1 Introduction

What is petrophysics? Petrophysics, as understood in the oil and gas industry, is the characterization and interaction of the rock and fluid properties of reservoirs and non-reservoirs:

1. determining the nature of an interconnected network of pore spaces – *porosity*;
2. the distribution of oil, water and gas in the pore spaces – *water saturation*; and
3. the potential for the fluids to flow through the network – *permeability*.

Petrophysical interpretation is fundamental to the much of the work on the subsurface carried out by geologists, geophysicists and reservoir engineers and drillers. To characterize the subsurface successfully requires physical samples, electrical, chemical, nuclear and magnetic measurements made through surface logging, coring and drilling and wireline tools (sondes). Terms such as 'formation evaluation' and 'log analysis' are often used to capture specific parts of the petrophysical workflow, but should not be seen as synonyms. 'Rock physics', which sounds as though it might be similar, is usually reserved for the study of the seismic properties of a reservoir; similar concepts apply but at larger scale.

The evaluation, analysis and interpretation of these petrophysical data is as much an art as a science, as it requires an understanding of geology, chemistry, physics, electronics, mechanics and drilling technology. At its simplest, petrophysics determines the porosity and water saturation of a reservoir, then estimates the permeability of the rock and the mobility of the fluids in place. The interpretation is dependent on the lithology of the rocks being evaluated, as sandstone, limestone, shale and any other potential hydrocarbon-bearing rocks all have differing characteristics. The acquisition and interpretation techniques applied in formation evaluation have been developed over the last

Petrophysics: A Practical Guide, First Edition. Steve Cannon.

century primarily by the oil and gas industry, but the principles are equally relevant in coal mining, hydrogeology and environmental science. The type of data acquired is generic and can be used in a number of different analytical ways; indeed, as computing power and microelectronics have developed over the last 30 years, more high-resolution data can be collected and used for ever more detailed interpretation. However, measurements can be influenced by a number of variables, including the borehole environment; borehole diameter, temperature, pressure and drilling fluid, all affect the quality and type of data acquired. The reservoir rocks and the fluids therein can further affect the data quality and interpretation – a virtuous or viscous circle depending on how you look at it.

This book can be divided into two sections: first data acquisition and second interpretations, applications and workflow. This introductory chapter reviews the basics of petrophysics, including the confusing topics of measurement units, reservoir lithology, basic measurements and how the results may be used and the value of information and data management.

- *Chapter 2* reviews data acquisition in some detail, from drilling data to core analysis and wireline logs. I have not tried to give a detailed description of wireline tool technology, because I am not a physicist or electronics engineer; I refer you to the appropriate manufacturers' publications. In an appendix I have tried to collect basic tool information, but I would direct you to the third edition of The Geological Interpretation of Well Logs (Rider and Kennedy, 2011) for a full description and discussion of the range of logging tools available.
- *Chapter 3* discusses rock and fluid properties and what controls porosity, water saturation and permeability in the reservoir. Each property is defined and described and how the measurements are made, with a discussion of uncertainty.
- *Chapter 4* is focused on data quality control, especially the validation of log data and the integration with core data.
- *Chapter 5* looks at the characteristic response of different logs to reservoir rocks and fluids and how the data may be used in log analysis. The response to shales and matrix and fluid properties are fundamental.
- *Chapter 6* is about the evaluation of porosity and formation water resistivity and estimation of water saturation.
- *Chapter 7* looks at different petrophysical workflows, starting with data management and then quick-look single-well analyses, followed by multi-well studies. This part of the process is supported by worked examples.
- *Chapter 8* is called 'beyond log analysis' and looks at permeability estimation, cut-offs and zone averages, saturation height relationships, pressure measurements and fluid contacts. There is also a discussion of

lithology prediction, facies analysis and rock typing and also integration with seismic data.
- *Chapter 9* looks at carbonate reservoir characterization.
- *Chapter 10* describes the role of petrophysics in reservoir modelling, with a particular emphasis on property modelling in three dimensions.

One outcome of a petrophysical analysis forms the basis of the estimation of fluids in place, upon which, together with the gross rock volume of a reservoir, major investment decisions are made by oil and gas companies: the quality of the interpretation will change with time as new wells and new data are collected, so there is a need for consistency in approach at all times. One aspect that should never be forgotten is that most of the measurements that are made are a proxy for the real property that we are trying evaluate: porosity is never actually measured but interpreted from a density or neutron log; water saturation is interpreted from a resistivity measurement, dependent on the analyst knowing some fundamental properties of the formation fluid. A petrophysicist therefore has to be a general scientist with a strong numerical bias to be able to cut through the complex analytical methods and uncertainties inherent in the process of evaluating a reservoir; above all, a petrophysicist must be imaginative and thorough in their analysis and be flexible in their attitude to an interpretation that will change over time through either additional data or greater insight.

Beyond volumetric estimation, petrophysics is at the core of many other subsurface disciplines: the geophysicist relies on correctly edited and calibrated logs for depth conversion and rock property analysis, likewise the geologist for well correlation, reservoir modelling and fluid contact estimation, and the engineers for well completions and pressure prediction and as input for dynamic simulation. How you approach a petrophysical data set will often depend on the objective of the study: a single-well log analysis without core data requires a very different workflow to that adopted for a full-field petrophysical review.

Petrophysics is not just log analysis – it is log analysis within a geological context or framework, supported by adequate calibration data, including sedimentology, core analysis and dynamic data from pressure measurements and well tests (Figure 1.1). Logs do not measure porosity, permeability or water saturation; they make measurements of acoustic velocity, electrical conductivity and various nuclear relationships between the rock and the fluids to allow computer programs to process and interpret the results. The petrophysicist role is to validate and organize the input data and to understand and calibrate the results. A little harsh, you may say, but how many petrophysicists do the job without using log analysis software and how many integrate the analysis with the geological interpretation?

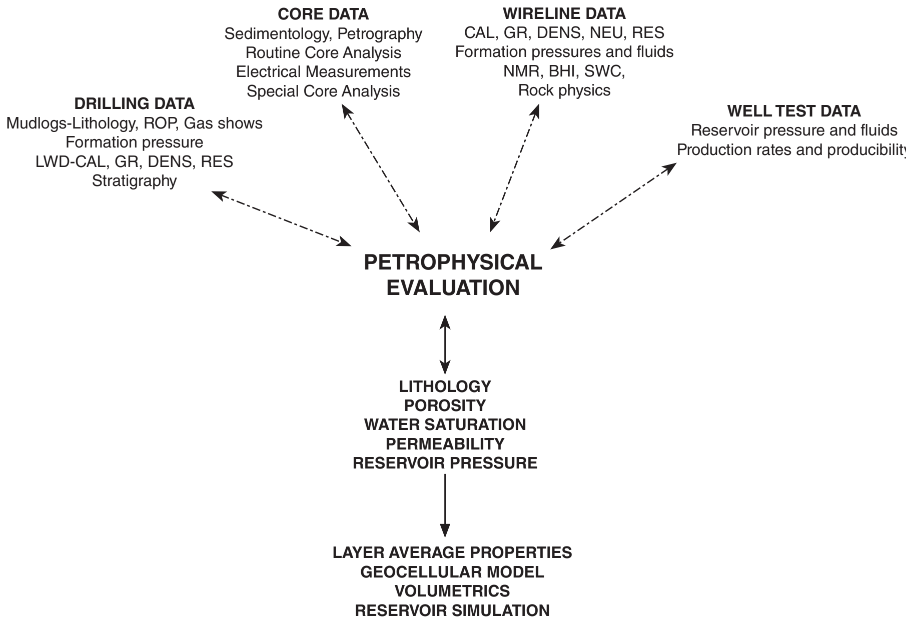

Figure 1.1 Petrophysical evaluation: schematic showing the primary data sources, products and deliverables of an integrated petrophysical evaluation.

1.1 The basics

It is worthwhile looking at the context in which the rest of the book lies before diving into the detail. Although not attempting to be a primer in geology, physics or chemistry, we will touch on these disciplines as we progress, so I will try to set the scene and leave the reader to dig deeper into interesting subject matter from the references. However, it is worth considering that both of our primary sources of data, wireline/LWD (logging while drilling) and core data, present challenges in terms of sampling, data quality and integration. Log measurements, although made *in situ*, are invariably indirect; we seldom measure an actual property of the rock, only one inferred from its response to physical input: core measurements are broadly speaking direct but they are *ex situ*. It is not my intention to describe in any detail the tool physics behind logging measurements, as there are many other books that cover this vital part of the technology; rather, this handbook is designed for the user of these data to evaluate the potential commercial value of a hydrocarbon reservoir.

All the log measurements that are made come from one or more penetrations of a reservoir made by a drill bit usually between 6 and 12½ inches in diameter, attached to a drill-string often several thousands of feet or metres long; we use this penetration to infer reservoir properties tens to thousands of metres away from the borehole (Figure 1.2). The borehole environment at depth is hostile;

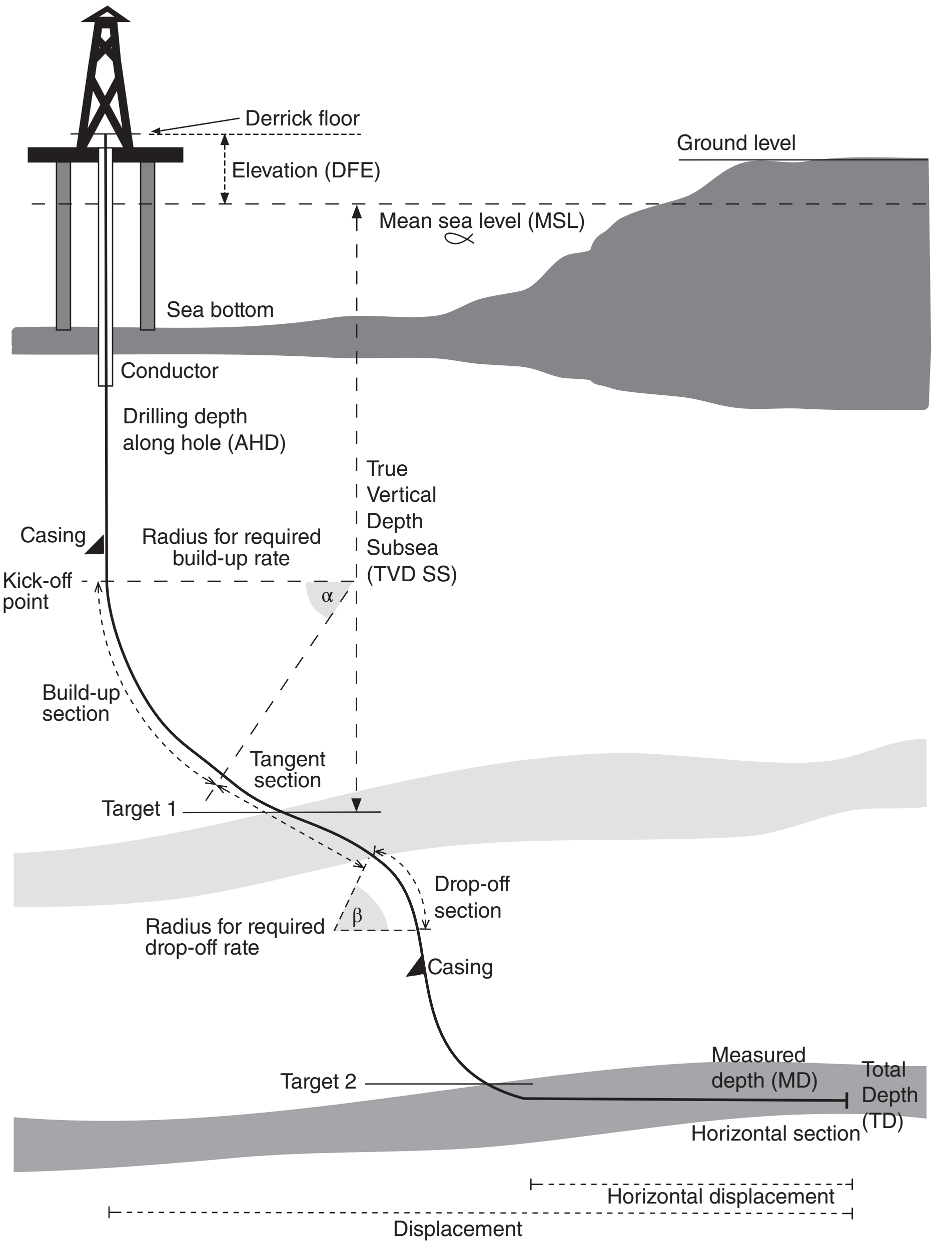

Figure 1.2 Depth measurement: terminology used to describe the stages and geometry of a well path designed to achieve a number of geological objectives.

Table 1.1 Comparison of different unit systems of measurement.

Measurement	SI units	Metric/imperial units	Field units	Abbreviation
Length/distance	Metre (m)	Metre/foot	Metre/foot	m/ft
Mass	Kilogram (kg)	Kilogram/pound	Pound	kg/lb
Time	Second (s)	Second	Second	s
Temperature	Kelvin (K)	Centigrade	Fahrenheit	°C/°F
Amount of substance	Mole (mol)	Mole	Parts per million	mol/ppm
Pressure	–	Pascal/bar	Pounds per square inch	Pa/bar
Volume	–	Cubic metre/barrel	Barrel	m^3/bbl
Area	–	Hectare/acre	Acre	ha/ac

it can be hot enough to bake the sensitive electronics in the tools or be at pressures that result in the drilling mud being forced into the borehole wall (invasion) such that all the tool measures is a man-made fluid consisting of minerals and chemicals, which renders the results invalid or at best questionable. Even core measurements are made on material that has undergone physical change since it was cut; without careful handling, the change in confining pressure from reservoir to laboratory conditions will affect the pore volume and in-place fluids and even then measurement corrections are normally required to calibrate the results. Drillers, who generally do not like coring because of slow progress, have been heard to say that the only thing you know about a core once it has been cut is 'where it has come from, possibly'!

1.1.1 Units and abbreviations

The oil and gas industry can seem very confusing to the modern scientist brought up in the world of Système International (SI) units, because in general the industry uses either a mixed metric and 'imperial' unit system or 'field units' as the norm (Table 1.1).

The industry is also the home of more abbreviations and TLAs (three-letter acronyms) than probably any other, apart from the medical professions. There is a 'complete' glossary as an appendix; however, those given in Table 1.2 are some of the more pertinent for use in petrophysics.

1.1.2 Cores and logs

The two primary sources of reservoir information acquired during drilling of a well are cores and logs. Coring can be an expensive and time-consuming process that is usually reserved for potential reservoir sections. When the top reservoir is reached, signalled by a rapid increase in drilling rate and the presence of hydrocarbon shows, drilling is halted and the drill string recovered and the bit replaced

Table 1.2 Common abbreviations and three-letter acronyms.

Abbreviation	Meaning	Application
API	American Institute of Petroleum	Measure of gamma-ray activity; oil density
a	Archie exponent of tortuosity	Used in calculation of FRF and S_w
BHA	Bottom hole assembly	Drill-string from bit to top of drill collars
CAL	Calliper	Measures borehole diameter and rugosity
CPOR/CPERM	Core porosity/permeability	Core-derived porosity and permeability
DENS	Density log	Bulk density of formation from induced gamma activity
FRF	Formation resistivity factor	Core-derived resistivity of fully saturated sample
FVF	Formation volume factor	Ratio of oil volume at reservoir and surface conditions
GR/NGS	Gamma-ray log/spectral gamma log	Natural gamma radioactivity of formation
GDEN	Core grain density	Core-derived grain density of unsaturated sample
GRV	Gross rock volume	Volume of rock above a fixed datum
GIIP/STOIIP	Gas/stock tank oil initially in place	Hydrocarbons in place at time of discovery
LWD/MWD	Logging/measurement while drilling	Real-time telemetry and sensor measurements
m	Archie cementation exponent	Used in calculation of FRF and S_w
MW	Mud weight	Density of drilling fluid, usually in pounds per gallon, or specific gravity
NMR	Nuclear magnetic resonance	Uses the magnetic moment of hydrogen atoms to determine porosity and pore size distribution
n	Archie saturation exponent	Used in calculation of S_w from FRF
NTG	Net-to-gross ratio	Ratio of reservoir/pay to non-reservoir
NEUT	Neutron log	Measure of total hydrogen in a formation from water- and hydrocarbon-bearing pores
P_c	Capillary pressure	Fluid pressure/buoyancy of hydrocarbon–water systems
POR/PERM	Absolute porosity/permeability	Measure of connected pores
PhiT/PhiE	Porosity total/porosity effective	Porosity of isolated and connected pores
ROP	Rate of penetration	Drilling rate in feet or metres per hour
R_w	Resistivity of formation water	Function of water salinity
R_t	Formation resistivity	True resistivity of rock plus fluids
SONIC	Sonic log	Acoustic velocity of formation
S_w	Water saturation	Volume of water in pores
S_{wirr}	Irreducible water saturation	Volume of capillary-bound water/immoveable
S_{wc}	Connate water	Water trapped during deposition of sediments
Vugs/vuggy	Pore type in carbonates	Usually isolated or poorly connected pores

with a core barrel. Core barrels are usually made up of 30 ft lengths of pipe with a special coring head and retrieval mechanism, the catcher. There are in fact an inner and an outer barrel that can rotate independently; the inner barrel is the repository for the core as it is being cut. Upon retrieval at the surface, the core is stabilized and sent to shore for analysis; on occasion, some samples are evaluated at the well site, but this is becoming less and less common.

Logs are acquired while drilling (LWD) and also at the end of a hole-section on wireline. LWD and wireline logs represent among the most important data types available to a reservoir geoscientist or petrophysicist because they provide a continuous record of borehole measurements that can be used to interpret the environment of deposition of a sequence, the petrophysical properties and also the fluid distribution in the reservoir; in other words, to answer the questions do these rocks contain oil and gas and will it flow? However, the log measurements are greatly influenced by a number of variables, including the borehole environment, the rocks themselves and the type of fluid used to drill the well.

1.1.3 Lithology identification

Most hydrocarbons are found in either clastic or carbonate reservoirs; clastic rocks such as sandstones comprise grains of quartz, feldspar, mica, lithic fragments, clays and exotic minerals. Depending on the sediment source, these grains will be deposited in different proportions and represent different depositional processes, and these distinctive characteristics should be discernible to some extent in the petrophysical data collected. To a petrophysicist, clastics are either sand or shale or maybe siltstone; sometimes a grain size distinction such as coarse or fine may be added, or whether shale has a high organic content. For a geologist, a much greater variation in sandstone classification is required based on a simple ternary diagram with quartz, feldspar and lithic (QFL) fragments at the apices (Figure 1.3). By strict definition, shale is a fine-grained clastic rock composed of mud comprising clay minerals and silt grains or other minerals, mainly quartz, feldspar and carbonate, that exhibits a fissile nature; it splits along lamina. A mudstone does not show this fissility, but in composition may be exactly the same as the equivalent shale. For a complete review of sandstone petrology, see Folk (1980).

Carbonate rocks generally fall into three types for the petrophysicist: limestone, dolomite and anhydrite or evaporites, if a mixture of different salt deposits is recognized. The range of carbonate rocks to the geologist is even more extensive than the clastics; fortunately, many carbonate classification systems have some basis in pore types, giving a direct link to the petrophysical world (Figure 1.4). The petrophysics of carbonate reservoirs is a specialist role – highly challenging but ultimately very rewarding, especially when one considers the proportion of the world's oil to be found in these reservoirs. For an extensive study of carbonate reservoir characterization, see Lucia (1999).

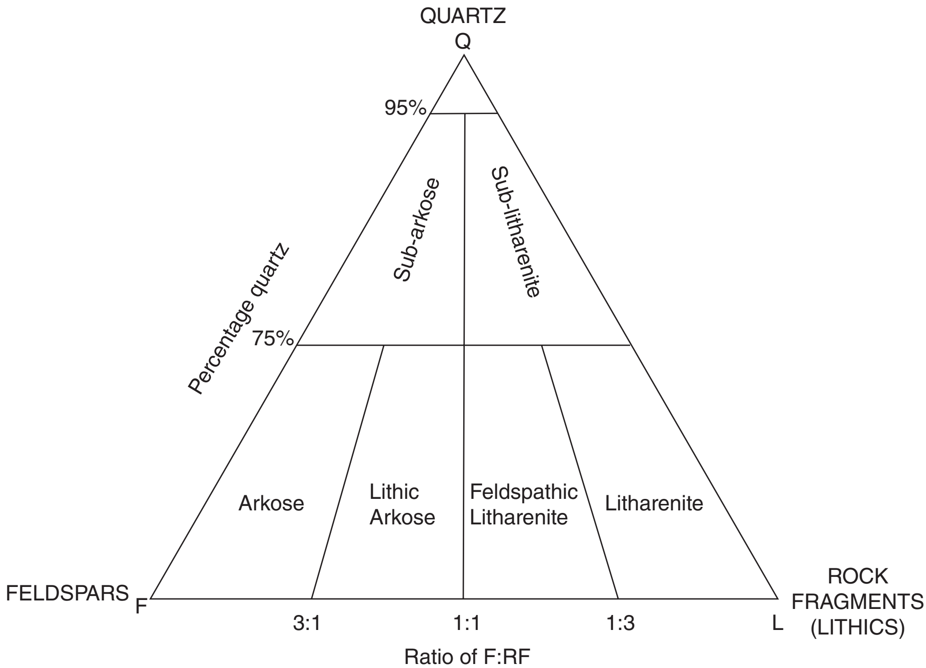

Figure 1.3 QFL plot: a standard lithology ternary plot based on the proportions of quartz, feldspar and rock fragments in sandstone. Source: after Folk (1980).

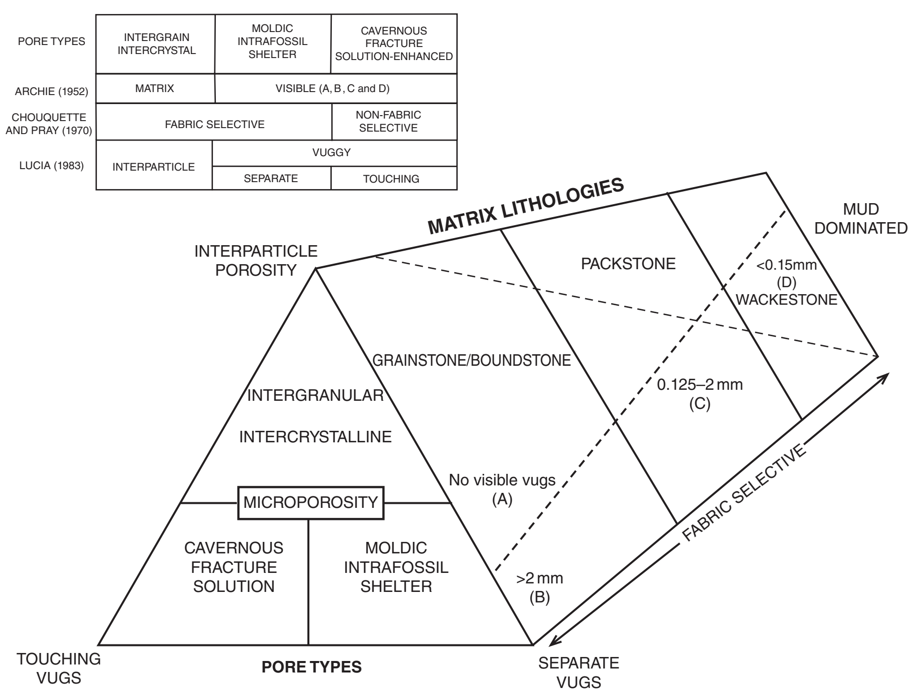

Figure 1.4 Carbonate pore types: classification of carbonate rock into intergranular and vuggy pore types; comparison of alternative classification schemes. Source: after Lucia (1999).

With the rapid increase in development of unconventional reservoirs in recent years, especially in North America, has come a series of new challenges for the petrophysicist: to evaluate their potential as both source rock and reservoir. Most of this book will consider conventional reservoirs; however, there will be some discussion of 'unconventionals' as appropriate. It is worth pointing out that the terms clay and shale are often used as though they mean the same thing: this is not the case and the differences will be discussed later.

1.1.4 Rock properties

The presence of an effective pore network and the capacity of it to allow fluids to flow through it are a function of a rock's primary depositional process, the resulting grain size distribution and the effect of post-depositional processes, principally compaction, chemical diagenesis and fracturing. This statement applies equally to clastic or carbonate reservoirs; however, the effects of post-depositional processes are generally more significant in carbonates. Clastic reservoirs can be unconsolidated or consolidated or lithified to varying extents depending on the post-depositional history of the sediments, the process of compaction and cementation. The degree of lithification can be obvious in some logs, such as an acoustic log, where the transit time of the sound waves will vary from slow to fast depending on the consolidation of the rock. This in turn may have an effect on the porosity of the rock; softer rocks generally have higher porosity.

1.1.5 Physics of a reservoir

The pore spaces of a hydrocarbon reservoir begin life filled with water that is either mobile or bound by capillary pressure. The water becomes displaced by hydrocarbons during migration because of the contrast in fluid density: water is more dense than either gas or oil; this is known as the drainage cycle. Under the correct structural or stratigraphic conditions, the hydrocarbons become trapped and continue to displace the water, until only the smallest pores remain water filled; this is connate water. Where water saturation is 100% and capillary pressure is zero is called the free water level (FWL), a datum that is defined by the physics of the reservoir (Figure 1.5). Where the reservoir is homogeneous and has large pore throats, the hydrocarbon water contact and FWL will be contiguous, but if the reservoir quality is poor at the base of the hydrocarbon column, the two levels will be separated by a transition zone.

1.1.6 Porosity

Porosity is defined as the capacity of a rock to store fluids and estimated as the ratio of the pore volume to the bulk volume. Porosity is a non-dimensional parameter expressed as a fraction or percentage. The porosity of a rock comprises

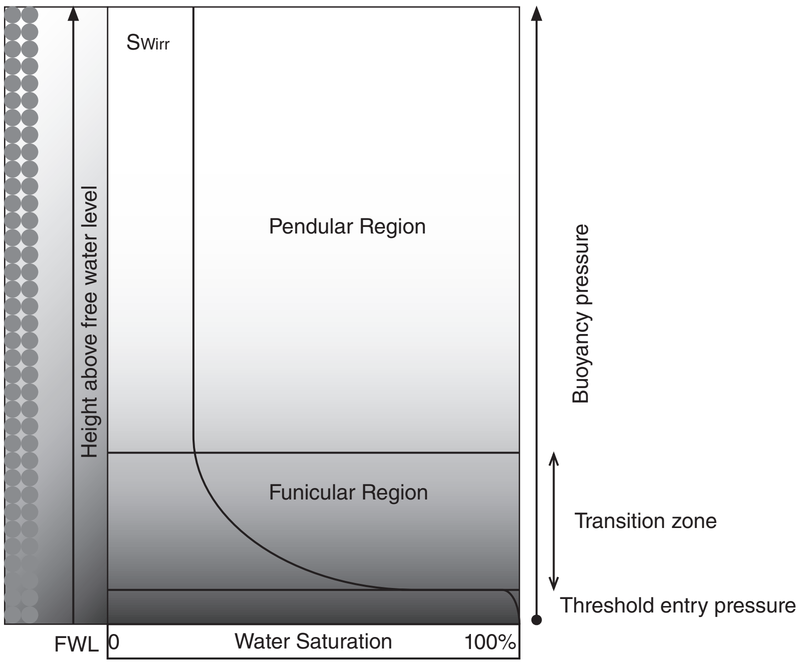

Figure 1.5 Physics of the reservoir: representation of fluid distribution within an oil reservoir based on the relationship between water saturation, capillary pressure and the free water level datum.

two main elements, primary depositional or intergranular porosity and secondary porosity, which may be the result of grain or particle dissolution or present as microporosity in authigenic clays (Figure 1.6a). Porosity may be defined as *effective* or *total* depending on whether it includes porosity associated with clays; some tools measure total porosity and must be corrected for the clay content. This is a simple classification that does not include all carbonate rocks or certain clay-rich shale reservoirs. Fractured reservoirs need also to be treated separately, being defined as having a dual porosity system, matrix and fracture.

1.1.7 Water saturation

Water saturation (S_w) is the proportion of total pore volume occupied by formation water; hydrocarbon saturation is derived from the relationship $S_h = 1 - S_w$. It may be expressed as a fraction or a percentage depending on how porosity is defined (Figure 1.6b). Another direct link to porosity terminology exists, as water saturation can be either a total or an effective value. Logs measure both the mobile water and the clay-bound water in the pore space. The terms irreducible, residual, connate and initial water saturation are also commonly used, sometimes without due regard to the meaning.

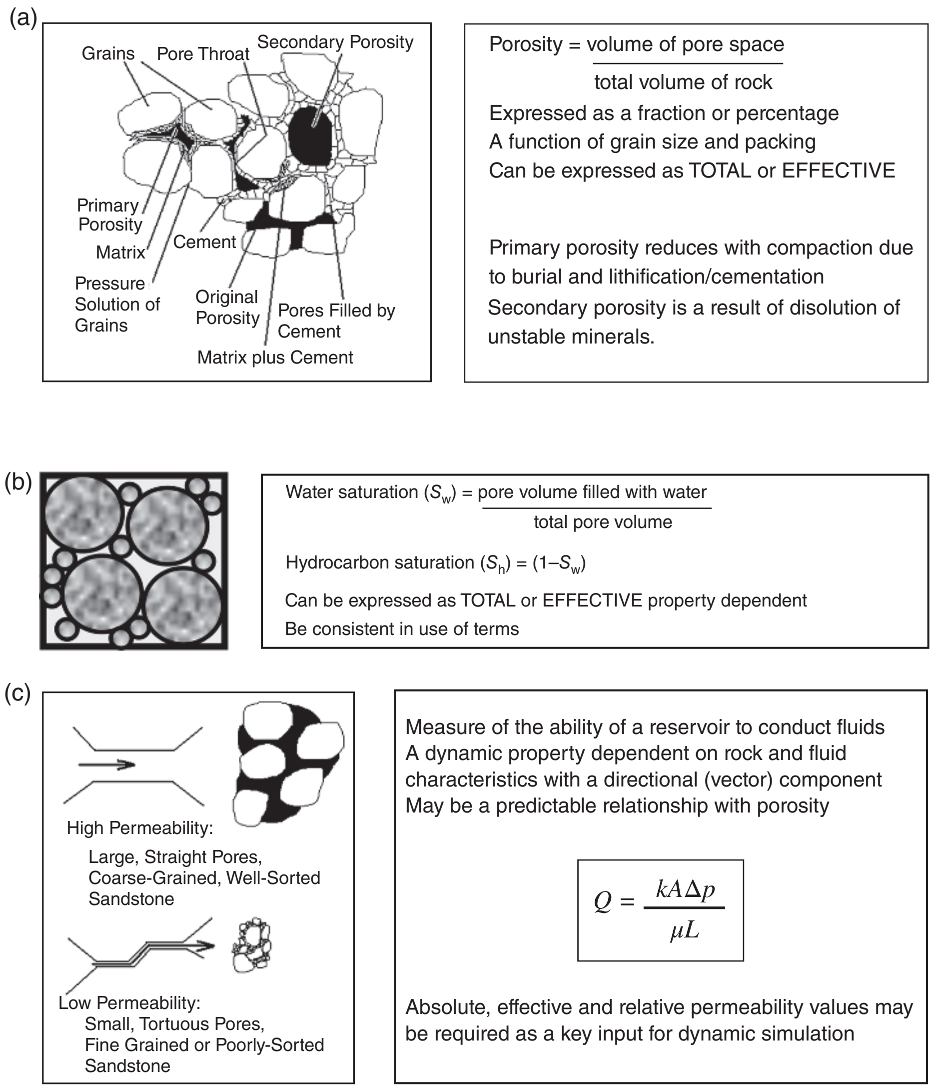

Figure 1.6 (a) Porosity: the relationship between volume of pore space and total volume of rock is a function of grain size, sorting and packing at time of deposition. Post-depositional processes such as compaction and diagenesis can alter the original relationship. (b) Water saturation: the proportion of the total reservoir pore volume filled with water: the remaining pore volume is filled with oil or gas, not necessarily hydrocarbon gas. (c) Permeability: the ability of a reservoir to conduct fluids through an interconnected pore network.

Irreducible water saturation (S_{wirr}) is defined as the minimum S_w at high capillary pressure and saturation, as the effective permeability to water approaches zero. The initial water saturation (S_{wi}) is the proportion of water in the reservoir at the time of discovery and may be synonymous with connate water, the water saturation at time of deposition, if no hydrocarbons are present. In a hydrocarbon-bearing reservoir, S_{wirr} is always less than S_{wi}. The term 'transition zone' also has more than one meaning depending on who is using it: to a geologist or petrophysicist it is the zone between the lowest level of irreducible water and the free water level – this is a static definition; to a reservoir engineer it is an interval in a well that flows both oil or gas and water at the same time – the two 'zones' may be contiguous.

1.1.8 Permeability

Permeability (K or k) is the measure of the capacity of a reservoir to conduct fluids or for flow to take place between the reservoir and a wellbore. A dynamic property, permeability is dependent on the associated rock and fluid properties (Figure 1.6c); it is also one of the most difficult to measure and evaluate without data at all relevant scales – core, log and production test. At the microscopic or plug scale, permeability is a function of pore network and whether there are large or small pore throats and whether the connecting pathways are straight or tortuous; a function of grain size and sorting. Permeability is also a vector property as it may have a directional component, resulting in anisotropy. Permeability may vary greatly between the horizontal and vertical directions, impacting on the directional flow capacity of a reservoir. Given the difficulties in reliably measuring permeability, a qualitative assessment is often made depending on the hydrocarbon in place (Table 1.3).

Permeability is measured in darcies (D) but usually reported as millidarcies (mD), named after the French water engineer Henry Darcy, who first attempted to measure the flow of water through a vertical pipe packed with sand. The rate of flow (Q) is a function of the area (A) and length (L) of the pipe, the viscosity of the fluid (μ) and the pressure differential (Δp) between the ends of the pipe (Figure 1.6c). This law only applies to a single fluid phase and may be termed absolute or intrinsic permeability. Effective permeability (K_{eff}) is the permeability of one liquid phase to flow in the presence of another; relative permeability (K_r) is the ratio of effective to absolute permeability for a given saturation of the flowing liquid, i.e. permeability of oil in the presence of water (K_{ro}). Permeability is a key input for numerical reservoir simulation.

Relative permeability is the normalized value of effective permeability for a fluid to the absolute permeability of the rock. Relative permeability

Table 1.3 Permeability ranges for different qualitative descriptions of permeability.

Poor	<1 mD	'Tight' for gas
Fair	1–10 mD	'Tight' for oil
Moderate	10–50 mD	
Good	50–250 mD	
Excellent	>250 mD	

expresses the relative contribution of each liquid phase to the total flow capacity of the rock.

1.1.9 Capillary pressure

Capillary pressure acts at a microscopic scale in the reservoir, which in conjunction with viscous and gravitational forces define how a reservoir performs dynamically. Capillary pressure occurs whenever two immiscible fluids occur in the pore space of a rock and is defined as the pressure difference measurable in the two phases (Figure 1.7a). There is an inherent relationship between capillary pressure and water saturation because water is retained in the pore space by capillary forces. Capillary pressure also determines the fluid distribution and saturation in a reservoir, hence the link to wettability.

1.1.10 Wettability

Wettability is a measure of a rock's propensity to adsorb water or oil molecules on to its surface in the presence of the other immiscible fluid. At deposition, a thin film of water is usually formed around the grains, leaving the rock water

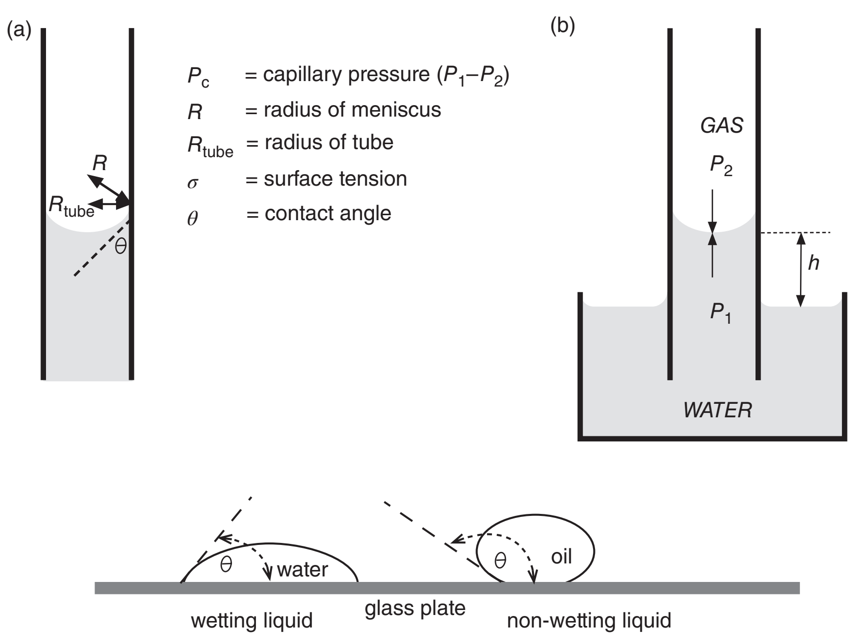

Figure 1.7 Capillary pressure (P_c) and wettability: (a) representation of a liquid-filled capillary tube and the relationship between the buoyancy pressure generated between two immiscible fluids; (b) the difference between wetting and non-wetting liquids as a function of the surface tension and contact angle.

wet – the normal situation; however, carbonate rocks are commonly oil wet or have intermediate wettability. Wettability is a function of the surface tension between the solid grain and the fluid in the pores (Figure 1.7b).

It is important to understand the impact of wettability on the other dynamic properties of a rock as it controls the fluid saturation and distribution in a reservoir. Although most (clastic) reservoirs would be considered to be water wet, under certain conditions all reservoirs can become oil wet, at least in part. Carbonate reservoirs have a greater tendency for the oil wet state because of the greater adsorption capacity of calcium/magnesium carbonate. Many reservoirs are of mixed wettability – oil wet in the large open pores and water wet in the smaller isolated pores often filled with microporous clays.

1.2 The results

When the petrophysical analysis of a single well or group of wells has been completed, the results will be used in a number of ways: as the estimate of hydrocarbon pay in a well; in making the decision to production test an exploration well; as input for a simple volumetric calculation; to build a 3D property model of a field; or as a key element in a major investment or divestment decision.

1.2.1 Hydrocarbon pay

The *gross reservoir thickness* is described as the total reservoir thickness in a well; layers of non-reservoir (shale) are discounted from the total, leaving a *net reservoir thickness*. The ratio is thus the *net-to-gross* (NTG). Hydrocarbon-bearing levels, *net pay*, in a well are normally defined in terms of minimum porosity and saturation values calculated from the log analysis; sometimes a permeability limit is also applied (Figure 1.8) This approach can be too harsh if the wrong cut-off parameters are applied. If sufficient net pay is recognized in a well, then the decision to test the interval or intervals is made; the results should be integrated into the rest of the reservoir evaluation.

1.2.2 Simple volumetrics

Map-based volumetrics require a *gross rock volume* (GRV), usually a top reservoir surface and hydrocarbon–water contact; an alternative is to use a simple slab model (Figure 1.9). Apart from a value for the formation volume factor (FVF), all the terms can be derived from log analysis.

$$\mathrm{HIIP} = \mathrm{GRV} \times \mathrm{NTG} \times \Phi \times (1 - S_w) \times \mathrm{FVF}$$

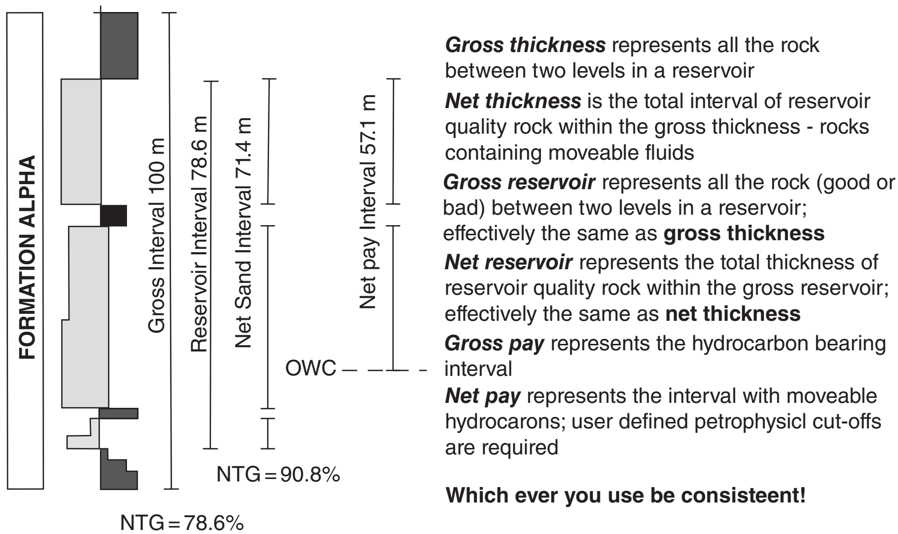

Figure 1.8 Net to gross: terminology used to describe the proportions of an oil or gas reservoir in terms the different interval thicknesses.

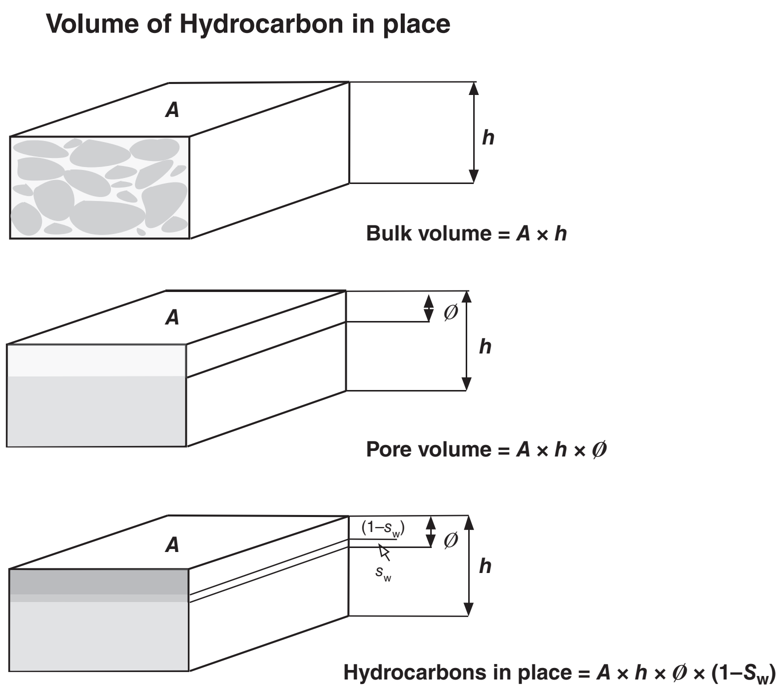

Figure 1.9 Volume of HIIP: schematic to show the calculation of the volume of hydrocarbons in place in an oil or gas reservoir; to estimate potential resources it is necessary to apply the appropriate conversion factor from reservoir volume to surface volume, the formation volume factor.

Often these same data are run through a Monte Carlo analysis to give a range of results; specific cases can then be selected from a representative distribution.

1.2.3 3D static models

The most accurate volumetrics can be calculated in a 3D static or geocellular model; this is because it will be geometrically more correct, especially where the field is faulted. The inputs remain the same, although now the petrophysical properties are distributed throughout the model randomly or following some established trend, and uncertainties can be modelled to establish volumetric ranges for the field. These should always be compared with the simple Monte-Carlo results above to provide a sense check. As a rule of thumb, variations in *hydrocarbon initially in place* (HIIP) greater than ~25% are a function of the GRV; petrophysical properties properly constrained and distributed seldom impact the result by more than a few per cent.

1.2.4 Value of information

Acquiring petrophysical data, be they logs or core, is expensive; the formation evaluation programme for a well can be several hundred thousand dollars or can run into millions. The value of the information must always be seen in terms of where you are in the project cycle and also the use to which the data will be put. Sometimes too much data can result in indecision just as much as an incomplete dataset, and when dealing with brownfield developments where only an older log set is available, it may be more important to calibrate the basic data than to run the most sophisticated tools.

The key decision making data sets are as follows:

- Logs to establish lithology, porosity and fluids.
- Cores to confirm lithology and calibrate the log-derived properties and to establish a depositional environment; in an exploration well, cores may be replaced by image and scanner tools, but cores should be acquired in subsequent appraisal wells.
- Pressure measurements and fluid samples.
- Production data to establish that the reservoir will flow, recover fluids and test the limits of the hydrocarbons connected to the well.

With a good, well-distributed, basic data set, a robust reservoir description will be possible even if some of the 'bells and whistles' beloved of specialist disciplines are not available; any additional information should not be ignored but recognized as single points in the overall population and should not bias the interpretation.

1.3 Summary

In this chapter, we have looked at the basics of petrophysics; the types of data required for a petrophysical interpretation and some of the fundamental results of the analysis. It should be apparent that for an accurate calculation of porosity and water saturation, the petrophysicist is dependent on many input properties over which he or she has little control. Most of the measurements are either indirect or *ex situ* and are subject to sample bias, acquisition issues and experimental (human) error. The uncertainties are compounded when the results are used inappropriately or without sufficient caveats regarding how the data were collected, edited, manipulated or applied. In the simplest form, the results of a petrophysical study can be managed by applying cut-offs or error bounds, but when incorporated in some geostatistical model or multi-scale dynamic model, their application may be incorrect or inappropriate.