

1. INTRODUCTION TO PETROPHYSICS AND FORMATION EVALUATION

1.1 Introduction

The search for economic accumulations of oil and gas starts with the recognition of likely geological provinces, progresses to seismic surveying, and the drilling of one or more wild-cat wells. If one is lucky, these wells may encounter oil, and if that is the case, measurements made down the hole with wireline tools are used to assess whether sufficient oil is present, and whether it can be produced. Clearly, the evaluation of sub-surface formations requires the combined efforts of geologists, petrophysicists, drilling engineers and even geophysicists. However, it is the geologist and petrophysicist that has the most influence.

The geologist is interested in the lithology, stratigraphy and depositional environment of the sub-surface strata penetrated by the drilling bit. The *exploration geologist* uses wireline tool responses in a number of wells to create a large scale image of the sub-surface geology by correlating wireline responses that are characteristic of a given formation or horizon between formations. This picture is very useful when carrying out initial reservoir modelling and in the decision where to drill new wells. Later the *production geologist* carries out much the same process with much more well information, and adds any extra information that has been gathered to produce a detailed geological model of the reservoir and related sub-surface formations. This model will be the basis of reservoir modelling, and all major reservoir management decisions from primary drainage through to enhanced oil recovery and shut-down.

The *petrophysicist's* job is to use all available information to analyze the physical and chemical properties of the rocks in the sub-surface, and their component minerals, with particular emphasis given to the amount and distribution of those fluid minerals that we know of as water, oil, and gas. The petrophysicist will use extensively wireline log data and data from experiments done on cores extracted from the well, and will occasionally use other sources of information such as engineering and production logs, as well as mud logging data. Initially, it is the aim of the petrophysicist to differentiate between oil, gas and water bearing formations, estimate the porosity of the formations and the approximate amount of hydrocarbons present in each formation. Ultimately, the petrophysicist also uses laboratory data to estimate how easy it will be to extract the hydrocarbons in place, and to design reservoir management strategies to optimize long term oil recovery.

There is a large database of information available to both the geologist and the petrophysicist, and as time passes the amount and variety of information increases. Table 1.1 summarizes a few of the main measurements that a geologist or petrophysicist will have access to, arranged in approximate chronological order. It is the responsibility of the wellsite geologist or engineer to ensure that all this data is properly collected and recorded.

This course is designed to introduce you to wireline logs and the simple analysis of the data that they provide. The following sections cover the theory behind the operation of each tool, how each tool operates, its advantages and limitations, and its main applications. There is a huge number of tools available in the industry, many too many to be covered individually. However, all are variations on a small number of generic tool types, which will be described.

Table 1.1 Main sources of data concerning sub-surface rocks.

Source	Data Type
Drilling (Mud logging)	Rate of penetration of drill bit (ROP) Analysis of drill cuttings Analysis of drilling mud Shows of gas, oil or water Gains or losses of drilling mud
Wireline Logs	Mechanical logs (e.g., calipers) Electrical logs (e.g., laterologs, induction logs, SP logs) Natural radiation logs (e.g., simple and spectral gamma ray logs) Acoustic logs (e.g., sonic logs) Pressure and temperature logs Artificial radiation logs (e.g., density and neutron logs) Imaging logs (e.g., dipmeter and various other types) Special logs (e.g., NMR logs)
Cores	Lithology Hydrocarbon shows Heterogeneity and fracturing Porosity Permeability (Klinkenberg, liquid and relative permeability) Wettability and capillary pressure Grain and pore size distributions
Production Logs	Formation testing (e.g., RFT –Repeat Formation Tester) Drill stem tests Production tests Pressure build-up and spinner tests

It should be remembered at all times that the main job of the petrophysicist is to evaluate the amount of hydrocarbons in place in the reservoir. Hence, the evaluation sequence for a straightforward reservoir will be as follows:

For any given well interval:

1. **Distinguish between reservoir and non-reservoir rock**
(Reservoir rock contains a reasonably high connected porosity.)
2. **For the reservoir intervals only, distinguish between hydrocarbons and water filling the pores, hence calculate water saturation in reservoir rocks**
(Hydrocarbons are electrical insulators, while water conducts.)
3. **For the hydrocarbon fraction, distinguish between oil and gas, hence calculate gas and oil saturations in reservoir rocks**
(Gas has a much lower density than oil.)

1.2 Conditions Allowing the Accumulation of Hydrocarbons in a Reservoir

Oil and gas reservoirs have come into being over large periods of time as the result of geological processes. The gasses and oils have been formed from organic remains, have migrated into the reservoir rock, and then have been trapped there by overlying rock formations with very low permeability. Hence, for a hydrocarbon reservoir to exist we need the following to be available at the same location:

1. A *source rock* containing the original organic remains.
2. Pressure and temperature conditions suitable to convert the organic remains into oil and gas.
3. A *porous, permeable reservoir rock* where the hydrocarbon can accumulate.
4. A migration pathway from the source rock to the reservoir rock for the hydrocarbons.
5. A suitable *trap* to keep the hydrocarbons in the reservoir rock until we wish to exploit it.

These processes can take extremely long periods of time. Most formations that contain reservoirs are sedimentary rocks, where the deposition of organically rich material has been followed by clean sandstones that form high porosity well connected pore systems, and are subsequently capped by shales with very low permeabilities. Here the burial of the initial deposition provides the pressures and temperatures to produce hydrocarbons. The hydrocarbons are less dense than water, so migrate upwards into the sandstones, replacing the water that originally occupied the reservoir sandstone, where the hydrocarbons are constrained from rising further by the shale cap. The hydrocarbon then waits until we decide to produce it.

The depositional and post-depositional history of the reservoir rock, and particularly its diagenetic history (compaction, cementation and dissolution), all contribute to the mineralogical composition of the rock, and hence its grain size distribution, porosity, pore size distribution and the connectivity of its pores. Note that in the process of migration the hydrocarbon replaces water in the reservoir rock because it is less dense than water. In practice, the replacement is almost never complete, with some water associated with even the best oil accumulations. The reason for the remaining water is that the grains comprising the reservoir rock are usually *water-wet*, i.e., having a chemical preference to be covered in water rather than hydrocarbon, hence they retain a thin film of water when the hydrocarbon replaces most of the water in the pores. *Oil-wet* rocks do exist, and the ability to distinguish between oil and water wet rocks is extremely important in reservoir management, especially in the final stages of reservoir production. In general, any given reservoir rock the pore space will be occupied by a *water saturation* S_w , a *gas saturation* S_g , and an *oil saturation* S_o .

Since gas is less dense than oil, which is less dense than water, the fluids separate in hydrocarbon reservoirs with the gas occurring just below the trapping lithology, oil a little deeper, and water at the bottom. The fluids are commonly immiscible and so we can define a *gas-oil contact* (GOC) and an *oil-water contact* (OWC). Since, gravity is the force that separates the fluids into these layers, the GOC and OWC are horizontal providing that horizontal and vertical permeability is good in the reservoir and there are no complicating structures or fractures. Note that it is not compulsory to have all three fluids occurring together. Hence in gas reservoirs the oil is missing and there is a *gas-water contact* (GWC). Similarly, oil reservoirs can exist without a *gas cap*.

1.3 Calculating Hydrocarbon Volumes in a Reservoir

We can define a *reservoir rock* as one that has a porosity and permeability that allows it to contain a significant amount of extractable hydrocarbon, AND contains hydrocarbons. A non-reservoir rock may have a porosity that is too low, a permeability that is too low, or a low or zero hydrocarbon saturation. The major control is often the basic lithology. For example, shales often contain hydrocarbon with high saturations, but have porosities and permeabilities that are much too low for the hydrocarbon to be extractable. Shales are considered to be non-reservoir rock. In contrast a high porosity, high permeability sandstone could be a reservoir rock providing that the hydrocarbon saturations are sufficiently high, i.e., above the oil water contact.

The calculation of hydrocarbon volume requires us to know the volume of the formations containing the hydrocarbons, the porosity of each formation, and the hydrocarbon saturation in each formation. In practice each reservoir will be made up of a number of *zones* each with its own thickness, areal extent, porosity and hydrocarbon saturation. For example, reservoir sandstones may alternate with non-reservoir shales, such that each zone is partitioned. Such zonation is mainly controlled by lithology. Hence, it is an early requirement to identify the lithologies in a particular well, identify which formations have the required porosity to enable it to be a reservoir rock, and determine whether the formation contains hydrocarbons. Reservoir rocks containing hydrocarbons are allocated a zone code.

The volume of reservoir rock in a single zone depends upon the area of the zone A , and the thickness of reservoir rock in the zone h . The area is obtained usually from seismic data (from the reservoir geologist), and is the only data used in the calculation of hydrocarbon volumes in place that is not derived from petrophysical techniques. The thickness of reservoir rock is derived from the zonation of the reservoir based upon an initial lithological interpretation and zonation of the reservoir from the wireline logs. The bulk volume of the reservoir $V_{bulk} = A \times h$.

The majority of this volume is occupied by the solid rock matrix, and the remainder is made up of the pore space between the minerals. The relative amount of pore space to the bulk volume is denoted by the porosity f , where the *porosity* is the fraction of the bulk volume occupied by pore volume, and is expressed as a fraction or as a percentage; $f = V_{pore} / V_{bulk}$. However, note that the fractional form is used in ALL calculations. The pore volume in any given zone is therefore $V_{pore} = f \times A \times h$.

In general the porosity is completely occupied by either water and hydrocarbon, where the saturation of the water is S_w , and that of the hydrocarbon is S_h , and $S_w + S_h = 1$. In most reservoirs the hydrocarbon has replaced all the water that it is possible to replace, and under these conditions the water saturation is termed the irreducible water saturation S_{wi} . Now we can write the hydrocarbon saturation as $S_h = (1 - S_w)$. Hence the volume of hydrocarbons in place can be written as

$$V_h = A h f (1 - S_w) \quad (1.1)$$

The determination of this value is the **primary** job of the petrophysicist, and requires a lithological assessment and zonation of the reservoir. At a later stage the petrophysicist may also be called upon to assess the permeability of the reservoir under various conditions. However, the primary function of the petrophysicist is to assess the amount of hydrocarbons initially in place.

All the parameters in Eq. (1.1) except the area are derived from measurements made in the borehole using wireline tools or increasingly using data obtained from tools that measure the rock formations during drilling (measurement/logging while drilling: MWD/LWD).

Figure 1.1 illustrates the derivation of Eq. (1.1) diagrammatically.

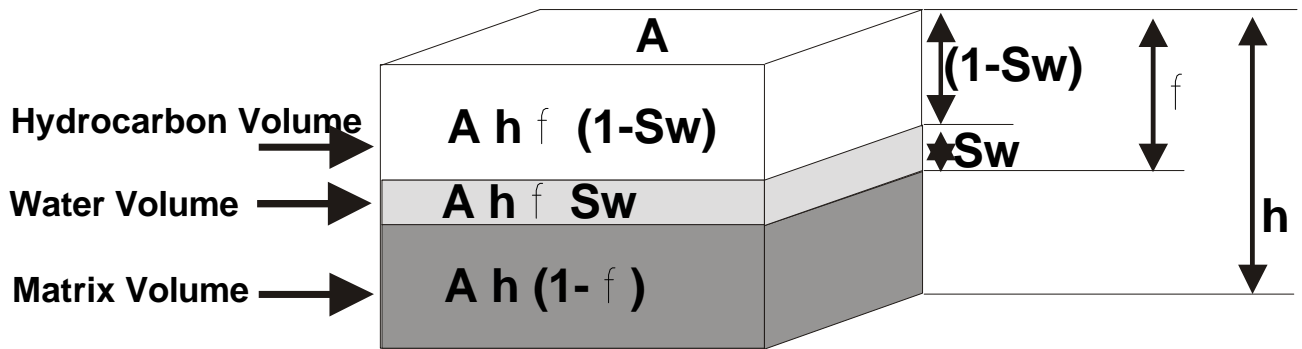


Figure 1. Volume of hydrocarbons in place

Equation (1.1) gives the volume of hydrocarbons in m^3 , and the calculated values are often unwieldy. The oil industry uses a range of industry standard units, in which all calculations should be carried out. The volume of oil is measured in barrels, the amount of gas in cubic feet, thickness in feet, and area in acres. Conversions for these are given in Table 1.2 below.

Table 1.2 Common oil-field units.

Unit	Equivalent in foot-units	SI Equivalent
1 acre	43560 sq.ft	4047 m^2
1 barrel (bbl)	5.6154 cu.ft	159 litres
1 acre foot	43560 cu.ft	1233522 litres = 7758 bbl

Hence, for an oil reservoir zone of A acres and h feet thickness, the volume of oil in place (OIP) is

$$OIP = 7758 Ahf (1 - S_w) \text{ bbl.} \tag{1.2}$$

and for a gas reservoir of the same dimensions, the volume of gas in place (GIP) is

$$GIP = 43560 Ahf (1 - S_w) \text{ cu.ft.} \tag{1.3}$$

Note that sometimes these values are phrased as the amount of oil originally in place (OOIP) and gas initially in place (GOIP).

If the area is not known, the amounts of oil or gas are quoted in bbl/acre or cu.ft/acre respectively, and if the reservoir zone thickness is also not known, the values are given in bbl/acre.ft and cu.ft/acre.ft respectively.

These calculations are done for *reservoir zones*, which are thicknesses of formation of the same lithology, with similar cleanness (i.e., containing little clay), porosity, permeability, and hydrocarbon saturation (i.e., deep resistivity). The zonation of a reservoir is a qualitative exercise that often depends upon the individual petrophysicist. There will often be a minimum thickness for a zone that depends upon the study, however zones are rarely defined less than 5 ft. thick.

The thickness of the reservoir zone used in this calculation is the *net sand*. The *net sand* is the thickness of clean, permeable, hydrocarbon-containing sand in the reservoir zone. The *gross sand* is

the thickness of sand in the reservoir zone irrespective of whether it is clean, its permeability or its fluid saturation. The *net to gross ratio* (thickness of net sand divided by the thickness of gross sand) is often used to represent the quality of a reservoir zone.

Also note that the oil and gas will be at raised temperature and pressure in the reservoir. The compressibility of oil and especially gas, and their coefficients of expansion with temperature means that they will occupy different volumes at surface pressure and temperature conditions, or those present in the stock tank at the surface. For this reason reserves are often quoted corrected for the changes in temperature and pressure at the conditions of the stock tank. If this has been done the stock tank oil and gas originally in place is given as STOOIP and STGOIP.

The expansion or reduction in volume undergone by oil and gas as its temperature and pressure conditions change from that in the reservoir to that in the stock tank depend upon the changes in pressure and temperature and the composition of the oil or gas. The change is expressed by what are called *formation volume factors*. The *oil formation volume factor* B_o is the ratio of the volume of a standard mass of oil at reservoir conditions to that at stock tank conditions, and has no units. Hence, we can calculate now the amount of oil originally in place in the reservoir when measured at the pressure and temperature conditions prevailing in the stock tank (i.e., during production).

$$\text{STOOIP} = \frac{7758 Ahf (1-S_w)}{B_o} \text{ bbl.} \tag{1.4}$$

Similarly, the *gas formation volume factor* B_g is the ratio of the volume of a standard mass of gas at reservoir conditions to that at stock tank conditions, and also has no units. Hence, we can calculate now the amount of gas originally in place in the reservoir when measured at the pressure and temperature conditions prevailing in the stock tank (i.e., during production).

$$\text{STGOIP} = \frac{43560 Ahf (1-S_w)}{B_g} \text{ cu.ft.} \tag{1.5}$$

Oil Field Example

Area of zone, A	2000 acres
Thickness, h	150 ft
Porosity, f	15%
Water saturation, S_w	30%
Oil formation volume factor, B_o	1.65 (reservoir bbl per stock tank bbl)

Note that $B_o > 1$, hence the volume of oil is less at the surface than at depth. This is because the effect compressibility of oil with pressure for the range of pressures usually found in reservoirs is less than the effect of thermal expansion of the oil caused by reservoir temperatures. Therefore, when hot, pressurized oil at depth is brought to the cooler, lower pressure stock tank it contracts due to the lowering of temperature more than it expands due to the lowering of pressure.

Using Eq. (1.4) gives

$$\text{STOOIP} = \frac{7758 \times 2000 \times 150 \times 0.15 \times (1-0.3)}{1.65} = 148.10727 \text{ Mbbbl}$$

Whereas, the calculation for reservoir OOIP from Eq. (1.2) would have given 244.377 Mbbbl.

Gas Field Example

Area of zone, A	2000 acres
Thickness, h	150 ft
Porosity, f	15%
Water saturation, S_w	30%
Gas formation volume factor, B_g	0.0035 (reservoir cu.ft per stock tank cu.ft)

Note that $B_g \ll 1$, hence the volume of gas is much greater at the surface than at depth. This is because the effect compressibility of gas with pressure for the range of pressures usually found in reservoirs is enormous compared to the effect of thermal expansion of the gas caused by reservoir temperatures. Therefore, when hot, pressurized gas at depth is brought to the cooler, lower pressure stock tank it expands considerably more due to the lowering of pressure more than it contracts due to the lowering of temperature. This is the opposite of the case for oil.

Using Eq. (1.5) gives

$$\text{STGOIP} = \frac{43560 \times 2000 \times 150 \times 0.15 \times (1-0.3)}{0.0035} = 392.04 \text{ billion cu.ft}$$

Whereas, the calculation for GOIP from Eq. (1.3) would have given 1.372 billion cu.ft. The huge difference in the volume of the gas at stock tank conditions compared with that at depth indicates the importance of taking full account of the formation volume factor for gas.

It should, however, be noted that gas and oil cannot usually be taken as independent as in the two examples above. In practice, gas is dissolved in oil, and comes out of solution as the oil is brought to the surface. This results in additional shrinkage in the apparent oil volume, and this is taken into account in quoted figures for the oil formation volume factor. The reservoir then also produces gas, and the exsolved gas adds to the volume of the gas produced.

The complex interplay between gas and oil phase behaviours will be covered in formation evaluation course later in the MSc.

1.4 Uncertainties

Note that errors in any of the measurements leads to errors in the final value, and that the porosity and water saturation are in some ways inter-dependent, which can lead to larger error than might otherwise be expected.

The error in the area of a reservoir zone is usually quite small because seismic surveys can delineate the extent of reservoirs with great accuracy now. A greater error can be introduced from petrophysical measurements. These values are derived from a small number of wells that intersect the reservoir. There arises, therefore, the possibility that the well information is not representative of the reservoir as a whole. Clearly, the greater the number of wells, the smaller the possible errors from this source. However, early in the development of a field, when the result of reservoir management decisions can have a large impact upon the reserves and life of a field, the amount of petrophysical data is small, and the resulting errors can be quite large. It is therefore, always important to realize the impact that uncertainty in the knowledge of the petrophysical parameters can have in the final value of STOOIP.

Table 1.3 shows the impact that a 10% variation in the petrophysical parameters can have in the calculation of STOOIP.

Table 1.3 Propagation of errors in calculations of STOOIP.

Parameter	Base Case	Possibility 1	Possibility 2
Area, acres	2000	2000	2000
Thickness, ft	150	135	165
Porosity, %	15	13.5	16.5
Water saturation, %	30	33	27
Oil formation volume factor	1.65	1.815	1.485
STOOIP, Mbbbl	148	104	208
Percentage relative difference, %	0	-30	40

These errors can be analyzed statistically to give a probability curve from which the most likely value of STOOIP can be judged. As more and better quality data become available, we can reduce the possible error on the STOOIP analysis, generating probability curves with less variation. Figure 1.2 shows an example of probability curves for an initial appraisal, followed by two other curves made 8 and 15 years later. Note that there has been great improvement in the first 8 years, when appraisal drilling added much more data to the data base, followed by less improvement in the subsequent 7 years, when appraisal drilling was reduced significantly, and hence there was less new data added to the database. As with all things, there is an economic balance between added value generated from new data and the cost of obtaining the new data.

Figure 1.2 is read by taking the ordinate (y-axis) and reading across. For example in 1972 there was 100% probability that the reservoir contained greater than 80 Mbbbl, and 75% probability that it contained more than 250 Mbbbl. By 1980 there was 100% probability of the reservoir containing greater than 220 Mbbbl and 75% probability of it containing greater than 310 Mbbbl of oil. Thus, as time progresses the range of possible STOOIP decreases from a possible range of 80 Mbbbl < STOOIP < 600 Mbbbl in 1972 to 260 Mbbbl < STOOIP < 470 Mbbbl in 1987.

The data represented by Fig. 1.2 is shown in the Table 1.3 below.

Table 1.3 Probability vs. STOOIP data for Fig. 1.2

Probability (%)	STOOIP Greater Than (Mbbbl)		
	1972	1980	1987
100	80	220	260
75	250	310	320
50	350	360	360
25	450	420	400
0	600	500	470

Most critical financial and reservoir management decisions usually have to be made early in the life of a field when data is at a premium and errors in the estimated STOOIP are greatest. This is particularly true of offshore fields, where the cost of top-side production structures is a significant factor in the economic viability of the field. For example, globally, the Norway and UK sectors of the North Sea are the two most expensive oil provinces to produce from due to their deep off-shore nature combined with inhospitable conditions. In these cases it is critical to obtain as much high quality data as possible from the first few appraisal wells in each prospective reservoir.

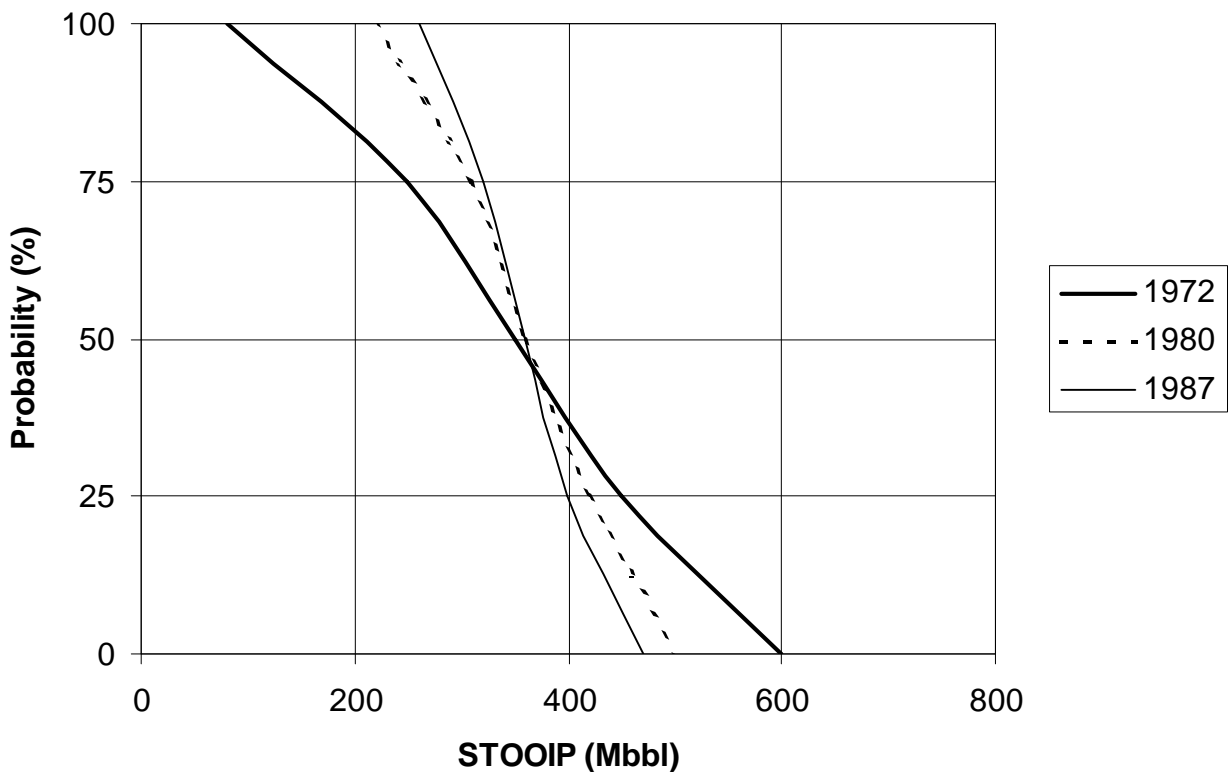


Figure 1.2 STOOIP Probability Curve

Since it is clear that the main interests of petrophysicists are porosity and permeability, the following few chapters (Chapters 2 and 3) will deal with these parameters. Fluid saturations are also critical, and these depend upon capillary pressure, which is described in Chapter 4.