates while the upper succession is dominated by evaporites. The lower succession is composed of Early to Early-Middle Miocene rocks. The lower part of this succession is composed of Basal Miocene Clastics (BMC) which rests unconformably on the pre-rift sequences, dominated by conglomerates and conglomeratic sandstones of alluvial fans to fan delta systems. Most of the clastic components are reworked from pre-existing pre-rift Eocene, Cretaceous, Paleozoic rocks and Precambrian Basement (Figure 6.2). Overlying the
BMC are the Miocene reservoirs, which are composed predominantly of thick carbonate sequences and represent the main focus data set of the present thesis.

Figure 6.2: Stratigraphic column of Field X showing the penetrated rock units relative to the Gulf of Suez Region (after Darwish et al., 2016).

6.3 Time Boundaries (Breaks and Unconformities)

The Miocene syn-rift sequences forming the main carbonate reservoir of Field X include several breaks of inter- and intraformational types. The successive development of the syn-rift sequences is controlled by the combination of climatic changes (sea-level fluctuations) and syn-depositional tectonics which resulted in a pronounced facies change through time and space that controlled the distribution and performance of the carbonate hydrocarbon-bearing reservoirs (Figure 6.3).
Based on the biostratigraphic analyses, the oil-bearing carbonate sequences of Miocene age are correlated with the eustatic events on the global sea level chart (Haq et al., 1988). The Aquitanian-Langhian sequences of higher 3rd order cycles are differentiated as: 1.5, 2.1, 2.2 and 2.3 (Figure 6.3 and 6.4). These cycles include the Basal Miocene clastics, the Rudeis, and the Kareem formations. The 3rd order cycle boundaries are well correlated with the major tectonic rifting events which controlled the development of the main carbonate facies of the oil-bearing reservoirs of cycles 2.1, 2.2 and 2.3.

Figure 6.3: Cyclo-bio-chronostratigraphic chart of Early to Early-Middle Miocene oil-bearing succession in the Field X - Chronology and eustatic curves are after Haq et al., 1988 (after Darwish et al., 2016).

Figure 6.4: Representative well model showing cyclic evolution of the carbonate sequences in Field X (after Darwish et al., 2016).
Using the cycle boundaries and maximum flooding events, being biostratigraphically defined, cyclicity analysis using wireline logs shows prograding and retrograding depositional patterns. The interpretation of the Integrated Prediction Error Filter Analysis curve (INPEFA created by Cyclolog® Software), the lithofacies of the cored intervals, and lithologic investigation of ditch cuttings led to an integrated approach of cyclo-chronostratigraphic assignment and definition of higher 4th order cycles representing reservoir scales (Figure 6.4). The identified cycles were related to the sedimentation controlling factors, tectonic setting and events, sediment supply, carbonate production rate, and global eustatic sea-level rising and falling. These factors are the main parameters affecting the available accommodation spaces and the sedimentation hierarchal patterns. They also determine missing cycles due to erosional and/or non-depositional events (i.e. unconformities of Intra-Lower Rudeis, Mid-Rudeis and Mid Clysmic, etc.).

6.4 Systems Tracts and Syn-depositional Tectonic Control on Reservoir Quality

The penetrated carbonate sequences of the Rudeis Formation (3rd order cycles 2.1, 2.2 and 2.3L) are found to be of variable rock types and reservoir performances. The highest quality is variably distributed. It is determined that the high quality reservoir coincides with the Lowstand Systems Tracts (LST) and Transgressive Systems Tracts (TST) with less quality at the Maximum Flooding (MF) systems tracts while the high quality of the Highstand Systems Tracts (HST) system is variable.

The intra-Lower Rudeis tectonic event affected the reservoir quality, especially at the higher parts of the structure, where leaching and karstification processes increased the rock type quality. Considering the 2.2A Cycle, the LST and TST systems tracts are of high quality rock types. The mid-Rudeis tectonic event controlled the high quality reservoir rock types (mainly dolomites), that coincides with the relative rise of global sea-level.

The HST systems tracts of the 3rd order cycle 2.2 are correlated with 2.2B 4th order cycle which proved to be a high quality reservoir. The mid-Rudeis tectonic event bounds the top of the 2.2B cycle where the upper Rudeis carbonates (limestone and dolomites) rest unconformably on the 2.2 cycle with a time-gap of about 0.5 m.a.
Paleontologically, the lower part of the 3rd order cycle 2.3 is represented by the LST. This cycle is differentiated into six higher 5th order cycles (1-6) of limestone and dolostone that changes rapidly to open marine shales with reservoir qualities rapidly changing from one block to the other.

The mid-Clysmic tectonic event, where the major rift shoulder uplifts took place and the rotation and tilting of the faulted blocks, represents the Kareem/Rudeis Formation unconformity. The uplifted blocks were inundated from the north and the east by the open marine shales (Shagar Member) with subordinate basal sandstone (Markha Member) that represent the 3rd order cycle 2.3U (Figure 6.5).

![Cyclo-chronostratigraphic cross section along 1, 2, 3, 4 & 5 wells north central sector of Field X (after Tawfik et al., 2016).](image)

**6.5 Depositional Sedimentological Environment**

The depositional environment is the aggregate of physical, chemical and biological conditions that prevail at a given local area within a given period of time. These conditions are controlled by several sedimentary processes in addition to syn-depositional tectonics and climate. The depositional facies are quite distinct in terms of architectural elements, micro-lithofacies assemblages, texture and sedimentary structures. These reflect the depositional processes responsible for the formation of the carbonate reservoirs (Rudeis Dolostones and Limestones), (Figure 6.6).
The distinguished genetic units within the Rudeis Carbonates include four facies complexes: (Figure 6.7)

- Patch reefs essentially composed of algal and coral developments (bindstones and partly bafflestones), sometimes with distinctive back-reef, reef-core and fore-reef zones
- Inter-reef debris of rudstone, floatstone, packstone and wackestones textural types
- Carbonates shoals of calcarenite accumulations
- Lagoonal to tidal flat facies dominated by wackestones and mudstone types, mostly associated with anhydrite and occasionally mixed with siliciclastic interbeds or scattered sand grains.

Such a suite of genetic units suggests a shallow marine carbonate platform depositional setting (essentially within the photic zone) with the development of reef complexes and tidal flat within enclosed or barred lagoons, all formed under a warm to semi-arid climate.
The early rift stage is dominated by deposition of Basal Miocene Clastics (Cycle 1.5) as prograding fan deltas fed from NW feeding margin and limited by the eastern Precambrian Basement highs (Figure 6.8). With increasing tectonic accommodation during the Late Aquitanian time, the first marine record occurred as a subtidal lagoon with patch reefs (Cycle 2.1) in the back side of the eastern basement high. The intra-Lower Rudeis tectonic events during Early Burdigalian time created more accommodation accompanied by the global sea-level rise, and resulted in the development of the depositional Cycle 2.2 being built-up mainly of lagoonal carbonate facies of dolomites and dolomitic limestones forming the main reservoir in the field. The mid-Rudeis tectonic event contributed to the aggradational build-up of reefal facies and talus cones of the Upper Rudeis Formation (Cycle 2.3L). During the Late Langhian mid-Clysmic tectonic event, extensive uplift of rift shoulders occurred creating more accommodation in the subsided blocks, where shales and thin limestone interbeds were developed on basal feldspathic sandstones of the Kareem Formation (Cycle 2.3U). The thick evaporite section of the Belayim Formation of latest Langhian/Early Serravalian age was developed concomitant with the Post Kareem Formation quiescent tectonics forming the main cap rock.
6.6 Core Facies and Diagenetic History

The Rudeis Formation carbonate reservoir association is composed of reef-core boundstone, fore-reef rudstone and fine-grained mud-to wackestone sediments that form a distinctive facies reflecting the interaction of tectonic uplifts and sea-level change. The reef core was sub-aerially exposed and developed a karstic weathering feature.
As a result, a distinctive surface results showing evidence of erosion and dissolution that enhances the reservoir rock properties, unless it is preserved by the subsequent sea-level rise and/or tectonic submerging of the block.

Depositional, diagenetic and fracture processes were identified from cores and thin sections petrography. It was found that the reservoir rock types were controlled essentially by depositional systems that were later modified by diagenetic features and fracture networks. The Lower Miocene reservoirs were differentiated into 12 rock types: limestones (L1-L6) and dolostones (D1-D6).

Basal Miocene clastics (B.M.C, 1.5 3rd order cycle) represent prograding east and southeastward fan-lobe shape. High quality reservoirs (types S6/S5) were developed at the lobe margins. Some patchy dolomite occurred within the sandy facies having different qualities. The lower sedimentary cycles (2.1 and 2.2A) of the Rudeis Formation reservoirs were represented by dolomite facies made of a partly restricted subtidal lagoon with the development of patch reefs with high quality facies of D6/D5 types. Sandy facies were developed in the northern area with high quality facies of S6/S5 types.

Considering the diagenetic history, the post depositional changes acting on the sediments are interpreted to be related to a combination of compaction, dolomitization, anhydritization and micritization. The development of stylolites in the carbonate pre-dates the introduction of diagenetic anhydrite. Stylolites post-dating anhydrite are very rare. Remnants of stylolites are present with seams engulfed in the diagenetic anhydrite.

The thin sections petrographic examination (core chips and ditch cuttings) of the Rudeis Formation dolostones indicated a secondary (diagenetic) origin of the dolomite. The movement of the dolomitizing fluids in the meteoric-marine mixing zone is proposed to be responsible for such dolomitization process, where the sea water was acting as a source for the Mg2+ needed in the calcite to dolomite replacement. In addition, the tidal pumping in the tidal environment might act as a driving mechanism for the dolomitizing fluid movement.
Figure 6.9: Core description within cyclo-sequence stratigraphic framework of a representative well from Field X of Lower Miocene carbonate facies (after Tawfik et al., 2016).
Figure 6.10: Representative well model showing core description of Lower Miocene dolomite facies (after Darwish et al., 2016).
Figure 6.11: Representative well model showing core description of Lower Miocene limestone facies (after Darwish et al., 2016).
6.7 Effect of Depositional Fabric, Diagenesis and Fracture on Reservoir Properties

The interrelationship between depositional processes, diagenetic, and fracturing mechanisms effect on rock typing schemes were scrutinized in previous chapters. In this section, the hierarchal importance of these processes is investigated on the reservoir quality of limestones and dolostones in Field X. The rocks are analyzed first using core description based on purely textural, mineralogical and diagenetic effects. It is found that the limestone reservoir quality of the Rudeis Formation is controlled mainly by its depositional factors including textural aspects that were modified by the diagenetic factors (dissolution, cementation and replacements) that were modified later by fracturing. On the other hand, the dolostone quality is controlled mainly by the post depositional diagenetic and fracturing factors (Figures 6.12 & 6.13).

In limestone, the depositional fabrics are the major controlling parameters while diagenesis and fractures are subordinate. In the matrix-supported fabrics, the lime mud fills the primary pores and shows relatively lower reservoir quality. The mudstone is fractured, stylolitic, and algal but the fractures are filled by dolomicrite. In the grain-supported texture, a good interconnected porosity network is found and higher reservoir quality is observed. The wackestone pores are partly open and fractured but the fracture is filled by carbonate breccia supported by dolomicrite matrix. The dolomitic algal, bioclastic wacke to packstone pores are open and are highly fractured but the fractures are filled with dead oil. Although the boundstone facies were subjected to dissolution and development of cavernous and vuggy pores, they were embedded in wackestone lowering reservoir quality due to lack of interconnected pores. Fracture filling with anhydrite is common closing any fracture porosity and/or permeability.

Dolomite facies, on the other hand, is highly affected by diagenesis as the controlling parameter affecting the reservoir quality. Dolomitization, leaching and mechanical fracturing enhance the reservoir quality, while anhydrite filling pores and fractures are significant reservoir quality deteriorating factors. Dense stylolitic dolostone enhances the permeability while the vuggy/moldic pores are partly open and partly filled by anhydrite.
The porosity types encountered in the limestone and dolostone facies from thin section petrography are shown in Figures 6.14 and 6.15.

Figure 6.12: From core description, the limestone reservoir quality main controlling factor is the depositional fabrics while diagenetic and fracturing processes are subordinate (after Tawfik et al., 2016).

Figure 6.13: the dolostone reservoir quality main controlling factor is diagenesis while depositional and fracturing processes are subordinate (after Tawfik et al., 2016).
<table>
<thead>
<tr>
<th>Limestone texture</th>
<th>Encountered porosity types</th>
<th>Thin section photomicrograph examples</th>
</tr>
</thead>
<tbody>
<tr>
<td>Boundstone</td>
<td>Cavernous, vuggy, fracture, stylolitic, intraparticle</td>
<td><img src="image" alt="Intraparticle porosity" /></td>
</tr>
<tr>
<td>Rudstone</td>
<td>Cavernous, vuggy, fracture, stylolitic</td>
<td><img src="image" alt="Interparticle porosity" /></td>
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<td>Floatstone</td>
<td>Fracture, stylolitic, vuggy</td>
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<tr>
<td>Packstone</td>
<td>Fracture, stylolitic, intergranular, vuggy, moldic</td>
<td><img src="image" alt="Moldic and microfracture porosity" /></td>
</tr>
<tr>
<td>Wackestone-Packstone</td>
<td>Fracture, stylolitic, intergranular, intraparticle, vuggy, moldic</td>
<td><img src="image" alt="Fracture and moldic porosity" /></td>
</tr>
<tr>
<td>Wackestone</td>
<td>Fracture, stylolitic, intraparticle, vuggy</td>
<td><img src="image" alt="Isolated vugs and intraparticle porosity" /></td>
</tr>
<tr>
<td>Mudstone</td>
<td>-----</td>
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</tbody>
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Figure 6.14: From thin section petrography, the main limestone textures and compiled aspects of porosity types (*after Tawfik et al., 2016*).
<table>
<thead>
<tr>
<th>Dolostone texture</th>
<th>Encountered porosity types</th>
<th>Thin section photomicrograph examples</th>
</tr>
</thead>
<tbody>
<tr>
<td>Boundstone</td>
<td>Cavernous, vuggy, fracture, stylolitic, intraparticle</td>
<td>Touching intraparticle and fracture porosity</td>
</tr>
<tr>
<td>Rudstone</td>
<td>Cavernous, vuggy, fracture, stylolitic, intraparticle</td>
<td>Moldic and intraparticle porosity</td>
</tr>
<tr>
<td>Packstone</td>
<td>Vuggy, moldic, fracture, stylolitic, intercrystalline</td>
<td>Biomoldic porosity</td>
</tr>
<tr>
<td>Wackestone-Packstone</td>
<td>Vuggy, moldic, fracture, stylolitic, intercrystalline</td>
<td>Isolated Biomoldic porosity</td>
</tr>
<tr>
<td>Wackestone</td>
<td>Vuggy, moldic, fracture, stylolitic, intercrystalline</td>
<td>Intercrystalline and fracture porosity</td>
</tr>
<tr>
<td>Mudstone</td>
<td>Vuggy, fracture, intercrystalline, stylolitic</td>
<td>Touching vugs in dolomicrite</td>
</tr>
</tbody>
</table>

Figure 6.15: From thin section petrography, the main dolostone textures and compiled aspects of porosity types (after Tawfik et al., 2016).
The previously derived sedimentological facies are combined with wireline logs and petrophysical properties to come up with a comprehensive rock typing scheme. The reservoir properties are used for rating the dolostone and limestone intervals based on the increasingly and improved reservoir qualities (Dolostone D1 through D6, Limestone L1 through L6) respectively forming 12 rock types (Figures 6.16 & 6.17). The rock typing scheme includes RCA and wireline logs from the cored intervals as well as thin section microscopic examination of the core chips and ditch cuttings. The facies models and rock typing schemes were constructed based on the textural, mineralogic and diagenetic aspects that were compiled and integrated with the porosity types. The result of the reference sedimentological study will be denoted as Original Rock Type (ORT) for comparison with other rock typing methods throughout chapters 6 and 7.

Figure 6.16: Limestone rock typing scheme from the sedimentological study denoted as original rock type (ORT) for Field X (after Tawfik et al., 2016).
Figure 6.17: Dolostone rock typing scheme from the sedimentological study denoted as original rock type (ORT) for Field X (after Tawfik et al., 2016).

The sedimentological facies observed from core description, thin section petrography and routine core analysis has a profound effect on phi, k, and $S_{wirr}$ values. The effect is not easily predicted but can be deciphered using (phi, k) and (phi, $S_w$) crossplots. Original sediments burial porosity is reduced by overburden, compaction and differential pore pressure mechanisms. The original burial porosity is affected by post diagenetic and fracturing processes. These values change over geological time based on the amount of post depositional changes by enhancing or reducing effects. The limestones tend to be affected less than dolomites since the post depositional changes in the dolomites are much more severe. This can be observed from the standard deviation of porosity of a particular rock type in dolomites which has a much higher value than its equivalent in limestones (Figures 6.18-6.21). Leaching and vuggy processes may enhance the storage capacity, but not necessarily affect pore throat radius and consequently not affect permeability.
Burial permeability is a function of the rock grain and rock particle size. The higher the size, the higher the permeability. Post depositional diagenesis often affects porosity and permeability synchronously. On the other hand, fracturing might only affect permeability. The fractures might be open or closed based on subsequent processes such as anhydrite filling. Irreducible water saturation is the amount of water retained on the grain surface of a rock type with a specific porosity and permeability. Rocks with fine grained/crystals will have a high specific surface area and high $S_{wirr}$, while coarse grained/crystals will have a lower specific area and lower $S_{wirr}$.

Figure 6.18: Crossplot showing Limestone facies response of wireline log porosity versus predicted permeability of wells from Field X colour coded with original rock type (ORT) derived from the sedimentological study (after Tawfik et al., 2016).
Figure 6.19: Crossplot showing Limestone facies response of wireline log porosity versus wireline log water saturation of wells from Field X colour coded with original rock type (ORT) derived from the sedimentological (after Tawfik et al., 2016).

Figure 6.20: Crossplot showing Dolostone facies response of core porosity versus core horizontal permeability of wells from Field X colour coded with original rock type (ORT) derived from the sedimentological (after Tawfik et al., 2016).
Figure 6.21: Crossplot showing Dolostone facies response of core water saturation of wells from Field X colour coded with original rock type (ORT) derived from the sedimentological (after Tawfik et al., 2016).

Figure 6.18 shows the clustering of the derived sedimentological original rock types (ORT) on a porosity-permeability crossplot derived from wireline logs for limestones. The lowest quality reservoir rock type (L1) has an average porosity of 0.13 and an average permeability of 0.2md. On the other hand, the highest quality reservoir rock type (L6) has an average porosity of 0.28 and an average permeability of 30md. A similar trend can be observed on the porosity-water saturation crossplot (Figure 6.19). The poorest limestone rock type quality ranges from a water saturation average of 0.56 to 0.14 for the highest quality rock type. The trend of the limestone sedimentological facies has a logical phi, k, Swirr trend (NB: the plots are derived from an unbiased sedimentological study showing the applicability of TRT concept where a distinction of any rock type has a pronounced effect on all three parameters of porosity, permeability and irreducible water saturation).

Figure 6.20 shows the clustering of the derived sedimentological rock types on a porosity-permeability crossplot derived from routine core analysis for dolomites. The lowest quality reservoir rock type (D1) has an average porosity of 0.1 and an average permeability of 0.5md. On the other hand, the highest quality reservoir rock type (D6) has an average porosity of 0.28 and an average permeability of 50md. A similar trend can be observed on the porosity-water saturation crossplot (Figure 6.21). The poorest dolomite rock type quality (D1) ranges from a water saturation average of
0.35 to 0.08 for the highest quality rock type. The trend of the dolomite sedimentological facies has a logical phi, k, $S_{\text{wirr}}$ trend too like limestones, but with a much greater spread than that of the limestone. This has a twofold explanation. The first is that limestone property values have a lower standard deviation than that of dolomite because of their sedimentation, diagenetic and fracturing mechanism. The sedimentological fabrics of limestone are the main contributor of the reservoir properties and thus give a narrow spread. The extensive dolomite alteration to the original fabric implies properties have a wider spread since it is a compound effect of a multi stage diagenetic and fracturing process over long time span. The other reason is that in this particular data set, no water saturation routine core analysis for limestones was available and hence wireline log data was used. Prediction of properties using wireline logs usually gives a narrower spread than measured data. This can be observed from predicted permeability that is predicted from porosity and for water saturation determination that uses a porosity-based equation.

### 6.8 Rock Typing Using Routine Core Analysis

Using the TRT software that was developed as part of the present thesis, the following rock typing methods were tested against real carbonate field data:

- Amaefule, FZI
- Winland, R35
- Wibowo, PGS
- Corbett, GHE
- Lucia, RFN
- Buckles, BVW
- Pittman, R50, R25
- Un-Guided Ternary Rock Typing (rTRT)
- Guided Ternary Rock Typing (gTRT)

A representative well, namely Well W1, will be used for the demonstration of different rock typing techniques and their effect on:

- similarity of derived rock types compared to the derived sedimentological study rock type (ORT)
- change of porosity/permeability equations
- change in the centroids of ellipsoids of phi, k, and $S_{\text{wirr}}$ domain
- relative position and separation of the ellipsoids for each rock type
Figure 6.22: Log plot for Well W1 showing petrophysical log interpretation and routine core analysis data.

Figure 6.23: Consistency montage showing porosity-permeability crossplot, porosity-water saturation crossplot, OLP and wireline log response of Original Rock Type (ORT) of Well W1.
Figure 6.24: Consistency montage showing porosity-permeability crossplot, porosity-water saturation crossplot, OLP and porosity, predicted permeability and water saturation log response of Original Rock Type (ORT) of Well W1.

Figure 6.25: TRT plot showing the ellipsoid response for each rock and ellipsoid centroids on porosity-permeability and porosity-water saturation crossplots of Original Rock Type (ORT) of Well W1.
Figure 6.26: Consistency montage showing porosity and permeability crossplot, porosity and water saturation crossplot, OLP, core porosity, permeability and saturation versus wireline log porosity, predicted permeability and wireline water saturation response of the Flow Zone Indicator (FZI) derived rock types of Well W1.

Figure 6.27: TRT plot showing the ellipsoid response for each rock and ellipsoid centroids on porosity-permeability and porosity-water saturation crossplots of Flow Zone Indicator (FZI) derived rock types of Well W1.
Figure 6.28: Consistency montage showing porosity and permeability crossplot, porosity and water saturation crossplot, OLP, core porosity, permeability and saturation versus wireline log porosity, predicted permeability and wireline water saturation response of Winland (R35) derived rock types of Well W1.

Figure 6.29: TRT plot showing the ellipsoid response for each rock and ellipsoid centroids on porosity-permeability and porosity-water saturation crossplots of Winland (R35) derived rock types of Well W1.
Figure 6.30: Consistency montage showing porosity and permeability crossplot, porosity and water saturation crossplot, OLP, core porosity, permeability and saturation versus wireline log porosity, predicted permeability and wireline water saturation response of Wibowo (PGS) derived rock types of Well W1.

Figure 6.31: TRT plot showing the ellipsoid response for each rock and ellipsoid centroids on porosity-permeability and porosity-water saturation crossplots of Wibowo (PGS) derived rock types of Well W1.
Figure 6.32: Consistency montage showing porosity and permeability crossplot, porosity and water saturation crossplot, OLP, core porosity, permeability and saturation versus wireline log porosity, predicted permeability and wireline water saturation response of Corbett (GHE) derived rock types of Well W1.

Figure 6.33: TRT plot showing the ellipsoid response for each rock and ellipsoid centroids on porosity-permeability and porosity-water saturation crossplots of Corbett (GHE) derived rock types of Well W1.
Figure 6.34: Consistency montage showing porosity and permeability crossplot, porosity and water saturation crossplot, OLP, core porosity, permeability and saturation versus wireline log porosity, predicted permeability and wireline water saturation response of Lucia (RFN) derived rock types of Well W1.

Figure 6.35: TRT plot showing the ellipsoid response for each rock and ellipsoid centroids on porosity-permeability and porosity-water saturation crossplots of Lucia (RFN) derived rock types of Well W1.
Figure 6.36: Consistency montage showing porosity and permeability crossplot, porosity and water saturation crossplot, OLP, core porosity, permeability and saturation versus wireline log porosity, predicted permeability and wireline water saturation response of Buckles (BVW) derived rock types of Well W1.

Figure 6.37: TRT plot showing the ellipsoid response for each rock and ellipsoid centroids on porosity-permeability and porosity-water saturation crossplots of Buckles (BVW) derived rock types of Well W1.
Figure 6.38: Consistency montage showing porosity and permeability crossplot, porosity and water saturation crossplot, OLP, core porosity, permeability and saturation versus wireline log porosity, predicted permeability and wireline water saturation response of Pittman (R25) derived rock types of Well W1.

Figure 6.39: TRT plot showing the ellipsoid response for each rock and ellipsoid centroids on porosity-permeability and porosity-water saturation crossplots of Pittman (R25) derived rock types of Well W1.
Figure 6.40: Consistency montage showing porosity and permeability crossplot, porosity and water saturation crossplot, OLP, core porosity, permeability and saturation versus wireline log porosity, predicted permeability and wireline water saturation response of Pittman (R50) derived rock types of Well W1.

Figure 6.41: TRT plot showing the ellipsoid response for each rock and ellipsoid centroids on porosity-permeability and porosity-water saturation crossplots of Pittman (R50) derived rock types of Well W1.
Figure 6.42: Consistency montage showing porosity and permeability crossplot, porosity and water saturation crossplot, OLP, core porosity, permeability and saturation versus wireline log porosity, predicted permeability and wireline water saturation response of unguided Ternary Rock Typing (rTRT) derived rock types of Well W1.

Figure 6.43: TRT plot showing the ellipsoid response for each rock and ellipsoid centroids on porosity-permeability and porosity-water saturation crossplots of raw unguided Ternary Rock Typing (rTRT) derived rock types of Well W1.
The Pearson product moment correlation coefficient is called Pearson coefficient for short. It is an estimate of the stability of the linear association between two variables. It tries to draw a line of best fit through the data of two variables, and indicates how far away the data points are from this line of best fit. The Pearson correlation coefficient ranges in value from +1 to -1. A value of 0 indicates that there is no association between the two variables. A value greater than 0 indicates a positive association while a value less than 0 indicates a negative association. The strength of the association between the two variables is positively small for values from 0.1-0.3, medium for values 0.3-0.5 and high from 0.5 to 1. The same concept applies for negative association, but with a negative association value.

The advantage of using Pearson coefficient is that the two variables do not have to have the same comparison measurements. The units of measurement do not affect the association comparison calculation. An assumption is made that there is a linear relationship between the two variables and hence in this thesis, the same variable is compared to itself from different sources so that this assumption is met.

\[
\text{Pearson correlation coefficient} = \frac{N\Sigma xy - (\Sigma x)(\Sigma y)}{\sqrt{[N\Sigma x^2 - (\Sigma x)^2][N\Sigma y^2 - (\Sigma y)^2]}} \tag{Eq. 6.1}
\]

where

- \(N\) is the number of data points
- \(\Sigma xy\) is the sum of products of paired points
- \(\Sigma x\) is the sum of x variable
- \(\Sigma y\) is the sum of y variable
- \(\Sigma x^2\) is the sum of squared of x variable
- \(\Sigma y^2\) is the sum of squared of y variable
Less than one percent of the data points were omitted from the analysis based on the extreme value behaviour when applied on the TRT plot. The reason for the extreme value is error in the measurement in one of the three routine core analysis measurements (k, phi, Sw).

The original sedimentological study derived rock types (ORT) of Well W1 shows an increasing response of porosity and permeability values towards the higher quality rock types as depicted in section 6.7. This is also obvious for water saturation values, where the higher values correspond to the lower quality reservoir types and the lower values to the higher quality reservoirs types. The porosity and permeability equations tend to overlap in one point which is sedimentologically not possible as it entails that six rock types will have the same porosity and permeability interrelation (Figures 6.23-6.25). The highest flow capacity includes low quality rock types as observed from the OLP plot, which means that the prediction of these rock types is not accurate. The ellipsoids' sizes of the different rock types are widely spread and no distinctive separation is found.

The Flow Zone Indicator (FZI) and Corbett (GHE) derived rock types of Well W1 show similar responses to each other since they both rely on similar equations. The increasing of permeability centroids for the higher quality rock types is achieved, but the porosity centroids give almost the same value for all various rock types. This means that porosity is distributed almost homogeneously among all rock types. This goes against all geological and engineering observations. The porosity-water saturation trend is reversed where the highest quality rock type gave the lowest porosity centroid. The porosity and permeability equations are equally and uniformly distributed and are able to predict the highest permeability rock types and at the same time are able to predict the low permeability barriers. The ellipsoids' sizes of the different rock types are widely spread and no distinctive separation is found, where big ellipsoids enclose other smaller ellipsoids representing other rock types (Figures 6.26-6.27 and 6.32-6.33).

The Winland (R35) derived rock types of Well W1 show increasing porosity and permeability values towards the higher quality rock types. This is also obvious for porosity-water saturation centroids, where a good separation is obtained for all rock types. The porosity and permeability equations are equally and uniformly distributed
and are able to predict the highest permeability rock types and at the same time able to predict the low permeability barriers. The flow and storage capacity plot shows a correct grading contribution of rock types. Some of the ellipsoids' sizes of the different rock types are widely spread but a general distinctive separation is found (Figures 6.28-6.29).

The Wibowo (PGS) derived rock types show increasing porosity and permeability values towards the higher quality rock types. This is also obvious for porosity-water saturation centroids, where a good separation is obtained for all rock types. The method tends to underestimate the highest and lower quality rock types in favour of the moderate quality reservoirs. The porosity and permeability equations have mostly a negative slope. The permeability prediction fails for high permeability values. The flow and storage capacity plot shows a correct grading contribution of rock types. The ellipsoids' sizes of the different rock types are narrow and have an excellent distinctive separation (Figures 6.30-6.31).

The Lucia (RFN) derived rock types show an increasing of permeability centroids for the higher quality rock types but with the porosity centroids almost the same for the various rock types. The porosity-water saturation trend is reversed where the highest quality rock type incorrectly gave the lowest porosity centroid. The porosity and permeability equations are equally and uniformly distributed and are able to predict the highest and lowest permeability rock types. The ellipsoids' sizes of the different rock types are widely spread and no distinctive separation is found (Figures 6.34-6.35).

The Buckles (BVW) method gives an inverted response for all rock types, where the highest quality rock type gives the lowest porosity and lowest water saturation centroid. The Pittman (R25) derived rock types of Well W1 show increasing porosity and permeability values towards the higher quality rock types. This is also obvious for porosity-water saturation centroids, where a good separation is obtained for all rock types. The porosity and permeability equations are equally and uniformly distributed and are able to predict the highest permeability rock types and at the same time able to predict the low permeability barriers. The flow and storage capacity plot shows a correct grading contribution of rock types. Some of the ellipsoids' sizes of
the different rock types are widely spread but a general distinctive separation is found (Figures 6.38-6.39).

The Pittman (R50) derived rock types of Well W1 show increasing porosity and permeability values towards the higher quality rock types but are not able to predict the highest quality reservoir. The porosity-water saturation centroids have a low separation obtained for all rock types. The porosity and permeability equations are generally acceptable. There is a tendency to predict the moderate reservoir quality at the expense of the higher magnitude qualities. The flow and storage capacity plot shows a tendency toward contribution of the moderate rock types. Some of the ellipsoids' sizes of the different rock types are widely spread. The ellipsoids' boundaries overlap and no separation is found (Figures 6.40-6.41).

The raw unguided Ternary Rock Typing (rTRT) derived rock types of Well W1 show increasing porosity and permeability values towards the higher quality rock types. This is also obvious for porosity-water saturation centroids, where a good separation is obtained for all rock types. A logical water saturation decrease towards the good facies is obtained. The porosity and permeability equations are equally and uniformly distributed between data with a minor negative slope as observed in water saturation derived methods but not as severe as the Wibowo method. Highest permeability rock types as well as low permeability barriers were well predicted. The flow and storage capacity plot shows a correct grading contribution of rock types. Ellipsoids' sizes are narrow and a minimal overlap between different rock types is observed. The highest distinctive separation among all other methods is found (Figures 6.42-6.43). In the next section guided Ternary Rock Typing (gTRT) will be demonstrated and how seed points obtained from the sedimentological study greatly enhance the rock typing scheme and associated reservoir properties.
6.8.1 Porosity, Permeability, and Swirr Creaming Curves of Field X

The following section introduces the concept of creaming curves to determine the centroids of the rock types derived from the sedimentological study. The creaming curve was designed by Shell in the 80s to model the cumulative discovery of hydrocarbon in place versus the cumulative number of pure exploratory wells for a certain exploration play type. The steep slope is called creaming part which indicates that for each new discovery well, hydrocarbon reserves are added. The plateau part of the curve signifies that adding new wells does not add any new reserves and hence a new exploration strategy is to be envisioned. The same plot is used for infill drilling testing in hydrocarbon simulation by checking the sensitivity and the optimum number of infill wells to the addition of cumulative production. The creaming curve in this thesis is used to check the sensitivity of the reservoir property to the number of wells. Adding more wells increases the knowledge base to that particular reservoir property until a plateau is reached where adding more wells does not increase the accuracy or mean value of that property.

![Creaming curve standard plot](Image)

Figure 6.44: Creaming curve standard plot

The technique verifies if adding more wells will result in a change in the average value of porosity, permeability, and water saturation for a specific rock type until a plateau is reached. This means that adding more wells will not change the centroid values and thus gives more confidence in their values. These values can be used as a first trial for the centroid ellipsoids in the guided Ternary Rock Typing (gTRT) workflow. The stabilization of the plateau of the variable suggests an REV has been found.
Figure 6.45: Creaming curve of average core porosities for various dolomite facies (ORT) from six wells in Field X.

Figure 6.46: Creaming curve of average core permeability for various dolomite facies (ORT) from six wells in Field X.
Figure 6.47: Creaming curve of average core water saturation for various dolomite facies (ORT) from six wells in Field X.

Table 6.1: Centroids of various rock types derived from the sedimentological study (ORT) using creaming curves

<table>
<thead>
<tr>
<th>ORT</th>
<th>Av. Phi</th>
<th>Av. k</th>
<th>Av. S_w</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ellipsoids Centroids</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 7</td>
<td>0.074</td>
<td>0.222</td>
<td>0.266</td>
</tr>
<tr>
<td>RT 8</td>
<td>0.139</td>
<td>0.687</td>
<td>0.264</td>
</tr>
<tr>
<td>RT 9</td>
<td>0.151</td>
<td>3.695</td>
<td>0.356</td>
</tr>
<tr>
<td>RT 10</td>
<td>0.188</td>
<td>13.95</td>
<td>0.308</td>
</tr>
<tr>
<td>RT 11</td>
<td>0.242</td>
<td>23.047</td>
<td>0.208</td>
</tr>
<tr>
<td>RT 12</td>
<td>0.281</td>
<td>141.036</td>
<td>0.183</td>
</tr>
</tbody>
</table>

The porosity average for all rock types in the creaming curve retains a consistent average even with the addition of more wells (Figure 6.44). This means that any particular well can reliably represent the whole field from the point of view of porosity. Permeability behaves in a consistent manner similar to porosity where a consistent creaming curve is observed (Figure 6.45). Water saturation on the other hand, changes dramatically until a plateau is reached (Figure 6.46). RT12 and RT11 are well separated on porosity and permeability plots; however they overlap on water saturation behaviour. RT10 and RT11 are overlapping on the permeability plot, but they are well separated on porosity and water saturation plots. RT7 and RT8 are overlapping on the water saturation plot, but they are well separated on porosity and permeability plots. It can also be observed that water saturation doesn't follow the same porosity and permeability trend, where the better RT9 and RT10 from porosity and permeability point of view have a higher water saturation response. A plateau was not achieved for permeability for RT12 and a water saturation plateau was also not reached for most of the rock types. This means that more wells are needed to reach a representative average for the various rock types. This proves that the ternary interrelationship between porosity, permeability and water saturation in carbonate rocks is independent.
6.8.2 Guided Centres of Ellipsoids for TRT Training

Sedimentologically derived rock types (ORT) from only Well W1 were plotted against core porosity, permeability and water saturation. The average values for each rock types were used as seed points for the ternary rock typing (gTRT) algorithm to predict the likelihood for rock typing clusters. It can be seen that the sedimentological rock types behave in a different manner than presented in the previous unguided methods. The centroids of the water saturation are not aligned in a linear pattern, nor do they have a common trend. It can be seen that rock types 11 and 12 have the same porosity values but different water saturation values despite the fact that they have a close permeability trend. It can be seen for rock types 7 to 10 that distinct clusters of phi, k, and Sw are obtained. However, the permeability prediction is slightly lower than the un-guided TRT in the previous section (Figure 6.47).

Figure 6.48: Consistency montage showing ellipsoid response for each rock and ellipsoid centroids on porosity-permeability and porosity-water saturation crossplots of guided Ternary Rock Typing (gTRT) derived rock types of Well W1 using guided centres of ellipsoids ORT from only Well W1.

<table>
<thead>
<tr>
<th></th>
<th>Av. Phi</th>
<th>Av. k</th>
<th>Av. Sw</th>
<th>Av. Phi</th>
<th>Av. k</th>
<th>Av. Sw</th>
</tr>
</thead>
<tbody>
<tr>
<td>RT 7</td>
<td>0.16</td>
<td>4.7</td>
<td>0.312</td>
<td>0.131</td>
<td>1.79</td>
<td>0.287</td>
</tr>
<tr>
<td>RT 8</td>
<td>0.175</td>
<td>4.98</td>
<td>0.319</td>
<td>0.178</td>
<td>5.76</td>
<td>0.365</td>
</tr>
<tr>
<td>RT 9</td>
<td>0.232</td>
<td>5.8</td>
<td>0.297</td>
<td>0.215</td>
<td>4.382</td>
<td>0.234</td>
</tr>
<tr>
<td>RT 10</td>
<td>0.24</td>
<td>14</td>
<td>0.307</td>
<td>0.225</td>
<td>27.901</td>
<td>0.315</td>
</tr>
<tr>
<td>RT 11</td>
<td>0.3</td>
<td>23.9</td>
<td>0.277</td>
<td>0.286</td>
<td>51.853</td>
<td>0.282</td>
</tr>
<tr>
<td>RT 12</td>
<td>0.31</td>
<td>21</td>
<td>0.26</td>
<td>0.28</td>
<td>28.447</td>
<td>0.206</td>
</tr>
</tbody>
</table>
In Figure 6.48, the averages are derived from the whole field using sedimentological derived rock types (ORT) and not just using Well W1 as in the previous section. The average values for each rock type were used in the same manner as seed points for the ternary rock typing (gTRT) algorithm to predict the likelihood for rock typing clusters. It can be seen that it has a very different behaviour than the un-guided methods, but is very close to the guided sedimentological TRT (gTRT) using only Well W1. The centroids of phi, k, and S_w are well separated. It can be seen for rock types 7 to 12 that distinct clusters of phi, k, and S_w are obtained. The permeability prediction has better results compared to the un-guided rTRT in the previous section.

<table>
<thead>
<tr>
<th></th>
<th>Sedimentological ellipsoids centroids of Field X</th>
<th>Actual gTRT ellipsoids centroids of W1</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>RT 7</strong></td>
<td>0.074, 0.222, 0.266</td>
<td>0.075, 0.149, 0.291</td>
</tr>
<tr>
<td><strong>RT 8</strong></td>
<td>0.139, 0.687, 0.264</td>
<td>0.154, 1.247, 0.255</td>
</tr>
<tr>
<td><strong>RT 9</strong></td>
<td>0.151, 3.695, 0.356</td>
<td>0.16, 3.82, 0.39</td>
</tr>
<tr>
<td><strong>RT 10</strong></td>
<td>0.188, 13.95, 0.308</td>
<td>0.207, 16.88, 0.311</td>
</tr>
<tr>
<td><strong>RT 11</strong></td>
<td>0.242, 23.047, 0.208</td>
<td>0.241, 20.47, 0.223</td>
</tr>
<tr>
<td><strong>RT 12</strong></td>
<td>0.281, 141.036, 0.183</td>
<td>0.301, 87.612, 0.237</td>
</tr>
</tbody>
</table>

Figure 6.49: TRT plot showing the ellipsoid response for each rock and ellipsoid centroids on porosity-permeability and porosity-water saturation crossplots of guided Ternary Rock Typing (gTRT) derived rock types of Well W1 using guided centres of ellipsoids ORT from the whole Field X.
6.8.3 Predicted Permeability Comparison

The Pearson coefficient was used to compare the previous rock typing methods compared to the original routine core analysis results. The original sedimentological study (ORT) gave the poorest result with a value of 0.35. Wibowo (PGS) and Buckles (BVW) methods gave the second lowest values. The best methods are related to Flow Zone Indicator (FZI), Corbett (GHE) and Pittman (R25) giving a 0.96 coefficient. Wibowo (PGS) fell short by 0.41 coefficient. The TRT un-guided gave a 0.94 value, while the guided TRT using different sedimentological seed centroid gave 0.85 and 0.9 respectively, Figure 6.49.

![Figure 6.50: Predicted permeability comparison among different rock typing methods.](image)

It was shown that each rock typing method gave a completely different rock typing vertical profile along the well. Each method also gave a very different porosity-permeability relation. Despite all these differences almost all of them were able to predict the permeability with an acceptable accuracy. This leads us to conclude that permeability alone is not a clear quality control for the rock type log obtained since all gave acceptable comparable results. A clear quality control has to be envisioned to accept any particular rock typing method and results, as will be seen in the next sections.
6.8.4 Rock Types Comparison Results

Rock types’ prediction has to pass through a quality control procedure and becomes one of the most critical factors to judge the effectiveness of any rock typing method. The importance of rock types comes from the fact that all subsequent steps in static and dynamic modelling are related to that rock type assignment. The permeability prediction is based on rock types. Rock types are used primarily for 3D static model building, facies and reservoir property distribution. The dynamic association of capillary pressure and relative permeability curves are based on rock types. Hence, hydrocarbon in place, static and dynamic behaviour depends solely on that assignment (Figures 6.50 a and b, Table 6.2).

Figure 6.51: a) Rock typing comparison prediction for Well W1. b) Pearson coefficient of predicted facies compared to original rock type (ORT).
Table 6.2: Pearson Coefficient of facies comparison prediction for Well W1 compared to rock types derived from the sedimentological study (ORT)

<table>
<thead>
<tr>
<th>Rock Type Method</th>
<th>Pearson Coefficient</th>
</tr>
</thead>
<tbody>
<tr>
<td>Flow zone indicator (FZI)</td>
<td>0.060</td>
</tr>
<tr>
<td>Winland (R35)</td>
<td>0.350</td>
</tr>
<tr>
<td>Wibowo (PGS)</td>
<td>0.410</td>
</tr>
<tr>
<td>Corbett (GHE)</td>
<td>0.060</td>
</tr>
<tr>
<td>Lucia (RFN)</td>
<td>-0.213</td>
</tr>
<tr>
<td>Buckles (BVW)</td>
<td>-0.341</td>
</tr>
<tr>
<td>Pittman (R25)</td>
<td>0.370</td>
</tr>
<tr>
<td>Pittman (R50)</td>
<td>0.220</td>
</tr>
<tr>
<td>Unguided Ternary Rock Typing (rTRT)</td>
<td>0.530</td>
</tr>
<tr>
<td>Guided Ternary Rock Typing (gTRT)</td>
<td>0.582</td>
</tr>
</tbody>
</table>

Comparing the derived facies from various rock-typing methods to check their similarity to the sedimentological derived rock types (ORT), it is seen that the rTRT and gTRT method gave the highest similarity using only routine core analysis data with a value of 0.53 and 0.58 respectively. The third best ranking was Wibowo (PGS) with a value of 0.41. The Pittman (R25) and Winland (R35) methods gave similarities of 0.37, and 0.35 respectively. The rest of the methods gave unsatisfactory results. It can be concluded that Ternary Rock Typing (TRT) both: guided (gTRT) and unguided (rTRT) gives the best similarity to reference sedimentological study (ORT) results.

6.9 TRT Using Wireline Data

For Field X there is no water saturation core analysis data available for the limestone facies. The wireline log data was used to investigate the applicability of using TRT where no routine log analysis is available compared to the sedimentological derived rock types (ORT). Porosity, predicted permeability and water saturation derived from wireline logs are shown in Figures 6.51 and 6.52.

Figure 6.52: Plot showing wireline porosity-predicted permeability crossplot, wireline porosity-wireline water saturation crossplot, OLP and wireline log response of Ternary Rock Typing (TRT) derived rock types of Well W2 compared to ORT.
Figure 6.53: Consistency montage showing wireline porosity-predicted permeability crossplot, wireline porosity-wireline water saturation crossplot, OLP and porosity, predicted permeability and water saturation log response of Ternary Rock Typing (TRT) derived rock types of Well W2 compared to ORT.

Figure 6.54: Ternary Rock Typing (TRT) plot showing wireline porosity, predicted permeability and wireline water saturation (colour coded with TRT derived rock types of Well W2).
Comparing the derived facies using Ternary Rock Typing (TRT) to the sedimentological derived rock types compared to ORT, it is seen that the TRT gave a high Pearson coefficient of 0.92 using only wireline log derived properties. The porosity-permeability relation is increasing towards the higher quality rock types and towards the lower irreducible water saturation values. Distinct ellipsoids can be extracted and minimal overlap between clusters is seen from the TRT plot.

6.10 TRT Rock Typing Using RCA and SCAL

Two wells from Field X had special core analysis in the dolomite facies. In this section, an investigation will be conducted on the application of TRT on RCA, SCAL and wireline logs on phi, k, S_{wirr} (Figures 6.54-6.66).

Figure 6.55: Capillary pressure curve data from two wells in Field X.
Figure 6.56: Relative permeability data from two wells in Field X.

Figure 6.57: Ternary rock type parameters extracted from capillary pressure samples related properties for dolomite facies.

Figure 6.58: $S_{wirr}$ and Phi crossplot derived from relative permeability samples for dolomite facies.
Figure 6.59: Capillary pressure grouping based on TRT facies and associated J-function parameters. Poor facies are represented by: D1-D2, Moderate Facies: D3-D4 and High Quality Facies: D5-D6.

Figure 6.60: Relative permeability curves grouping based on TRT facies for the dolomite facies.

The capillary pressure profile identifies the prevailing pore throat and pore geometry affecting fluid flow depending on the plateau curvature, which relates to a specific sedimentological facies. This allows for the definition of mono and poly-pore related facies. The relative permeability of the water phase differs from one rock type to the
other based on its wettability and rock to fluid interaction affecting its irreducible water saturation. By adding capillary pressure and relative permeability, points to the TRT plot an integrated rock typing scheme is easily achieved (Figure 6.60).

Figure 6.61: Conceptual TRT plot and effect of rock typing quality to capillary pressure and relative permeability data.

Figure 6.62: Crossplot showing core porosity versus capillary pressure porosity colour coded with gTRT derived rock type for wells W2 and W3.
Figure 6.63: Crossplot showing core porosity versus wireline porosity (colour coded with gTRT derived rock type for wells W2 and W3).

Good match between core porosity using RCA and SCAL data and wireline log porosity and associated TRT rock types.

Figure 6.64: Crossplot showing core permeability versus capillary pressure permeability (colour coded with gTRT derived rock type for wells W2 and W3).

Non-representative RCA sample giving wrong permeability response related to assigned rock.
Non-representative SCAL sample giving wrong water saturation response related to assigned rock.

Figure 6.65: Crossplot showing core water saturation versus capillary pressure irreducible water saturation (colour coded with TRT derived rock type for wells W2 and W3).

Figure 6.66: Crossplot showing core water saturation versus wireline water saturation (colour coded with TRT derived rock type for wells W2 and W3).
Figure 6.67: Crossplot showing core water permeability versus predicted permeability from TRT crossplots (colour coded with gTRT derived rock types for well W2).

It can be seen from Figures 6.61-6.66 that TRT rock typing properties for all rock types with different qualities match wireline logs data, routine and special core analysis.

### 6.11 Quality Control

Saturation Height Modelling is a representation of free water level (FWL), initial water saturation, porosity, permeability, wettability, transition zone and dry oil limit. Hence, it will be used as a quality control tool for applicability of any rock typing method. Since the TRT method uses capillary pressure parameters, water saturation and permeability in the identification of rock types, it should give a better saturation profile than the techniques that only use porosity and permeability or that use porosity and water saturation only. Since the J-function is related to FWL, porosity, permeability, wettability for each facies, if the resultant water saturation agrees with the core (RCA and SCAL) and wireline saturation then it is evident that this specific rock type scheme is properly identified. TRT utilizes one phase and two phase, static and dynamic rock typing derived properties and the quality control becomes part of the rock typing process.
6.11.1 Quality Control using J-function (Figures 6.67-6.81 and Table 6.3)

Figure 6.68: Quality control consistency montage comparison of J-function derived saturation versus measured core saturation and wireline resistivity derived saturation using sedimentological study derived rock types (ORT) of Well W2.

Figure 6.69: Quality control consistency montage comparison of J-function derived saturation versus measured core saturation and wireline resistivity derived saturation using Flow Zone Indicator (FZI) derived rock types of Well W2.
Figure 6.70: Quality control consistency montage comparison of J-function derived saturation versus measured core saturation and wireline resistivity derived saturation using Winland (R35) derived rock types of Well W2.

Figure 6.71: Quality control consistency montage comparison of J-function derived saturation versus measured core saturation and wireline resistivity derived saturation using Wibowo (PGS) derived rock types of Well W2.
Figure 6.72: Quality control consistency montage comparison of J-function derived saturation versus measured core saturation and wireline resistivity derived saturation using Corbett (GHE) derived rock types of Well W2.

Figure 6.73: Quality control consistency montage comparison of J-function derived saturation versus measured core saturation and wireline resistivity derived saturation using Lucia (RFN) derived rock types of Well W2.
Figure 6.74: Quality control consistency montage comparison of J-function derived saturation versus measured core saturation and wireline resistivity derived saturation using Buckles (BVW) derived rock types of Well W2.

Figure 6.75: Quality control consistency montage comparison of J-function derived saturation versus measured core saturation and wireline resistivity derived saturation using Pittman (R25) derived rock types of Well W2.
Figure 6.76: Quality control consistency montage comparison of J-function derived saturation versus measured core saturation and wireline resistivity derived saturation using Pittman (R50) derived rock types of Well W2.

Figure 6.77: Quality control consistency montage comparison of J-function derived saturation versus measured core saturation and wireline resistivity derived saturation using unguided Ternary Rock Typing (rTRT) derived rock types of Well W2.
Figure 6.78: Quality control consistency montage comparison of J-function derived saturation versus measured core saturation and wireline resistivity derived saturation using guided centres of ellipsoids Ternary Rock Typing (gTRT) derived rock types of Well W2.

<table>
<thead>
<tr>
<th></th>
<th>Av. Phil</th>
<th>Av. k</th>
<th>Av. Swi</th>
<th>Av. Phil</th>
<th>Av. k</th>
<th>Av. Swi</th>
</tr>
</thead>
<tbody>
<tr>
<td>Seed ellipsoids centres</td>
<td>Sedimentological Facies W2</td>
<td>Actual TRT ellipsoids centres</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 7</td>
<td>0.11</td>
<td>3</td>
<td>0.34</td>
<td>0.112</td>
<td>1.555</td>
<td>0.338</td>
</tr>
<tr>
<td>RT 8</td>
<td>0.17</td>
<td>8</td>
<td>0.327</td>
<td>0.171</td>
<td>11.228</td>
<td>0.379</td>
</tr>
<tr>
<td>RT 9</td>
<td>0.206</td>
<td>6.4</td>
<td>0.31</td>
<td>0.22</td>
<td>6.921</td>
<td>0.293</td>
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<tr>
<td>RT 10</td>
<td>0.175</td>
<td>13.96</td>
<td>0.304</td>
<td>0.186</td>
<td>27.035</td>
<td>0.295</td>
</tr>
<tr>
<td>RT 11</td>
<td>0.17</td>
<td>8.4</td>
<td>0.287</td>
<td>0.16</td>
<td>4.294</td>
<td>0.227</td>
</tr>
<tr>
<td>RT 12</td>
<td>0.26</td>
<td>8.8</td>
<td>0.365</td>
<td>0.265</td>
<td>13.949</td>
<td>0.393</td>
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Figure 6.79: Quality control consistency montage comparison of J-function derived saturation versus measured core saturation and wireline resistivity derived saturation using guided centres of iterated ellipsoids Ternary Rock Typing (gTRT) derived rock types of Well W2.
Non-representative SCAL sample giving wrong permeability response related to assigned rock

Figure 6.80: Core permeability from routine and special core analysis versus predicted permeability using guided gTRT for Well W2.

Figure 6.81: Core saturation from routine and special core analysis versus predicted saturation from J-function using guided gTRT for Well W2.
Figure 6.82: Pearson coefficient of water saturation predicted from J-function compared to core water saturation from special core analysis.

Table 6.3: Pearson coefficient of water saturation predicted from J-function compared to core water saturation from core analysis

<table>
<thead>
<tr>
<th>Study/Marker</th>
<th>Pearson Coefficient</th>
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<tr>
<td>Sedimentological Study</td>
<td>-0.083</td>
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<tr>
<td>Flow Zone Indicator (FZI)</td>
<td>-0.195</td>
</tr>
<tr>
<td>Winland (R35)</td>
<td>-0.202</td>
</tr>
<tr>
<td>Wibowo (PGS)</td>
<td>-0.121</td>
</tr>
<tr>
<td>Corbett (GHE)</td>
<td>-0.196</td>
</tr>
<tr>
<td>Lucia (RFN)</td>
<td>-0.07</td>
</tr>
<tr>
<td>Buckles (BVW)</td>
<td>-0.05</td>
</tr>
<tr>
<td>Pittman (R25)</td>
<td>-0.28</td>
</tr>
<tr>
<td>Pittman (R50)</td>
<td>-0.106</td>
</tr>
<tr>
<td>Unguided TRT</td>
<td>-0.238</td>
</tr>
<tr>
<td>Guided TRT - W2</td>
<td>0.193</td>
</tr>
<tr>
<td>Guided TRT - W2 (Iterated)</td>
<td>0.435</td>
</tr>
</tbody>
</table>
Figure 6.83: Limestone rock typing scheme updated based on Ternary rock type (TRT) for Field X.

Figure 6.84: Dolostone rock typing scheme updated based on Ternary rock type (TRT) for Field X.
The Pearson coefficient (Table 6.3) was used to compare core water saturation to water saturation predicted from J-function for different rock typing methods. All methods gave a negative coefficient and that can be seen from a negative relation from the crossplots in Figures 6.67 to 6.76 including the unguided TRT.

When taking the sedimentological study into account (ORT), the seed points for Well W2 were applied to the guided TRT (gTRT) and a positive trend for the water saturation is observed. Iterating the seed points increased the coefficient tremendously. It can be concluded that the effect of geological facies including sedimentological, diagenetic and fracturing processes has a great effect on porosity, permeability and irreducible water saturation. When taking geological facies as seed point calibration the water saturation prediction is greatly enhanced compared to other methods. The gTRT workflow proved to give a better saturation profile than all other methods for water saturation initialization.

6.12 Conclusion

In this chapter, it was proved that the TRT workflow can be used as a comprehensive carbonate rock typing workflow in 1D domain utilizing actual carbonate field data. The TRT utilises sedimentological facies (including fabric, diagenesis and fractures), wireline logs, routine core analysis, special core analysis and saturation height function in one integrated workflow. It was proved that permeability alone is not a clear quality control for rock typing methods and hence water saturation height modelling was chosen as a quality control criterion. It was also demonstrated that ternary interrelation between porosity, permeability and water saturation in carbonate rocks is independent.

The TRT software proved that it was able to quantify and quality control the generated rock types, predicted permeability and derived saturation height function water saturation. It was also able to generate quality control consistency montage to check the applicability of various rock typing methods.

A representative well (W1) was used for the demonstration of different rock typing techniques and their effect on:
• similarity of derived rock types compared to the derived sedimentological study rock type (ORT)
• change of porosity/permeability equations
• change in the centroids of ellipsoids of phi, k, and $S_{wir}$ domain
• relative position and separation of the ellipsoids for each rock type

The raw unguided Ternary Rock Typing (rTRT) derived rock types of Well W1 showed good separation of rock type ellipsoids in the three domains namely; porosity, permeability and water saturation. The flow and storage capacity plot showed a correct grading contribution of rock types. Ellipsoids' sizes are narrow and a minimal overlap between different rock types is observed. The guided rock typing TRT (gTRT) algorithm showed that the centroids of phi, k, and $S_w$ are well separated with distinct clusters in the phi, k, and $S_w$ domains.

The permeability quality control proved that the best methods related to Flow Zone Indicator (FZI), Corbett (GHE) and Pittman (R25) giving a 0.96 coefficient. The un-guided TRT (rTRT) gave very close value of 0.94 values, while the guided and iterated gTRT gave 0.85 and 0.9 respectively.

The quality control of the rock types of various rock-typing methods compared to the sedimentological derived rock types (ORT), proved that rTRT and gTRT methods gave the highest similarity using only routine core analysis data with a value of 0.53 and 0.58 respectively. It can be concluded that Ternary Rock Typing (TRT), both guided (gTRT) and unguided (rTRT), gives the best rock type similarity to reference sedimentological study (ORT) results.

The TRT also proved to work well when no core analysis is available, where testing and prediction of a limestone interval was compared to the sedimentological derived rock types (ORT), and a high Pearson coefficient of 0.92 was achieved.

Saturation height function was used as part of the TRT workflow as a quality control tool for applicability of any rock typing method. The J-function is related to FWL, porosity, permeability, wettability for each facies, and the resultant water saturation was compared to the core (RCA and SCAL) and wireline saturation. TRT utilizes one phase and two phase, static and dynamic rock typing derived properties and the quality control becomes part of the rock typing process. The cross plots were able to
exclude non-representative RCA and SCAL samples giving false response related to assigned rock.

The Pearson coefficient was used to compare core water saturation to water saturation predicted from J-function for different rock typing methods. All methods gave unsatisfactory negative results. The seed points from the ORT for Well W2 applied to the guided TRT (gTRT) gave positive trend for the water saturation. Iterating the seed points increased the coefficient tremendously. It can be concluded that the effect of geological facies including sedimentological, diagenetic and fracturing processes has a great effect on porosity, permeability and irreducible water saturation. When taking geological facies as seed point calibration the water saturation prediction is greatly enhanced compared to other methods. The gTRT workflow proved to give a better saturation profile than all other methods for water saturation initialization.
CHAPTER SEVEN

TRT AND ROCK TYPING EFFECT ON STATIC AND DYNAMIC MODELS: 3-D OIL FIELD EXAMPLE

7.1 Introduction

The uncertainty associated with rock typing was scrutinized in previous chapters. The effect of data source, scale, discipline are all part of the uncertainty process. Chapter 2 reviewed the geological/sedimentological rock typing concepts and applications. Chapter 3 challenged the concepts of static one phase rock and reservoir property interaction based methods utilizing wireline logs and routine core analysis. Chapter 4 stressed on two phase dynamic and hydraulic rock/fluid relationships including wettability, relative permeability, capillary pressure and saturation height functions. Chapter 5 introduced a novel application for carbonate rock typing; namely Ternary Rock Typing (TRT). The method uses depositional facies, wireline logs, routine core analysis, and special core analysis in one integrated workflow. Chapter 6 tested the Ternary Rock Typing (TRT) concept as a carbonate comprehensive workflow against actual carbonate reservoir data in 1D space.

In this chapter, the applicability of the ternary rock typing (TRT) is verified: concept, workflow, plot and tool in a real field scale scenario. The effect on static and dynamic conditions will be tested and quantified. The TRT will be compared utilizing the reference sedimentological dataset (ORT) to other rock typing methods. The carbonate workflow will be tested using core data, wireline logs, routine core analysis, and SCAL data. The static and dynamic output of various rock typing outcomes will be quantified with respect to volumetrics and fluid dynamics using carbonate oil field data (Figure 7.1).

Two strategies will be tested in this chapter: the first is an active water drive where the aquifer is below the entire reservoir and water movement is almost in a vertical direction. The second strategy is using one injector and one producer with no effect of aquifer drive. The models will be tested using Petrel RE and Eclipse software. The fluid movements are greatly affected by the modelling of barriers, baffles and reservoirs. This affects the production and completion strategy. It also affects water breakthrough, fingering, channelling, and by passed oil.
Figure 7.1: Carbonate Comprehensive Workflow adapted for testing TRT and other rock typing methods on a field level in static and dynamic conditions.
7.2 Composite Core Rock Typing

A composite core is amalgamated from six cored wells to cover representative rock types contributing to Field X reservoir. The composite core covered limestone and dolomite facies. Routine core analysis is available for both lithologies but no water saturation measurements or SCAL samples are present for limestone (Figures 7.2 and 7.3). The TRT tool is used to generate the rock type logs in the next sections. Rock Type legend used for this chapter: Limestone rock types (L1-L6; RT Code 1-6); Dolomite rock types (D1-D6; RT Code 7-12).

Figure 7.2: Composite core rock type log from sedimentological study (ORT) and associated wireline and routine core analysis. Rock Type legend: Limestone rock types (L1-L6; RT Code 1-6); Dolomite rock types (D1-D6; RT Code 7-12)

Figure 7.3: Composite core rock type log change using various rock typing methods
Figure 7.4: Composite core porosity vs. permeability relationship using various rock typing methods for Field X showing rock types relationships and centroid averages.
Figure 7.5: TRT plot response of the sedimentological study derived rock types (ORT) in addition to core porosity, core permeability and core water saturation crossplots.

Figure 7.6: TRT plot response of the Flow Zone Indicator (FZI) derived rock types in addition to core porosity, core permeability and core water saturation crossplots.
Figure 7.7: TRT plot response of the Winland (R35) derived rock types in addition to core porosity, core permeability and core water saturation crossplots.

Figure 7.8: TRT plot response of the Wibowo (PGS) derived rock types in addition to core porosity, core permeability and core water saturation crossplots.
Figure 7.9: TRT plot response of the Corbett (GHE) derived rock types in addition to core porosity, core permeability and core water saturation crossplots.

Figure 7.10: TRT plot response of the Lucia (RFN) derived rock types in addition to core porosity, core permeability and core water saturation crossplots.
Figure 7.11: TRT plot response of the Buckles (BVW) derived rock types in addition to core porosity, core permeability and core water saturation crossplots.

Figure 7.12: TRT plot response of the Pittman (R25) derived rock types in addition to core porosity, core permeability and core water saturation crossplots.
Figure 7.13: TRT plot response of the Pittman (R50) derived rock types in addition to core porosity, core permeability and core water saturation crossplots.

Figure 7.14: TRT plot response of the unguided Ternary Rock Typing (rTRT) derived rock types in addition to core porosity, core permeability and core water saturation crossplots.
Figure 7.15: TRT plot response of the guided Ternary Rock Typing (gTRT) derived rock types in addition to core porosity, core permeability and core water saturation crossplots.

In chapter 6, the various rock typing methods were tested against one cored well. In this section, a more realistic field scale dataset from six cored wells is modelled. The reference sedimentological study data set (ORT) shows an almost overlapping porosity and permeability relationship for all rock types (Figure 7.4). The cloud of ellipsoids from the TRT plot shows no distinctive separation for all rock types with centroids overlapping (Figure 7.5).

The Flow Zone Indicator (FZI) and Corbett (GHE) methods show a distinctive porosity and permeability relationship with a good separation on porosity vs. permeability crossplot (Figure 7.4). However, this separation fails to show on a TRT
plot and on porosity vs. water saturation plot where the rock type ellipsoids are widely spread (Figures 7.6 and Figure 7.9). Both methods underestimate the presence of the highest rock type D6 which is the medium crystalline Dolowackeestone-packstone with solution enlarged vugs.

The Winland (R35) method shows a distinctive porosity and permeability relationship with a good separation on porosity vs. permeability crossplot with a good prediction of the highest rock type D6 (Figure 7.4). On a TRT plot, D6 shows a distinctive ellipsoid while the other rock types fail to show a distinctive separation in the water saturation domain (Figure 7.7).

The Wibowo (PGS) derived rock types show distinctive ellipsoids for porosity and permeability. The range for water saturation for each rock type is large, posing a problem when matching to capillary pressure data. The method tends to underestimate the highest and lower quality rock types in favour of the moderate quality reservoirs (Figure 7.8).

The Lucia (RFN) derived rock types show a good estimation for the solution enlarged dolostone type D6. The higher and lower reservoir qualities have distinctive ellipsoid signature while the moderate reservoir rock types have overlapping ellipsoids. The porosity-water saturation trend is reversed where the highest quality rock type incorrectly represents the lowest porosity centroid (Figure 7.10).

The Buckles (BVW) derived rock types show distinctive ellipsoids for porosity-water saturation and for permeability-water saturation. However, in the porosity and permeability domain the lowest rock type is assigned falsely to the highest storage and flow capacity. In addition, the highest quality rock is assigned to a wide range of porosity and permeability values (Figure 7.11).

The Pittman (R25) derived rock types show increasing porosity and permeability values towards the higher quality rock types. This is also obvious for permeability-water saturation centroids, where a good separation is obtained for all rock types. The porosity and permeability equations are equally and uniformly distributed and are able to predict the highest permeability rock types and at the same time able to predict the low permeability barriers. The moderate quality rock types have a wide range in
porosity and saturation domains (Figure 7.12). The Pittman (R50) is performing poorer than the R25 where the overlaps between ellipsoids are greater (Figure 7.13).

The unguided and guided Ternary Rock Typing (rTRT and gTRT) derived rock types show increasing porosity and permeability values towards the higher quality rock types. There are distinctive porosity-water saturation, porosity-permeability, and permeability-water saturation centroids. A good separation is obtained for all rock types. A distinctive water saturation trend is maintained for all rock types. The porosity and permeability equations are equally and uniformly distributed between data with a minor negative slope. It can be seen that the water saturation trend is not linear but every rock type has its own unique $S_{wirr}$ behaviour. This is one of the advantages of TRT; that it is a data driven approach, not a model driven approach such as most of the other rock typing methods. The TRT proves also to be able to predict the highest permeability rock types as well as low permeability barriers. The highest distinctive separation among all other methods is obtained in the $k$, $\phi$, and $S_{wirr}$ domains (Figures 7.14 and 7.15). The guided TRT is able to separate between RT11 and RT12 rock types which have overlapping porosity and permeability response through water saturation separation thus increasing the accuracy of the SCAL assignment during water saturation initialization in dynamic simulation; hence each can take a different representative capillary pressure curve. From the previous plots it can be concluded that the unguided and guided Ternary Rock Typing (rTRT and gTRT) derived rock types gave the best distinctive clustering ellipsoids in porosity-water saturation, porosity-permeability, and permeability-water saturation domains compared to all other methods.

7.3 Uncored Rock Typing Using Wireline Logs (Figures 7.16-7.19)

The prediction of rock types all over the uncored interval becomes necessary to allow for a robust static and dynamic model. The prediction of the aquifer becomes as important as the producing intervals as the hydrodynamics are acting as a total system rather than specifically over a narrow interval. The methods used for prediction are usually Fuzzy Logic, Neural Networks, Multi-linear regression, or K-nearest neighbours algorithm (KNN) etc. The KNN algorithm was used in this section for the prediction from cored to uncored rock types since it was recommended by several authors as part of the prediction algorithm to add to the TRT workflow.
Figure 7.16: Example of rock typing prediction from cored to uncored intervals of dolomite facies using various rock typing methods of a representative well

Figure 7.17: Example of predicted permeability prediction from cored to uncored intervals of dolomite facies using various rock typing methods of a representative well
Figure 7.18: Example of rock typing prediction from cored to uncored intervals of limestone facies using various rock typing methods of a representative well.

Figure 7.19: Example of predicted permeability prediction from cored to uncored intervals of limestone facies using various rock typing methods of a representative well.
7.4 TRT and Rock Typing Methods Effect on 3D Static Realizations
(Figures 7.20-7.35)

The static model reference used in this chapter is based on the in-house study that included sedimentological and sequence stratigraphic interpretation. The study used an integrated approach to construct the static model. In this section, the rock typing of six cored wells using all rock typing methods under testing are used to populate the facies model and associated porosity and permeability transform for each rock type. A geo-statistical approach (Sequential Gaussian Simulation) is used to populate the property model with petrophysical data (facies, porosity, permeability) for each reservoir layer. Variogram analysis was performed in the three dimensions for proper property distribution parameters.

The scaling up of the well log data from the acquisition resolution to the grid resolution is kept to a minimum as the average grid size resolution was kept at 0.7’ resolution to correctly represent the vertical heterogeneity and rapid lateral facies change of the carbonate reservoirs. It is important in carbonate modelling to model barriers and baffles with the same confidence as with reservoirs. The hydrodynamic flow is greatly affected by the proper identification of all rock types in the 3D space.

The logs used are:
- PHIE, is used to represent effective porosity log
- K_Predicted, predicted permeability log obtained from each rock type transform function obtained from the TRT tool
- Rock type log, is obtained from the TRT tool representing all the tested rock typing methods
- Reference rock type log, is obtained from the previous sedimentological study (ORT).

![Limestone Facies](image1)
![Dolomite Facies](image2)

Figure 7.20: Rock type legend used for 3D static and dynamic modelling: Limestone rock types (L1-L6; RT Code 1-6); Dolomite rock types (D1-D6; RT Code 7-12).
Figure 7.21: 3D view showing static model of facies, porosity and permeability.
Figure 7.22: Facies, porosity and permeability cross section filtered on high storage and high flow capacity rock types (RT5-6 and RT11-12) from sedimentological study (ORT).
Figure 7.23: Facies, porosity and permeability cross section filtered on high storage and high flow capacity rock types (RT5-6 and RT11-12) using Flow Zone Indicator (FZI) method.
Figure 7.24: Facies, porosity and permeability cross section filtered on high storage and high flow capacity rock types (RT5-6 and RT11-12) using Winland (R35) method.
Figure 7.25: Facies, porosity and permeability cross section filtered on high storage and high flow capacity rock types (RT5-6 and RT11-12) using Wibowo (PGS) method.
Figure 7.26: Facies, porosity and permeability cross section filtered on high storage and high flow capacity rock types (RT5-6 and RT11-12) using Corbett (GHE) method.
and high flow capacity rock types (RT5-6 and RT11-12) using Lucia (RFN) method.

Figure 7.27: Facies, porosity and permeability cross section filtered on high storage and high flow capacity rock types (RT5-6 and RT11-12) using Lucia (RFN) method.
Figure 7.28: Facies, porosity and permeability cross section filtered on high storage and high flow capacity rock types (RT5-6 and RT11-12) using Buckles (BVW) method.
Figure 7.29: Facies, porosity and permeability cross section filtered on high storage and high flow capacity rock types (RT5-6 and RT11-12) using Pittman (R25) method.
Figure 7.30: Facies, porosity and permeability cross section filtered on high storage and high flow capacity rock types (RT5-6 and RT11-12) using Pittman (R50) method.
Figure 7.31: Facies, porosity and permeability cross section filtered on high storage and high flow capacity rock types (RT5-6 and RT11-12) using unguided Ternary Rock Typing (rTRT) method.
Figure 7.32: Facies, porosity and permeability cross section filtered on high storage and high flow capacity rock types (RT5-6 and RT11-12) using guided Ternary Rock Typing (gTRT) method
Figure 7.33: Rock type cumulative cell-count contribution percentage in the 3D Model using various rock methods (L1-L6 Limestone rock types 1-6 and D1-D6 Dolomite rock types from 7-12)
Figure 7.34: Upper Figure (a): Rock type cell-count contribution in the 3D model per rock type for limestone facies. Lower Figure (b): Highest storage and flow capacity rock types (RT 5-6) difference representation compared to the reference sedimentological model (ORT).

Figure 7.35: Upper Figure (a): Rock type cell-count contribution in the 3D model per rock type for dolomite facies. Lower Figure (b): Highest storage and flow capacity rock types (RT 11-12) difference representation compared to the reference sedimentological model (ORT).
Facies, porosity and permeability cross sections for the different rock typing methods are shown in Figures 7.22 to 7.32. The plots were filtered to show the highest storage and highest flow capacity rock types of limestone (RT5 and RT6) and of dolomite (RT11 and RT12). This makes it more feasible to compare various rock typing schemes for the most important contributors in the hydrocarbon in place and flow dynamic movements. From the sedimentological study (ORT) it can be seen that the highest rock types contribute to about 50% of the section. The Flow Zone Indicator (FZI) and Corbett (GHE) have modelled the highest facies with a very low percentage. Winland (R35) performs better than the FZI method but still falls short compared to the reference model. Wibowo (PGS), on the other hand, performs much better, where the result can be closely compared to the sedimentological reference model. Lucia (RFN) model gives better results than the R35 model. Buckles’ (BVW) method tends to overestimate the good rock types and underestimates the lower quality rock types. Pittman (R25) performs better than the Pittman (R50), which almost ignores the occurrence of RT 5 & 6 and RT 11 & 12.

The unguided Ternary Rock Typing (rTRT) method gives a very close result to the reference sedimentological model, taking into account that rTRT is only using routine core analysis and wireline logs with no influence from the sedimentological study. This gives the TRT methodology a great advantage in that the comparable results are achieved if limitations exist in time and cost that prevent the performance of a comprehensive sedimentological study. The guided Ternary Rock Typing (gTRT) method, on the other hand, uses the sedimentological results for locating the centroids of the ellipsoids clouds representing the different rock types. It can be seen that gTRT is giving comparable results to the sedimentological reference model with the added advantage of simultaneously performing well in the phi, k, S_w domains (Figures 7.22-7.32).

To quantify the results in the previous model, the contribution of each facies is quantified as a percentage to the reference sedimentological model (Figures 7.23-7.35). The best method modelling dolostone facies is Wibowo (PGS) method with a 15% difference than the reference model followed by guided TRT (gTRT) with a 20% difference. The other methods fall short by more than 40%. For limestone facies the second and third place, with a 10% difference, is Wibowo (PGS) and Buckles’ (BVW) methods. The unguided TRT is off by only 27%. All the other methods fall short by more than 80%. The best method modelling limestone facies is the guided TRT (gTRT) method with a 2% difference compared to the reference model.
Water saturation modelling is one of the highly uncertain parameters facing all carbonate geoscientists. In this section, the effect of changing the rock typing scheme’s effect on the grouping of SCAL data is investigated and consequently volumes of hydrocarbon in place. Changing the rock type method has a great impact on how capillary pressure and relative permeability are grouped to represent static and dynamic rock typing parameters only achievable from SCAL modelling. These groupings are used to generate a saturation height function to be used in static and dynamic simulation model initialization.

The impact of changing rock typing scheme on static and dynamic models is seldom quantified, as it creates a great number of realizations often not feasible to dynamically simulate all of them. A subset is usually chosen for the simulation testing. The TRT workflow disregards rock typing schemes that are not satisfying the static and dynamic interrelationships, hence minimizes the effort for simulating unnecessary models.

In this section, quantifying the effect of changing rock typing and consequently changing the grouping of capillary pressure curves will be performed. J-function will be used to produce saturation height tables. The J-function parameters for each rock type grouping using each rock typing method will be used to generate saturation tables that are used in Petrel RE and Eclipse to initialize water saturation models.

The grouping and rock typing methods are quality controlled using TRT plots and comparing the hydrocarbon in place of the highest quality facies to the reference sedimentological based model (ORT), (Figures 7.36- 7.46).

Note: The same concept was used for all other rock typing methods and the grouping results were used to initialize the static and dynamic models in the next section.
Figure 7.36: Rock type assignment variation of 25 SCAL samples of dolomite facies using different rock typing schemes.

Figure 7.37: Routine and SCAL data grouped based on sedimentological study (ORT)

Figure 7.38: Routine and SCAL data grouped based on Flow Zone Indicator (FZI)
Figure 7.39: Routine and SCAL data grouped based on Winland (R35)

Figure 7.40: Routine and SCAL data grouped based on Wibowo (PGS)

Figure 7.41: Routine and SCAL data grouped based on Corbett (GHE)
Figure 7.42: Routine and SCAL data grouped based on Lucia (RFN)

Figure 7.43: Routine and SCAL data grouped based on Buckles (BVW)

Figure 7.44: Routine and SCAL data grouped based on Pittman (R25)
Figure 7.45: Routine and SCAL data grouped based on Pittman (R50)

Figure 7.46: Routine and SCAL data grouped based on Unguided Ternary Rock Typing (rTRT)

Figure 7.47: a) Average ellipsoid centroids of dolomite rock types (ORT)
b) Average ellipsoid centroids of Guided Ternary Rock Typing (gTRT)
Figure 7.48: Consistency montage showing average ellipsoid centroids of Guided Ternary Rock Typing (gTRT)

Figure 7.49: Routine and SCAL data grouped based on Guided Ternary Rock Typing (gTRT)
Figure 7.50: TRT plot and effect of rock typing quality change showing rock types ellipsoids and associated effect on capillary pressure and relative permeability grouping using Guided Ternary Rock Typing (gTRT).

Figure 7.51: a) Original Oil In Place in MM BBl per Rock type contribution in the 3D model for limestone facies. b) Original Oil In Place percentage difference of the highest storage and flow capacity rock types (RT 5-6) compared to the reference sedimentological model (ORT)
Figure 7.52:  a) Original Oil In Place in MM BBl per Rock type contribution in the 3D model for dolomite facies. b) Original Oil In Place percentage difference of the highest storage and flow capacity rock types (RT 11-12) compared to the reference sedimentological model (ORT)

As part of the TRT workflow, the quality control crossplots of the k, phi or S_w show the great impact of rock typing methods on SCAL grouping (Figures 7.36-7.50). Figure 7.36 shows the remarkable variation using different rock typing schemes of SCAL samples of Dolomite facies. The sedimentological SCAL grouping mixes all rock types with no logical trend in any of the k, phi or S_w domains (Figure 7.37). Despite the fact that there is an acceptable trend of routine core analysis parameters using sedimentological results (ORT), they fail to transfer this order to the SCAL based grouping. The FZI based RCA data has a good trend in the moderate rock types but fails to capture the high perm rock type D6. The SCAL data of the FZI and GHE methods are scattered on water saturation vs. porosity and on permeability vs.
water saturation plots with no decisive trend. Poor quality rock types are mixed with moderate types making capillary pressure curve grouping inaccurate. The R35 method performs better than the FZI method with assigning a representative SCAL point to D6 but mixes all the moderate rock types of D3 to D5.

Wibowo (PGS) has proved to work well in previous sections, but failed to represent the highest quality rock types as the irreducible water saturation data is covering the whole spectrum from ranges 0.1 to 0.45. These increases in the variance of the water saturation range per rock type affects the volumetric in place calculation uncertainties. The RFN method was excellent in predicting the highest rock type using routine core analysis but failed to do that on SCAL based data. The only sample representing D6 has a very low porosity of 0.1 and an irreducible water saturation of 0.3. The BVW method worked very well in porosity and water saturation domains as seen in previous chapters. However, it failed to represent that in a porosity and permeability domain whether on routine core analysis or SCAL data. It can be seen in Figure 7.43 that the lowest rock type was assigned to the highest porosity and permeability SCAL data of 0.3 and 100md respectively. The Pittman (R25) performs again better than Pittman (R50) but also failed to represent SCAL data in the water saturation domain.

The unguided Ternary Rock Type (rTRT) is able to model satisfactorily the low quality rock types with D1 and D2. The same can be seen for the moderate rock types of D3 and D4. D5 and D6 are also well represented but with a minor overlap of SCAL data between the two best rock types on water saturation domain. This was seen from sedimentological data that the best rock types D5 and D6 are overlapping on the porosity and permeability domain but separate in the irreducible water saturation domain. The unguided TRT (rTRT) was able to capture this phenomenon with no sedimentological input and assigned most of the SCAL data properly. The guided TRT Average (gTRT) ellipsoid centroids for all rock types are quite comparable to the sedimentological results (Figure 7.47). It was also able to locate and capture the difference in the irreducible water saturation between D5 and D6. The SCAL data is grouped very satisfactorily in porosity, permeability and irreducible water domains.
Quantifying the above observations with respect to volumetrics of the oil in place is a key quality control and a decisive criterion on the selection of any rock typing method. Predicting the oil in place from the initialized SCAL data per rock type for all rock typing schemes is shown in Figures 7.51 and 7.52 compared to the sedimentological based referenced model. The BVW and guided TRT (gTRT) methods were the best matches of the cumulative in place for the high limestone facies; namely L5 and L6. The Wibowo (PGS) and unguided TRT (rTRT) gave a good approximation also. All of the other methods fail with more than 70% underestimating the volume.

For dolomite highest rock type D5 and D6, the best in place volume comparison is the guided TRT (gTRT) with a difference of only 10%. The PGS also performs well with an 11% underestimation. The BVW and unguided TRT (rTRT) are within a 14-23% variation. All of the other methods fail by more than 35%.

7.6 TRT and Rock Typing Methods' Effect on Fluid Dynamic Movements

In this section, the effect of rock typing on the hydrodynamic movements of water and consequently oil is compared. The water movement speed and direction affect how the reservoir is to be produced, the completion strategy, water breakthrough, fingering, channelling, and by passed oil. Two strategies will be tested, the first of which, is an active water drive where the aquifer is below the whole reservoir and the movement of water is mostly in a vertical direction. The second strategy is using one injector and one producer with no bottom water drive effect (Figures 7.53-7.65).

The multiple oil reservoirs in the field are in complete hydraulic communication. The carbonates are volumetrically the largest hydrocarbon bearing reservoirs with more than 50% of the total reserves and initial production from about 800' oil column. An obvious observation is that water is rising bottom up and this affected how production strategy is performed. Shutting in wells was a major problem due to high water cut and this mimics the first tested scenario. The aquifer volume was simulated to be 50 times the modeled pore volume to account for the unmodelled extension of the aquifer.
The second scenario tested the effect of changing rock typing methods on fingering and by passed oil in the horizontal direction in a water injection scheme. The scheme tested water front change and effectiveness of the injection scenario. One producer and one injector are used in this scenario, where the injection rate is assumed to be 2000 Bbld and the producer rate is assumed to be 1500 Bbld. No aquifer volume is in effect. Production and injection are assumed to start simultaneously from the first day of the simulation.

The model assumed sandstone water bearing zone at the bottom of the model overlain by carbonate reservoir dominated by limestone and dolomite intercalations with oil bearing reservoir. Six wells were used in the model comprising only a small tilted fault block of the entire field. The GOC and OWC were assumed to be at 4010' TVDSS and 4850' TVDSS respectively based on initial well observations. A live oil and dry gas fluid model was used to simulate the gas cap reservoir, where the reservoir pressure was assumed to be 2171 psi at reference depth 4606' TVDSS and temperature of 150F while water salinity was interpreted to be 120,000 ppm. Perforation intervals assumed that only oil is produced with start up production of 1500 Bbld oil rate and an assumption of minimum well bottom hole pressure of 100 psi. The vertical permeability was assumed to be 0.3 from horizontal permeability based on the available RCA. Rock compressibility was assumed to be 4E-06 psi.

There was no available production data to perform a full history match. The bottom water drive production scheme assumed a start of production at 1984 till end of 2017 with a time step 1 year, with an economic well cutoff at 50 Bbld oil rate, while water cut limit was assumed to be 90%. A well was shut in if meeting any of these conditions. This appeared as a "saw-tooth" pattern on a water cut field level plot where wells were shut in due to a decrease of oil rate or increase in water production (Figure 7.64).
Figure 7.53: a) Upper Figure: Initial and final water movement under active water drive using ORT. Lower Figure: Filtered version of the upper figure on the highest storage and flow capacity rock types (RT 5-6 & 11-12). b) Initial and final water movement under Injector/Producer scheme using sedimentological based model (ORT).
Figure 7.54: a) Upper Figure: Initial and final water movement under active water drive using Flow Zone Indicator (FZI). Lower Figure: Filtered version of the upper figure on the highest storage and flow capacity rock types (RT 5-6 & 11-12). b) Initial and final water movement under Injector/Producer scheme using Flow Zone Indicator (FZI).
Figure 7.55: a) Upper Figure: Initial and final water movement under active water drive using Winland (R35). Lower Figure: Filtered version of the upper figure on the highest storage and flow capacity rock types (RT 5-6 & 11-12). b) Initial and final water movement under Injector/Producer scheme using Winland (R35).
Figure 7.56: a) Upper Figure: Initial and final water movement under active water drive using Wibowo (PGS). Lower Figure: Filtered version of the upper figure on the highest storage and flow capacity rock types (RT 5-6 &11-12).  b) Initial and final water movement under Injector/Producer scheme using Wibowo (PGS).
Figure 7.57: a) Upper Figure: Initial and final water movement under active water drive using Corbett (GHE). Lower Figure: Filtered version of the upper figure on the highest storage and flow capacity rock types (RT 5-6 & 11-12). b) Initial and final water movement under Injector/Producer scheme using Corbett (GHE).
Figure 7.58: a) Upper Figure: Initial and final water movement under active water drive using Lucia (RFN). Lower Figure: Filtered version of the upper figure on the highest storage and flow capacity rock types (RT 5-6 & 11-12). b) Initial and final water movement under Injector/Producer scheme using Lucia (RFN).
Figure 7.59: a) Upper Figure: Initial and final water movement under active water drive using Buckles (BVW). Lower Figure: Filtered version of the upper figure on the highest storage and flow capacity rock types (RT 5-6 & 11-12). b) Initial and final water movement under Injector/Producer scheme using Buckles (BVW).
Figure 7.60: a) Upper Figure: Initial and final water movement under active water drive using Pittman (R25). Lower Figure: Filtered version of the upper figure on the highest storage and flow capacity rock types (RT 5-6 & 11-12). b) Initial and final water movement under Injector/Producer scheme using Pittman (R25).
Figure 7.61: a) Upper Figure: Initial and final water movement under active water drive using Pittman (R50). Lower Figure: Filtered version of the upper figure on the highest storage and flow capacity rock types (RT 5-6 & 11-12). b) Initial and final water movement under Injector/Producer scheme using Pittman (R50).
Figure 7.62: a) Upper Figure: Initial and final water movement under active water drive using unguided Ternary Rock Typing (rTRT). Lower Figure: Filtered version of the upper figure on the highest storage and flow capacity rock types (RT 5-6 & 11-12). b) Initial and final water movement under Injector/Producer scheme using unguided Ternary Rock Typing (rTRT).
Figure 7.63: a) Upper Figure: Initial and final water movement under active water drive using guided Ternary Rock Typing (gTRT). Lower Figure: Filtered version of the upper figure on the highest storage and flow capacity rock types (RT 5-6 & 11-12). b) Initial and final water movement under Injector/Producer scheme using guided Ternary Rock Typing (gTRT).
Figure 7.64: Cumulative oil production, water cut, oil production rate and difference of cumulative oil production relative to the reference model (ORT) of the active water drive scenario.

Figure 7.65: Cumulative oil production, water cut, oil production rate and difference of cumulative oil production relative to the reference model (ORT) of the Injector/Producer scheme scenario.
Two simulation model strategies are demonstrated in Figures 7.53 to 7.64. The first strategy is an active water drive, while the second model is an injector/producer scheme with no water drive. All models are compared to the reference sedimentological based model (ORT).

The reference model (ORT) shows a homogeneous sweep efficiency because of the occurrence of the best limestone and dolomite rock types having the highest storage and flow capacity; namely L5/L6 and D5/D6. The FZI and GHE models underestimate the good reservoir types. The down dip structure retains unswept oil compared to the reference model. Water breakthrough occurred through a narrow unit of the reservoir rather than along the entire completion profile.

The R35 model drained the downdip oil better than the FZI model and also performed satisfactorily in the water injection model but missed the upper reservoir layers. The Wibowo (PGS) model still contains a considerable amount of unswept oil along the reservoir layers and in the downdip structure. The RFN and BVW models follow a channelling feature mechanism where bypassed oil can be found at initial saturation. The Pittman (R25) and (R50) behaved well in the updip structure but again missed the downdip oil. The water front follows an obvious baffling feature along the modelled surfaces.

The TRT rock typing method was the only method able to properly drain the downdip structure. The homogeneous sweep was captured in both models the guided and unguided TRT. The waterfront in the guided TRT followed the sedimentological reference model slightly better than the rTRT. The TRT models the fluid movements accurately compared to other rock typing methods.

Quantifying the above observations with respect to cumulative oil produced is a key quality control and a decisive criterion on the selection of any rock typing method. Cumulative oil production, water cut, oil production rate and the difference of cumulative oil production relative to the reference model (ORT) of the active water drive scenario is shown in Figure 7.64. It can be seen that the unguided (rTRT) and guided (gTRT) Ternary Rock gave the best cumulative oil prediction compared to the ORT with only 2.8% difference. In the Injector/Producer scheme scenario unguided TRT (rTRT) gave also the best cumulative oil prediction.
7.7 Conclusion

In this chapter, ternary rock typing (TRT) was tested against other rock typing methods using core data, wireline logs, routine core analysis, and SCAL data. A comprehensive carbonate workflow was presented and adapted to work with any of the rock typing methods using real carbonate field data. The utilization of TRT is subdivided into several applications: rock typing scheme, concept, workflow, plot and software. All of the previous applications can be adapted to work with TRT or accompanied by any of the other rock typing methods.

The TRT proved to work well with routine core analysis using six cored wells. The cored intervals were then transferred to the uncored intervals. The facies distribution of the unguided TRT (rTRT) in the static model proved to be comparable with the reference sedimentological model, thus giving an edge to the workflow when no core and no RCA are available. Using rTRT with only wireline logs can be used and yield comparable results as the sedimentological study. When core description, SEM, XRD, RCA, SCAL and sedimentological data is available, the resultant sedimentological rock types can be transferred to the guided TRT concept using ellipsoid centres of porosity, permeability and water saturation. The result is TRT rock types that follow the integration of sedimentological, geological, and petrophysical and reservoir engineering concept. Using SCAL data among various rock types, the TRT proved to assign and group SCAL data accurately with guided TRT performing slightly better than the unguided TRT.

It was also demonstrated that the unguided and guided Ternary Rock Typing (rTRT and gTRT) derived rock types gave the best distinctive clustering ellipsoids in porosity-water saturation, porosity-permeability, and permeability-water saturation domains compared to all other methods.

Quantifying the above observations with respect to volumetrics of the oil in place is a key quality control and a decisive criterion on the selection of any rock typing method. Predicting the oil in place from the initialized SCAL data per rock type for all rock typing schemes compared to the sedimentological based referenced model. The BVW and guided TRT (gTRT) methods were the best matches of the oil in place for the high limestone facies; namely L5 and L6. For dolomite highest rock types D5 and
D6, the best in place volume comparison is the guided TRT (gTRT) with a difference of only 10%.

The effect of rock typing on the hydrodynamic movements was tested using two strategies: the first is an active bottom water drive and the second strategy is using one injector and one producer with no bottom water drive effect. Quantifying the hydrodynamic observations with respect to cumulative oil produced is a key quality control and a decisive criterion on the selection of any rock typing method. Cumulative oil production, water cut, oil production rate and the difference of cumulative oil production relative to the reference model (ORT) were observed. The unguided (rTRT) and guided (gTRT) Ternary Rock gave the best cumulative oil prediction compared to the ORT with only 2.8% difference for the active bottom water drive scenario. For the Injector/Producer scheme scenario unguided TRT (rTRT) gave also the best cumulative oil prediction with a 5% difference than the ORT. This means that TRT proved to accurately model barriers, baffles and reservoirs. Thus, gave the best fluid movement comparison compared to other rock typing schemes. This affects the production and completion strategy. It also affects the prediction of water breakthrough, fingering, channelling, and by passed oil. The TRT workflow proved to work well with various data types and disciplines. It disregards data and rock typing schemes that are not satisfying the static and dynamic interrelationships, hence minimizing the effort of simulating unnecessary models.
CHAPTER EIGHT

SUMMARY, CONCLUSIONS AND FUTURE WORK

The results and conclusions presented in chapters 2 to 7 are summarized in this chapter along with recommendations for future work.

8.1 Summary

A review of geological/sedimentological rock typing concepts and their application were discussed in chapter 2 as well as a critical review of the various methods presented. The key conclusions that can be drawn from this chapter are summarized below:

Various authors tackled the characterization process of carbonates from a geological and sedimentological perspective. Dunham and Folk's schemes are based on mud to grain ratios depicting original energy levels. Dunham's classification is most applicable to core description utilizing the detailed textural characteristics of the rocks, while Folk's terminology is used by thin section petrography. They both lack the description of reef rocks and fracturing mechanisms. The abundance of mud content according to their interpretation is an indication of areas with low energy environment while higher grain content is a sign of higher energy environment. High mud content lowers reservoir quality dramatically if not affected by post depositional processes.

Embry and Klovan, and Riding developed detailed reef description methods featuring the heterogeneity observed in reef sedimentary components and physical structure. They modified Dunham’s textural scheme to take into account the biological process of building the reefal accumulation. This remains the most adopted scheme for reef classification.

Wright adopted a genetic scheme for the geological processes affecting carbonate rocks from deposition to post-deposition. Following Wright’s work, Ahr and Hammel and Ahr et al., included porosity to be depositional, diagenetic, or fracture porosity. This genetic superposition approach is a great enhancement to the classification process as it includes a rock based geological approach and a reservoir-based property thus approaching a multi-disciplinary scheme.
Geological and sedimentological classification techniques for rock typing of carbonate rocks are excellent tools for understanding the origin, mechanism and depositional environment of rock types, porosity types and pore network characteristics. On a grain/pore scale, the compound effect of depositional, diagenetic and fracturing processes on porosity, permeability and pore size characteristics can only be explained through geological and sedimentological investigations. On an outcrop scale, the lateral prediction and vertical accumulation of the depositional environment can be achieved through biostratigraphic, geological and sedimentological interpretations. These, however, fail to quantify petrophysical and reservoir engineering parameters as demonstrated in chapters 3 and 4. A robust carbonate classification scheme has to link sedimentological facies to petrophysical and dynamic properties. Linking pore space and pore network to sedimentological facies and the depositional environment allows for the prediction of the pore system since rocks can be mapped and predicted for longer distances.

In chapter 3, static rock and reservoir property interaction of single phase properties were investigated through the examination of storage and flow capacity’s effect on rock volume and its associated pore network using routine core analysis and wireline logs.

Static Rock Typing (SRT) is an integrated approach combining geology and petrophysics. Geological Rock Typing (GRT) emphasizes the depositional, diagenetic and fracture processes on the rocks. On the other hand, Petrophysical Rock Typing (PRT) uses wireline and routine core analysis to quantify reservoir petrophysical parameters. Applying the static rock typing concept on cored intervals allows for the integration of petrophysical parameters such as porosity, permeability, water saturation, pore throat radius with geological rock types including depositional fabric, diagenesis and fracturing mechanisms.

- SRT categories can be divided into:
  - k and Φ techniques (e.g. Amaefule FZI, Corbett GHE, etc.)
  - S_w and Φ techniques (e.g. Archie, Buckles, Aguilera, etc.)
  - S_w and k techniques (e.g. WWJ, etc.)
  - Wireline Clustering (e.g. Ebanks, etc.)
Integrated Approach (e.g. Lucia RFN, etc.)

Permeability and Porosity ($k$ and $\Phi$) techniques are easy to use because of the direct application of routine core analysis. The major drawback in $k$ and $\Phi$ techniques is in assuming that the same rock type can represent a continuous porosity/permeability relationship from the low porosity/low permeability to the extremely high porosity/high permeability. Sedimentologically, this is seldom the case and banding of porosity and/or permeability solves this constraint. Porosity and permeability in carbonate rocks are not directly proportional, especially when they deviate from the intergranular, intragranular, interparticle, intercrystalline and intracrystalline porosities and approach vuggy, moldic and fracture behaviours.

Water Saturation and Porosity ($S_w$ and $\Phi$) techniques are very insightful because of the use of water saturation, which is a quantitative measure that can be derived from analytical, petrophysical, and engineering sources using core analysis, wireline logs and saturation height functions respectively. To minimize the uncertainty of water saturation modelling, the three mentioned quantities should be verified against each other. However, water saturation is one of the most uncertain quantities to measure. A slight change in clay content, wettability, or mineral composition will have a great impact on the outcome.

Water Saturation and Permeability ($S_w$ and $k$) techniques are even more attractive to use for rock typing, but the assumption that a linear relationship between both parameters exists in carbonate rocks is not always the case. In addition, the relationship can only be derived reliably from routine and special core analysis data. Permeability is even much harder to obtain than water saturation.

Wireline logs are not a direct indicator of facies and rock types. They possess problems derived from acquisition, bore hole, and drilling mud. Conventional wireline logs have problems with bed effect, mud filtrate invasion, cavings and breakouts. They perform with less accuracy for thin bedded reservoirs, minerals effect, wettability change and clay effect. NMR and bore hole image tools yield a better resolution, but still possess part or all of the wireline tool problems.
The integrated approaches of static rock typing are the backbone of any reliable rock typing methodology since they integrate rock and pore space. They only lack the rock to fluid interaction which affects the dynamic movements of fluids within the pore system.

Diagenetic effects, fracture identification and poly pore sizes are only part of the problem that complicates the carbonate characterization problem since one effect might be seen by one data source but missed by another. For example, it is often found that vuggy porosity rock types as well as very high permeability rock types are seldom represented in routine core analysis because they are harder to sample. Also, there is always a tendency to choose the sample in the better reservoir rock types missing the baffles thus over estimating reservoir performance in some intervals. The prediction of SRT’s for un-cored intervals utilizes the integration of cores, wireline logs and routine core analysis.

Chapter 4 focused on the concepts and techniques used for dynamic rock typing of two phase flow. The dynamic/hydraulic rock typing concept includes rock/fluid interaction and is affected by the scale of pore throat aperture radius and pore network connectivity. The primary tools used are routine and special core analysis.

Dynamic rock typing (DRT) is an essential link of rock and fluid interaction by understanding multiphase flow characteristics that cannot be deciphered from geological and petrophysical disciplines. However, DRT fails to predict pore space and pore network laterally and vertically for simulation modelling purposes. If a proper rock typing scheme is established, then the rock can be coined to its associated pore system. Then predictability of rocks through depositional model building can be applied and hence prediction of its associated pore system.

DRT classification schemes were classified according to various disciplines into the following main categories:

- **Statistical Clustering** (e.g. Guthrie and Greenberger)
- **Simulating Flow** (e.g. Kozeny-Carman)
- **Wireline Log Based Saturation Height Function** (e.g. Cuddy et al.)
- **Capillary Pressure Modelling** (e.g. Leverett, Thomeer, Brooks and Corey, Lambda Function, Heseldin, Wu and Berg, Kwon and Pickett, Adel Ibrahim, Johnson, El-Khatib, etc.)

- **Integrating SCAL and Wireline Data** (e.g. Skelt & Harrison, Shedid)

- **Pore Throat Size** (e.g. Winland/Kolodzie, Pittman, Swanson, Wells and Amaefule)

Statistical Clustering techniques have no theoretical background. However, because they are derived from a particular data set in a special reservoir setting they prove to be useful if a relationship between parameters can be found. If the mathematical relationship between parameters cannot be extracted from real data then the polynomials cannot be justified (Wiltgen et al., 2003).

Simulating flow equations like Kozeny-Carman have a solid theoretical basis but can only be applied within the limits of the application of Darcy’s law, especially for carbonate reservoirs. Some of the constants in the equation are also hard to quantify or measure, as is the case with specific surface area. Several authors chose not to use the simulation equation directly but an approximation using substitution constants with known parameters (e.g. Amaefule et al., Flow Zone Indicator). This, however, is not a reliable technique as it assumes that the substitution can be applied universally for all reservoirs. This defies the known heterogeneous nature of carbonate rocks.

Capillary pressure modelling techniques are a key part of any simulation study for initializing water saturation in the static model before production. A common use is using Leverett J-function modelling. However, a unique J-function fails to model saturation properly when multi-modal pore throat distribution exists in a single rock type. Because of the averaging nature of the Leverett J-function, it was documented to have a conservative behaviour for high permeability rocks which have the best reservoir quality. It also underestimates water saturation for low quality reservoirs. It was found that the J-function should not be used when the range in permeability difference is greater than two to three orders of magnitude. The J-function is a poor technique to identify flow units and to characterize carbonate reservoirs. The function gives good results when a standard Archie equation can be used in good quality reservoirs. Banding of porosity and permeability groups has given better results, where for each group a separate J-function is used.
Other functions for capillary pressure modelling are empirical like Johnson’s technique, where they assume a log/log relationship between water saturation and permeability with no theoretical foundation. A linear relationship between $S_w$, $k$ and $P_c$ is not universal and if there is no relationship between water saturation and permeability, then the method cannot be used. An advantage of Johnson’s method over others is that it does not need the estimation of irreducible water saturation beforehand.

Wireline log based saturation height functions like the FOIL function of Cuddy et al. has an advantage in low porosity rock types that are well presented as well as high porosity types. It can be used without porosity banding but it ignores SCAL data and only works above the transition zone. In addition, there is no theoretical basis behind the methodology. Cuddy’s function also over estimates hydrocarbon saturation in low quality reservoir rocks and that is why it tends to overestimate hydrocarbon in place. It is also not suitable for long transition zones.

Integrating SCAL and wireline log data was achieved by Skelt and Harrison who established a non-linear regression function using capillary pressure data and refined these results using wireline log saturation data. An advantage of Skelt's function over other methods is that it does not simplify the relationship between parameters using linear approximation, but rather preserves the non-linearity of the relationships and hence produces a more realistic result.

Pore throat size methods simplify the dynamic flow by assuming a dominant pore throat size (e.g. Winland, Pittman) attributing to fluid flow. This assumes a uni-modal pore network, which is only applicable when depositional pore space dominates. A modal pore system prevails when superposition of post diagenesis and fracturing affects reservoir rocks and hence a unique pore throat size is not representative. This is evident by the change of published representative pore throat radius to be R20, R25, R35 or R50. Applying a porosity permeability relationship for rock typing derived from a specific dataset to another very different dataset is a common mistake because there is no evidence that both reservoirs share the same dominant pore throat and pore size distribution.
Chapter 5 elaborated on proper integration of SRT with DRT and quality controlled by saturation height function to become an integral part of defining a novel Ternary Rock Type (TRT) concept. This novel concept resulted in the integration of most rock typing disciplines, scales and data types into one robust rock typing approach that can be used in static as well as in dynamic modelling. Proper initialization narrows the gap between static and dynamic model hydrocarbon in place volume calculations. It leads to the modelling of fractional fluid saturation more accurately in the 3D space. The proper prediction of rock and pore relationship enhances IOR and EOR predictions and thus becomes more economically feasible.

A novel Ternary Rock Typing (TRT) application was presented that focuses on the interrelation between porosity, permeability and irreducible water saturation in the shape of a 3D ellipsoid. The change of rock fabric and its post depositional diagenesis and fracturing changes the ellipsoid characteristics. The complex interaction of rock, pore and fluid affect the location, shape, orientation and relative position of the three-parameter ellipsoid. The three measurements are extracted from wireline logs, routine and special core analysis, and are associated with capillary pressure and relative permeability measurements. Hence, these parameters are a good representation of rock type from a static and dynamic point of view. The ellipsoid characteristics are derived from the particular data and not inherited from non-relevant data sets and non-representative depositional environments. The technique overlaps between different datasets and disciplines.

From a review of previous methods and techniques, it is concluded that a multi-scale and multi-disciplinary carbonate rock typing workflow should posses the following features:

- match routine core analysis
- work well with clustered wireline logs
- have a clear separation between clusters
- match capillary pressure
- match relative permeability end points
- be able to predict facies and properties over intervals with no routine and special core analysis
- work well when RCA is not present
- work well above and below OWC
- be able to exclude non-reliable/representative points
- be able to be used when there is no SCAL
- differentiate between mono and poly pore types
- have a minimum number of clusters
- link to rock physics model
- differentiate/integrate depositional, diagenetic and fracture effect of rock to pore types
- provide a common platform to visualize different data sources and suggest alternative interpretations
- derive the equation constants from the concerned data set and not inherit them from other datasets

It was concluded that porosity and permeability rock typing schemes on their own are misleading for carbonate rock typing as the heterogeneity of carbonate rocks proves that irreducible water saturation cannot be implicitly predicted from porosity and permeability. Hence, $S_{wir}$ has to be included explicitly in any carbonate rock typing method. Also, it was shown that porosity and irreducible water saturation rock typing schemes on their own did not capture the carbonate fabric satisfactorily with their associated reservoir properties.

The TRT methodology has the advantage in that it does not omit any of the pore type parameters like pore throat radius, tortuosity at the core plug volume, shape factor and specific surface area or even wettability. Instead of trying to explicitly determine them individually, they are included implicitly in the three dimensional relationship of the above-mentioned parameters. The rock typing procedure becomes more robust since the data governs the relationship instead of trying to force data to follow a predefined equation or relationship.

Saturation height modelling is used as part of the quality control of the TRT rock typing scheme. This leads to the validation of static rock types through the quality control of their imbibition characteristics and hence their geological and petrophysical measurements can be confirmed. This results in a robust association between static and dynamic rock types and establishes an accurate saturation height function and fluid distribution across the reservoir. TRT is innovative and differs from other
methods in utilizing the static and dynamic rock typing and where quality control becomes part of the rock typing process.

As part of this research, a TRT tool was programmed that is able to generate rock typing logs, 1D plots, crossplots and output data and quantifies the match of various reservoir properties using various rock typing techniques.

The guided TRT (gTRT) using the centre of ellipsoids representing "sedimentological facies" proved to be able to replicate the prediction of a perfect match of the original synthetic data set. The porosity and permeability assignment to rock fabrics is properly predicted. The porosity and irreducible water saturation assignment to rock types is also properly predicted. The hydraulic contribution of each rock type is also correctly assigned. It can be concluded that using guided TRT (gTRT) gives the best results using the synthetic data set.

Advantages of Ternary Rock Typing (TRT):

• Ability to incorporate sedimentological fabric, routine and special core analysis in one plot
• Uses cloud ellipsoid assignment concept rather than single cutoffs
• Integrated with RCA
• Integrated with capillary pressure irreducible water saturation
• Integrated with relative permeability critical water saturation
• Uses clustered wireline logs
• Ability to exclude unreliable/non-representative points (located outside the ellipsoids)
• Integrates (phi/k) techniques (Winland, Pittman, FZI, Corbett, etc.)
• Integrates (phi/Sw) techniques (Aguilera, Cuddy, etc.)
• Integrates (k/Sw) techniques (Timur, etc.)
• Possibility of differentiation between depositional, diagenetic and fracture effect on rock if a signature in (phi, k ,Swirr) domain can be found
• Narrows the gap of data scale differences as the workflow used is parallel rather than linear
• Eliminates the need for multi-scheme; same rock type is used from start of geological interpretation, petrophysical analysis, static and dynamic modelling
• Saturation height function modelling is part of the rock typing technique as a quality control (as presented in subsequent chapters)
• The technique can be used as a data only driven approach (rTRT) or as a guided data driven approach (gTRT)

Chapter 6 tested the Ternary Rock Typing (TRT) concept and the global comprehensive workflow against actual carbonate reservoir data in 1D space. The TRT utilises sedimentological facies (including fabric, diagenesis and fractures), wireline logs, routine core analysis, special core analysis and saturation height function in one integrated workflow. It was proved that permeability alone is not a clear quality control for rock typing methods and hence water saturation height modelling was chosen as a quality control criterion. It was also demonstrated that ternary interrelationships between porosity, permeability and water saturation in carbonate rocks are independent.

The TRT software proved that it was able to quantify and quality control the generated rock types, predicted permeability and derived saturation height function water saturation. It was also able to generate quality control consistency montage to check the applicability of various rock typing methods.

A representative well, namely Well W1, was used for the demonstration of different rock typing techniques and their effect on:
  o similarity of derived rock types compared to the derived sedimentological study rock type (ORT)
  o change of porosity/permeability equations
  o change in the centroids of ellipsoids of phi, k, and Sw domain
  o relative position and separation of the ellipsoids for each rock type

The raw unguided Ternary Rock Typing (rTRT) derived rock types of Well W1 showed good separation of rock type ellipsoids in the three domains namely; porosity, permeability and water saturation. The flow and storage capacity plot showed a correct grading contribution of rock types. Ellipsoids' sizes are narrow and a minimal overlap between different rock types is observed. The guided rock typing TRT (gTRT) algorithm showed that the centroids of phi, k, and Sw are well separated with distinct clusters in the phi, k, and Sw domains.
The permeability quality control proved that the best methods related to Flow Zone Indicator (FZI), Corbett (GHE) and Pittman (R25) giving a 0.96 coefficient. The un-guided TRT (rTRT) gave very close value of 0.94 values, while the guided and iterated gTRT gave 0.85 and 0.9 respectively.

The quality control of the rock types of various rock-typing methods compared to the sedimentological derived rock types (ORT) proved that rTRT and gTRT methods gave the highest similarity using only routine core analysis data with a value of 0.53 and 0.58 respectively. It can be concluded that Ternary Rock Typing (TRT), both guided (gTRT) and unguided (rTRT), gives the best rock type similarity to reference sedimentological study (ORT) results.

The TRT also proved to work well when no core analysis is available, where testing and prediction of a limestone interval was compared to the sedimentological derived rock types (ORT), and a high Pearson coefficient of 0.92 was achieved.

Saturation height function was used as part of the TRT workflow as a quality control tool for applicability of any rock typing method. The J-function is related to FWL, porosity, permeability, wettability for each facies, and the resultant water saturation was compared to the core (RCA and SCAL) and wireline saturation. TRT utilizes one phase and two phase, static and dynamic rock typing derived properties and the quality control becomes part of the rock typing process. The cross plots were able to exclude non-representative RCA and SCAL samples giving a false response related to the assigned rocks.

The Pearson coefficient was used to compare core water saturation to water saturation predicted from J-function for different rock typing methods. All methods gave unsatisfactory negative results. The seed points from the ORT for Well W2 applied to the guided TRT (gTRT) gave a positive trend for the water saturation. Iterating the seed points increased the coefficient tremendously. It can be concluded that the effect of geological facies including sedimentological, diagenetic and fracturing processes has a great effect on porosity, permeability and irreducible water saturation. When taking geological facies as seed point calibration, the water saturation prediction is greatly enhanced compared to other methods. The gTRT workflow proved to give a better saturation profile than all other methods for water saturation initialization.
Chapter 7 tested the applicability of the ternary rock typing (TRT) concept, workflow, plot and software in a real field scale scenario. The effect on static and dynamic conditions was demonstrated. The models were tested using Petrel RE and Eclipse.

The TRT proved to work well with routine core analysis using six cored wells. The cored wells were then transferred to the uncored intervals. The facies distribution of the unguided TRT in the static model proved to be comparable with the reference sedimentological model, thus giving an edge to the workflow when no core and no RCA are available. Using rTRT with only wireline logs can be used and yield comparable results as the sedimentological study. When core description, SEM, XRD, RCA and sedimentological data is available, the resultant sedimentological rock types can be transferred to the guided TRT concept using ellipsoid centres of porosity, permeability and water saturation. The result is TRT rock types that follow the integration of sedimentological, geological, petrophysical and reservoir engineering concepts. Using SCAL data among various rock types, the TRT proved to assign and group SCAL data accurately with guided TRT performing slightly better than the unguided TRT.

The unguided and guided Ternary Rock Typing (rTRT and gTRT) derived rock types gave the best distinctive clustering ellipsoids in porosity-water saturation, porosity-permeability, and permeability-water saturation domains compared to all other methods.

Quantifying the above observations with respect to volumetrics of the oil in place is a key quality control and a decisive criterion on the selection of any rock typing method. Predicting the oil in place from the initialized SCAL data per rock type for all rock typing schemes compared to the sedimentological based referenced model. The BVW and guided TRT (gTRT) methods were the best matches of the oil in place for the high limestone facies; namely L5 and L6. For dolomite highest rock type D5 and D6, the best in place volume comparison is the guided TRT (gTRT) with a difference of only 10%.

The effect of rock typing on the hydrodynamic movements was tested using two strategies: the first is an active bottom water drive and the second strategy is using
one injector and one producer with no bottom water drive effect. Quantifying the hydrodynamic observations with respect to cumulative oil produced is a key quality control and a decisive criterion on the selection of any rock typing method. Cumulative oil production, water cut, oil production rate and the difference of cumulative oil production relative to the reference model (ORT) were observed. The unguided (rTRT) and guided (gTRT) Ternary Rock gave the best cumulative oil prediction compared to the ORT with only 2.8% difference for the active bottom water drive scenario. For the Injector/Producer scheme scenario unguided TRT (rTRT) gave also the best cumulative oil prediction with a 5% difference compared to the ORT. This means that TRT proved to accurately model barriers, baffles and reservoirs and thus gave the best fluid movement comparison compared to other rock typing schemes. This affects the production and completion strategy. It also affects the prediction of water breakthrough, fingering, channelling, and by passed oil. The TRT workflow proved to work well with various data types. It disregards data and rock typing schemes that are not satisfying the static and dynamic interrelationships, hence minimizes the effort for simulating un-necessary models.

8.2 Conclusions

It was demonstrated that the ternary interrelationship between porosity, permeability and water saturation in carbonate rocks is independent. Porosity and permeability rock typing schemes on their own are misleading for carbonate rock typing as the heterogeneity of carbonate rocks proves that irreducible water saturation cannot be implicitly predicted from porosity and permeability and hence $S_{wir}$ has to be included explicitly in any carbonate rock typing scheme.

A novel Ternary Rock Typing (TRT) application was presented that focuses on the interrelationship between porosity, permeability and irreducible water saturation in the shape of a 3D ellipsoid. The change of rock fabric and its post depositional diagenesis and fracturing changes the ellipsoid characteristics. The complex interaction of rock, pore and fluid affect the location, shape, orientation and relative position of the three-parameter ellipsoid. The three measurements are extracted from wireline logs, routine and special core analysis, and are associated with capillary pressure and relative permeability measurements. Hence, these parameters are a good representation of rock type from a static and dynamic point of view. The ellipsoid
characteristics are derived from the particular data and not inherited from non-relevant data sets and non-representative depositional environment. The technique overlaps between different datasets and disciplines.

Conceptual Ternary Rock Typing (TRT) Plot was introduced showing generalized carbonate texture and fabric associated with the three TRT parameters; porosity, permeability and irreducible water saturation. Size, shape and orientation of the ellipsoids will vary based on variation in depositional environments’ fabric, diagenesis and fracture effect.

Quality control consistency montages were introduced showing porosity-permeability crossplot, porosity-water saturation crossplot, permeability-water saturation, OLP, core porosity, permeability versus predicted permeability, wireline water saturation, versus core water saturation versus J-function derived water.

The TRT workflow proved to work well with various data types. It disregards data and rock typing schemes that are not satisfying the static and dynamic interrelationships, hence minimizes the effort for simulating unnecessary models.

The TRT methodology has the advantage that it does not omit any of the pore type parameters such as pore throat radius, tortuosity at the core plug volume, shape factor and specific surface area or even wettability. Instead of trying to explicitly determine them individually, they are included implicitly in the three dimensional relationship of the above-mentioned parameters. The rock typing procedure becomes more robust since the data governs the relationship instead of trying to force data to follow a predefined equation or relationship.

Saturation height modelling is used as part of the quality control of the TRT rock typing scheme. This leads to the validation of static rock types through the quality control of their imbibition characteristics and hence their geological and petrophysical measurements can be confirmed. This results in a robust association between static and dynamic rock types and establishes an accurate saturation height function and fluid distribution across the reservoir. TRT is innovative and differs from other methods in utilizing the static and dynamic rock typing and where quality control becomes part of the rock typing process.
The technique can be used as a solely data driven approach (rTRT) or as a guided data driven approach (gTRT).

8.3 Future Work

The fractured carbonate effect on porosity and permeability is well documented in case studies and in the literature. However, the diagenetic fracture history effect on irreducible water saturation is not well presented. The TRT concept needs to be extended to a well fractured carbonate reservoir data set where the influence of fractures which modify matrix rock types can be evaluated.

The ternary relationship of porosity, permeability and irreducible water saturation holds for siliciclastic sedimentary reservoirs. However, the sedimentological, diagenetic and fracture processes will differ from that of carbonate reservoirs. Hence, the TRT concept is expected to be applicable to clastic reservoirs, and it is recommended to test the concept against a sand dominated data set.

The integration of different data sets from different scales entails upscaling and downscaling to a common scale. It is recommended to test the effect of upscaling and downscaling on the optimum number of TRT clusters and associated data. Since the TRT is an initial step before static and dynamic 3D modeling, the scale testing will minimize the effort and time when performing this step in a 3D environment.

The TRT application is using geostatistical algorithms for distribution of facies and properties in the 3D space. The workflow can be extended to test the application of using real 3D data sets from multi-well production data and/or seismic inversion.
symbols

\( a \quad \text{Tortuosity factor} \)

\( A, B, C, D \quad \text{Numerical Constants} \)

\( a_1, a_2, a_3, a_4, a_5 \)

\( a, b, c, d, f \)

\( \alpha \quad \text{and} \quad \beta \)

\( A_T \quad \text{Adhesion tension} \)

\( d \quad \text{Grain size diameter in mm} \)

\( D_p \quad \text{Diameter of the related spherical particle} \)

\( F \quad \text{Formation factor} \)

\( F_g \quad \text{Pore geometry} \)

\( F_s \quad \text{Shape factor} \)

\( F_s \tau^2 \quad \text{Kozeny’s constant} \)

\( g \quad \text{Gravity acceleration} \)

\( G \quad \text{Pore geometric factor} \)

\( H \quad \text{Height above free water level} \)

\( H \quad \text{Height of capillary rise} \)

\( I \quad \text{Hydraulic gradient} \)

\( J \quad \text{Dimensionless function} \)

\( k \quad \text{Permeability} \)

\( k_a \quad \text{Air permeability} \)

\( k_h \quad \text{Horizontal permeability} \)

\( k_{ro} \quad \text{Relative permeability of oil} \)

\( k_{rw} \quad \text{Relative permeability of water} \)

\( k_w \quad \text{Brine permeability} \)

\( L \quad \text{Total height of the bed} \)

\( \text{Lab} \quad \text{Lab conditions} \)

\( \ln \quad \text{Natural logarithm} \)

\( m \quad \text{Cementation factor} \)

\( n \quad \text{Saturation exponent} \)

\( P_a \quad \text{Pressure of air} \)

\( P_c \quad \text{Capillary pressure} \)

\( P_{ce} \quad \text{Mercury/air capillary pressure} \)

\( P_{d} \quad \text{Displacement pressure} \)

\( P_{d} \quad \text{Mercury/air extrapolated displacement pressure} \)

\( P_e \quad \text{Entry pressure} \)

\( \phi \quad \text{Porosity} \)

\( P_l \quad \text{Pressure of liquid} \)

\( P_{nw} \quad \text{Non-wetting pressure} \)

\( \text{psi} \quad \text{Pounds per square inch} \)

\( P_{th} \quad \text{Threshold Pressure} \)
<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$P_w$</td>
<td>Wetting pressure</td>
</tr>
<tr>
<td>$r$</td>
<td>Pore throat radius</td>
</tr>
<tr>
<td>$r$</td>
<td>Radius of capillary tube</td>
</tr>
<tr>
<td>$r_{apex}$</td>
<td>Pore throat radius at the apex</td>
</tr>
<tr>
<td>Res</td>
<td>Reservoir conditions</td>
</tr>
<tr>
<td>$R_o$</td>
<td>Resistivity of a porous rock at 100% saturation</td>
</tr>
<tr>
<td>$r_p$</td>
<td>Pore throat radius</td>
</tr>
<tr>
<td>$r_{p35}$</td>
<td>Size of pore throats at 35% non-wetting phase saturation</td>
</tr>
<tr>
<td>$r_{pd}$</td>
<td>Pore throat radius at displacement pressure</td>
</tr>
<tr>
<td>$R_t$</td>
<td>True resistivity of the formation</td>
</tr>
<tr>
<td>$r_{thres}$</td>
<td>Pore throat radius at threshold pressure</td>
</tr>
<tr>
<td>$R_w$</td>
<td>Formation water resistivity at formation temperature</td>
</tr>
<tr>
<td>$S_b$</td>
<td>Mercury saturation in percent of bulk volume</td>
</tr>
<tr>
<td>$(S_b)_{P_c}$</td>
<td>Mercury saturation at infinite capillary pressure</td>
</tr>
<tr>
<td>$(S_b)_{P_c}$</td>
<td>Mercury saturation at capillary pressure $P_c$</td>
</tr>
<tr>
<td>$S_e$</td>
<td>Effective water saturation (sometimes denoted $S^*$)</td>
</tr>
<tr>
<td>$S_gv$</td>
<td>Surface area per unit grain volume</td>
</tr>
<tr>
<td>$S_h$</td>
<td>Hydrocarbon saturation</td>
</tr>
<tr>
<td>$S_{HG}$</td>
<td>Mercury saturation</td>
</tr>
<tr>
<td>$S_w$</td>
<td>Water Saturation</td>
</tr>
<tr>
<td>$S_{wi}$</td>
<td>Initial water saturation</td>
</tr>
<tr>
<td>$S_{wi}^{irr}$</td>
<td>Irreducible water saturation</td>
</tr>
<tr>
<td>$S_{wn}$</td>
<td>Normalized water saturation</td>
</tr>
<tr>
<td>$T_2$</td>
<td>Relaxation Time</td>
</tr>
<tr>
<td>$V_b$</td>
<td>Interconnected pore volume</td>
</tr>
<tr>
<td>$V_{bh}$</td>
<td>Bulk volume of hydrocarbon</td>
</tr>
<tr>
<td>$(V_b)_{P_c}$</td>
<td>Fractional bulk volume occupied by mercury at infinite pressure</td>
</tr>
<tr>
<td>$(V_b)_{PC}$</td>
<td>Fractional bulk volume occupied by mercury at pressure $P_c$</td>
</tr>
<tr>
<td>$\nu_s$</td>
<td>Superficial or “empty tower” velocity</td>
</tr>
<tr>
<td>$v$</td>
<td>Darcy Velocity</td>
</tr>
</tbody>
</table>

**Greek Letters**

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\beta$</td>
<td>Shape factor</td>
</tr>
<tr>
<td>$\gamma$</td>
<td>Unit weight of the fluid</td>
</tr>
<tr>
<td>$\Delta p$</td>
<td>Pressure drop</td>
</tr>
<tr>
<td>$\cos \theta$</td>
<td>Contact angle</td>
</tr>
<tr>
<td>$\lambda$</td>
<td>Dimensionless pore size distribution index</td>
</tr>
<tr>
<td>$\mu$</td>
<td>Fluid viscosity</td>
</tr>
<tr>
<td>$Mm$</td>
<td>Micrometre</td>
</tr>
<tr>
<td>$\rho_a$</td>
<td>Air density</td>
</tr>
<tr>
<td>$\rho_g$</td>
<td>Gas density</td>
</tr>
</tbody>
</table>
\( \rho_l \) Liquid density
\( \rho_o \) Oil density
\( \rho_w \) Water density
\( \sigma \) Interfacial tension
\( \sigma_{o-w} \) Oil-water interfacial tension
\( \sigma_1 \) Specific surface expressed in squared metres per bulk volume of the porous material
\( \tau \) Tortuosity
\( \Phi \) Porosity
\( \Phi_e \) Effective Porosity
\( \Phi_s \) Sphericity of the particles in the packed bed
\( \Phi_z \) Pore volume to grain volume ratio

**Abbreviations**

1D 1 Dimensional
3D 3 Dimensional
BBl Barrels
BMC Basal Miocene Clastics
BVH Bulk Volume of Hydrocarbon
BVI Bulk Volume Water Irreducible
BVW Bulk Volume Water
CMR Combinable Magnetic Resonance
CN Characterization Number
CT Computer Tomography
DIA Digital Image Analysis
DRP Digital Rock Physics
DRT Dynamic Rock Typing
DST Drill Stem Test
Dth Depth where \( P_c = P_e \)
EOR Enhanced Oil Recovery
FMI Formation MicroImager log
FOIL Bulk Volume of Water Function
FWL Free Water Level
FZI Flow Zone Indicator
GHE Global Hydraulic Elements
GOS Gulf of Suez
GRT Geological Rock Typing
GWC Gas Water Content
HAFWL, \( H_{FWL} \) Height Above Free Water Level
HIIP Hydrocarbon Initially In Place
HST Highstand Systems Tracts
INPEFA Integrated Prediction Error Filter Analysis
<table>
<thead>
<tr>
<th>Acronym</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>IOR</td>
<td>Improved Oil Recovery</td>
</tr>
<tr>
<td>KNN</td>
<td>K-Nearest Neighbour Algorithm</td>
</tr>
<tr>
<td>Log</td>
<td>Logarithm</td>
</tr>
<tr>
<td>LST</td>
<td>Lowstand Systems Tracts</td>
</tr>
<tr>
<td>MF</td>
<td>Maximum Flooding</td>
</tr>
<tr>
<td>MICP</td>
<td>Mercury Injection Capillary Pressure</td>
</tr>
<tr>
<td>MID</td>
<td>Matrix Identification Plot</td>
</tr>
<tr>
<td>Mm</td>
<td>Millimeter</td>
</tr>
<tr>
<td>MM</td>
<td>Million</td>
</tr>
<tr>
<td>M-N Plot</td>
<td>“M” Value is calculated from sonic and density logs while the “N” value is determined from neutron and density logs</td>
</tr>
<tr>
<td>NMR</td>
<td>Nuclear Magnetic Resonance</td>
</tr>
<tr>
<td>ORT</td>
<td>Original Sedimentological Rock Type (Reference)</td>
</tr>
<tr>
<td>OWC</td>
<td>Oil Water Content</td>
</tr>
<tr>
<td>PCA</td>
<td>Principle Component Analysis</td>
</tr>
<tr>
<td>PGS</td>
<td>Pore Geometry Structure</td>
</tr>
<tr>
<td>PHIE</td>
<td>Effective porosity</td>
</tr>
<tr>
<td>PRT</td>
<td>Petrophysical Rock Typing</td>
</tr>
<tr>
<td>PVT</td>
<td>Pressure, Volume Temperature Analysis</td>
</tr>
<tr>
<td>RCA</td>
<td>Routine Core Analysis</td>
</tr>
<tr>
<td>RCF</td>
<td>Reservoir Conversion Factor</td>
</tr>
<tr>
<td>RFN</td>
<td>Rock Fabric Number</td>
</tr>
<tr>
<td>RQI</td>
<td>Reservoir Quality Index</td>
</tr>
<tr>
<td>RT</td>
<td>Rock Type</td>
</tr>
<tr>
<td>rTRT</td>
<td>Raw Unguided Ternary Rock Typing</td>
</tr>
<tr>
<td>SCAL</td>
<td>Special Core Analysis Laboratory</td>
</tr>
<tr>
<td>SEM</td>
<td>Scanning Electron Microscope</td>
</tr>
<tr>
<td>SMLP</td>
<td>Stratigraphic Modified Lorenz Plot</td>
</tr>
<tr>
<td>SPI</td>
<td>Secondary Porosity Index</td>
</tr>
<tr>
<td>SRT</td>
<td>Static Rock Typing</td>
</tr>
<tr>
<td>TRT</td>
<td>Ternary Rock Typing</td>
</tr>
<tr>
<td>TST</td>
<td>Transgressive Systems Tracts</td>
</tr>
<tr>
<td>TVD</td>
<td>True Vertical Depth</td>
</tr>
<tr>
<td>XRD</td>
<td>X-Ray Diffraction</td>
</tr>
</tbody>
</table>
REFERENCES


References


Swanson, B. F., 1977, Visualizing pores and non-wetting phase in porous rocks: SPE 6857, 10 p.


Sun, Hongjun, Bai, Guoping and Teng, Binbin, 2012. Comparison of Hydrocarbon Accumulations in Global Marine Carbonate Sequences and Its Implication for Exploration, Adapted from extended abstract prepared in conjunction with poster presentation at AAPG Annual Convention and Exhibition, Long Beach, California, 22-25 April.


References


## APPENDIX 1

Summary, comparison and critic of selected carbonate rock typing scheme classifications.

<table>
<thead>
<tr>
<th>Classification</th>
<th>Initiation/Methodology</th>
<th>Year</th>
<th>Model</th>
<th>Rocks</th>
<th>Data Used</th>
<th>Scale</th>
<th>Advantages</th>
<th>Drawback</th>
</tr>
</thead>
<tbody>
<tr>
<td>Texture</td>
<td>The Udmo-Wansano scale</td>
<td>1951-1952</td>
<td>Average grain diameter</td>
<td>Physical Grain Measurement</td>
<td>Thin Section and Core</td>
<td>Easy to use</td>
<td>In some sedimentological studies</td>
<td>Indicator of the rock system rather than the pore-vigorous network which determines porosity and permeability.</td>
</tr>
<tr>
<td>Textures</td>
<td>Folk</td>
<td>1959, 1962</td>
<td>Mindo grain ratio</td>
<td>Physical Grain Measurement</td>
<td>Thin Section and Core</td>
<td>Thin Section and Core Scale</td>
<td>Quantitative and detailed indication of grain size, mineralogical, and other properties.</td>
<td>Used worldwide among petrographers and sedimentologists</td>
</tr>
<tr>
<td>Detrital textural principles</td>
<td>Dunham</td>
<td>1962</td>
<td>Grain versus matrix support and the presence of any biological binding</td>
<td>Microscope/Hand specimen Examination</td>
<td>Thin Section and Core</td>
<td>Thin Section and Core Scale</td>
<td>Easy to use</td>
<td>Used in the field and by well-site geologists</td>
</tr>
<tr>
<td>Reef rock textural principles</td>
<td>Enzey and Elston</td>
<td>1971</td>
<td>Modification to dunham classification to accommodate differences in biogenic deposits of reefs and buildups</td>
<td>Hand Lens, Microscope/Hand specimen Examination</td>
<td>Core</td>
<td>Core</td>
<td>Easy to use in the field</td>
<td>Used worldwide for reef classification.</td>
</tr>
<tr>
<td>Reef rocks</td>
<td>Riding</td>
<td>2002</td>
<td>Support by matrix, skeletal, or cement</td>
<td>Hand Lens, Microscope/Hand specimen Examination</td>
<td>Core/Outcrop</td>
<td>Core/Outcrop</td>
<td>Classification for reef rocks</td>
<td>More useful for authigenic and cementstone reefs or buildups.</td>
</tr>
<tr>
<td>Genetic classification</td>
<td>Wright</td>
<td>1992</td>
<td>Interpretation of deposition</td>
<td>Physical Rock Examination</td>
<td>Core/Outcrop</td>
<td>Core/Outcrop</td>
<td>Inclination of the basic of Dunham and Enzey &amp; Elston classifications.</td>
<td>This scheme integrates sedimentologic, biologic, and other concepts.</td>
</tr>
<tr>
<td>Genetic classification</td>
<td>Alk et al.</td>
<td>2005</td>
<td>Superposition of depositional, diagenetic processes, and mechanical factors</td>
<td>Process Superposition of Porosity</td>
<td>Thin Section and Core</td>
<td>Thin Section and Core</td>
<td>Triangulation classification of the origin of porosity.</td>
<td>Diagenetic, diagenetic, or fracture processes represent the cause.</td>
</tr>
<tr>
<td>Hydraulic Rock Typing</td>
<td>Keeney, Cameron</td>
<td>1957-37,56</td>
<td>Capillary Thta Model</td>
<td>Theoretical</td>
<td>Core Analysis</td>
<td>Core Analysis</td>
<td>Derived from Poisson's law and Darcy's law.</td>
<td>Good agreement between geologists.</td>
</tr>
<tr>
<td>Hydraulic Rock Typing</td>
<td>Leverett - Reservoir Quality Index (RIQ)</td>
<td>1941</td>
<td>Dimensionless expression using average pore radius equation</td>
<td>Empirical</td>
<td>Core Analysis</td>
<td>Core and Wireless Log</td>
<td>Leverett's RIQ is simple to use.</td>
<td>Special core analysis measurements of capillary pressure on core samples is needed.</td>
</tr>
<tr>
<td>Hydraulic rock typing</td>
<td>Buckley, Buhl, Volumetric Water (BVW)</td>
<td>1970/1965</td>
<td>Hypothetical equations for porosity and irreducible-water saturation</td>
<td>Empirical</td>
<td>Core Analysis and Wireline Logs</td>
<td>Core and Wireline Log Scale</td>
<td>Indication of pore size influence and presence of mobile water</td>
<td>Easy to implement. Good correlation between rock types and BVW. Only applicable above the transition zone where rocks are at irreducible water saturation. Used only on initial well not affected by water movements.</td>
</tr>
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<td>-------------------------------</td>
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<td>------------------------------------------------------------------</td>
<td>------------------------------------------------------------------</td>
</tr>
<tr>
<td>Genetic classification</td>
<td>Choquette - Pany</td>
<td>1970</td>
<td>Pore types. Fractures genetically and deformationally</td>
<td>Physical Rock Examination</td>
<td>Thin Section and Core</td>
<td>Thin Section and Core</td>
<td>Definition involves 15 porosity types genetically and deformationally. Includes modifying terms to describe the processes affecting pores. Terms for evaporation stage of the process and timing. Accurate porosity description schema widely used for geological modeling. Does not include interstitial porosity. Limited relation to petrophysical properties. Does not include spatial distribution. Describes the types of pores, but not the process of imbibition.</td>
<td></td>
</tr>
<tr>
<td>Graphical</td>
<td>Schunhammer</td>
<td>1972, 1974</td>
<td>Difference between total porosity and sonic transit time porosity</td>
<td>Empirical</td>
<td>Wireline Logs</td>
<td>Wireline Log Scale</td>
<td>Applicable for secondary porosity such as vugs, and fractures. No sedimentological input. No distinguish between depositional, diagenetic and fracture pore types.</td>
<td></td>
</tr>
<tr>
<td>Graphical</td>
<td>Schunhammer + M - N plot</td>
<td>1979</td>
<td>Binary and ternary mineral mixtures</td>
<td>Empirical</td>
<td>Wireline Logs</td>
<td>Wireline Log Scale</td>
<td>Easy to implement. No Physical meaning of M &amp; N. assumption that carbonate rocks are represented by unmodified pore throat distribution. No theoretical or physical justification for using 33% saturation. Weakly used without regard for its limitations. Overestimates E35 in presence of fractures or connected vugs. No geologic descriptions to Schunhammer porosity (E35). Assumption that there is a linear relationship between porosity, permeability, and E35. It does not take into consideration heterogeneity or wettability.</td>
<td></td>
</tr>
<tr>
<td>Hydraulic rock typing</td>
<td>Winland's R35 (Eldredge, 1980)</td>
<td>1980</td>
<td>Regression analysis for mercury saturations using injection capillary pressure curves</td>
<td>Empirical</td>
<td>MCP</td>
<td>Core and Wireline Log Scale</td>
<td>Can be used without special core analysis. Widely used. Pittman used conduits samples. Max Porosity was 28.0% and permeability of 998 md. This doesn't cover high porosity high permeability streaks found in carbonate rocks. Used in carbonate rock permeability. Not applicable for high porosity carbonate rocks. Core porosity used is restricted to integrable porosity and not necessarily total porosity. E35 values are calculated using a correlation not measured. E35 method may be inappropriate for low permeability samples. Does not take into account the depositional features of carbonate rocks.</td>
<td></td>
</tr>
<tr>
<td>Hydraulic rock typing</td>
<td>Pittman</td>
<td>1992</td>
<td>Correlations to conclude pore type rock at different mercury saturation percentages</td>
<td>Empirical</td>
<td>MCP</td>
<td>Core and Wireline Log Scale</td>
<td>Permeability and porosity is linked to dynamic properties. F22 method used conduits samples. Max Porosity was 28.0% and permeability of 998 md. This doesn't cover high porosity high permeability streaks found in carbonate rocks. Used in carbonate rock permeability. Not applicable for high porosity carbonate rocks. Core porosity used is restricted to integrable porosity and not necessarily total porosity. E35 values are calculated using a correlation not measured. E35 method may be inappropriate for low permeability samples. Does not take into account the depositional features of carbonate rocks.</td>
<td></td>
</tr>
<tr>
<td>Hydraulic Flow Unit</td>
<td>Annular Flow Zone Indicator (FZI)</td>
<td>1993</td>
<td>Formulation of Kozey-Carman's equation and hydraulic mean radius concept</td>
<td>Theoretical footing</td>
<td>Core Analysis and Wireline Logs</td>
<td>Core and Wireline Log Scale</td>
<td>Mathematical footing from the concept of bundle of capillary tubes considered by Kozey and Carman. Quasi-static approach to select FZI. Grouping zones with similar petrophysical properties using the Kozey-Carman equation. The flow zone indicator (FZI) is a unique parameter that includes the geological and mineralogy of the structure of different pore geometrical factors. Establish regression models for permeability- porosity- saturation in the uncored wells. Easy to use and cluster RCA measurements. FZDQI method is purely petrophysical. Depositional environments, sedimentological facies are not evident in the model. No basis for the choice of the FZDQI. Suffers from the same limitations of an original Kozey-Carman model.</td>
<td></td>
</tr>
</tbody>
</table>

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<table>
<thead>
<tr>
<th>Study Type</th>
<th>Authors</th>
<th>Year</th>
<th>Methodology</th>
<th>Properties</th>
<th>Classification</th>
<th>Notes</th>
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<tr>
<td>Graphical for Hydraulic Flow Unit Identification</td>
<td>Martin et al.</td>
<td>1997</td>
<td>Picket plot to characterize petrophysical flow units</td>
<td>Core Analysis and Wireline Logs</td>
<td>Core and Wireline Logs</td>
<td>No sedimentological input</td>
</tr>
<tr>
<td>Graphical for Hydraulic Flow Unit Identification</td>
<td>Guiter et al.</td>
<td>1997</td>
<td>Quantify reservoir flow based on petrophysical pore types, storage capacity, flow capacity, and reservoir pressure speed</td>
<td>Core Analysis and Wireline Logs</td>
<td>Core and Wireline Logs</td>
<td>No sedimentological input</td>
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