Chapter 21

Production Geology

Knut Bjørlykke

Production Geology has become an important field and in mature sedimentary basins more geologists and geophysicists are involved in production than exploration. Today more of the global reserves of petroleum are added by increasing the recovery in existing fields than by discovering new fields.

The development of horizontal drilling has made it possible to produce oil much more efficiently than from vertical wells. It is now possible to drill wells up to 8–9 km along a very complex path draining several small reservoir compartments. Horizontal drilling has also opened up for production from low permeability reservoirs and from shales. See Chap. 23 on unconventional oil and gas.

During high oil prices much more can be invested in methods to increase oil and gas recovery.

The production of oil and gas requires detailed mapping of the reservoir with respect both to the distribution of petroleum and the flow properties of the reservoir rock.

After the discovery of a new field it may therefore be necessary to drill some delineation wells to acquire more information about the extent of the reservoir and the distribution of reservoir properties. Production wells and injection wells must be planned carefully to secure optimal recovery. Each new production well will provide a large database which needs to be interpreted; this will include information about pressure barriers in the reservoir. In many cases 3D seismic surveys will be repeated during the producing lifetime of the reservoir, providing a fourth dimension (time) to make it a 4D survey, see Chap. 19. It is then often possible to follow the change in the oil/water contact, gas/oil contact or gas/water contact by the density and velocity contrast which is a function of petroleum saturation. This may enable poorly drained parts of the reservoir to be identified and the financial feasibility of drilling a new production well to drain this part to be assessed.

Securing optimal production from oil and gas fields is an important challenge both from an economical and environmental perspective. The presence of free gas provides good pressure support for the oil production. The oil must normally be produced before the gas, otherwise production of the gas will reduce the reservoir pressure markedly and distort the oil/gas contact, making it difficult to recover the remaining oil. There is also gas dissolved in the oil and water which will bubble up from the oil phase and the water phase when the pressure is reduced during production. (Fig. 21.1).

21.1 Capillary Forces

The pores in the reservoir rocks may be filled with oil and water and in some cases there may be also gas so that we have three phases. This complicates and retards fluid flow in the reservoir during production. The contact between the solid phase, mostly minerals and the fluid phases is then very important. Minerals have different preferences to be wetted by fluids such as water, oil and gas. This is measured by the wetting angle which depends on temperature, pressure and the composition of the fluids.

K. Bjørlykke (✉)
Department of Geosciences, University of Oslo, Oslo, Norway
e-mail: knut.bjorlykke@geo.uio.no

K. Bjørlykke (ed.), *Petroleum Geoscience: From Sedimentary Environments to Rock Physics*,
DOI 10.1007/978-3-642-34132-8_21,

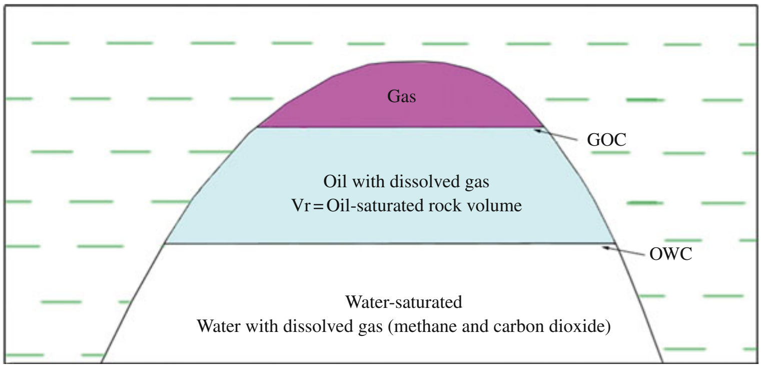

Fig. 21.1 Simple petroleum trap with a gas/oil contact (GOC) and an oil/water contact (OWC)

If the wetting angle is more than 90° the oil/water contact in the pipe will be below the general OWC, which means the oil is drawn downwards because it is preferentially wetting the inside of the pipe (Fig. 21.2); with lower wetting angles the OWC is raised.

The pores in a reservoir rock are usually filled with some water in addition to the oil or gas. If we submerge a very thin pipe (e.g. of glass) in oil and water, the water will rise above the oil/water contact. This capillary rise is a function of the radius of the pipe bore (R) and the wetting angle (θ).

The capillary forces ($F1$) must be in equilibrium with the gravitational forces ($F2$) which is the difference in density between oil (ρ_o) and water (ρ_w) over the capillary rise H (Fig. 21.2). We then obtain $H = 2\gamma \cos\theta / Rg(\rho_w - \rho_o)$ and we see that the capillary rise is a function of the interfacial tension (γ) and the wetting angle (θ). This is assuming that the rocks are water-wet ($\theta < 90°$).

γ is the interfacial tension between gas and water, varying within the range 30–70 dynes/cm for gas. For oil, γ is 5–35 dynes/cm (Schowalter 1979). In a sediment, R represents the radius of the intergranular pore throats (Fig. 21.2), θ is the wetting angle between petroleum or water against a mineral surface (Fig. 21.3). The wetting angle depends on the surface properties of different minerals, as well as on the composition of the petroleum and water, and on the temperature. The capillary resistance is thus also a function of the lithology. In sandstones the mineral surfaces may be dominated by quartz, mica and clay minerals and the system is water-wet. Biodegraded oil may nevertheless wet these mineral surfaces and produce an oil-wet system. Carbonates tend to be more oil-wet than siliceous sandstones and have a higher wetting angle.

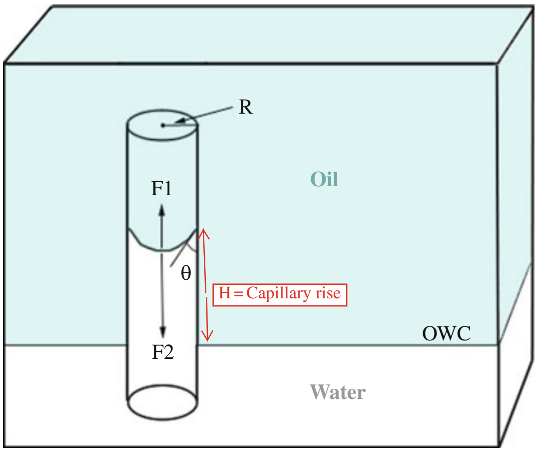

Fig. 21.2 Capillary rise of water in a very thin pipe of water-wet material. The capillary forces acting upwards are $F1 = 2R\pi\gamma\cos\theta$. Here R is the radius of the pore throat, γ the surface tension and θ is the wetting angle. The contact between fluid surface and the grain surface in the pore throat is thus $2R\pi$ and this must be multiplied with the surface tension (γ) and the wetting angle (θ) between the fluid and the grain surface. The gravitational forces acting downwards are $F2 = \pi R^2 gH(\rho_w - \rho_o)$. Here $(\rho_w - \rho_o)$ is the difference between the density of water and the density of oil. At equilibrium the forces acting downwards must be equal to the forces acting upwards so that $F1 = F2$ and we can calculate capillary rise (H) by $H = 2\gamma\cos\theta / Rg(\rho_w - \rho_o)$

Coarse-grained sandstones with little cement, and fractured rocks, have the lowest capillary entry pressures (Fig. 21.4).

We see that the capillary rise H is larger if the pores are small and the wetting angle is low.

In fine-grained sediment the OWC is drawn upwards higher than in coarse-grained sediments.

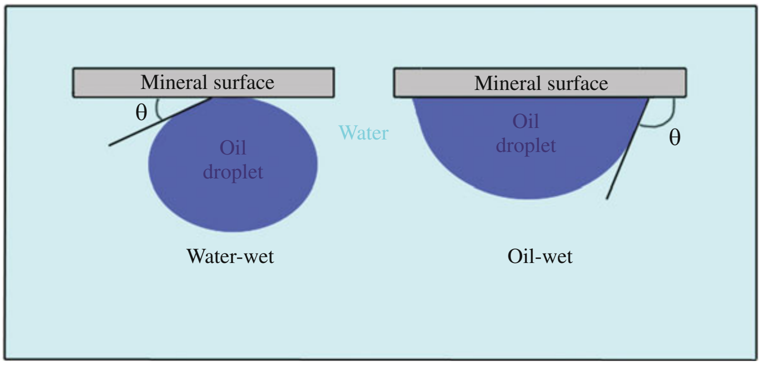

Fig. 21.3 Wetting angle for oil in water against a mineral surface. If the wetting angle is higher than 90° the system is oil-wet. At lower wetting angles it is water-wet

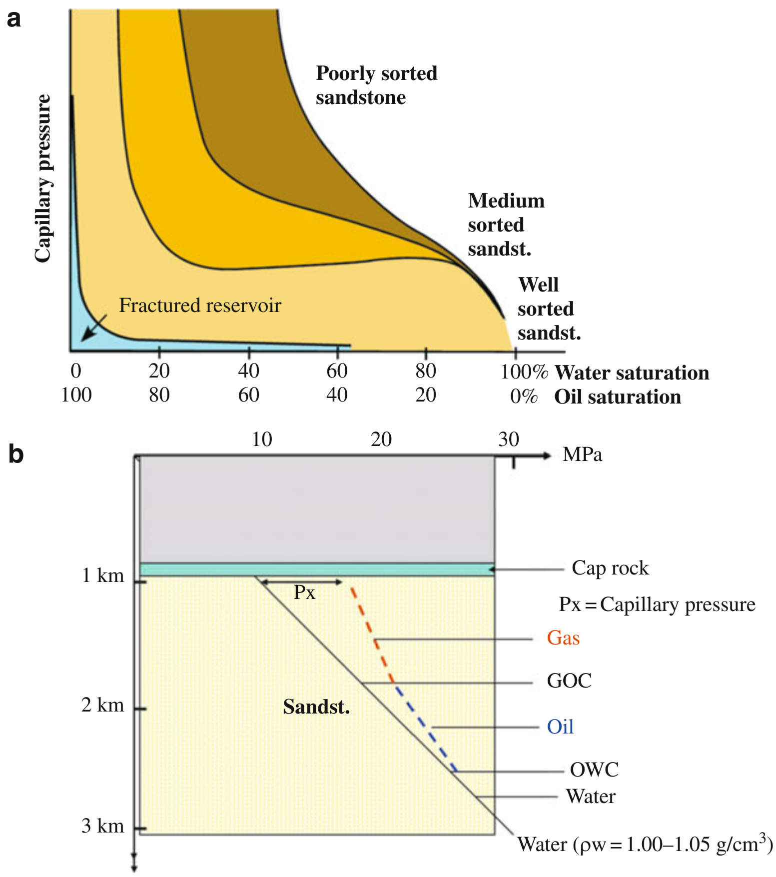

Fig. 21.4 (**a**) Capillary pressure as a function of sediment composition controlling the size of the pore throats. Fractured reservoirs have the largest pore throats and the lowest capillary pressures. (**b**) The pressure in the hydrocarbon phase increases upwards from the oil/water contact (OWC) due to the lower density. The pressure difference between the petroleum phase and the water in the pores is the buoyancy directed upwards. This is equal to the capillary pressure directed downwards. As a result petroleum will be able to fill smaller pores (that have higher capillary entry pressures) with increasing height above the OWC

During production the capillary resistance from fine-grained sand will be greater, due to the small pore throats. In fine-grained sandstones or siltstones with small pores, water is drawn (imbibed) upwards due to capillary forces. The difference in OWC which is recorded on the resistivity logs may be as much as a few metres. Since the pores in the reservoir rock usually also contain some water, the percentage of oil or gas in the pores is called the *oil saturation* or the *gas saturation*.

The petroleum saturation depends on the composition of the petroleum phase and its surface properties, on the mineral surfaces and on the pressure difference between the petroleum and the water phase. This pressure difference increases with increasing height above the OWC due to the lower density of the hydrocarbon column (Fig. 21.4b). As a result, petroleum will enter smaller pores higher up in the reservoir, and the degree of petroleum saturation there will be higher if everything else remains constant.

Most sandstone reservoirs are water-wet and this means that the minerals are lined with a thin layer of water. The smallest pores, i.e. between clay minerals or along the contacts between quartz grains, will then be filled with water. The percentage of water in the pores (water saturation) may be from 80 to 90% in well-sorted sandstones to 50–60% in sandstones with higher clay content. Also clay minerals formed during diagenesis (kaolinite, chlorite and illite) will have rather low water saturation if the system is water-wet because oil can not enter into the smaller pores due to capillary forces. The gas saturation will normally be higher. In reservoirs with biodegraded heavy oil, however, the wetting angle is normally more oil-wet.

In carbonate reservoirs the wetting angle is normally higher than in sandstone reservoirs but it may vary as a function of the composition of both the oil and the porewater.

In the Ekofisk Field it has been shown that injection of seawater has changed the wetting angle towards a more water-wet system, thus contributing to a higher recovery. This is probably due to the effect of the high sulphate and Mg^{++} concentrations in the seawater which change the surface charge of the carbonate minerals.

When the wetting phase (i.e. water) increases, the contact angle (wetting angle) will increase and reduce the capillary resistance. This is called *imbibition* and a core with high oil saturation may take up (imbibe) water. When the wetting phase decreases, this is called *drainage*. The contact angle forms a hysteresis in water-wet reservoirs as a function of displacing oil and water (Fig. 21.5).

Starting with 100% water saturation, the water is displaced by oil so that the water saturation is reduced

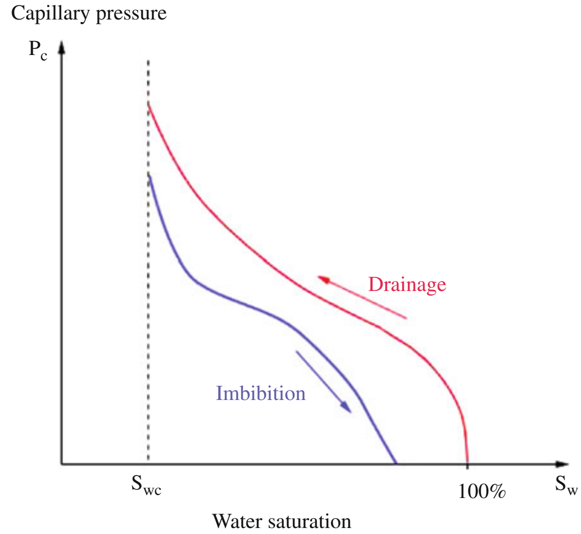

Fig. 21.5 Drainage and imibibition of oil and water as a function of water saturation and capillary pressure (Pc)

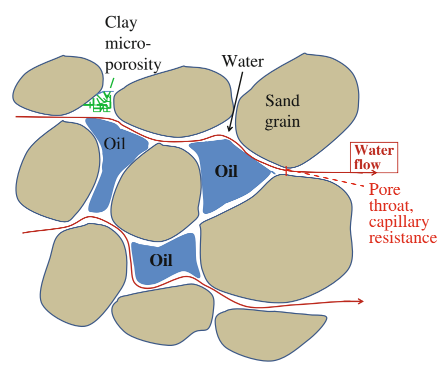

Fig. 21.6 Schematic figure showing how oil may be by-passed as water flows around the oil. Oil must overcome a greater capillary resistance to flow through the pore throats

to a value Swc. This is called the connate water saturation. It is not possible to expel more water (reduce the water saturation) by oil beyond this value due to the high capillary pressures Pc. When water flows back into the rock (imbibition), the capillary pressure curve follows a different path, reaching a point where the capillary pressure is zero. The water can therefore not displace all the oil and we can not get back to 100% water saturation. This is because the oil phase is no longer continuous and there are only droplets of oil in water. The droplets of oil will meet strong capillary resistance when trying to pass through pore throats and water can then flow through the reservoir without moving the remaining oil (Fig. 21.6).

21.2 Determination of Petroleum Reserves

When an exploration well has detected oil an estimate must be made of the reserves that can be produced. In many cases additional wells (appraisal wells) are needed before the full extent of the field and its financial viability for production can be determined.

The total initial volume of oil in the reservoir is called the volume of oil in place (V_p).

The percentage of that oil which can be produced is called *recovery* or the recovery factor.

The volume of rock above the oil/water contact (OWC) and below the cap rock, V_r, is determined by 3D seismic and data from the wells. This requires that the (OWC) is correctly defined, but it may not be visible on the seismic records, nor necessarily be at the same depth throughout the reservoir.

Good reservoir intervals are often called *pay* zones, whereas the tight zones are called *non-pay* zones. Intervals (layers) where the porosity is low ($<10\%$) and the permeability below a few milli Darcy (mD) may not be capable of producing significant amounts of oil even if they lie above the oil/water contact. In fractured rocks (e.g. fractured limestones) oil can be produced at very much lower porosities. The ratio between the volume of reservoir rocks (N) that possess sufficient reservoir quality to produce significant amounts of oil (pay), and the total volume (G), is called *net to gross (N/G)*. We then need to estimate the average porosity (φ_a).

The volume of oil or gas in place (V_p) is then:

$$V_p = V_r \cdot N/G \cdot \varphi_a \cdot \mathrm{Sat}$$

Calculation of the volume above the OWC also depends on correct depth conversion of seismic travel times. If the velocity of the overlying rocks changes across the field, this will influence the calculated volume. The oil/water contact may not always be horizontal across a structure and there may be sub-compartments within the field with different OWCs.

The average porosity φ_a is difficult to determine. We may have a very wide range of porosities in the same reservoir, from good reservoir quality to rather poor. Sandstones with less than 10–12% porosity usually have such low permeability that they are not considered to be producing parts (zones) of the reservoir.

We see that the calculation of oil in place is based on factors that are impossible to determine accurately. Each value, such as porosity or oil saturation, may be represented by a probability distribution and the calculation of oil is then based on statistical analysis. If the estimated average porosity in a reservoir is for example 18% we are interested in the probability of the average porosity being significantly lower or higher (e.g. 15 or 21%).

The fraction of the oil in place that can be produced is called the *recovery* and this can vary greatly, from 20–30% to 60–70%. The number of wells and their position are critical for field production, and the recovery can also be stimulated by injection of gas or a chemical. While 20–30 years ago the maximum recovery was considered to be 40–50%, it has since increased due to improved technology. Recovery in highly porous and permeable reservoirs may approach 70%. Towards the end of the production life of a field the wells may produce much more water than oil, but the water is then re-injected.

21.3 Reservoir Energy

A reservoir may be overpressured, giving it the potential to flow to the surface. If the wells are not managed properly a blow-out may occur. Even with reservoirs at hydrostatic pressure in the water phase, the pressures in the oil and gas will be higher due to their buoyancy relative to water and they will flow towards the surface. When oil is rising up a well the pressure is falling and gas may then bubble out of solution in the oil phase, as well as in the water phase. This will reduce the density and further increase the buoyancy effect so that a very high flow rate results. The formation of free gas is an important part of the mechanism that causes blow-outs in wells.

21.4 Relative Permeability

Permeability is a term expressing the resistance to fluid flow. It is a function of the rock properties and is independent of the viscosity of the fluid phase. However, when there are more than two fluid phases present in the pores, the flow and the permeability are different compared with when there is only one fluid phase.

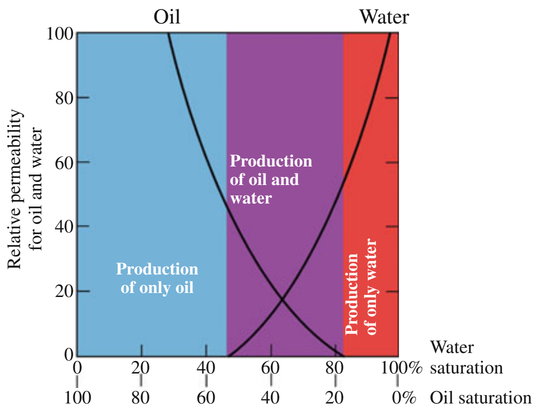

Fig. 21.7 Diagram showing the relative permeability with a mixture of water and oil. Similar relations exist between oil and gas, and between gas and water

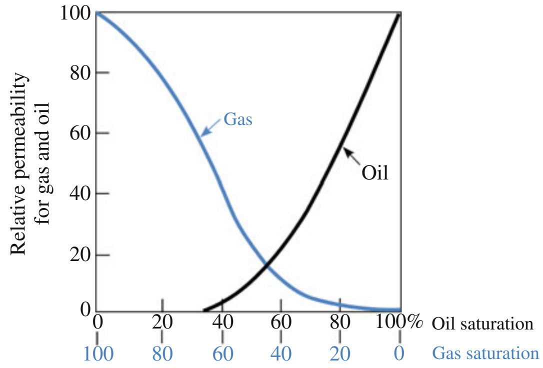

Fig. 21.8 Relative permeability of oil and gas. We see that if the oil saturation is less than about 35% only gas will flow. Even with high oil saturation (80%) there will still be some production of gas

In pores containing two fluid phases, the permeability of one of the fluid phases is expressed as the relative permeability (k_r). This is the permeability with two fluid phases divided by the permeability with only one fluid phase. In the case of oil and water:

$$k_r = k_{o+w}/k_w$$

The relative permeability is a function of the percentage of each fluid phase in the pore space and also of the wetting properties (wetting angle) of the phases.

The permeability with both oil and water present (k_{o+w}) is lower than the permeability with only water (k_w) (Fig. 21.7).

Two phase flow will always reduce the total flow rate (Figs. 21.7 and 21.8) and this is critical for flow near the well and in the pipes.

We see that if the oil saturation is less than about 35% only gas will flow. Even with high oil saturation (80%) there will still be some production of gas. In some cases we may have three phases together (water, oil and gas) and this is very difficult to model.

21.4.1 Behaviour of Reservoir Fluids

The reservoir fluids obey the phase rules. For an ideal gas we have:

$$p \cdot V = nRT$$

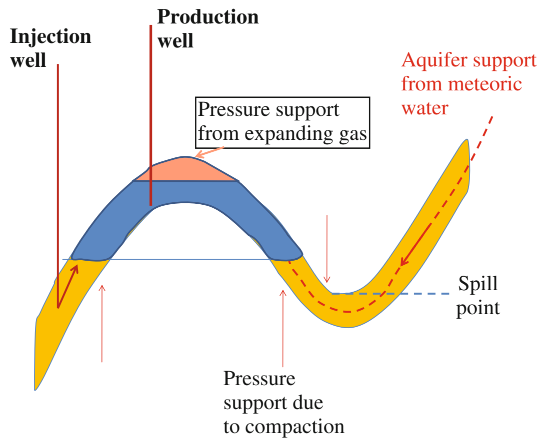

Fig. 21.9 Different types of flow of water into the reservoir providing pressure support. This may be from the volume of sandstones communicating with the reservoir, from adjacent shales and siltstones, from meteoric water and from water injection

Here p is the pressure, V is the volume and T is temperature (K). n is the molecular weight of the gas and R is the universal gas constant.

When oil and gas are produced, the pressure within the reservoir is reduced and water then flows into the reservoir rock (Fig. 21.9). The rate of flow from the surrounding rocks controls the rate of pressure drop during production (Fig. 21.9). If the reservoir is connected to another, very large and extensive, reservoir there will be very significant pressure support from the surrounding rocks, which are often referred to as *the formation*. In a relatively isolated sand body surrounded by low permeability shales the pressure

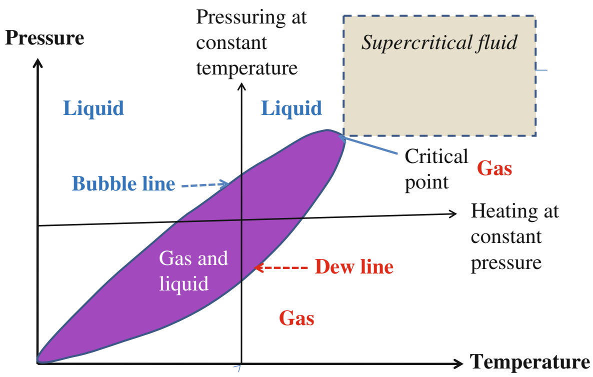

Fig. 21.10 Simple phase diagram showing how gas will form in the reservoir as pressure is reduced during production. When gas is produced, lower temperatures and pressures at the surface may cause liquids to form (condensate). If the pressure is reduced in the reservoir gas, methane in particular will bubble out of solution from both the oil and water phases. This has a feedback effect which helps to maintain reservoir pressure. At the critical point gas and liquid have the same properties. This is a temperature and pressure where liquids can be transformed to gas without any change in volume. For water this is 22.1 MP (221 bar) and 374°C. For hydrocarbons it depends very much on their composition

will drop fairly quickly during production. The rate of pressure reduction is thus a function of the volume of sandstones connected to the oil-saturated reservoir. If the sandstone volume is large or if it is communicating with siltstones and sandy shale with significant permeability, there will be more pressure support to the reservoir during production. Changes in the reservoir pressure may also cause changes in the petroleum phase (gas/oil ratio, formation of condensate etc.).

At the critical point gas and liquid have the same properties (Fig. 21.10). This is the temperature and the pressure where liquids can be transformed to gas without any change in volume. For water this is 22.1 MP (221 bar) and 374°C. For hydrocarbons it depends very much on their composition.

A reservoir may be thought of as a large container; during production we can therefore calculate reservoir pressures using material balance equations. If there is little compaction of the reservoir during production, the volume available for the fluids (the porosity) will be almost constant. The main change is due to elastic deformation due to loading or unloading. In some cases as in the Ekofisk Field, where the reservoir rock is mechanically weak, there is significant compaction of the reservoir during production due to increased effective stress or chemical effects of the water flooding.

The equation of state is:

$$V \cdot P/T = C$$

If the temperature is constant, the pressure is a function of the change in volume, thus

$$C = \Delta V/V\Delta p$$

$$\Delta V = CV\Delta p$$

Fluid flow during production can be calculated by applying the conservation of mass. The volume of hydrocarbons produced must be replaced either by fluids flowing into the reservoir from outside or by an expansion of the fluid phases with corresponding reduction in pressure.

When we produce petroleum from a reservoir the volume of produced petroleum can at least partly be replaced by water flowing into the reservoir from surrounding rocks. The drop in volume (ΔV) is then a function of the volume of produced petroleum (V_{pro}) minus the volume of water flowing into the reservoir which is referred to as the *water drive* (V_{wd}).

$$\Delta V = V_{\text{prod}} - V_{\text{wd}}$$

The drop in pressure due to produced oil, gas and water is a function of:

(1) The compressibility of the fluids present. Oil with a low content of dissolved gas has relatively low compressibility and the pressure will be reduced rather rapidly. If free gas is present as a separate phase above the oil, it will be highly compressible and will expand as the oil is produced and help to maintain the higher pressures in the oil phase. Oil saturated with gas will form a separate gas phase when the pressure is reduced and thus maintain the pressure.
(2) The supply of fluids from outside the reservoir. This may be from meteoric water connecting to the surface where there is a continual supply of water, or by the injection of water or gas.
(3) Supply of water from around the reservoir. Pressure reduction in the reservoir during production creates a potential for water to flow from the

surrounding rocks. Reservoir sandstones that are surrounded by low permeability shales will have a very low supply of water (water drive) and the pressure will therefore drop faster during production. This is particularly true when reservoir sandstones are offset laterally by faults. In most cases the permeability of shales is so low as to be almost irrelevant in the time span during which petroleum is produced from a field. However, if the reservoir is part of a thick sandstone sequence, the pressure support provided from a larger sand volume may be very significant. If we only consider the water phase, the pressure drop in a sandstone reservoir is a function of the volume of sandstone in communication with the reservoir.

21.5 Meteoric Water Drive

Reservoirs connected to an aquifer that is part of the meteoric water flow system will experience very little drop in pressure during production because the produced petroleum is quickly replaced by meteoric water from the aquifer.

While the supply of meteoric water may be relatively fast, compaction-driven water flow is many orders of magnitude lower and can be ignored.

In a closed system the response to production and the associated reduction in reservoir pressure is a function of the compressibility of the water (C_w), the compressibility of the oil (C_o) and the compressibility of the gas (C_g). There will also be changes in the reservoir volume (porosity) because reduced fluid pressure will result in higher effective stresses, but this response will normally be rather small unless the reduction is sufficiently large to cause mechanical compaction with grain crushing.

When the pressure is reduced there will be an expansion of both the water and the petroleum in the reservoir, but this is relatively small.

21.6 Gas Expansion Drive

Gas has a high compressibility and if free gas is present in the reservoir this gas phase will expand as the pressure is reduced. The pressure drop relative to the volume of oil produced will therefore be relatively small. In addition, gas that was originally in solution in the oil will bubble out as a separate phase and add to the gas drive.

21.7 Compaction Drive

If the fluid pressure is reduced, the increase in effective stress may cause mechanical compaction, reducing the pore volume. While this will also contribute to the maintenance of high pressure, it may damage the reservoir by grain crushing and closing fractures (if present). In the Ekofisk Field, however, the compaction of the reservoir provides a drive that enhances recovery of the oil.

21.8 Water Injection

Water is injected into the reservoir to replace the produced petroleum and thus maintain high pressure in the reservoir. It will also help to maintain the pressure gradients towards the production wells. Injected water will follow the most permeable layers at the base of sandstones because it is denser than oil. Injection of water to displace oil or gas is called “immiscible replacement” because oil is not soluble in water. Water will displace oil found in pockets (depressions) against low permeability shales (Fig. 21.13b).

The vertical distribution of permeability and capillary resistance within a bed is important for the flow of oil and water and the total recovery (Figs. 21.11 and 21.12). We see that in coarsening-upwards sequences the highest permeability and lowest capillary resistance are at the top, where oil or gas flow will

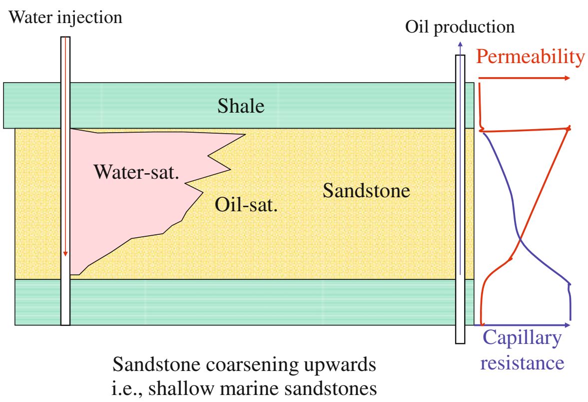

Fig. 21.11 Production from a coarsening-upwards unit, e.g. a marine shoreface sequence. The injected water will sink in to the less permeable layers and displace oil also from there

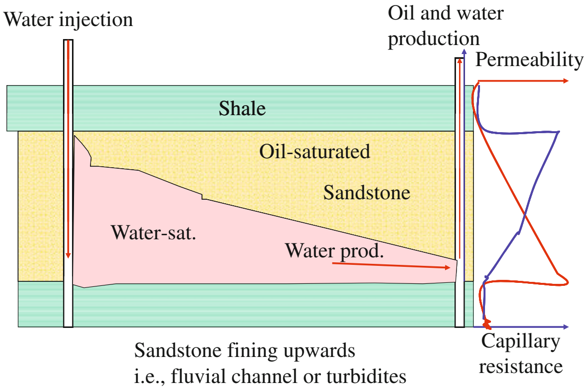

Fig. 21.12 Production from a fining-upwards sequence, e.g. fluvial channel facies. The injected water will sink to the lowermost permeable layers and then may break through to the production well, leaving most of the oil in the less permeable beds behind. Addition of polymers to increase the viscosity of the water may result in a better sweep and produce more oil

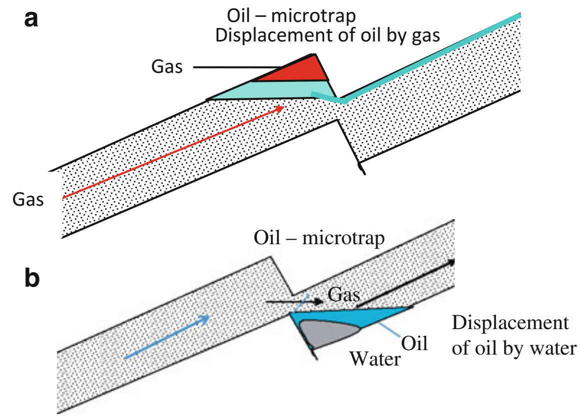

Fig. 21.13 (**a**) Displacement of oil by gas in small traps during production. (**b**) Displacement of oil by water in a reservoir with mostly gas

preferentially occur due to the buoyancy relative to water. In fining-upwards sequences the injected water will tend to follow the basal permeable part, causing early water breakthrough to the production well.

21.9 Gas Injection

When gas is injected in to the reservoir it is partly soluble (miscible) in both the oil phase and the water phase. The most common gases used are methane, nitrogen and more recently also carbon dioxide. Gas injection contributes to the maintenance of the pressure in the reservoir. Gas is less dense than oil and is efficient in terms of displacing oil from small microtraps where pockets of oil are found above water. Gas will therefore sweep the upper parts of sandstone beds in a reservoir and displace the oil downwards, so that it can flow out of the small traps (Fig. 21.13a).

The injected gas may be methane that is produced along with the oil. These gases are also to a large extent dissolved in the oil phase during the injection.

The use of CO_2 is now encouraged for injection in reservoirs because this represents a storage of carbon dioxide, reducing the contributions to global warming.

Carbon dioxide has been applied, for example, in the Sleipner Field in the North Sea, but not in the reservoir.

Tracers may be employed to see if water from the injection well has reached the production well.

21.10 Other Methods for Enhanced Recovery

When there is breakthrough of water from the injection well to the production well, the flow of water may be reduced by adding polymers that increase the viscosity of the water. The pressure gradient will then increase in the oil phase and it may be possible to displace more oil towards the production well.

When the oil saturation is low, particularly towards the end of production, movement of the remaining oil drops is prevented by the capillary forces. By adding surfactants (soap) the oil drops may be broken down into an emulsion which can flow with the water to the production well.

Many enhanced recovery methods are more effective in onshore oil fields where the distance between the wells is much less than offshore. During high oil prices it may be economical to spend more on chemicals to stimulate production.

There are three main enhanced recovery methods:

I. *Thermal processes:* These are processes which increase the temperature of the oil and thus lower its viscosity. The most common are:
   (a) Steam injection. This is the main recovery method for heavy oil and tar sand.
   (b) *In situ* combustion. Supplying oxygen to partially burn heavy oil or coal to increase the

temperature and reduce the viscosity of oil, and to produce gas from coal.

II. *Chemical processes:* These involve injection of chemicals into the reservoir. The most important types are:
   (a) Injection of caustic (alkaline) chemicals which reduce surface tension (surfactants).
   (b) Polymers which are injected into water to increase its viscosity to prevent water breakthrough.

III. Injection of various types of gas to increase the miscibility of hydrocarbon phases. These may include carbon dioxide, neutral gases (e.g. nitrogen) or hydrocarbon gases.

I. *Thermal Processes:* These are only used with reservoirs with highly viscous oil, where an increase in temperature will greatly reduce the viscosity. This will normally be heavy, asphaltic oil which has been subjected to bacterial breakdown and evaporation. Oil reservoirs of this type are normally fairly shallow (less than 1,500 m). Deeper reservoirs will have a high temperature anyway, so there is less to be gained by artificially heating the oil.

In situ combustion can be induced by pumping air down into the reservoir, and the combustion can be regulated by addition of oxygen. The hydrocarbons which do not burn will then become hotter and less viscous. Burning also produces gases, which may increase production. Special wells can be used for injecting air, and combustion spreads from these to the production wells, forcing a zone of hot water, gas and light oil ahead of it to the production wells. Combustion may also increase the porosity of the reservoir rock, making it possible to produce later on from the wells in which combustion has taken place.

Steam injection is responsible for 90% of all production through secondary recovery methods apart from water injection. One of the major reasons for the low recovery percentage from oil reservoirs is that the oil is too viscous. This is particularly true of oil which has been subjected to bacterial degradation (biodegradation), leaving the viscous asphaltic part of the oil behind as heavy oil (low gravity 16–17 API). The Cretaceous Athabasca tar sand in Alberta, Canada, is the most famous example, and contains huge oil reserves. When oil reservoirs with such heavy biodegraded oil are exposed at the surface, the oil is almost solid at normal temperatures, and is called tar sand. For it to be possible to produce oil, the pressure difference between the oil in the reservoir rock and the well must exceed the resistance to flow exerted by capillary forces (in water-wet reservoirs) and viscosity forces (friction).

Biodegraded oil is normally found at relatively shallow depths, and the temperature of the oil is low and the viscosity consequently high. By injecting steam the temperature can be raised and the viscosity lowered considerably. There are examples of the viscosity of oil being reduced from 300 to 10 cP after steam injection, and biodegraded oil is often too viscous to flow at all without steam injection. Steam injection is particularly important in California, where 300,000 barrels/day are produced using this method. Steam injection must be repeated at regular intervals because the viscosity increases again as the reservoir cools off. Sandstones which are to be subjected to steam injection must also have high oil saturation, because otherwise water and steam can flow past the oil. Steam is recovered from the produced oil, and in some fields one out of every three barrels produced is used for steam production.

II. *Chemical Processes:* When oil flows out of a reservoir rock into a producing well, it must overcome the capillary forces involved in two-phase flow. By reducing the surface tension between oil and the water which is injected into the wells, the capillary forces can be reduced. The addition of surfactants, a sort of soap, will reduce the surface tension so that the *wettability* changes. The wettability can be measured by means of the contact angle, i.e. the angle which the liquid phases make with a mineral surface, for example (Fig. 21.3).

If an oil reservoir is *oil-wet*, it means that oil is more strongly bound to the mineral surface than water. By reducing the surface tension in the water phase, the *wetting angle* is altered and the system may become *water-wet*, and the oil will become more mobile so that the relative permeability to oil is increased. A mixture of different chemicals (*slug*) is injected into oil reservoirs to reduce the surface tension. It includes micro-emulsions, soluble hydrocarbons, micelles and frequently also alcohol and various salts.

One serious drawback of this method is that chemicals can easily be adsorbed onto the reservoir rock. Clay minerals in particular have high ion exchange and adsorption capacities. The specific surface (m^2/g) of rocks is also of significance.

Consequently chemicals are often pumped down in advance (*preflush*) to reduce adsorption of the chemicals which are intended to reduce surface tension. This treatment ought also to take into account which clay minerals occur in the rock.

Polymers. In oil reservoirs with an undesirably high relative water permeability, large amounts of oil will remain in the reservoir rock. Water will flow where there is least resistance to its movement, e.g. along cracks and permeable sand beds, and injection of water will then have little effect. This is particularly relevant with oil reservoirs with low oil saturation (high water saturation). If the viscosity is increased so that the pressure gradient in the water phase increases, the gradient in the oil phase will also increase. Polymers reduce the mobility of the water, causing a piston-like replacement mechanism. With increased viscosity, the polymer-bearing water will exert greater shear forces on the oil phase, so that oil drops are more easily carried along. Water containing polymers is no longer a Newtonian liquid, but a pseudoplastic liquid in which the apparent viscosity is reduced by the rate of deformation.

Polymers will also have a tendency to be adsorbed onto the surface of minerals so that their effect decreases with increasing distance from the injection well.

Addition of Alkaline (Caustic) Chemicals. Strong alkaline solutions, for example NaOH, will also reduce the surface tension of aqueous phases. Injection of a mixture of these alkaline solutions may therefore increase both the water-wetness of the reservoir and oil production. The most common chemicals include sodium and potassium hydroxide, sodium orthosilicate, sodium carbonate and sodium phosphate. The method is used largely in sandstone reservoirs. Small amounts of gypsum or anhydrite will cause $Ca(OH)_2$ to precipitation and neutralise caustic soda (NaOH).

The object of *gas injection* is to produce a fluid phase which will dissolve the reservoir oil. The flow of such a fluid through reservoirs with low oil saturation may dissolve the oil and carry it along to the production well. Hydrocarbon gases which are in the liquid phase at reservoir pressure (*Liquid Petroleum Gas – LPG*) will be fully miscible with oil. This requires that the reservoir temperature be below the critical temperature for the gas. At higher temperatures the gas is in gaseous form regardless of pressure, and is not fully miscible with oil. Propane is often used in the oil-expelling mixture, and gas and water are injected subsequently.

CO_2 has a critical temperature of about 31°C, and is therefore gaseous at all reservoir pressures. Carbon dioxide is very soluble in oil, which increases in volume when it is saturated with respect to CO_2. This creates a sort of gas drive.

Increasing the CO_2 content also reduces the viscosity and density of oil, making it very mobile. The method is used for oil reservoirs with oil saturation of 25–55%. Neutral gases such as nitrogen may also be injected into reservoirs, but far greater pressure is then required to make the gas soluble in oil.

21.11 Changes During Production

With production from sandstone reservoirs, the physical properties of sandstone must be taken into account, e.g. distribution of porosity and permeability. The actual production, however, will lead to changes in the reservoir rock which may have an adverse effect on the reservoir properties, i.e. cause reservoir damage. This may happen in two ways:

1. Chemical reactions between minerals and liquids which are used in drilling or injection of water.
2. Mechanical damage through relatively loose clay minerals or other small grains being carried by the fluid flowing towards the well, and obstructing the pore throats.

As oil flows into a well, the flux (cm^3/cm^2) is inversely proportional to the distance to the well. If we can improve the permeability of the reservoir nearest the well, we may be able to step up the production rate considerably. For this reason chemicals are sometimes injected into the reservoir to improve the permeability. We then need to understand some of the chemical properties of minerals in order to be able to predict the reactions which will result from treatment with acids and other chemicals.

As far as chemical reactions are concerned, clay minerals are important because they have a large specific surface and ion exchange capacity. The specific surface varies with the size and shape of the mineral grains. Kaolinite will typically have a specific surface of 5–30 m^2/g, chlorite 10–50 m^2/g, illite and smectite (montmorillonite) >100 m^2/g. The high specific surface of illite and smectite is due to the fact that they often occur as very thin sheets or fibres.

Kaolinite has very low solubility in water, and strong acid (HF) is required to dissolve it. Kaolinite is therefore chemically stable and its ion exchange capacity is lower than that of other clay minerals. Chlorite, on the other hand, is soluble in acids such as HCL. If acid is used to dissolve minerals like chlorides in order to increase the permeability around the well, it is important to avoid iron being precipitated as iron hydroxide ($Fe(OH)_3$). This could reduce the porosity very severely because it forms pore-filling cement. To avoid this, one can add chemicals which form complexes with iron (e.g. citrate).

Illite and smectite are not very soluble in HCL, and hydrofluoric acid (HF) must be added to dissolve these minerals. They are sensitive to variations in salinity and in particular to the K^+ content. K^+ and other alkali ions will be held in the interlayer position in smectite so that water is expelled and the mineral contracts in volume. On the other hand, injection of fresh or slightly saline water into a reservoir may lead to uptake of water and expansion of smectite and mixed layer minerals, which may greatly reduce the porosity. Sodium smectites can swell to 5–10 times their original volume. Swelling can be reduced by injecting dilute acid (HCl) or water with a high salinity (e.g. KCl). Water is also often injected to maintain reservoir pressure. Offshore drilling platforms in particular depend on using seawater. However, seawater may have adverse effects on the reservoir. The high sulphate concentration in seawater may cause precipitation of baryte ($BaSO_4$) which is the least soluble of the common sulphate minerals. Seawater also contains sulphate-reducing bacteria which will start to reduce SO_4^{2-} to H_2S in the reservoir. This is most undesirable since H_2S is a very poisonous gas which also has a highly corrosive effect on steel during production.

To avoid unforeseen chemical damage to the reservoir rock, it is necessary to carry out very thorough mineralogical analyses so as to be able to predict the effect of various types of chemical stimulation.

Physical damage to the reservoir, as previously mentioned, is due to mineral grains being loosened and carried by oil and water, eventually clogging the flow paths. If the reservoir is water-wet, fine-grained minerals will tend to remain suspended in the aqueous phase, and will not come into the oil phase very easily because of surface tension. When considerable quantities of water are produced together with oil, therefore, the aqueous phase is particularly likely to carry clay minerals and other small mineral particles, for example of quartz and felspar, which may block the pore throats. This effect can be reduced by lowering the production rate. In the laboratory this type of mechanical formation damage can be tested in an experimental flow rig. If the measured permeability increases temporarily when the flow direction is reversed, formation damage has been caused by "a moving clay and silt fraction". Sandstones with a high percentage of secondary porosity will have relatively large pores with small pore throats. The ratio between the pore diameter and the pore throat is often referred to as the aspect ratio. Pores with high aspect ratios will be particularly vulnerable to mechanical formation damage. Pore geometry is also important with respect to two-phase flow (oil and water) because of the capillary forces that have to be overcome in the pore throats. This is even more the case with condensate reservoirs, where we may have three phases (oil, gas, water).

The planning of production from a reservoir involves a detailed production strategy and optimal positioning of production and injection wells. The trend production will take with time is simulated on extremely powerful computers which are fed with a very large number of parameters relating to the reservoir. Simulations depend very heavily on the geometry of the reservoir and internal communication, e.g. between sandstone bodies, the exact position of the sealing fault, etc. The internal properties of the reservoir can be measured on cores from the wells, but a three-dimensional representation of the distribution of porosity and permeability and the pore geometry must be constructed, using models for the detailed depositional environment and diagenetic alteration.

It may now be possible to follow fluid flow within the reservoir compartments during production using 4D time-lapse seismic data (Lynn et al. 2014).

21.12 Carbonate Reservoirs and Fractured Reservoirs

Many of the same principles apply to carbonate reservoirs as apply to sandstones. There is a tendency for carbonate reservoirs to be less water-wet than sandstone reservoirs, but this depends on the composition of the oil and on the temperature and pressure. Pores often have a high aspect ratio, particularly in limestones where we often have intragranular porosity inside fossils or vuggy mouldic porosity after selective dissolution of organic fossils. The reservoir properties of bioclastic and reef limestones are largely a result of the palaeo environment, which determined the distribution of fauna.

Fractures are generally much more important in carbonate than in sandstone reservoirs. Stylolites are sometimes found in sandstone reservoirs that have been buried to at least 3.4–4 km. In limestones stylolites develop at much shallower depths, often forming a thin clay surface that is quite impermeable, and which may divide a reservoir up into compartments or even serve as a cap rock.

In fractured reservoirs there is a high percentage of porosity due to fractures rather than more uniformly distributed porosity. Fractures are most extensively developed in brittle rocks like well-cemented limestones and chert. They may also form in metamorphic and igneous rocks. Fractures are often invaded by drilling mud, causing lost circulation, and this may damage the reservoir near the well. The flow of petroleum through a fractured reservoir during production is very complex, and it is difficult to map out the fracture system of the subsurface in sufficient detail.

As a result of reduced pressure during production, fractures may start to close due to increased net stress. By injecting water at very high pressures (higher than the geostatic pressure) fractures may be widened (hydrofracturing), a method also sometimes used in other reservoirs to create or widen fractures close to wells and improve the permeability of the critical area around the well. The introduction of some coarse-grained material like sand and also other types of granular materials may help to wedge the fractures and prevent them from closing.

Onshore oil fields have much closer well spacing than offshore fields because of the lower drilling costs. This means that many of the enhanced recovery methods can be used much more effectively. At high oil prices mature oil fields can have a very long tail production and be economical even with very high water production (>90% water).

21.13 Monitoring Production

During production, comparison of pressure changes in the production and injection wells will provide information about fluid communication within the reservoir. These data are fed into vary large and complex reservoir simulation models.

4D seismic may be successful in some fields for detecting changes in the gas/oil contact (GOC) and in some instances also the oil/water contact (OWC). Repeated seismic surveys at 1–3 years intervals may detect an upward movement of the OWC as the reservoir is depleted. The difference in impedance may, however, not be as pronounced at the primary OWC because there may be 30–40% oil saturation in the drained intervals, It may then be possible to detect parts of the reservoir which are not drained and which are large enough to justify an additional well.

21.14 Well-to-Well Tracers

Tracers can be added to the water in the injection well and their arrival in the production well can provide important information about the reservoir. If the tracer is recorded in the production well relatively soon after the injection there must be a high permeability connection in the form of an open fault or fracture or a high permeability sand layer. The time of the arrival of the tracers makes it possible to calculate the flow velocity of the water phase. The tracers must remain dissolved in the water and should not be adsorbed on the minerals. Since they become part of the produced water they should be environmentally acceptable. Many of the tracers are radioactive but only with β radiation, such as tritiated water (HTO), $^{36}Cl^{-}$ and $^{22}Na^{+}$. Most of them have a relatively short half life, except $^{36}Cl^{-}$.

It is also possible to use non-radiocative tracers, but extremely low levels must be detectable (in the ppb range) because of the strong dilution. Gas tracers may also be used.

The concentration of the tracer as a function of time during production may provide very important information about the rock properties and the flow in the reservoirs. Different types of tracers may to different degrees interact and be adsorbed onto the reservoir rocks.

21.15 Reservoir Models and Field Analogues

When planning the production of a reservoir, a relatively detailed reservoir model is required.

Seismic data has limited resolution and in offshore reservoirs the spacing between wells may be relatively large, usually several 100 m or a few kilometres. It is difficult to construct a 3D model when the producing units are offset by faults that are below seismic resolution so that they can not be detected. Outcrops of similar reservoir rocks may be used to provide quantitative data on the geometry of sand bodies and the distribution of minor faults. to be used in the reservoir model.

It is however critical that the field analogue was deposited in a similar sedimentary environment and plate tectonic setting. Many factors such as sediment supply, climate, water depth, tidal range, etc. have to be similar.

All reservoir analogues that are exposed have been buried to a certain depth and then uplifted to the surface. It is difficult to reconstruct the burial history in terms of temperature and effective stress so that the diagenetic effects can be compared with reservoirs at their maximum burial depth.

The structures observed in the field analogue must be analysed so that the deformation which occurred during uplift can be distinguished from that produced during subsidence.

Offshore production from a separate platform is expensive and requires a relatively high production to offset the production costs. Still many oil fields can be produced with a tail production stimulated by different methods. Onshore oil and gas fields on the other hand can be economical at rather low production rates.

21.16 Conclusion

Production geology encompasses many different specialities in geology, geophysics and engineering subjects:

Reservoir sedimentology/diagenesis.

Reservoir geophysics.

Reservoir modelling (modelling of fluid flow).

Reservoir modelling has become a special field where the flow during production is simulated mathematically based on assumptions about the distribution of rock types with different porosity and permeability. See Chap. 22.

Drilling and well completion.

A team of specialists is therefore required to produce a reservoir efficiently.

This depends very much on reservoir modelling which is a complex process were the fluid flow in the reservoir is simulated.

Further Reading

Archer, J.S. and Wall, C.G. 1994. Principles of Petroleum Engineering. Principles and Practice. Graham and Trotman, London, 362 pp.

Burchette, T.P. 2012. Carbonate rocks and petroleum reservoirs: a geological perspective from the industry. In: Garland, J., Neilson, J.E., Laubach, S.E. and Whidden, K.J. (eds.), Advances in Carbonate Exploration and Reservoir Analysis. Geological Society Special Publication 370, pp. 17-37.

Dandekar, A.Y. 2006. Petroleum Reservoir Rocks and Fluid Flow Properties. CRC Publications, Boca Raton, FL, 460 pp.

Dickey, P.A. 1979. Petroleum Development Geology. Petroleum Publishing Co., Tulsa, OK, 398 pp.

Dikkers, A.J. 1985. Geology in Petroleum Production. Developments in Petroleum Science 20, Elsevier Science, 239 pp.

Hyne, N.J. 2012. Nontechnical Guide to Petroleum Geology, Drilling and Production, 3rd. edition. Pennwell Corporation, Tulsa, Oklahoma, pp. 698.

Loudon, R.C. 1996. Principles of Petroleum Development Geology. PTR Prentice Hall. New Jersey. 267pp.

Lynn, G.J., Ellis, A.C., Brain, J., Parker, R., Lortzer, G-J. and Michelet, S. 2014. Gannet F field - Unexpeted fluid flow between reservoirs identfied from time-lapse seismic data. First Break 32(4), 53-59.

Robinson, A., Griffiths, P., Price, S., Hegre, J. and Muggeridge, A. 2009. The Future of Geological Modelling in Hydrocarbon Developments. Geological Society Special Publication 309, 232 pp.

Tiab, D. and Donaldson, E.C. 2004. Petrophysics. Elsevier, Amsterdam, 889 pp.