4.6.1 Oil recovery processes

Natural drive mechanisms

The main drive mechanisms in oil reservoirs are (Dake, 1978): (a) solution gas; (b) gas cap; (c) natural water influx; and (d) compaction (see Chapter 4.3).

In a reservoir with solution-gas drive, oil production results from a change in volume as the reservoir pressure is reduced. As the pressure decreases, the oil and associated dissolved gas expand resulting in an increase of the volume which is recovered by the production wells. If the reservoir is above the bubble-point pressure, $p_b$ (i.e. undersaturated oil), then there is no free gas in the reservoir, and hence there is no gas cap overlying the oil. Thus, in undersaturated oil reservoirs where there is no active aquifer support, the primary drive mechanism is solution gas. In undersaturated oil reservoirs, one must account for the decrease in the HydroCarbon Pore Volume (HCPV) as the pressure decreases. This decrease in the HCPV is due to the expansion of the connate, or interstitial, water and the reduction of the pore volume due to rock (pore) compressibility.

As the reservoir pressure falls below the bubble point, gas is liberated from the oil phase, and a free gas phase develops. Gas compressibility is larger than that of liquid oil and significantly larger than the compressibility of water and rock (pore volume). As a result, the free gas dominates the effective compressibility of the system, and the contributions from the compressibility of rock and water may be neglected as a first approximation. In solution-gas reservoirs, the reservoir pressure typically declines rapidly until the bubble point is reached; subsequently, the pressure decline continues, but at a slower rate, due to the high compressibility of the free gas. The gas dissolved in the oil is the only source of primary energy for gas production at the surface until the bubble-point pressure is reached. Shortly thereafter, the presence of a highly mobile free-gas phase in the reservoir usually leads to a significant increase in the producing gas/oil ratio. The sharp increase in the producing gas/oil as the reservoir pressure falls below the bubble point further depletes the reservoir of the main energy source. Later in the life of the reservoir, the producing gas/oil ratio itself declines as the available reservoir energy diminishes.

If the reservoir is at the bubble point when discovered, then it is likely that a gas cap, which lies on top of the oil region, may be present. Expansion of the gas cap provides significant pressure support and slows down the rate of pressure decline in the reservoir compared to the case in which only a solution-gas drive is present. Of course, solution gas contributes to oil production in reservoirs with a gas cap. A natural water drive occurs when the oil reservoir overlies, or is flanked by, a water aquifer. As the pressure in the oil reservoir decreases due to fluid production, the aquifer water expands, leading to water influx from the aquifer into the oil reservoir. For a given pressure drop at the boundary between the oil reservoir and the water aquifer, however, the influx of large volumes of water into the oil reservoir is necessary in order to provide adequate pressure support. This is due to the much smaller water compressibility compared to that of the reservoir fluids. Consequently, active aquifer support requires relatively large aquifer sizes. When active aquifer support is present, relatively high pressures can be sustained in the oil reservoir, thus leading to improved oil recovery.

In the case of gas reservoirs the main drive mechanism is the gas expansion which could lead, in bounded reservoirs, to very high gas recovery (80-90% of the Original Gas In Place, OGIP). By contrast, with
an active water drive the gas recovery could decrease considerably, due to the water breakthrough and the residual gas saturation left behind the waterfront.

**Improved oil recovery**

Natural drive mechanisms present in the reservoir system lead to the flow and recovery of oil to production wells. However, only a small fraction of the Original Oil In Place (OOIP) is usually recovered using natural drive mechanisms. In order to improve oil recovery, pressure support by injection processes can usually prolong the productive life of a reservoir. Common approaches are peripheral water injection into the aquifer to maintain the pressure level in the oil reservoir while fluids are being produced. Similarly, gas injection into the original or secondary gas cap may be used to support the pressure and increase the effective compressibility of the reservoir system. Unfortunately, pressure support is only a partial remedy to declining oil production.

Secondary recovery displacement processes are usually employed to increase the amount of oil recovery. Waterflooding, a technique in which water is injected into the reservoir to displace the resident oil, is the most common secondary recovery process. Waterflooding operations are usually conducted using patterns, which are groups of injection and production wells arranged in a certain areal geometric shape. Well spacing, injection allocation schedules, and operating conditions are case specific. The design and operation of a waterflood is usually obtained from simulation studies augmented by field experience. Waterflooding can add significantly to the cumulative oil recovery. However, it is often the case that the sweep efficiency of a waterflood may be quite low. Moreover, a significant amount of residual oil is usually left behind, or trapped, in the flooded regions. Of course, the performance of a waterflood strongly depends on the specific case under study. In general, however, at the end of waterflooding operations significant oil reserves remain in place because of complete bypassing and trapping by the invading water.

Enhanced Oil Recovery (EOR) displacement processes have been developed to recover more oil. EOR processes involve the injection of a fluid into the reservoir in order to displace the resident oil, and they fall in one of three general categories (Lake, 1989): thermal, chemical, and solvent methods. In each category, a wide variety of displacement processes have been devised and applied. The mechanisms for improving the displacement of the resident oil depend on the particular EOR process used. The objective is usually to improve the sweep efficiency and/or the local displacement efficiency. For that purpose, EOR schemes attempt to improve the mobility ratio of the displacing fluid to that of the displaced oil. For example, polymer flooding aims to improve the mobility ratio by increasing the viscosity of the injected water, while steam injection attempts to improve the mobility of the resident oil by reducing its viscosity. Solvent flooding, including miscible and near-miscible gas injection, is used with the goal of improving the local displacement efficiency by achieving miscibility with the resident oil, which allows the miscible mixture to be driven towards the production wells. Of course, the viability of an EOR project depends on the economics of the specific process for a particular site. EOR techniques will be discussed in detail in Volume 3.

The physics of EOR processes must be accurately described by the equations, which are solved numerically by the reservoir flow simulator. The mathematical statement of many EOR processes can be quite involved; as a result, precise modelling of EOR processes usually requires sophisticated numerical solution methods and implementations. A detailed understanding of the physics at work in each particular case, which we are trying to model using a reservoir simulator, is very important. Using a simulator that does not represent the important physical processes that dictate the flow behaviour for the system in question is one of the major misuses of reservoir simulation. Thus, in addition to field experience, practitioners of reservoir simulation must also have an in-depth understanding of the relevant physical processes being modelled.

It should be remembered that before performing any 3D-reservoir-simulation modelling, it could be useful to carry out material balance calculations in order to preliminarily investigate the main drive mechanisms acting in the reservoir. This can be easily and quickly done using a personal computer equipped with available windows-based material balance software. Material balance calculations can also help in evaluating the efficiency of the displacement processes.

### 4.6.2 Reservoir flow simulation

Reservoir simulation is a broad discipline of petroleum engineering concerned with predicting reservoir performance using computer programs that generate numerical solutions of the equations governing the complex physical processes in oil
reservoirs. It is an essential tool in contemporary reservoir management. Performance predictions obtained from reservoir simulation can be used to resolve a wide range of issues related to both operational and design considerations during all stages of field development.

Reservoir simulation is a blend of physics, applied mathematics, computational fluid dynamics, numerical analysis, and computer programming. The objective is to provide an accurate and computationally efficient quantitative description of complex behaviours in geologic formations of large extent lying at great depths. It is often the case, however, that only limited data about the reservoir under study are available to the engineer. Consequently, engineering experience and judgement lie at the core of reservoir simulation practice. Significant human and capital resources are necessary for the development and operation of oil reservoirs. Typically during the life of an asset, reservoir management decisions must be made even though very limited information is usually available. Consequently, uncertainty quantification and risk management are at the core of sound reservoir management. Reservoir simulation is used to make predictions of flow performance and quantify the uncertainty associated with these predictions; it is a primary tool for making quantitative decisions. In broad terms, the important uses of simulation are: a) forecasting reservoir performance under a variety of scenarios; b) improving reservoir description through history matching; c) analysing physical experiments; d) understanding the complex mechanisms that dictate the flow and transport; e) developing simple, yet effective, models and correlations. Within each category, a wide range of activities and applications may be listed. In the following, the core components of reservoir flow simulators are described. Namely: reservoir flow equations; discretization of the equations; formulations; numerical solution. Subsequently a brief discussion about gridding methods, which play a central role in reservoir simulation, is presented.

**Reservoir flow equations**

Equations used to model isothermal flow and transport in reservoirs are obtained by combining the conservation of mass with Darcy’s law. An energy balance equation is needed when the assumption of constant temperature is not valid. The equations that describe the physics under consideration are usually expressed in continuous (differential or integral) form. Reservoir characterization models often display geometric complexity and are populated with spatially variable properties. Moreover, highly non-linear behaviours are usually associated with reservoirs flows. As a result, numerical solution techniques are normally the only choice, and working with a discrete form of the governing equation is necessary.

A discrete form of the governing equations along with appropriate constraints, constitutive relations, and with boundary and initial conditions is then solved by numerical techniques to yield predictions of reservoir performance. This computational tool, a reservoir simulator, can then be used to model different scenarios and operating conditions.

Here, we derive the flow equations, both in differential and discrete forms, and introduce appropriate nomenclature. Important assumptions involved in the derivation will be emphasized (see Aziz and Settari, 1979).

**Compositional flow equations**

Consider an isothermal reservoir system with \( n_c \) components (\( c \) is the component index) and \( n_p \) phases (\( p \) is the phase index). Normally \( n_p \leq 3 \), but \( n_p \) can be arbitrary in compositional models. The differential form of the conservation equation for component \( c \), which may exist in \( n_p \) phases, is:

\[
\frac{\partial C_c}{\partial t} + \nabla \cdot F_c = 0
\]

Eq. [1] is a differential equation that describes the mass balance of component \( c \) over an arbitrary control volume. It states that for component \( c \), net mass flux into the control volume is balanced by accumulation. In Eq. [1], \( C_c \) is the overall mass concentration of component \( c \) in the arbitrary control volume over which the mass balance is written, and it can be expressed as:

\[
C_c = \Phi \sum_{p} \rho_p S_p y_{c,p}
\]

where \( \Phi \) is the porosity of the porous medium, and \( \rho_p \) and \( S_p \) are the density and saturation of phase \( p \), respectively. The mass fraction of component \( c \) in phase \( p \) is denoted by \( y_{c,p} \). The overall mass flux (mass per unit area per unit time) of component \( c \) across a control-volume boundary is denoted by \( F_c \), which we write as:

\[
F_c = \sum_p F_{c,p} = \sum_p \rho_p y_{c,p} u_p
\]

where \( u_p \) is the Darcy velocity of phase \( p \). Note that in the treatment here, the flux expression accounts only for transport by convection. This is a common simplification in general-purpose applications of reservoir simulation. However, in some cases, accurate description of the flow process under study may require explicit modelling of additional mechanisms, such as diffusion and dispersion.

\[ \frac{\partial}{\partial t} \left( \Phi \sum_p \rho_p c_v p c \gamma_p \gamma_p \rho_p \right) + \nabla \cdot \left( \rho_p c_v p c \gamma_p \gamma_p \rho_p \mathbf{u}_p \right) = 0 \]

The Darcy velocity of phase \( p \) is given by

\[ \mathbf{u}_p = -k_{r,p} \frac{\rho_p c_v p c \gamma_p \gamma_p \rho_p}{\mu_p} (\nabla p - \gamma_p \mathbf{D}) \]

where \( k \) is the absolute permeability of the porous medium, which can be a full tensor, and \( k_{r,p}, \mu_p, p_p \), and \( \gamma_p \) denote, respectively, the relative permeability, viscosity, pressure and density of phase \( p \). The vertical depth (assumed positive downward) is denoted by \( D \).


\[ \sum_p \left( \frac{\partial}{\partial t} \left( \Phi \sum_p \rho_p c_v p c \gamma_p \gamma_p \rho_p \right) - \nabla \cdot \left( \rho_p c_v p c \gamma_p \gamma_p \rho_p k_{r,p} \right) \right) \left( \nabla p - \gamma_p \mathbf{D} \right) = 0 \]

where \( \lambda_{r,p} = k_{r,p}/\mu_p \) is the relative mobility of phase \( p \).

We have one conservation equation like Eq. [1] for each component in the system. Therefore, there are \( n_c \) conservation equations like Eq. [1], one for each component. However, there are many more unknown variables than \( n_c \). They are:

<table>
<thead>
<tr>
<th>Unknown</th>
<th>Number</th>
</tr>
</thead>
<tbody>
<tr>
<td>( y_{cp} )</td>
<td>( n_c, n_p )</td>
</tr>
<tr>
<td>( p_p )</td>
<td>( n_p )</td>
</tr>
<tr>
<td>( S_p )</td>
<td>( n_p )</td>
</tr>
<tr>
<td>Total</td>
<td>( n_c, n_p + 2 n_p )</td>
</tr>
</tbody>
</table>

The remaining equations to complete the description of our system are obtained from:

1. a) capillary pressure relations; b) phase equilibrium relations; c) phase constraints; and d) saturation constraints. Thus, we have:

<table>
<thead>
<tr>
<th>Equation</th>
<th>Number</th>
</tr>
</thead>
<tbody>
<tr>
<td>conservation</td>
<td>( n_c )</td>
</tr>
<tr>
<td>capillary pressure</td>
<td>( n_p - 1 )</td>
</tr>
<tr>
<td>equilibrium</td>
<td>( n_c(n_p - 1) )</td>
</tr>
<tr>
<td>phase constraints</td>
<td>( n_p )</td>
</tr>
<tr>
<td>saturation constraint</td>
<td>1</td>
</tr>
<tr>
<td>Total</td>
<td>( n_c n_p + 2 n_p )</td>
</tr>
</tbody>
</table>

Only the flow, or component conservation, equations have flux terms that connect the gridblock (control volume) to its neighbouring gridblocks. The remaining expressions are referred to as constraint relations, and they depend only on the variables of the gridblock itself. We can use \( n_p - 1 \) capillary pressure relations, one saturation constraint and \( n_c \) phase constraints to eliminate \( 2 n_p \) variables from the component conservation equations. This reduces the number of equations and unknowns to \( n_c n_p \). In general, a component can partition, or exist, in any of the \( n_p \) phases; as a result, there are \( n_c (n_p - 1) \) phase equilibrium relations. To describe component partitioning for the general case where \( n_p = 3 \), a three-phase flash is needed. However, since general three-phase flash computations are difficult, it is often reasonable to ignore the mutual interaction of water with the oil and gas phases, i.e. we assume that the water phase contains only the water component and the hydrocarbon phases do not contain any water component. With this simplification, we are left with \( n_k \) equilibrium relations, where \( n_k \) is the number of hydrocarbon components. Together with \( n_c = n_k + 1 \) component conservation equations, the total number of variables becomes \( 2 n_k + 1 \).

**Black-oil model**

In standard black-oil models, which are the most common models used in the oil industry, there are only two hydrocarbon components \( (n_k = 2) \): a non-volatile oil and a volatile gas, which is soluble in the oil. Moreover, the hydrocarbon components do not interact with the water phase, which is made up of the water component only. The three components in the standard black-oil model, namely, water, oil and gas, are defined as phases at standard conditions, and simple empirical relations are used to describe the phase behaviour.

Here, we describe a generalized black-oil model, where each of the three phases can contain up to two components, and each component is associated with a particular (master) phase. For example, the master phase for the gas component is the gas phase. Black-oil models are simplified versions of the compositional statement. When working with these models, however, it is important to keep a clear distinction between components (phases at standard conditions) and phases. The relationships between components and phases are illustrated in **Fig. 1**.

The following notation is introduced: \( V_p \) is the volume of phase \( p \) at reservoir pressure and temperature, and \( V_{c,p} \) is the volume of component \( c \) at standard conditions that is liberated from phase \( p \). To reduce the general compositional statement to the common black-oil form, the concepts of formation volume factor and solubility are introduced (see Chapter 4.2). The formation volume factor of phase \( p \) is defined as the ratio of the volume of phase \( p \) at some specified conditions (usually reservoir conditions) to the volume of the component associated with that phase at standard conditions:

\[ B_p = \frac{V_p}{V_{p,p}} \quad p = o, w, g \]

where \( o, w, g \) refer to the oil, water, and gas phases, respectively. The solubility of component \( c \) in phase \( p \),
measured with respect to a reference reservoir condition, is defined as

\[ R_{c,p} = \frac{V_{c,p}}{V_{p,p}} \]

which is a ratio of two volumes at standard conditions. Namely, the ratio of the volume of component \( c \) in phase \( p \) to the volume of the component associated with phase \( p \). Obviously, the solubility of a component in its master phase is unity (i.e. \( R_{p,p} = 1 \)).

Relationships for mass fractions and equilibrium ratios can be derived as functions of formation volume factors, solubilities, and densities. It can be shown that

\[ \omega_{c,p} = \frac{R_{c,p}}{B_p} \]

where \( \omega_{c,p} \) is the concentration of component \( c \) in phase \( p \) (mass, or moles, per unit volume), and \( B_p \) is the density of component \( c \) at standard conditions. Substituting Eq. [9] into the general compositional equation, Eq. [6], and dividing by \( B_p \) yields

\[ \frac{\partial}{\partial t} \left( \Phi \sum_{p} \frac{R_{c,p}}{B_p} \right) + \nabla \cdot \left( \sum_{p} \frac{R_{c,p} \mathbf{u}_p}{B_p} \right) = 0 \]

for \( c = w, o, \) or \( g \). Substitution of Darcy’s law, Eq. [5], into the above equation yields the form commonly used to describe the generalized black-oil model.

**Discretization of the equations**

The conservation equations for reservoir flows are non-linear. As a result, they are not amenable to methods involving an analytical solution. Instead, numerical techniques are used to solve these systems of equations. The first step is to express the governing equations in discrete form as opposed to the differential, or continuous form, given in Eq. [1].

Consider the control volume, or gridblock, shown in Fig. 2. The conservation of mass for component \( c \), which may be transported via \( n_p \) flowing phases, in gridblock \( i \) can be written as:

\[ \frac{1}{\Delta t} (M_{c}^{n+1} - M_{c}^{n}) = \sum_{l} m_{c,i} - m_{c,i}^{w} \]

This equation is a discrete form of Eq. [1]. In Eq. [11], \( \Delta t \) is the timestep size over which the mass balance is written, and \( M_{c} = V_{c} C_{c} \) is the mass of component \( c \) in gridblock \( i \) whose bulk volume is \( V_{c} \). Superscripts \( n \) and \( n+1 \) denote previous and current time levels, respectively. The mass flow rate of component \( c \) through a cross-sectional area \( A \) is

\[ m_{c} = F_{c} A \]

where \( F_{c} \) is the overall flux of component \( c \) defined previously. In Eq. [11], \( \Sigma_{l} \) indicates summation over all \( l \) connections to gridblock \( i \). Note the additional source term, \( m_{c,i}^{w} \), which accounts for the presence of a well production

\[ \text{influx from l} \]
well in the gridblock. The left hand side of Eq. [11] is the rate of mass accumulation, and the right hand side is the rate of mass influx into the block (production is positive). Overall component quantities are obtained by summing over the individual phases. Specifically, 

\[ M_c = \Sigma_p M_{c,p} \quad \text{and} \quad m_c = \Sigma_p m_{c,p} \quad \text{and} \quad m^n_c = \Sigma_p m^n_{c,p}, \]

and we have

\[ \frac{1}{\Delta t} \Sigma_p \left[ M_{c,p}^{n+1} - M_{c,p}^n \right] = \Sigma_p \left[ \sum_i m_{c,p,i} - \sum_w m^n_{c,p,w} \right].\]

The mass flow rate of component \( c \) in phase \( p \) at the interface between blocks \( i \) and \( l \) can be written as:

\[ m_{c,p,i,l} = T_{c,p,i} \left[ \Phi_{p,i} - \Phi_{p,l} \right],\]

where

\[ T_{c,p} = \rho_{c,p} \lambda_{p} T_s\]

is the transmissibility,

\[ \rho_{c,p} = \frac{\phi_{c,p}}{v_{c,p}}\]

is the concentration of component \( c \) in phase \( p \), \( \lambda_{p} \) is the relative mobility, and

\[ T_s = \frac{kA}{\Delta x} \]

is the static component (geometry and permeability) of the transmissibility. In Eq. [14], \( \Phi \) is the potential defined as

\[ \Phi_{p,i} - \Phi_{p,l} = (p_{p,i} - p_{p,l}) - \gamma_{p,i} (D_i - D_l),\]

where

\[ \gamma_p = g\Phi_p \]

with \( g \) being the acceleration due to gravity. The well term can be expressed as

\[ m^n_{c,p} = \rho_{c,p} \gamma_{p} \]

So far, we have not specified the time level at which the flow terms in the discrete equations are evaluated. If an explicit treatment is employed, then the flow terms are evaluated at the previous time level, \( n \). In contrast, fully implicit treatment requires that the flow terms be evaluated at the current (new) timestep, \( n+1 \). The spatial and temporal discretization applied to the governing equations play a central role in the convergence, stability, and accuracy of the computed solutions.

We presented the differential and discrete forms of the basic equations that describe flow and transport in reservoirs. These equations form the foundation of most of the reservoir simulators used in the industry. Proper use of a reservoir simulator requires an understanding of the physics being modelled, and of the assumptions and limitations associated with the equations being solved.

Formulations

For the case of isothermal compositional flow with simple water treatment (see above), we used the linear formulation with three levels of implicitness, namely, IMPES, IMPSAT (IMplicit Pressure and SATurations) formulation with three levels of implicitness, namely, IMPES, IMPSAT (IMplicit Pressure and SATurations) and the fraction of gridblocks requiring implicit treatment.

For isothermal compositional flow, the number of primary variables is equal to the number of components, \( n_c \), and several different primary variable sets have been proposed in the simulation community (Cao, 2002). On the other hand, the \( n_c \) conservation equations are the natural choice as primary equations.

Formulations are usually referred to as explicit or implicit depending on whether the primary variables are treated implicitly or explicitly. A variable is implicit if it is evaluated at the current time level, \( n+1 \), and explicit if it is evaluated at the previous time level. Two major formulation types are common (Coats, 2000): Fully Implicit Method (FIM) and IMplicit Pressure, Explicit Saturations (IMPES). In FIM, all the primary variables in a gridblock are treated implicitly. In IMPES, pressure is the only implicit primary variable.

The Adaptive Implicit Method (AIM), which is a hybrid, is a third type (Thomas and Thurnau, 1983; Cao, 2002). In AIM systems, a primary variable in a gridblock can be labelled as implicit or explicit. Variables, other than pressure which is always implicit, are treated implicitly only when and where necessary. Criteria based on stability analysis can be used to label unknowns in a gridblock as implicit or explicit (Coats, 2003). Compared to FIM, an AIM formulation offers two major advantages: timestep sizes comparable to those obtained with FIM can be used at a significantly lower computational cost; and the quality of AIM numerical solutions is superior to that obtained with FIM, assuming similar timestep sizes, due to lower levels of numerical dispersion. Realizing these advantages, however, depends on achieving a good balance between the timestep size and the fraction of gridblocks requiring implicit treatment.

For compositional flows, a general AIM formulation with three levels of implicitness, namely, IMPES, IMPSAT (IMplicit Pressure and SATurations)
and FIM, has been proposed by Cao (2002). The cost advantage for this general AIM formulation, with optimal labelling of the unknowns, is expected to increase dramatically as the number of components increases, especially for highly detailed field models with large numbers of gridblocks. Most reservoir simulators are wedged to a particular formulation and choice of primary variables. This is because the details of computing the Jacobian, flash calculations, and issues related to the appearance and disappearance of phases, are related to the choice of the primary variable set. Cao (2002) built a general-purpose research simulator that allows for flexibility in choosing the primary variables. That simulator may be used to study the merits of the various choices that are in common use.

**Numerical solution**

The conservation equations for a given timestep, can be written in residual form as

\[ \mathbf{R}(\mathbf{u}^{n+1}) = 0, \]

where \( \mathbf{R} \) represents the vector of the non-linear residual equations written for each gridblock in the model. The objective is to find the primary unknowns for all the gridblocks of the current timestep (i.e. the \( n+1 \) time level), \( \mathbf{u}^{n+1} \) that satisfy Eq. \[21\]. The Newton-Raphson method is an iterative solution scheme for non-linear algebraic equations, in which iterations are performed until we converge (within some specified tolerance) to the solution of the non-linear system, Eq. \[21\]. The Jacobian matrix is defined as the partial derivative of the residual equations with respect to the vector of unknown variables. In other words, the element in the \( i^{th} \) row (equation) and \( j^{th} \) column (unknown) of the Jacobian matrix is given by

\[ J_{ij} = \frac{\partial R_j}{\partial u_i} \]

The elements of \( \mathbf{R} \) and \( \mathbf{u} \) are usually expressed using gridblock-priority ordering, where the equations and unknowns associated with a particular gridblock are kept together. For example, for the numbering scheme of the simple two-dimensional (2D) grid of Fig. 3, the resulting non-zero structure of the Jacobian matrix is shown in Fig. 4. A given row in the Jacobian matrix corresponds to the equations of that particular gridblock number. The non-zero element at row \( i \) and column \( j \), which is indicated by a bullet, is a small block matrix representing the derivatives of the equations of gridblock \( i \) with respect to the vector of unknowns in the \( j^{th} \) gridblock.

**Simulation grid**

The Partial Differential Equations (PDEs) that describe the flow process under consideration and the appropriate initial and boundary conditions must be specified. The simulation grid is a discrete decomposition of the reservoir volume into a large number of small volumes, which are often referred to as cells, or gridblocks. For each gridblock, an appropriate discrete form of the PDEs that govern the flow process of interest is written, and a numerical solution is sought. The coefficients that make up the discrete form of the PDEs are assembled using properties defined on the simulation grid. Examples include static data, such as gridblock geometry, volume, and permeability, as well as dynamic data, such as fluid and rock/fluid properties.

The simulation grid describes the geometry of the porous medium and the spatial distribution of the reservoir properties. The number of cells, or gridblocks, used to discretize the reservoir depends on the geometric complexity of the features (layers, faults, wells), the level of detail in property description, and the accuracy requirements for the numerical solutions of the specific governing equations.

Different types of grid may be used (Aziz, 1993). Grid types are often labelled based on their structure. A globally structured grid is one where the connectivity of any gridblock is described using a simple generic stencil. Dividing a regular domain into \( n_x \), \( n_y \), and \( n_z \) segments, in the \( x \), \( y \), and \( z \) directions, respectively, yields \( n = n_x \cdot n_y \cdot n_z \) structured gridblocks. In this case, away from the reservoir boundaries, the

![Fig. 3. Natural ordering of a two-dimensional grid.](image-url)
standard, or nearest-neighbour, discretization of the flow equations gives a seven-point stencil. Namely, the gridblock itself and its connection (transmissibility coefficient) to gridblocks in the positive and negative coordinate directions.

In reservoir simulation practice, globally structured Cartesian grids are quite common. If a higher resolution is desired only in a few locations, such as in the vicinity of wells, one can retain the global Cartesian grid, and refine that grid only locally where needed. This so-called Local Grid Refinement (LGR) approach can be quite effective. The type of grid in the LGR region does not have to be Cartesian. For example, a radial grid around the well may be used (Aziz, 1993).

A structured stratigraphic grid that uses corner-point geometry to conform more accurately to the complex shapes of geologic layers, may also be used. In that case, however, while the logically rectangular structure is retained, the grid is non-orthogonal. Special discretization techniques of the flow equations are required to obtain accurate numerical solutions when the grid is non-orthogonal and/or the permeability is a full-tensor (Lee et al., 2002).

The geometric complexity (sloping faults, geologic layers, deviated and multilateral wells), wide variation in the length-scales, and level of detail used in Reservoir Characterization Models (RCMs) continue to grow. It is difficult, if not impossible, to represent such complexity accurately using globally structured grids. Complete flexibility in representing these complex and highly detailed RCMs can be achieved using (completely) unstructured grid.

Multi-block grids, which are locally structured, but globally unstructured, offer an intermediate solution with significant flexibility (Lee et al., 2003). Examples of these grids are shown in Figs. 5 and 6.

Accurate gridding for simulation poses significant challenges. It is important, however, to recognize that the impact of the simulation-grid choice permeates throughout the major components of the reservoir simulator. This is expected since we work with a discrete representation of the governing flow equations on the simulation grid. The characteristics of the algebraic systems of equations (non-linear and linear), such as convergence, stability, and solution accuracy, are tightly linked to the properties of the grid and the discretization methods employed.

The steps involved in a reservoir flow simulator:
• Read input data (problem definition).
• Initialize (set initial conditions).
• Prescribe conditions at reservoir boundaries.
• Start timestep calculations: a) set an initial timestep size; b) specify production/injection rates for the current timestep; c) linearize the governing discrete equations; d) start the iteration loop (Newton iterations); e) solve the linear systems of equations; f) test for solution convergence; g) repeat Newton iterations if necessary.
• Output simulation results as required.
• End if the specified constraints are violated.
• Increment time and go to the third step if the ending conditions are not reached.
• End when the time period of interest is covered.

Fig. 4. Jacobian matrix structure for the example of Fig. 3.

Fig. 5. Faulted model.
4.6.3 Simulation workflow

An overall description of the general workflow for performing a reservoir simulation study is shown in Fig. 7. Here, we discuss the input data requirements, followed by a quick description of the history matching and performance forecasting phases of a dynamic reservoir study.

Input data

In order to perform a reservoir simulation, the following input data are required:

- **The RCM**: this includes a detailed description of the reservoir geometry (see Chapter 4.5) and grid information (spacing and dimensions) and associated (static) formation properties (porosity and permeability). The input data should allow for computation of the transmissibility field. Moreover, rock compressibility must be supplied (see Chapter 4.1).

- **Fluid properties**: the specific data requirements depend on the selected fluid model. In black-oil models, the variations of the formation volume factors, solubility ratios, and viscosities as a function of pressure are required (see Chapter 4.2). For compositional models, tables for the equilibrium ratios (K-values) may be adequate.

- **Rock/fluid properties**: these include relative permeability relations and capillary pressure curves (see Chapter 4.1).

- **Well data including the location, completion (perforation) information, operating conditions, and appropriate constraints must be specified.**

- **Complete specification of the boundary conditions, both on the reservoir boundaries and wells.**

- **Specification of the initial conditions**: enough information should be provided to allow for the computation of the initial distribution of the pressures (see Chapter 4.4), saturations, and if necessary, the compositions and temperatures. Often, the initial state of the system is provided directly to the simulator. This may be a preprocessing step, or a restart run, which refers to a continuation from the point where a previous simulation run left off.

Each of the input items listed above can range from a simple minimal set of values to a highly detailed specification with many levels of options and sub-options.

The quality of the predictions obtained from the reservoir flow simulator depends strongly on the quality of the input data. As a result, data sampling and collection schemes must be carefully planned and executed. Furthermore, experts should be deeply involved with the carrying out of laboratory tests and experiments conducted in the process of providing the properties of interest (formation volume factors, solubility, compositions, relative permeability, etc.). The properties needed for flow simulation are often obtained indirectly, or interpreted, using information from a wide range of data sources of varying quality and quantity. As a result, in order to place the flow simulation results in context, it is important to have a clear grasp of the assumptions and limitations associated with the interpretation methods that are used to construct the input data set for flow simulation.

The RCM and the methods used to obtain the required fluid properties are now discussed:

*The RCM*. The RCM describes the architecture of the reservoir, the geometry of the geologic features,
and detailed spatial distributions of the reservoir properties, such as porosity and permeability. The available information used to construct the RCM, often referred to as the geomodel, comes from many different sources with significant variations in both quality and quantity (see Chapter 4.5). Examples include seismic data, electronic well logs, core measurements, well tests, and production histories. Moreover, the length scales associated with available measurements, whether direct or inferred, vary greatly.

**Fluid and rock/fluid properties.** The fluid properties necessary are obtained from Pressure-Volume-Temperature (PVT) laboratory analysis of fluid samples from the reservoir under investigation. Ideally, a fluid sample should be collected when the reservoir is originally discovered. The reservoir fluid samples may be collected either downhole or at the surface. In either case, it is a challenge to make sure that the composition of the collected sample is representative of the reservoir fluids. Here, we touch on the subject very briefly; details on sample collection and analysis are given in Chapter 4.2.

When a sample is collected at the surface, the correct proportion of surface fluids (i.e. oil and gas) must be recombined such that the composite sample, when taken to reservoir conditions of pressure and temperature, matches the *in situ* reservoir fluid. On the other hand, downhole sample collection may be directly representative of the reservoir fluid if the reservoir itself and the downhole conditions are both above the bubble-point pressure, which ensures single-phase liquid (oil plus dissolved gas) flow into the wellbore where the sample is captured. This is not possible when dealing with a saturated-oil reservoir since the pressure drawdown at the well is likely to cause some gas to leave the oil as the fluids move to the wellbore making it difficult to collect a proper fluid sample.

For the purpose of PVT analysis, special laboratory equipment is used to place the reservoir fluid sample in a holding cell with environmental controls for both pressure and temperature. Subjecting the fluid sample to a liberation process is a basic PVT test. A liberation, or expansion, test starts with the reservoir fluid sample above the bubble-point pressure; then the pressure is reduced in small steps. As the pressure falls below the bubble point, gas is liberated from the liquid oil. If the liberated gas is removed from the cell, the process is referred to as differential liberation, while if the liberated gas is not removed and remains in contact with the oil, then the process is referred to as a flash liberation process. Differential and flash liberation processes can lead to different amounts of oil and gas at the final conditions of the test, and this why fluid samples are usually subjected to both tests.

The basic PVT analysis consists of three parts (Dake, 1978): bubble-point pressure determination from a flash expansion of the fluid sample, calculation of the formation volume factors of oil and gas and the solubility of gas in the oil as functions of pressure using a differential liberation process, and performance of flash liberation tests for a set of separator conditions of pressure and temperature so that the PVT data can be recalibrated as needed to match operating field conditions. More complex PVT tests include detailed compositional analysis of the reservoir fluid sample. Additional important measurements which are usually performed include, among others, measurement of the gas compressibility factor, gas specific gravity, and oil viscosity as functions of pressure.
The functional relations of rock/fluid properties, such as relative permeability and capillary pressure, are usually obtained from laboratory displacement tests performed on reservoir core samples. The relative permeability plays a very important role in reservoir displacement processes, and obtaining representative relative permeability curves for a particular reservoir formation is a challenging problem. Details of the methods used to obtain these important properties will not be presented here (see Chapter 4.1). We emphasize here that while discussions of reservoir heterogeneity usually focus on the spatial variation of (absolute) permeability and porosity, significant heterogeneity in relative permeability and capillary pressure is also commonly observed and is usually correlated with the complex lithology of reservoir rock.

**History matching**

Historical dynamic data include pressure measurements, oil production, Water/Oil Ratio (WOR), and Gas/Oil Ratio (GOR) as a function of time, both on a well-by-well and field basis. The frequency and accuracy of the measurements vary widely and depends on, among other things, the size of the reservoir asset, prevailing regulations, location, and the field operator.

Historical flow performance data are used to validate and update the RCM so that it is consistent with all available information about a specific site. This process of integrating the dynamic data into the RCM is referred to as history matching. Confidence in predictions of future performance using reservoir flow simulation hinges in a large part on the quality of the history match. Quality in this case is measured in terms of accurate representation of the relevant reservoir properties and physical processes that dictate the flow and transport behaviours. This important validation phase is often the most time consuming part of a simulation study because the history matching process itself usually requires running the reservoir flow simulator repeatedly to guide the calibration of the RCM.

Significant progress in history matching methods has taken place in the last few years. Given the complexity of the problem, however, engineering knowledge and experience are essential in order to arrive at a history match that is both consistent with the available information, and more importantly, a history match that is actually useful in making more reliable predictions of future performance. After all, reservoir simulation is intended to be a predictive reservoir management tool, both from the perspective of long term development plans as well as the ability to rationalize and optimize the relatively short term operating conditions of existing reservoir assets.

Obviously, history matching can only be carried out when the model is run during the production life of a field and not before the production begins.

**Forecasting performance**

Reservoir simulation can be used: (a) to update, or calibrate, the RCM based on dynamic historical data; (b) to make performance predictions based on the existing development strategy; (c) to explore a wide range of recovery processes and future development plans; (d) to optimize the placement and operations of existing and future wells; and (e) to quantify the uncertainty associated with the predictions.

A reservoir simulator is a computational tool. Thus, the range of possible uses is difficult to cover. The utility and value of this computational tool depends strongly on the engineer using it, and the context in which it is applied and integrated. Broadly speaking, a reservoir simulator allows the exploration of limitless ‘what-if’ scenarios related to recovery processes and development plans for a specific reservoir. Given the limited and incomplete information that is available in practice when making development decisions, a reservoir simulator also plays a vital role in the quantification of the uncertainty associated with predictions of future reservoir performance. In that sense, a reservoir simulator is a vital tool for quantitative reservoir management. We should also not overlook the utility of numerical reservoir simulation in exploring and understanding the complex physics associated with reservoir flow processes.

**4.6.4 Practical considerations**

In this section, we discuss model selection, in terms of the fluid model and grid selection.

**Fluid model choice**

The choice of the fluid model (e.g. black-oil, compositional, thermal-compositional) depends on the properties of the reservoir fluids and the recovery process under study. As described earlier, the standard black-oil model is based on a two-component (oil and gas) description of the hydrocarbon, which are partitioned between the oil and gas phases according to simple PVT relationships. These PVT relationships are in the form of pressure dependent formation volume factors and gas solubility. Generally speaking, a compositional model is only necessary when the mass transfer between the components cannot be described using the simple PVT relations employed in the black-oil model.
Despite its simplicity, the black-oil model is widely used in reservoir simulation practice. Unless the oil is volatile (e.g. if it is mainly composed of light components along with high gas solubility), natural depletion processes of oil reservoirs under the various drive mechanisms, including solution gas, gas cap, and aquifer support, can usually be modelled using a black-oil approach. The black-oil model is also popular for the simulation of various injection processes, including waterflooding and immiscible gas injection. However, a black-oil model is inadequate for accurate simulation of EOR processes where complex mass transfer between the injected and resident fluids takes place. Examples of such processes include the injection of gas that is miscible or near-miscible with the resident oil. For such recovery processes, a compositional formulation is necessary to describe the physics that dictates the behaviour of the flow and transport processes accurately.

In thermal processes, such as steam injection, the energy equation must be added to the mathematical statement that describes the flow and transport in the reservoir. A thermal, black-oil approach may be adequate for modelling steam injection. However, it is often the case that a thermal-compositional model is required to accurately describe the complex mass transfer and physical interactions that dictate the displacement behaviour.

The physics and equations that describe EOR displacement processes, such as polymer, and surfactant flooding, can be quite complex; as a result, special-purpose simulators capable of modelling chemical and surfactant injection processes have also been developed. It is not uncommon to have a different simulator for each fluid model: black-oil, compositional, miscible, thermal, etc. Recently, however, there has been a concerted effort to build multi-purpose reservoir simulators with the ability to model a wide range of recovery processes.

**4.6.5 Prediction uncertainty**

Building a coherent RCM that integrates all available information is closely tied to the predictive reliability of the computed predictions of future flow performance. However, the integration of data from different sources with varying quantity, quality, and scale is a challenging problem.

Populating the RCM with permeability is of central importance because it has a significant impact on the predicted behaviour of flow and transport. Detailed description of the spatial distribution of permeability is complicated because permeability of natural porous formations, such as oil reservoirs, often displays complex, multiscale spatial correlation structures and high levels of variability, and we typically have measurements at a few locations only (Dagan, 1989). To deal with the sparse availability of data on these highly heterogeneous natural geologic formations, a stochastic, or probabilistic, framework is usually employed (see Chapter 4.5). In this framework reservoir properties are treated as random space functions. In addition to available measurements, the property, e.g. permeability, is usually described by its mean, variance, and correlation structure. Such a description is possible when available data allow accurate delineation of large-scale features, but when only a weaker form of information (statistical moments) is available about spatial property variation within these large-scale features.

The uncertainty in the RCM due to incomplete knowledge of the formation properties leads to uncertainty in the performance predictions obtained from reservoir flow simulation. Above, we focused
on permeability uncertainty, however, we emphasize that other sources of uncertainty must also be considered.

The Monte Carlo Simulation (MCS) approach is widely used in the oil industry to quantify the prediction uncertainty (Haldorsen and Damsleth, 1990). In the MCS approach, high-resolution, equiprobable RCM realizations are generated. Each RCM realization is constructed such that available deterministic and statistical information are honoured (Deutsch, 2002). A flow simulation is then performed for each RCM realization in the ensemble. The number of realizations in the ensemble should be large enough to span the uncertainty space of interest. Statistical post-processing of the simulation results can then be used to generate a report on the predictions and the associated uncertainty for quantities of interest (e.g. mean, standard deviation, and confidence intervals for well pressures, production rates, and cumulative recovery). It should be noted that in addition to the RCM, the Flow Simulation Model (FSM) also includes the fluid properties (e.g. density, viscosity, and phase behaviour), and the rock/fluid properties (e.g. capillary pressure and relative permeability relations). Moreover, initial and boundary conditions and applicable controls must be specified.

When performing MCS in practice, time and cost considerations, in terms of both human and computational resources, usually limit both the resolution of the individual realizations as well as the number of realizations in the ensemble. The resolution gap between the RCM and the FSM is commonly bridged using scale-up techniques. Scale-up methods attempt to coarsen the RCM to a size that is more amenable to reservoir flow computations. The resulting coarse model should capture the essential effects of the fine-scale details of the flow behaviours. The process of scale-up often includes regridding for the purpose of flow simulation (Durlofsky et al., 1997).

A different approach to quantifying prediction uncertainty is based on solving the equations that describe the statistical moments of the quantities of interest (pressure, saturation, production rate). These Statistical Moment Equations (SMEs) are derived from a stochastic statement of flow and transport in the heterogeneous porous medium. It is now documented that SME methods are applicable for a wide range of variability levels and correlation length scales (Li et al., 2003). However, significant progress is necessary before SME methods can be used for practical general-purpose reservoir simulation.

4.6.6 Development plans

Development plans are usually based on detailed simulation studies that are linked with economic analysis of the development stages. For cases in which the recovery process is well defined, the development plan may include, for instance, the specification of optimal completion intervals for existing wells in addition to the drilling of new in-fill wells, their types and locations, and specific completion intervals. Reservoir simulators coupled to surface facilities can be used to specify the capacity and infrastructure requirements during the various development stages. Examples include water and gas handling facilities.

As mentioned earlier, with the help of reservoir simulation, development plans, whether modest and short term or ambitious and long term, focus on making predictions and providing a quantification of prediction uncertainty along with assessments of economic risk.

4.6.7 Development schemes

The location and the spacing of production wells and the interval to be open to production (perforations) depend upon a number of different factors: a) the structural configuration of the reservoir; b) the petrophysical characteristics of the reservoir rock and the type of fluid it contains; c) the presence or lack of a gas cap; d) the nature of the hydrocarbon-water contact (bottom contact or edge contact); e) the prevailing drive mechanism.

For example, in an undersaturated oil reservoir with no water drive, in which the principal drive mechanism is represented by solution gas, the wells may be spaced according to a square grid, where the distance between production lines (normally variable between 400-500 m to over 1 km) depends exclusively upon the petrophysical characteristics of the reservoir rock (Fig. 8). The interval to be open to production may be relatively wide and also close to the Oil-Water Contact (OWC) but need to avoid perforations in the upper structural layer, given that these types of reservoirs may form a secondary gas cap during the course of its productive life. This occurs when the pressure of the reservoir has dropped below the bubble point.

A similar strategy may also be adopted when dealing with a saturated oil reservoir with a gas cap, under weak or no water drive at all, and with oil-water bottom contact (the contact is referred to as bottom contact when the thickness of the level is greater than the hydrocarbon column, i.e. the difference in height between the upper structural area and the depth of oil-water contact).
In the case of a natural gas reservoir with characteristics similar to those described above, given equal properties of the rock, the spacing between the wells is greater as a result of the higher mobility of natural gas with respect to oil. The location of the wells and the perforations in this case must, however, be limited largely to the upper structural area (in the presence of either weak or strong water drive), in order to avoid an early water breakthrough in the wells and in order to recover all of the gas contained in the trap.

In the event of a saturated oil reservoir with a gas cap and edge oil-water contact (edge contact occurs when the hydrocarbon column is greater than the thickness of the level), the production wells can be situated mainly along an external ring located in the structural flanks (Fig. 9). In this case, the perforations can be placed at an adequate distance from the oil-water contact and closer to the Gas-Oil Contact (GOC), if the water drive is strong and the gas cap is of limited extent, in order to avoid the formation of water coning. The perforations will instead be located closer to the oil-water contact, and far away from the gas-oil contact, if the water drive is weak or zero and the gas cap is large, so as to avoid the risk of gas coning. The perforations will be located in an intermediate zone, between the two contacts, in the event of the concomitant presence of an wide gas cap and a strong water drive.

In the case of an undersaturated oil reservoir and a strong water drive, the production wells will be largely concentrated in the upper structural area (as far as the petrophysical characteristics of the reservoir rock allow it) in order to avoid, as much as possible, the early water breakthrough in the wells following the normal raising of the oil-water contact and/or phenomena of water coning and water fingering during the productive life of the field.

The above examples can be considered to be the basic development schemes; of course, in reality a series of intermediate cases with respect to those described above is possible, each of which must be individually considered, bearing in mind, in any case, the criteria explained here.

The schemes described above are based on the exclusive consideration of vertical wells. In the case of horizontal or multilateral wells (with a number of horizontal sections that branch out from a single borehole) these schemes may be slightly modified, especially with respect to the number of wells.

### 4.6.8 Injection schemes

In the processes of secondary recovery an attempt is made to increase the recovery factor by injecting fluids that are immiscible with oil into the reservoir in order to almost totally, or at least partially, restore the energy dissipated during production and to create or increase the process of displacement.

The methods of injecting immiscible fluids include the use of natural gas (gas injection) or water (water injection). The choice of which of these types of injection will be used may depend on the characteristics of the reservoir and the type of oil present, though in many cases it is determined by the availability of the fluid to be injected and its cost (natural gas is without doubt more costly than water). It would in fact be illogical to choose to inject natural gas into a reservoir if this fluid is not available in the area. According to statistics water injection currently represents the most widely used technique of secondary recovery.

The gas injection technique calls for the use of specific wells (existing or to be drilled), located in the upper portion of the structure, through which natural gas can be injected into an existing gas cap (original or secondary) or through the creation of an artificial gas cap. The displacement of oil towards the production wells by the injected gas is the same as that which occurs in the natural drive mechanism generated by the expansion of a naturally occurring gas cap (see Chapter 4.3).

The gas to be injected may be that which has been recovered in the separator (gas dissolved in oil), it may come from a gas layer that is present in the same geological structure, located above or below the level of oil production, though not in hydraulic...
communication with it, or it may come from nearby fields, whether it be a solution gas or a gas from gasiferous horizons.

Prior to being injected, the gas must undergo a series of treatments (normally it is dehydrated and in some cases the condensates may be removed); the injection is to be made using compressors or a series of compressors (see Chapter 5.3).

The injection of water into a reservoir, as part of the technique of secondary recovery, may take place within the aquifer below the oil zone, in a peripheral area (peripheral injection) or directly within the oil zone (dispersed injection), according to a variety of different injection patterns.

The choice to use peripheral injection or dispersed injection depends primarily upon the petrophysical characteristics of the reservoir rock (above all its permeability) and the size of the reservoir. In fact, peripheral injection is used in most cases for relatively permeable reservoirs, while dispersed injection is used for reservoirs with low levels of permeability. In both cases the injection of water has the objective — other than that of providing energy to the reservoir in order to maintain the pressure above a certain value (above the bubble point), thus preventing the gas liberation into the reservoir — of creating a displacement front in order to push the oil towards the production wells and, therefore, maintain an acceptable level of production while simultaneously increasing the recovery factor. In most cases the injection takes place at balance, i.e. by injecting a quantity of water that is comparable to the amount of oil being produced.

The peripheral water injection (Fig. 10) occurs, as has been stated, in the aquifer in an area that is peripheral to the reservoir, and is undertaken, in most cases, during the productive life of the field. The number, location and the injection rate of the wells is established by means of numerical simulations and injectivity tests (see Chapter 4.4). The action and the effectiveness of a peripheral water injection are, in all respects, very similar to those of the expansion of a strong natural aquifer and allow very high levels of recovery (greater than 50%) to be obtained.

In very large reservoirs where the reservoir rock presents low levels of permeability, the action of a peripheral injection (and also that of a natural aquifer) would be very slow and, therefore, ineffective in terms of keeping the production of oil at an economically sustainable level. In this case it is thus preferable to inject water directly into the oil zone (dispersed injection). In this technique of injection the production wells and the injection wells are uniformly distributed across the area of the reservoir, using a regular grid that may assume various configurations (injection patterns). The most commonly used patterns are those of parallel alignment (direct line drive), staggered alignment (staggered line drive), or geometries with four points (four spot), five points (five spot), seven points (seven spot) or nine points (nine spot), as illustrated in Fig. 11. In addition to maintaining the pressure of the reservoir, injection into the oil zone creates a number of displacement fronts moving towards the production wells and it is possible, in some cases, to obtain recoveries that are greater than those obtained with a peripheral injection (for details on the phenomenon of displacement see Chapter 4.3).

The technique of dispersed injection will be more effective when dealing with fairly homogeneous and, above all, non-fractured reservoir rocks, given that the injected water may be channelled into preferential paths and arrive too quickly at the production wells, leaving behind notable quantities of oil. Naturally, the injection pattern to be adopted must be tested using mathematical simulation models, with respect to the location and spacing of the wells, as well as their rates. In most cases before undertaking any pattern of dispersed injection it is standard practice to test the efficiency of the injection by means of pilot plants, for a fixed period of time in a particular area, in order to later extend the project to the entire area of the reservoir.

The dispersed injection pattern — given that, on the basis of the reservoir characteristics, it
must be assumed that the injection of water will take place during a relatively early period of its productive life — requires that also the injection wells be drilled during the initial development phase of the reservoir and put in production for a certain period of time, together with the production wells. Later, they will be converted into injection wells when the pressure has dropped to values that are close to the bubble point; in this way the process of injection will be assisted by the fact that it will not be necessary to pump the water at high pressures.

The water to be used for injection, which may be considerable in quantity, can be taken from superficial aquifers, from the sea if the reservoir is located offshore or on land but near the coast, or from surface waterways (in addition to the water produced by the reservoir, if the quantities are considerable).

Prior to proceeding with water injection it is necessary to chemically analyse the compatibility between the water to be injected, the reservoir rock and the fluids contained, in order to avoid the formation of precipitates (usually sulphates) which can plug the rock pores. Furthermore, the water must be filtered using appropriate filters in order to remove any suspended solids, as well as being de-oxygenated and treated with bactericides in order to prevent the formation of bacterial colonies, which in turn may lead to the creation of gelatinous masses which plug the rock pores; and finally it must also be treated with chemical additives in order to prevent scales and corrosion in the equipment being used. With regard to the systems for water pumping and water treatment, reference should be made to Chapter 5.3.

**References**


A. Direct line drive pattern

- $d/a = 1 \quad \eta_a = 57\%$
- $d/a = 4 \quad \eta_a = 90\%$

B. Staggered line drive pattern

- $d/a = 0.5 \quad \eta_a = 72\%$
- $d/a = 1.5 \quad \eta_a = 80\%$
- $d/a = 4.0 \quad \eta_a = 90\%$

C. Four spot pattern

- $\eta_a = 74\%$

D. Five spot pattern

- $d/a = 0.5 \quad \eta_a = 72\%$

E. Seven spot pattern

- $\eta_a = 74\%$

D. Nine spot pattern

- $\eta_a = 52\%$

$\eta_a$ coefficient of areal sweep efficiency

**Fig. 11.** Main oil injection patterns.
OIL FIELD CHARACTERISTICS AND RELEVANT STUDIES


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