This chapter covers the interpretation of depth related pressure measurements, primary production mechanisms (or drive mechanisms), material-balance equations and, finally, immiscible displacement mechanisms. In fact, these subjects are closely inter-linked in the evaluation of the volumes originally in place and the potential recovery factors of hydrocarbons, clearly assuming that the production strategies previously selected are suitable for the type of reservoir in question.

### 4.3.1 Pressure gradients

**Definitions**

A pressure gradient expresses the reservoir fluid’s increments in pressure in relation to a given increase in depth (generally a metre, or a foot); usually represented by the symbol $\gamma$, it is calculated by the formula $\gamma = \Delta p / \Delta z$, where $\Delta p$ represents the difference between the values of the pressure measured at two values of depth, whose difference is equal to $\Delta z$. The depths are measured from sea level, or from the level of the drilling rig (or rotary table), along a vertical axis that passes through the position pin-pointed by the coordinates of the wellhead (true vertical depth). If the well is not perfectly vertical, the pressures are not acquired in relation to the true depth, but along the profile of the well; in this case, the measured depths must be verticalized in order to correspond to true vertical depth. The value of the pressure gradient can immediately be correlated to the density (the mass corresponding to the unit of volume) of the fluid present in the pores of the reservoir rock. In fact, the pressure gradient, resulting from the force exerted by weight, is derived by multiplying the density by the gravity acceleration. The density of the fluids is dependent on the pressure and temperature at the time of measurement, which, therefore, should always be specified; generally, reference is made to the reservoir conditions, or alternatively to standard conditions – i.e. to pressure and temperature equal to 1 atm (0.1013 MPa) and 15.5°C (288.7 K) respectively. The instruments used to measure pressure and temperature in the reservoir along the profile of the well are called WFTs (Wireline Formation Tester): among these, the MDT (Modular Formation Dynamics Tester), which also enables the collection of formation fluid samples for further laboratory analysis, has superseded the classical RFT (Repeat Formation Tester), now rarely used. The MDT instrument can be configured in various ways and may contain one or more sondes to measure pressure and temperature, and to recover fluid. The sondes are pushed into direct contact with the formation in such a way as to bypass the mud cake that forms on the sidewalls of the well. They are all mounted at the bottom of a suitable string, which is lowered into the well during the test phase, and are electro-hydraulically operated from the surface.

**Fig. 1. Reservoir pressure gradients.**
Determining the pressure gradient is particularly important in order to define the nature of the reservoir fluids. In a Cartesian grid, where the pressures are plotted versus depth, the data measured along the well tend to form a straight line, whose angular coefficients correspond to the pressure gradients of the fluids present in the reservoir (Fig. 1). Thus, in a lithological sequence containing one type of fluid, the pressure of the formation increases in direct proportion to the increase in depth; on the other hand, in a case where a lithostratigraphic series is saturated with different types of fluids (e.g. hydrocarbons and water), a pressure gradient is recorded for each type of hydrocarbon present in the reservoir, as well as a separate gradient for the aquifer. Since gas, oil and water are the only fluids present in a reservoir, each of the pressure gradients obtained from the pressure profile along the well must correspond to the density of one of these fluids. Nevertheless, at times it is difficult to determine the nature of the fluid based solely on density: in the case of so-called heavy oils, the density values can be similar to that of water, and in the case of very light oils, the density can be close to that of a gas rich in condensates. Therefore, it is advisable to supplement examination of the pressure gradients with the information derived from laboratory analysis of the recovered fluid samples.

**Contact between fluids**

Gas, oil and water are stratified within a reservoir according to their specific gravity, as a result of a phenomenon called *gravity segregation*. Therefore, if all three fluids are present in a reservoir, the water accumulates at the lowest level of the formation, the gas – which is the least dense – occupies the upper level, while the oil lies between the gas and the water. Due to capillary pressures, which occur when there are porous rocks and non miscible fluids, the transition from one fluid to another is not distinct, but occurs gradually with a progressive variation in the saturation of the different fluids. The extent of the transition zone depends on the differences in the density of the fluids that are in contact, and on the characteristics of the reservoir rocks (in particular, their permeability). As an initial approximation, it is generally assumed that the separation between one fluid and another can be represented by a line, called ‘contact’, which is identified at the intersection of the lines corresponding to the pressure gradients of the different fluids in the reservoir. The position of the contact determined in this way does not exactly correspond neither to the depth at which the capillary pressures are zero (since the pressure values are altered by the presence of drilling mud filtrate, which has encroached into the formation near the wellbore), nor to the depth at which

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**Fig. 2.** Checking for hydraulic communication within a reservoir.

**Fig. 3.** Lenticular reservoir.
the least dense fluid becomes mobile (which can be determined only through logs). Nevertheless, the above provides a useful indication of the different hydrocarbon bearing intervals thickness, as well as the position of the aquifer. Since gas, oil and water are the only fluids present in a reservoir, only three types of contacts can exist: oil-water, gas-oil and, in the event there is no oil, gas-water. Even if the quantitative information on the contacts between the fluids (which may be obtained from the pressure data) is not precise, nonetheless, it is very useful from a qualitative point of view, since, in the absence of geological or log information, it can confirm the presence of a gas cap or an aquifer.

Pressure gradient analysis

Pressure data recorded in static conditions are often indispensable to better understand the information obtained through seismic or geological surveys. This is the case especially during the phase of initial characterization or delimitation of the reservoir, such as when faults are detected, but it is uncertain whether they form impermeable barriers. A comparison of pressure profiles obtained in different wells enables one to determine if the wells have penetrated reservoirs that are not in hydraulic communication or, instead, drain the same reservoir, thereby establishing whether any faults that may cross the reservoir form impermeable barriers. In order to confirm that hydraulic communication exists between two or more wells in a reservoir affected by tectonic events, the initial trend of the pressure measurements would have to be the same everywhere (although this alone is not proof enough); in such a case, it is possible to plot the pressure values recorded in the different wells where the same fluid is present onto a single gradient, ignoring the exceptions caused by errors in the measurements. However, it is still possible for the different zones to be separate although they may have the same initial pressure trend, and it may only be after production has started that the separation becomes evident. On the other hand, if the depth related static pressure data measurements taken in the different wells are aligned along two or more distinct lines, it indicates that there is no hydraulic communication (Fig. 2). The fact that the pressure profiles recorded in different zones of the reservoir have an identical form (i.e. they follow the same gradient) confirms that they relate to the same fluid.

On the basis of the trends and pressure gradients obtained from the data processing, it is also possible to identify certain recurring reservoir configurations. In the case of a lenticular reservoir, the gradient depends solely on the density of the hydrocarbon present, though the pressure cannot be compared with that in neighbouring zones, since it relates to an abnormal hydraulic regime that may be at either abnormally high or abnormally low pressure when compared with normal hydrostatic pressure (Fig. 3). In the case of reservoirs that are separate but share a common regional aquifer, the pressure of the hydrocarbon zones will differ one from another, although they all derive from the same hydraulic gradient. At this point, it is possible to determine the hydrocarbon-water contact for each reservoir (Fig. 4). In the case of a reservoir composed of several levels containing hydrocarbons of the same composition, but with different hydraulic regimes, both gradients relating to the aquifers as well as those relating to the hydrocarbon horizons will bear similarities, though they will not be aligned along the same line (Fig. 5).

Finally, through a comparison of pressure profiles recorded on the same well but at different times (generally at intervals of several years), it is possible to confirm whether the reservoir has lost energy and to identify the acting drive mechanism. If both the hydrocarbon zone and the aquifer have been encountered in the same well and the pressure profiles
recorded at different times are available, it may be ascertained that the hydrocarbon-water contact has risen. If during production the line representing the pressure gradient of the hydrocarbons moves parallel, but that recorded in the water zone remains unchanged, this means that a very active aquifer is present (Fig. 6); however, when the pressure profiles of both the water and the hydrocarbon zones are merely offset parallel to the original ones, the reservoir is of volumetric type and the horizontal offset of the pressure profile indicates a loss of energy from the system (Fig. 7). In this case, the aquifer is not active, or only slightly so, and the depth of contact will remain practically unchanged.

**Initial reservoir pressure**

When the measured pressure of the reservoir fluid is the same as the pressure that would be exerted by a column of water with a height span from the point of measurement at subsurface depth to sea level, the reservoir’s pressure is referred to as hydrostatic. Since hydrocarbons are found in the interstitial spaces of the reservoir rocks, which at one time formed the underwater sedimentary basins where the hydrocarbons accumulated through the expulsion of the water originally present, the initial pressure of the fluids in the reservoir is usually equal, or very close, to hydrostatic pressure. Nevertheless, it is possible that in specific geological circumstances the fluids may be subjected to abnormal pressure conditions, or, more specifically, to a pressure either below (subhydrostatic pressure) or above (abnormally high pressure) hydrostatic pressure. The causes of abnormal initial reservoir pressures are frequently traceable to tectonic movements, which took place after the hydrocarbons had accumulated in the reservoir rock. The formations affected by compressive tectonic activities are characterized by alternating compressed and expanded zones. In the former, the reduction of the pore volume induces an increase in the original pressure of the formation fluids, whereas in the latter there is an increase in the pore volume, causing a drop in pressure. The process of expansion of the sediments, linked to conditions of subhydrostatic pressure, can also be triggered by a reduction of the geostatic load, as a result of the earth’s surface rising followed by subsequent erosion.

Occasionally, abnormally high pressure conditions can be brought about by unusual hydraulic systems, for example when the formation outcrops at a higher elevation and thus becomes saturated with meteoric water. In this case, the hydrostatic pressure no longer equals that of a water column corresponding to the level depth (measured either from sea level or from the ground level of the well). Instead, it is equal to that of a higher column corresponding to the difference in level between the point of the outcrop and the underground level. Nevertheless, abnormally high pressure conditions are often also caused by abnormal development in the process of sedimentation occurring

![](https://example.com/image1.png)

**Fig. 5.** Multi-layer reservoir with different hydraulic regimes.

![](https://example.com/image2.png)

**Fig. 6.** Reservoir in contact with an active aquifer.
in the areas of certain deposits, as a result of an imbalance in the rates of sedimentation, compaction of the sediment and expulsion of the interstitial water. In rapidly subsiding basins, one may observe that the rate of sedimentation is greater than the rate of expulsion of the interstitial water and, therefore, the sediment is only partially compacted, and the geostatic load is partly sustained by both the reservoir matrix and the fluids, resulting in abnormally high pressure conditions. Moreover, when the intrusion of salt formations (salt domes) takes place in overlapping sediments, caused by the lower density and the plastic behaviour of salt, the adjacent formations are subjected to compression, resulting in an increase in the pressure of the fluids contained within.

Finally, abnormally high pressures can be due to chemical-physical processes, which include the formation of new minerals following variations in pressure and temperature, the recrystallization of substances present in the sediment, and the lithification and precipitation of cementing material contained in carbonate, sulphate and silica solutions in the formation water.

4.3.2 Drive mechanisms

The production of hydrocarbons is considered primary when it occurs due to the energy within the system itself; in other words, when it makes use of the pressure already in the reservoir. The sum of the forces that act on the hydrocarbons present in the reservoir and that are capable of making them move through the reservoir rocks, thus enabling production at the surface, are called natural drive mechanisms, or primary production mechanisms. Knowledge of these mechanisms is fundamental to accurately predict the reservoir’s behaviour during production, and to estimate the amount of recoverable hydrocarbons in relation to the quantity initially present in the reservoir, referred to as the primary recovery factor of hydrocarbons. In general, the primary recovery of gas is fairly high, since gas is a very compressible fluid, whereas the primary recovery of oil can result very low. To obtain an additional quantity of oil greater than that which is naturally recoverable, it is necessary to supply energy to the system through the injection of water or gas in a non-miscible phase (or, in some cases, both) with the objective of maintaining the reservoir pressure either entirely, or in part, and sweeping the oil towards the production wells. Historically, oil recovery through the injection of fluids into the reservoir has been described as secondary, while the additional quantity of oil produced through the injection of gas in a miscible phase (which reduces the viscosity and tends to lower the residual oil saturation) has been referred to as tertiary recovery. In addition, there are thermal processes (which apply heat to the system to reduce the oil’s viscosity) and chemical methods (which alter the characteristics of the reservoir fluids or their interactions with the reservoir rocks).

Nowadays, in order to stray from the idea of a chronological sequence implied by the definitions of ‘secondary’ and ‘tertiary’ recovery processes, which often do not reflect the actual sequence of hydrocarbon exploitation, it is preferable to divide the processes capable of improving the primary recovery into two categories: improved recovery processes (the so-called secondary recoveries, i.e. injection of water and/or gas in a non-miscible phase) and enhanced recovery processes (the so-called tertiary recoveries, or enhanced oil recovery).

The drive mechanisms that make use of the natural energy in the reservoir referred to certain characteristic typologies, which generally are associated with the compressibility of different components of the system. Compressibility is a property that describes the variation in volume of the fluids and the reservoir rocks, and occurs as a result of a variation in pressure. In particular, due to this drop in pressure, the fluids that saturate the formation tend to expand and fill the pore volume previously occupied by the hydrocarbons produced at the surface. At the same time, the pore volume available for these fluids tends to diminish as a result of both the expansion of the rock matrix and, possibly, the compacting effect of the formation, caused by an increase in the effective stress (Terzaghi’s principle). Nevertheless, since the compressibility of rock and water (in the order of $10^{-4}$ MPa$^{-1}$) is generally less by an order of magnitude compared to that of oil (in the order of $10^{-3}$ MPa$^{-1}$), and of two
orders of magnitude compared to that of gas (in the order of $10^{-2}$ MPa$^{-1}$), the effects of a reduction in pore volume and expansion of connate water are often negligible. Clearly, the compressibility of the rock can be significantly greater (in the order of $10^{-3}$ MPa$^{-1}$), especially in formations that are neither very deep nor very compacted, and therefore must be taken into high consideration. On the other hand, even though the compressibility of water is limited, the expansion of any aquifer in contact with the hydrocarbon reservoir may be sufficient to greatly offset the pressure decline, if not almost entirely. Clearly, this expansion of the aquifer is proportional to its volume and extension.

In a field, there is almost always more than one mechanism that contributes to production, but in general one alone predominates over the others. Fields with the same dominant drive mechanisms share common traits in terms of performance and efficiency, such as the ultimate recovery factor, the rate of the decrease in pressure, the evolution of the production gas/oil ratio, and any water production related to the mechanism.

The production gas/oil ratio (GOR) is the ratio between the gas rate and that of oil, both under standard conditions, produced from a well drilled into an oil field. This parameter is particularly indicative of the reservoir conditions, since the gas/oil ratio remains constant and equal to the solution GOR, as long as the reservoir pressure is greater than the saturation pressure of the oil, while it progressively increases the lower the reservoir pressure in relation to the saturation pressure. By monitoring the change in the production gas/oil ratio during exploitation, it is possible to determine if and when the reservoir pressure has fallen below the oil’s saturation pressure.

**Natural depletion drive**

When a reservoir is completely bounded due to the presence of faults and/or impermeable formations around its boundaries (ignoring the reservoir rock’s reduction in pore volume and the expansion of the connate water), the space available to the hydrocarbons varies very little during production: in this situation, the reservoir performance is defined as being volumetric type. For volumetric reservoirs bearing gas or under-saturated oil, the main drive mechanism for the primary recovery is manifested through the expansion of the hydrocarbons contained within, referred to as natural depletion drive. When the formation is gas bearing, since the compressibility of gas is quite high (in the order of $10^{-2}$ MPa$^{-1}$), the expansion mechanism of the hydrocarbons is very efficient and can achieve very high rates of recovery, as much as 80-90% of the gas volume originally in place. In a gas field, a reduction in pore volume and expansion of connate water generally contribute very little to production; nevertheless, reservoirs initially under abnormally high pressure conditions are an exception, for which the effect of a reduction in pore volume may not be negligible. In volumetric gas reservoirs, the final recovery percentage depends on the initial pressure of the reservoir, its abandonment pressure and the composition of the gaseous mixture contained within the reservoir, though not dependant on time, nor the adopted production strategy. The abandonment pressure (i.e. the pressure at which production is stopped) is determined on the basis of technical considerations (operating pressure of the natural gas pipeline) and economic considerations (the cost of gas recompression), and depends on the minimum gas rate that can be produced economically. If the formation contains under-saturated oil due to the fairly low compressibility of oil (in the order of $10^{-3}$ MPa$^{-1}$), while taking into account the contribution of the reduction in pore volume and the expansion of the connate water, the natural depletion drive mechanism results in very low recovery factors, usually between 2-5% of the volume of oil originally in place. During the natural depletion phase, above the oil saturation pressure, the quantity of gas produced corresponds to the quantity dissolved in the oil produced (or rather, to the solution gas-oil ratio).

**Dissolved gas drive**

When the pressure in an oil field falls below the saturation pressure as a result of production, the gas dissolved in the oil begins to liberate and expand. Under such conditions, due to the greater compressibility of gas, the drive mechanism of the oil is primarily derived from the expansion of the liberated gas and the consequent displacement of the oil at a microscopic level from the pore spaces of the rock in which it is contained. This occurrence is defined as a dissolved gas drive mechanism. In the initial phases of exploitation, this mechanism can be very effective in the recovery of oil. However, over a longer period of time, the reduction in the quantity of gas dissolved in the oil and the consequent increase in the reservoir’s gas saturation produce two negative effects: on the one hand, a reduction in the effective permeability to the oil, due to the progressive reduction of its saturation, in favour of that of the gas, and the progressive increase in the oil’s viscosity caused by the liberation of the lighter components. Both occurrences result in the reduced mobility of oil compared to that of gas; therefore, during the exploitation of the field, a rapid increase in the production gas/oil ratio occurs. The oil recovery possible through expansion of the dissolved gas is 15-20% of the oil initially in place.
Gravity segregation

The force of gravity responsible for the segregation of reservoir fluids, as a result of their respective density, generally does not play a fundamental role in the recovery mechanisms. However, in some circumstances, such as reservoirs that are very thick or steep, the effect of the gravity segregation of the formation’s fluids can significantly influence and actively contribute to hydrocarbon production. The drive mechanism caused by gravity segregation may be considered a case of dissolved gas drive, the effectiveness of which is enhanced. Due to gravity, the amount of gas liberated from the oil tends to move towards the highest part of the reservoir, generating an equivalent counter-flow of oil downwards, and creates a secondary gas cap. In this case, the best exploitation strategy consists of drilling the wells into the deepest part of the reservoir, where the most oil accumulates while the gas moves away. Final recovery depends on the oil’s viscosity, the total thickness of the reservoir, the tilting angle of the reservoir, the formation’s permeability, both vertically and along the direction of immersion of the beds, and the production regime, but generally ranges from 25-30%.

Gas cap drive

At times, an accumulation of gas above an oil bearing zone is present, known as a gas cap, which can be of either primary or secondary origin. A gas cap is considered primary if it forms during the migration of the hydrocarbons in the reservoir rock (i.e. if it is present before the field is put into production). Instead, secondary gas caps form during exploitation, under the following circumstances: through the liberation of gas from the oil, once the pressure has fallen below the saturation pressure, or through the injection of external gas (gas injection). Usually, if a primary gas cap exists, the reservoir oil is very close to saturation conditions. Therefore, once production begins and the pressure starts to decline, there is a liberation of new gas, which expands along with the gas in the cap. The expansion of the gas cap tends to sweep out the oil and partially compensates for the pressure decline caused by production. The ability of the gas cap to maintain the pressure in the reservoir is dependent on the volume of gas present in that location and the production strategy adopted. In particular, since gas cap drive enables a higher final recovery of oil compared with that of dissolved gas drive, the strategy for reservoir exploitation should be rightly formulated to favour the former. To avoid an early gas breakthrough in the wells, it is important that they are positioned in such a way that the intervals open to production are located as far as possible from the original gas-oil contact. Moreover, it is good practice to implement a production regime that is slow enough to allow the liberated gas to rise towards the cap, rather than to flow towards the production wells. The final oil recovery percentage thus depends on the vertical permeability and the degree of heterogeneity of the formation, as well as the viscosity of the oil and the ability to produce it while preserving the gas cap, in other words without inducing the formation of cones of gas (gas coning). In fact, there is a risk of causing a local deformation of the gas-oil contact, especially if the flow rate of the oil is high, drawing the gas cap towards the wells that are open for production in the oil zone.

During exploitation of the reservoir, the production gas/oil ratio rises progressively both as a result of the increase in free gas saturation, and the effect of the expansion of the gas cap, which, in time, tends to invade the area originally occupied by the oil. The final oil recovery that can be achieved though gas cap drive mechanism is 25-30%.

Water drive

The accumulated hydrocarbons are often bounded, either below or laterally, by aquifers (i.e. zones saturated with water belonging to the same porous formation forming the trap where the hydrocarbons accumulated), which can have a relatively large extension beneath the hydrocarbon-water separation contact. An aquifer is considered ‘limited’ when independently of the volume of water that it encloses, it is bounded by impermeable rock that together with the hydrocarbon formation constitutes a single hydraulically sealed system. An aquifer is referred to as ‘infinite’ when its extension is very large, or if it is in contact with either superficial porous formations (which allow the aquifer to replenish with rain or surface water), or the sea bed. Moreover, aquifers can be classified as more or less active depending on their dynamic behaviour, which becomes apparent during the exploitation phase or, more specifically, on the water flow necessary in order to feed the reservoir. This behaviour depends on the aquifer’s size, the permeability of the porous formations in which it is contained, and the production regime imposed by the reservoir. The aquifer’s ability to replace the volume of oil or gas produced, through the entry of equivalent volumes of water into the reservoir, is linked to the expansion of the rock-water system, of which it is composed. The reaction, and therefore the activity, of the aquifer itself varies over time, since the change in pressure caused when the reservoir initiated production does not have an immediate effect throughout the entire aquifer, but propagates across it at a finite rate.

In the case of oil reservoirs, the drive mechanism related to the aquifer expansion (water drive) generally enables one to achieve higher recovery
factors than with other natural drive mechanisms; the final recovery depends on the characteristics of the aquifer, the viscosity of the oil, and the water’s efficiency in displacing the oil. In particular, as the degree of heterogeneity of the formation increases, a lower oil recovery is achieved since the advancement of the water front is not uniform. In fact, the water that moves along the preferred flow paths (i.e. wherever the permeability is greater) can reach the production wells before (or even without) having displaced even extensive portions of the reservoir. On average, the achievable recovery factor when an active aquifer is present can vary between 30-50%. Under the most favourable conditions, in the case of medium or lightweight oils in contact with very active aquifers, pressure maintenance reduces the liberation of dissolved gas. This diminishes the viscosity increase of the oil and the gas saturation, which helps increase the oil’s mobility, thus improving the displacement efficiency. In this case, recovery may exceed 50-60%. When an aquifer is only partially active, or altogether absent, it is often necessary to inject water from an outside source in order to artificially reproduce the natural drive action generated by an active aquifer.

The presence of an active or partially active aquifer inevitably results in a considerable production of water, especially in the case of heavy and viscous oils. In order to limit the production of water, it is necessary to locate the wells in the top zones of the reservoir (i.e. furthest away from the oil-water contact), and maintain the lowest production level possible within the economic constraints. This strategy offers two benefits: it provides the aquifer enough time to react to the change in pressure caused by production, and reduces the local phenomena of deformation of the oil-water contact, which carries with it the risk of drawing encroaching water into the wells (water coning). The formation of water cones can occur above all in the presence of high capillary pressures, which can create an extended transition zone, where both water and oil are in motion, with the water mobility equal to, or greater than, that of the oil.

When an active aquifer is present, or even when water is injected, the production gas-oil ratio tends to remain constant during the productive life of the field. This occurs since the liberation of gas dissolved within the oil is inhibited by the natural, or artificial, pressure maintenance, whose values equal or exceed the saturation pressure.

In the case of gas fields, the presence of a very active aquifer generally has an adverse effect on the final hydrocarbon recovery (whose values possibly fail to reach 60-65% of the gas volume originally in place), as compared with the natural depletion mechanism. A very active aquifer can also cause a majority of the wells to flood with water and cease production, even though the reservoir pressure may remain fairly high. Moreover, behind the front of displacement water, there is always a residual gas saturation, which at times can be as high as 30-40%; consequently, the higher the abandonment pressure, the greater the amount of gas that will remain in the reservoir. Regarding final recovery, unlike oil, gas should be produced as quickly as possible, in order not to allow sufficient time for the aquifer to react, thus favouring expansion of the gas itself. Nevertheless, one should also bear in mind that maintaining the reservoir pressure by means of the aquifer makes it possible to achieve higher productivity (higher production rate) and, therefore, at times it may be better to settle for a compromise solution that optimizes the production strategy both in terms of final recovery and productivity.

4.3.3 Material balance

The general form of the material balance equation was presented for the first time by R.J. Schilthuis in 1936. The equation formulates a balance of volumes in which the observed cumulative production, expressed as the underground recovery, is considered equal to the expansion of the fluids still remaining in the reservoir (including the water of any aquifer in contact with the hydrocarbon zone), caused by the finite pressure decline induced by production itself. In other words, the material balance equation conveys the concept that the algebraic sum of the variations in the volumes of oil, gas and water in the reservoir must equal zero, also taking into account that the pressure decline induced by production causes a reduction in the available pore volume. The material balance, written in volumetric terms, can thus be expressed as:

\[
\text{Volume of fluids produced} = + \text{Expansion of oil and dissolved gas} + \text{Expansion of gas cap} + \text{Expansion of rock and connate water} + \text{Reduction of pore volume} + \text{Cumulative volume of water which invades the reservoir}
\]

Since volumes are a function of pressure and temperature, they must relate to conventionalized standard conditions (or stock tank). Therefore, the volumes of the different fluids under reservoir conditions are related to the reference conditions, by applying the respective volume factors.

The general material balance equation for a gas field is:

\[
G_p = G - \frac{GB_g}{B_g} \left( W_e - W_e B_e - W_w B_w \right)
\]
where $G$ is the original volume of gas in the reservoir (or GOIP, Gas Originally In Place); $G_p$ is the total volume of gas produced up to a specific point in time, corresponding to when the average reservoir pressure has reached value $P_s'$; $B_g$ is the volume factor of the gas at the reservoir’s initial pressure; $B_w$ is the volume factor of the gas at pressure $P_s'$; $W_w$ is the water volume related to the reservoir conditions, invading the reservoir as a result of the gas production $G_p'$, and the consequent decrease from the initial pressure value to the average value $P_s'$; $W_p$ is the total volume of water produced, and $B_w$ is the volume factor for the water.

In the case of oil reservoirs, the general material balance equation takes account not only of a potential aquifer invading the reservoir as a result of the production, but also of the possible presence of a gas cap (whose volume is defined in relation to the oil volume in place, measured under the reservoir conditions). The equation for oil, though written in terms of gas volumes (in accordance with the custom now established in relevant literature) is:

$$G_p = N_{Bo} + m \frac{N_{Bo}}{B_o} \left[ (N - N_p)R_s + \frac{NB_o + mNB_o - (N - N_p)B_o}{B_o} W_w - W_p B_o \right]$$

where $N$ is the original volume of oil in the reservoir (i.e. OOIP, Oil Originally In Place); $N_p$ is the total volume of oil produced up to a specific point in time, corresponding to when the average pressure of the reservoir has reached value $P_s'$; $B_o$ is the volume factor of the oil at the reservoir’s initial pressure; $B_w$ is the volume factor of the oil at the average pressure $P_s'$; $R_s$ is the solution gas-oil ratio at initial reservoir pressure; $R_s$ is the solution gas-oil ratio at average pressure $P_s'$; $m$ represents the ratio of the free gas volume initially present in the reservoir (i.e. the gas cap), $GB_{o,p}$, to the volume of oil initially present in the reservoir, $NB_{o,i}$. With reference to the notation previously mentioned, $W_w$ is the volume of water related to the reservoir conditions, which invaded the reservoir as a result of the production of oil $N_p$, and the consequent decrease in pressure from its initial value to the average value $P_s'$; $W_p$ is the total volume of water produced, and $B_w$ is the volume factor of the water.

The equation is zero-dimensional; in other words, no reference is made to the reservoir’s spatial dimensions, nor to the variations in its petrophysical or thermodynamic characteristics. This is the case since a reservoir is considered a region defined by average global parameters (i.e. total volumes of oil, gas and water, and relevant average values of pressure and saturation at each time step). The above infers that the reservoir is in a state of equilibrium. One of the greatest difficulties in applying the material balance equation lies in determining a realistic average pressure for the reservoir. The parameters depending on this quantity are then evaluated using the above pressure value. In the case of gas fields, unless the permeability of the formation is particularly low, the average pressure determined by evaluating the production tests carried out on a single well may be considered representative of the entire reservoir, since the high mobility of gas generally ensures that the system’s energy loss will be fairly uniform. Instead, in the case of oil reservoirs, it is possible for production to cause in pressure sinks, which may vary within the reservoir; as a result, the average estimated pressure determined by means of the above mentioned production tests may not be representative of the entire reservoir, but of only a specific zone.

Material balance equations have long been considered one of the fundamental tools to understand and predict the behaviour of hydrocarbon fields. Currently, the classic techniques based on material balance, for the most part, have been superseded by numerical simulations, which allow one to quantitatively define how the flow of several fluid phases evolve both in space and time, even in heterogeneous and geometrically complex reservoirs. Nevertheless, using material balance equations can still be very helpful to estimate the volume of hydrocarbons originally in place and, therefore, to confirm the results obtained through volumetric calculations based on log and geological information. Moreover, it is possible to identify the reservoir’s drive mechanism and, in particular, to discover whether the reservoir itself is of volumetric type, or if an active, or partially active, aquifer is present, which would supply energy and slow down the pressure decline caused by production. One of the most widespread methods of applying the material balance is that proposed by D. Havlena and A.S. Odeh, based on the consideration that, in the case of a volumetric reservoir, at any time the sum of the fluid volumes produced is equal to the volume of hydrocarbons originally in place, multiplied by the sum of the terms that express the expansion of the fluids in the reservoir and the contraction of the pore volume. Therefore, the observed production must be a linear function of the expansion of the fluids in the reservoir, evaluated on the basis of the PVT (pressure, volume, temperature) parameters at the average reservoir pressure reached as a result of production. The deviation of the actual data from a linear trend indicates the presence of an active or partially active aquifer or even, in the case of an oil reservoir, of a gas cap. In the case of gas fields, the material balance equation can be rewritten as:
If the first part of the equation (i.e. all terms relating to production) remains constant, then the water encroachment into the reservoir will be zero \((W_e=0)\), and the value of the above terms, at any time in the productive life of the field, will be equal to \(G\), the gas volume originally in place. If the first part of the equation increases in a non-linear form, term \(W_e\) present in the second part of the equation will also tend to increase, signifying the presence of an active aquifer progressively invading the reservoir (Fig. 8).

In a completely analogous way, it is possible to identify whether an aquifer is present even in the case of under-saturated oil reservoirs. The material balance equation in this case becomes:

\[
N_B g + W_p B_g = N_B g (P_i - P_a) + W_e \left( \frac{B_i}{B_g} - \frac{B_o}{B_g} \right)
\]

where \(P_i\) is the reservoir’s initial pressure, \(P_a\) is the average pressure reached as a result of the total production of oil \(N_c\), and \(c_{ae}\), is the equivalent compressibility of the oil, equal to:

\[
c_{ae} = \frac{c_o (1-S_{wo}) + c_w S_{wo} + c_g}{(1-S_{wo})}
\]

in which \(c_o\), \(c_w\), \(c_g\) are the compressibility of the oil, the water and the rock respectively, and \(S_{wo}\) is the irreducible water saturation.

In the case of volumetric fields, production takes place through a mechanism called natural depletion. The terms relating to the volumes of water are zero, and thus the material balance equations become more simple; the only unknown is the volume of gas or oil originally in place in the reservoir.

In the case of volumetric gas reservoirs, the equation becomes:

\[
G_p = \frac{G (B_g - B_o)}{B_g}
\]

Taking account of and substituting the expression that defines the gas volume factor, one obtains the following equation:

\[
P = \frac{P_i}{z} = \frac{P_i}{z_i} - \alpha G_p
\]

where \(z\) is the gas compressibility factor. The values \(P/z\), plotted as a function of the gas produced \(G_p\), tend to align along a straight line with slope \(-\alpha\). Extrapolating this curve until it intersects the \(x\) axis \((P=0)\), one obtains the value of the gas originally in place \(G\) (Fig. 9).

Regarding under-saturated volumetric oil fields, the equation can be reduced to:

\[
N_B_i g + W_p B_g = N_B_i c_{ae} (P_i - P_a)
\]

In this case the terms representing the production \(N_B_i g\), plotted as the function of the product \(B_i c_{ae} (P_i - P_a)\), tend to align along a line that passes through the point of origin with an incline equal to \(N\) (Fig. 10).

4.3.4 Displacement processes

In displacement processes, the fluid initially present in the pores of the reservoir rock is removed and replaced by a second fluid, with which it is not miscible. A displacement process can take place either naturally (e.g. when the connate water, which is present since the formation of the rock, or the gas cap invades the oil bearing zone following a decline in pressure caused by production), or by means of injection from the surface of either water, as in most cases, or gas. In oil fields, water drive is the drive mechanism that results in the highest recovery factor. When they lack a natural aquifer maintaining reservoir pressure, injecting water thus becomes the preferred method both to maintain the pressure of the reservoir at a value equal to or slightly higher than saturation pressure, and also to sweep the oil towards the production wells. Nevertheless, whenever the gas associated with the oil produced can neither be commercialized profitably nor flared, due to environmental and energy-saving regulations, re-injecting it can be useful to maintain the reservoir pressure. However, since displacing the oil by means of an immiscible gas is not always very efficient, generally gas injection may be alternated periodically with water injection, in order to increase the final recovery factor. In fact, during the immiscible displacement process, a fraction of the hydrocarbon always remains trapped in the pores of the reservoir rock, which cannot be recovered. The quantity of residual fluid depends on the pore structure of the reservoir.

**Fig. 8.** Identification of the drive mechanism of a gas reservoir.
porous medium, on the existing interactions between the fluid and the rock, and the interaction between the fluid being displaced and the displacement fluid.

On the other hand, in processes where the oil is displaced by means of a gas in a miscible phase, the oil and the injected gas form a single fluid phase, which in turn is displaced by the injection of additional gas or water. Since in this case the saturation of residual oil tends to be reduced to zero, in that no interfacial tensions between the oil and the gas exist, the displacement is usually very efficient and produces high final recovery values.

The quantity of oil that can be recovered by means of a displacement process depends both on the efficiency of the displacement at a microscopic level (i.e. the quantity of oil that can be removed from the pores in which it was originally contained), and on the efficiency of the displacement at a macroscopic level (i.e. the volume of the reservoir that the displacement fluid is able to invade). The oil recovery factor, which indicates the percentage of oil produced in relation to the amount originally present in the reservoir, is defined as the product of the microscopic displacement efficiency and the macroscopic displacement efficiency. The microscopic displacement efficiency depends on the ability of the displacement fluid to drive the oil out of the microscopic pores, and is calculated as the percentage of oil recovered from any given volume of reservoir rock with respect to the total volume of oil originally present. The efficiency of macroscopic displacement depends, instead, on the ability of the displacement fluid to invade large areas of the reservoir, regardless of the existing heterogeneity, and it is calculated as the percentage of pore volume invaded by the displacement fluid with respect to the reservoir’s total pore volume (see below).

**Immiscible displacement**

In the processes of immiscible displacement, the composition of the displacement fluid (e.g. water) and the displaced fluid (oil) remains unaltered and a separation interface is maintained throughout the entire process; water and oil constitute two completely distinct fluid phases. A process of immiscible displacement can occur naturally where an active aquifer is present, or can be produced by injecting water as the displacement fluid, as is usually the case, or a dry gas.

**Microscopic displacement efficiency**

Microscopic Displacement Efficiency (MDE) reflects the residual oil saturation value, that is, the oil left behind in the formation after the passage of the displacing fluid (Fig. 11). Oil saturation refers to the fraction of the rock’s pore volume filled with oil, and is dependent on the shape and dimensions of the pores, the properties of the oil, and the interaction between the rock and the fluids governed by interfacial tensions and wettability (the tendency of a fluid to stick to the rock’s surface, see Chapter 4.1). When two immiscible fluids come into contact with a solid surface, one is usually attracted to the wall more strongly than the other; the phase that sticks more strongly to the surface is called the ‘wetting’ phase. If the reservoir rock is water-wet, a thin film of water forms that adheres to the walls of the rock, while the oil remains confined within the pores. In the case of a rock that is oil-wet, the exact opposite occurs. The wettability of a rock is generally ‘mixed’ with respect to the various fluids present, and is dependent on the physical and chemical composition of the rock, as well as the composition of the fluids. Wettability is a fundamental property, being that it influences the fluid saturations and relative permeabilities. The relative permeability to a fluid is defined as the ratio between the effective permeability to that fluid and the absolute permeability of the rock. Absolute permeability is an intrinsic property of reservoir rock, and defines the
ease with which a fluid can flow through the interconnected pore spaces when the rock is saturated in a single fluid, whereas effective permeability defines a fluid’s ability to do the same in the presence of other fluids (water, gas, oil).

Therefore, relative permeability is a property that is dependent on the fractions or saturation degree of the different fluids present in the porous medium, and by definition can vary between zero and one. The greater the percentage of fluid present in the porous medium, the higher its relative permeability will be. On the other hand, every fluid has a saturation point, referred to as critical saturation; below this point, the fluid is no longer mobile, though still present within the porous medium; at that point the relative permeability becomes zero. During a displacement process, the relative permeability to the oil decreases progressively with the increase in the amount of water either injected into the reservoir or introduced through expansion of the aquifer. This occurs as a result of the water gradually occupying a greater fraction of the pore volume, which causes a corresponding reduction in the volume of oil. When the relative permeability to the oil is reduced to zero, the oil has reached its critical saturation point, also referred to as residual oil saturation.

The flow and distribution of the fluids within the porous medium are also influenced by interfacial tensions (i.e. the forces that develop on the separation surface between two non-miscible phases). The effects of these forces that occur at the interface between the fluids in contact are evaluated by measuring the capillary pressure (see Chapter 4.1), which is equal to the difference in pressure between the non-wetting phase and the wetting phase. The capillary pressures, together with the gravity forces, determine the vertical distribution of the fluids in the reservoir. The parameters that influence capillary pressures most, and, therefore, also the efficiency of microscopic displacement, are both the fluid saturation of the rock and the geometry of the pores. Experiments that evaluate the variation of relative permeability to a fluid in relation to its saturation, the wettability of the rock, and the capillary pressures, are fundamental in order to accurately plan a displacement process and predict future production rates.

To evaluate and define the efficiency of microscopic displacement, the theoretical approach is based on the Buckley-Leverett equation, also known as the fractional flow equation. The above enables one to define the process of displacement between immiscible fluids in the following conditions: a) monodimensional system; b) two-phase and equicurrent flow (i.e. two immiscible fluids flowing in the same direction and at the same velocity); c) incompressible fluids; d) homogeneous and incompressible porous medium; e) stationary flow conditions (i.e. where pressure does not vary with time); f) non-mobile connate water (i.e. present at its critical or irreducible saturation).

In common cases of displacement through water injection, the Buckley-Leverett equation makes it possible to calculate, at any point of the formation, the fraction of water \( f_w \) flowing from the porous medium with respect to the total flow rate \( q_{tot} \). The latter refers to the sum of the flow rate of water \( q_w \) and that of oil \( q_o \):

\[
f_w = \frac{q_w}{q_{tot}} = \frac{q_w}{q_w + q_o}
\]

If the flow rates of both water and oil derive from a generalized form of Darcy’s law, and their expression is substituted in the water fraction definition, the...
Buckley-Leverett equation becomes the following:

\[
f_w = \frac{1 + k_w \mu_o / k_o \mu_w}{1 + k_w \mu_o / k_o \mu_w} \left( 1 + \frac{k_r \mu_w}{\mu_o} \frac{\partial p_r}{\partial L} \right) \sin \alpha + g(q_w - q_o) \sin \alpha
\]

where \( A \) indicates the section of outflow and \( L \) the length of the porous medium; \( k_r \) represents the effective permeability to the oil; \( k_w \) and \( k_o \) are the relative permeabilities to the oil and water respectively; \( \mu_o \) and \( \mu_w \) are the viscosities of the oil and water; \( q_o \) and \( q_w \) are the densities of the oil and water; \( P_c \) represents the capillary pressure; \( \alpha \) is the angle of entry (or of injection) of the water into the reservoir relative to a horizontal plane; \( g \) is the gravity acceleration.

The local fraction of water \( (f_w) \), which by definition must range between zero and one, in practice variable between \( S_w \) (saturation in connate water) and \( 1 - S_{or} \) (maximum saturation in water, corresponding to the residual saturation in oil), is dependent on relative permeabilities and capillary pressure. If the characteristics of the fluids and the porous medium are equal, it is a function of the medium’s water saturation \( (S_w) \) where the displacement takes place (Fig. 12). The Buckley-Leverett equation identifies three terms, relating to three forces acting on the fluids: viscous, gravitational and capillary forces. The viscous forces have the greatest impact on the fraction of water flowing through the formation, and are dependent on the mobility of both water and oil (the mobility of a fluid is defined as the ratio between the effective permeability to that fluid and its viscosity). Regarding viscous forces, it is evident that as the viscosity of oil increases, the efficiency of displacement decreases. In order to increase oil recovery, these forces should be as minimal as possible; in other words, one must either decrease the ratio between the viscosities of oil and water, or increase the ratio between the relative permeability to the oil and that to the water. However, generally it is not possible to carry out these types of interventions, mainly for economic reasons.

Gravitational forces depend on a number of parameters, but mainly on the differences in density between the displacement fluid and the displaced fluid, and on the flow direction of the displacement fluid in the reservoir. From the analysis of these forces it can be reasoned that when water acts as the displacement fluid, since its density is greater than that of oil, in order to obtain a high oil recovery, displacement must take place from the bottom upwards. If, instead, the displacement fluid is gas, due to its lower density than that of oil, displacement should take place from the top downwards. Finally, capillary forces also depend on several parameters, in particular, on their variation along the direction of flow; furthermore these forces, and others such as gravitational forces, vary depending on the absolute permeability and the apparent velocity of the displacement front, which is equal to the ratio of the total flow rate to the section of the porous medium perpendicular to the direction of flow. If the displacement takes place slowly, a greater recovery of hydrocarbons can be achieved, since the fraction of water is directly proportional to the absolute permeability, and is inversely proportional to the apparent velocity of the front.

Thanks to the Buckley-Leverett equation, with which it is possible to calculate the percentage of water from the total carrying capacity, the Welge method has been developed. The latter method enables one to evaluate how the displacement front evolves within the formation and estimate the average water saturation of the porous medium. Therefore, in using the Welge method, one can determine the microscopic displacement efficiency at the breakthrough time – the time necessary for the water displacement front to cover the distance from the injection point to the production point. In fact, since the mobility of the displacement fluid and the displaced fluid are different, the water front does not move uniformly in the porous medium, in an ideal piston-like flow. Instead, it encounters a transition zone of water saturation, influenced by the injection rate and, thus, by the velocity at which the front is moving. If the water saturation behind the displacement front is low, a large quantity of oil will be found when the front reaches the production well, still remaining behind the front: in such a case, recovery is low and water must continually
be injected. If, instead, the water saturation behind the displacement front is high, most of the oil will have been displaced when the front reaches the production well, resulting in high displacement efficiency. When fluids are incompressible (i.e. the volume of displacement fluid is equal to the volume of the fluid displaced), knowing the average water saturation of the porous medium through which the flow takes place ($S_{BT}$) and the irreducible water saturation ($S_{wi}$) it is possible to calculate the volume of oil produced up to that moment and, therefore, the displacement efficiency for the flow time ($\eta_{MDE,BT}$) expressed as:

$$\eta_{MDE,BT} = \frac{S_{BT} - S_{wi}}{1 - S_{wi}}$$

The maximum value of displacement efficiency is reached when all of the mobile oil present within the porous medium has been produced, which is equal to:

$$\eta_{MDE} = \frac{1 - S_{or} - S_{wi}}{1 - S_{wi}}$$

where $S_{or}$ represents the residual oil saturation.

**Macroscopic displacement efficiency**

To achieve a good recovery factor, the displacement fluid, whether of natural origin or induced by injection, must efficiently sweep the hydrocarbons in the pore spaces and must also come into contact with the greatest possible volume of the reservoir. The macroscopic displacement efficiency, in turn, is the product of two elements: areal sweep efficiency and vertical invasion efficiency.

**Areal sweep efficiency.** Areal sweep efficiency (SE, Sweep Efficiency), is defined as the ratio between the area of the reservoir with which the displacement fluid comes into contact and the reservoir’s total area (Fig. 13). The above is dependent on factors such as the mobility ratio of the fluids, the presence of any heterogeneous zones in the formation and, in the case of injection, the arrangement and reciprocal distance of the injector wells and production wells, and the volume of the displacement fluid injected.

The ratio $M$ between the mobility $\lambda$ of both the displacement fluid and the displaced fluid has a fundamental influence on the areal and vertical efficiency. In particular, since mobility $\lambda$ is defined as the ratio between the effective permeability to a particular fluid and the viscosity of the same fluid under reservoir conditions, when oil is displaced by water the mobility ratio $M$ is:

$$M = \frac{\lambda_w}{\lambda_o} = \frac{k_w(S_{or})}{\mu_o k_o(S_{wi})}$$

where $k_w(S_{or})$ is the effective permeability to water in...
the presence of residual oil, $k_o(S_w)$ is the effective permeability to oil in the presence of irreducible water, and $\mu_o$ and $\mu_w$ are the viscosities of oil and water respectively under reservoir conditions. In the case of immiscible displacement of oil by gas, the mobility of the displacement fluid corresponds to that of the gas.

The mobility ratio is considered favourable or unfavourable depending on whether its value is less or greater than one. When the mobility ratio is less than one (i.e. when the oil tends to flow more easily than the displacement fluid), the displacement front is stable, which reduces the risk of the front becoming deformed with consequent, irregular and unexpected fluid movements towards the production wells (Fig. 14A). On the other hand, a high mobility ratio implies that the displacement front is accelerating and, as a result, will tend to deform progressively as the front advances through the porous medium (Fig. 14B). Furthermore, the instability phenomena are heightened as the front becomes more sensitive to the heterogeneity of the porous medium. At a macroscopic level, the heterogeneities of the reservoir have a notable influence on the area of the reservoir invaded by the displacement fluid and, therefore, on the success of the displacement. In fact, since only the zones of higher permeability are invaded by water, the portion of the reservoir affected by the displacement fluid is reduced. In particular, the flow of the fluids is distorted by the presence of discontinuities or fracture systems and, therefore, the recovery of the hydrocarbons can result much lower than in cases where the formations are homogeneous. In the case of injection, the location of injection wells and production wells influences hydrocarbon recovery: a uniform distribution of wells over the entire reservoir area can enable the displacement fluid to reach a larger area more uniformly, optimizing oil recovery. With this in mind, injection and production patterns have been drawn-up; the choice of such patterns is based on a variety of factors, among which the petrophysical characteristics of the porous medium and the mobility ratio are particularly important. In some cases, before starting a displacement process, it is advisable to carry out a pilot project on a small portion of the reservoir. In fact, pilot projects make it possible to evaluate, in a short amount of time and with reduced investment, the general outcome of particular exploitation strategies and, therefore, also to optimize the subsequent development plans and to carry out more reliable economic evaluations of the project.

**Vertical invasion efficiency.** Vertical invasion efficiency (CF, Conformance Factor) is a parameter that expresses the degree of displacement of the oil by the displacement fluid along a vertical section of the reservoir at a specific moment in its productive life. However, it becomes significant only if the reservoir extends along a preferential direction, if it can be assumed that the reservoir rock consists of several overlapping horizontally homogeneous levels, and if the displacement fluid moves along the principal direction in which the reservoir developed. The rocks that contain the hydrocarbons are generally of sedimentary origin and, therefore, stratified; consequently, though it is possible to hypothesize that the rocks’ layers are characterized by a certain degree of horizontal homogeneity, this is not the case vertically. Petrophysical characteristics (in particular, permeability), and therefore the fluids’ velocity along the strata, can thus vary significantly when oriented in a vertical direction. At a certain point during exploitation, the vertical invasion efficiency is evaluated as the ratio between the section of the reservoir crossed by the displacement fluid and the total area. As already mentioned, vertical efficiency is dependent mainly on the heterogeneity of the various levels of the reservoir, but also on the mobility ratio. The heterogeneities with the most impact regarding displacement are variations of permeability ($k$). In fact, the displacement fluid tends to flow in greater quantity and more quickly through the high permeability levels, therefore reaching the production wells too soon, which bears a negative impact on the overall flow rate of oil (Fig. 15). As far as the mobility ratio is concerned, generally the same considerations apply regarding areal sweep efficiency. In the case of

![Fig. 15. Effect of heterogeneity on vertical sweep efficiency.](image-url)
multi-layer reservoirs (i.e. those in which the hydrocarbon levels present different petrophysical characteristics, and are totally or partially separate one from another), a mobility ratio of less than one indicates an undoubtedly favourable condition. In fact, the velocity with which the water front flows along each level tends to diminish progressively as the front itself advances towards the production well; the different fronts, relative to the different layers, in time tend to become uniform and to constitute a single front that reaches the production well compactly and almost simultaneously (Fig. 16 A). On the other hand, when the mobility ratio is greater than one, there is instability of the front, and in the more permeable layers where the flow is favoured, the velocity of advancement tends to increase further, with negative effects on both displacement efficiency and recovery (Fig. 16 B).

The action of the force of gravity plays an important role in vertical efficiency. In the case of displacement of oil by either water from below, or gas from above, since the fluids have different densities, there is a floating drive that tends to compensate the negative effects of the rock’s heterogeneity, facilitating the formation of a more compact front. The effects of gravity become much greater as the thickness of the reservoir and the inclination of the layers along the direction of flow increase. For this reason, it is advisable to distance the positioning of the injection and production wells as much as possible, in relation to their depth. To this end, horizontal wells can be very useful.

Displacement by gas injection

Generally, in displacement processes, gas is used as a displacement fluid when it is necessary to eliminate or reduce either the liberation of gas in the formation, or the combustion of associated gas in the atmosphere. The injection of gas has two effects on the final recovery of the oil – one favourable and the other unfavourable. The first one is due to the considerable difference in the densities of gas and oil, which enhances the positive effects associated with the action of the force of gravity; the second relates to the greater mobility of gas compared to that of oil, which intensifies the negative effects caused by the presence of heterogeneity in the porous medium. In some cases, to cope with this second aspect, recourse is made to a technique of alternate injections of gas and water, called WAG (Water-Alternating-Gas), in which the gas and the water can be injected simultaneously or in alternating cycles. The simultaneous presence of the three fluid phases (gas, water and oil) modifies relative permeabilities, reducing the mobility of both the gas and the water. In the case of alternate injections, the presence of a water cushion, which immediately follows the gas volume, noticeably reduces the effective permeability to the gas and, as a result, its mobility.

Injection methods

The most appropriate method of injection should be chosen on the basis of the geometric and petrophysical characteristics of the reservoir and the

![Fig. 16. Development in time $t_1$ and $t_2$ of an injected water displacement vertical front for mobility ratios less than one (A) and greater than one (B).](image)

![Fig. 17. Possible gas injection systems (with or without water injection). The arrow indicates the direction of the displacement.](image)
characteristics of the oil. In general, the methods of gas injection can be classified into four categories: a) continuous injection of gas; b) continuous injection of gas followed by displacement with water; c) alternate injections of gas and water of conventional type; d) alternate injections of gas and water of non-conventional type (Fig. 17). In the case of continuous injection, a predetermined volume of gas is injected into the reservoir without any other fluid being injected behind it; this technique is suitable for reservoirs with significant gravitational effects or in reservoirs where it is not possible to inject water at the end of primary production. In the case of continuous gas injection followed by displacement with water, the volume of injected gas, which displaces the oil bank, is followed by a certain quantity of water; this is the preferred method used in reservoirs with low permeability. In the conventional method of alternate injection of gas and water, the gas is injected in cycles, in which given volumes of injected gas are followed by equal volumes of water; this method proves to be very effective in stratified heterogeneous reservoirs since this pattern greatly reduces the mobility of the gas, above all in the layers where permeability is high. In the case of non-conventional alternate injections of gas and water, with or without a final water cushion, the gas is injected in cycles, in which the volumes of gas are alternated with ever increasing volumes of water; this method of injection aims to minimize the use of displacement fluid, continually adjusting the water-gas ratio.

**Miscible displacement**

Displacement of oil by gas in a miscible phase will not be treated in depth here, since the subject will be fully developed in Volume 3, dealing with enhanced oil recovery. In the miscible displacement processes, the displacement fluid is, or becomes, miscible with the oil under the reservoir’s pressure and temperature conditions. This type of displacement is characterized by a progressive change in composition of both the displacement fluid and the displaced fluid, until the two fluids in contact form a single phase. In miscible processes, the displacement fluid is also referred to as solvent; it dissolves in the oil, reducing its viscosity and increasing its volume, and ensures greater mobility towards the production wells. Among the fluids that are miscible with oil and facilitate the flow towards the production wells, those most commonly used are various mixtures of gaseous hydrocarbons, carbon dioxide and nitrogen.

Miscibility is fundamental for successful recovery, in that it mobilizes the oil which often remains trapped in the pores as residual fractions. The conditions of miscibility between the displacement fluid and the displaced fluid ensure that the interfacial tensions between the two fluids are cancelled out and a single-phase is formed, which can flow freely towards the wells, contrary to conditions of immiscibility where the two phases, displacement and displaced, tend to obstruct each other.

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Francesca Verga
Dipartimento di Ingegneria del Territorio, dell’Ambiente e delle Geotecnologie
Politecnico di Torino
Torino, Italy