3.5.1 Introduction

The term completion, when applied to oil wells, is used to define all post-drilling operations that are necessary to hydrocarbon production. Completion has, on the whole, a permanent nature, which means that planning parameters must be carefully evaluated, and possible solutions must undergo technical and economical optimisation.

Completion planning involves choosing and organizing the equipment to be used, selecting materials, establishing production line tubing dimensions, stipulating production intervals, and finally defining the mode of formation fluid production. This evaluation must take into account the evolution of the productive characteristics of the well, according to the production forecast.

In fact, the production characteristics of each well depend on the interaction between the reservoir, the completion, and the surface equipment. These macro-elements, in their interaction, set the conditions for production in relation to the flowing pressure and the flowing rate at the wellhead.

One very important element that influences the fluid mechanics during production is the type of produced fluid. This fluid can be a liquid, a gas, or a mixture of liquids and gases. Therefore, the chemical and physical characteristics of the produced fluid and its evolution over time must be known when planning the completion. An understanding of the produced fluid’s characteristics is the basic element needed to define the pressure at the first separator, which will form the closing point of the reservoir, well and surface plant’s fluid mechanic system, and which is the starting point when planning a production plant.

The production capacity of a well is determined on the basis of reservoir data such as reservoir pressure, permeability and the thickness of the pay rock around the well, and according to the results of previous production tests, which are used to determine the Productivity Index (PI). Using the productive capacity, defined as a function that combines the flow rate and the acting pressure regime, which is known as the Inflow Performance Relationship (IPR), the service conditions of the well are determined. On the basis of these, the diameter and thickness of the tubing are chosen. It is also important to consider the efficiency of the completion in the light of the decrease in reservoir pressure over time, and to evaluate a possible substitution of the original completion with one of a bigger diameter, to reduce pressure loss, and guarantee the produced flow. If the reservoir pressure is insufficient for natural flow, it may be necessary to consider an artificial lift system.

The presence of non-hydrocarbon components in the produced fluid conditions the choice of the materials. In fact, the frequent presence of carbon dioxide and/or hydrogen sulphide in the hydrocarbon-water mixtures leads to the formation of acid solutions that attack the materials the completions are made of. This is why the materials generally used, such as special stainless steels, elastomers, and composite materials, have a good resistance to corrosive agents, and good retention of mechanical properties.

Another fundamental element to be taken into account when planning the choice of materials and the completion’s structural design is the temperature. As we know, the subsoil temperature increases by 3°C for every 100 m of depth. The metallic structure is therefore subjected to mechanical stress due to thermal dilatation. The temperature also influences in different ways the acidic components’ effect on the materials, and the mechanical behaviour and stability of the plastic and elastomeric materials.
The type of completion adopted will depend on the structural/geological characteristics of the reservoir, and on the type of mineralization. There are two categories of completions: conventional completions and so-called smart completions. The latter were introduced in the early 1990s with the aim of allowing production management to take place directly in the well, thus avoiding maintenance work leading to interrupted production and additional working costs.

In the course of a well’s producing life, which lasts several decades, interventions may be necessary to restore the optimal flow conditions. These conditions may be reduced because of clogging, scale, hydrate or asphaltene deposits or other problems in the hole or the formation. The operations to be undertaken to remove possible obstructions, or to restore the production capacities of the formation must be planned when designing the completion, in order to reduce the costs and simplify the interventions.

Some completion jobs aim to prevent problems that may arise during the productive phase. For example, the completion could get clogged up by solids dragged up through the production plant, causing erosion to the plant in general, or to specific parts of it, such as valves or bends. It is therefore necessary to separate the solid particles from the fluids, by installing filters and sand-catching devices. The solid particles must then be properly disposed of.

### 3.5.2 Types of completion

**Overview**

Oil and gas well completions can be divided into two main categories: open hole well completions, and the case-hole completions.

In open hole completions the pay rock is kept as it is, and no cemented casing columns are needed. This type of completion is realized when the formation is self-supporting or when, on the contrary, it is too severely fractured to guarantee successful cementation. It is the optimal solution since the entire drainage surface is available for production, and pressure drops are limited. Moreover, the absence of casing columns makes it easier to proceed to well stimulation. On the other hand, in open hole completions it is impossible to control the entrance of sand and water in the hole, and it is therefore very difficult to isolate the levels and proceed to their stabilization.

Case-hole completions are more widely used due to technical reasons relating to the stability of the hole. In this case the well to be completed is one that has been lined and cemented throughout its entire development. In order to make production possible, it is necessary to re-establish hydraulic communication between the pay rock and the hole. This operation involves drilling the lining, the cementation and the pay rock.

There are four possible solutions to establish communication between the productive formation and the surface: a) tubingless completion; b) packerless completion (with a tubing string and without isolation between casing and tubing); c) single string with hydraulic isolation completion; d) multiple string completion.

The tubingless completion method is used in wells where the pay rock pressure is low and high flow rates are required. In this case production must take place directly through the final lining of the well, with no support from production strings or isolation systems.
Packerless completion is a more financially advantageous system. Here, only the production tubing is placed in the well, and it is possible to produce both through it and through the annulus (Fig. 1). The production tubing can be used for injecting inhibitors or killing fluid. This method is somewhat limited in terms of flow conditions and the protection of the tubing materials. Moreover, it is difficult to detect leaks in the tubing or the casing, and to gather bottomhole pressure data.

The single stringe completion using hydraulic isolation and just one string is convenient when the production layer appears to be homogeneous and a selective-zone production is not necessary. It consists in the use of a single tubing string that is lowered into the well together with an isolation device for the formation section to be produced, called the packer (Fig. 2).

Where there are several production layers for one fluid, a single selective completion is used. This system has only one tubing string and several packers that isolate the various production levels. By using wire-line operations it is possible to open and close the valves so as to allow production on single layers (Fig. 3).

The multiple tubing string completion uses, at the most, two or three tubings, isolated by packers and producing on different levels at the same time (Fig. 4). This solution is useful when the reservoir presents different layers of mineralization, for example gas and oil, or different types of oil, because it allows us to produce selectively according to necessity, while keeping production active on various levels at the same time. For the single tubing strings, it is always possible to adopt a solution similar to the single selective completion, thus obtaining a multiple selective completion. This system’s drawback is the limited diameter of the tubing which in turn reduces the flow capacity of each tubing string.

**Multilateral completions**

The introduction of deviated well drilling, and in particular the adoption of multilateral schemes has led to the necessity to develop devices for *ad hoc* completions. In general, completion technology for
multilateral wells combines selective and multiple functions, and also has the particular characteristic of using several holes, which converge into a ‘father’ well. In fact, the multilateral system is based on several wells, all derived from one initial well. The number of wells, their orientation, disposition and inclination to the vertical, as well as the chosen type of completion and isolation, have led to the development of a number of systems. Below is a brief description of the systems currently available, based on the classification provided by the Technology Advancement of Multilateral (TAML), a group of experts operating in the field (Fig. 5).

**Level 1** is known as the *Openhole Sidetrack.* This method is the simplest completion system. Both the main well and the secondary wells are openhole. The secondary wells are not isolated. **Level 2** has a cased and cemented main well, while the secondary wells have an openhole completion. It is possible to install liners, or filters, in the lateral branches. The key element of this type of completion is the connection fitting for lateral inflow that is assembled together with a permanent packer. **Level 3** is similar to level 2. The difference lies in anchoring the lateral liner to the inside of the main well, thus giving the completion better mechanical strength. This type of completion also includes a hook hanger, which is a connecting device installed between the completions of the main well and that of the secondary branch, allowing for selective entry in both holes. In **level 4** the lateral well is cemented. This guarantees the mechanical resistance of the derivation section of the lateral branch, but does not grant it hydraulic sealing.

In **level 5** the hydraulic seal is obtained by isolating the junction between the lateral branch and the father well from the injected fluids and the produced ones. The hydraulic seal is achieved by means of three conventional packers: one in the lateral branch, one lowermost in the main well, and the last one above the junction. A *scoophead diverter tool* is also added to divert the tubing into the lateral branch. This method offers selective access to the single branches, and the possibility to manage independent production. **Level 6** aims to guarantee mechanical and hydraulic continuity by using casing to ensure hydraulic sealing in the branching section. To this end, *ad hoc* elements are used to make sure that it is perfectly continuous. For the completion, standard configurations, such as dual completion, are used, with the difference that the two tubing strings are set in two distinct holes. Once more, a *scoophead diverter tool* may be used.

Multilateral technology can potentially increase well productivity by exposing a limited number of wells, generally horizontal or severely deflected. Technological improvements in drilling and completion have made it possible to drill, cement, and complete several lateral wells starting from a single main well. This technology gives enhances the benefits of horizontal completion. Under certain conditions, such as production from very deep reservoirs, multilateral technology saves time and money, compared to traditional drilling of many single wells.

Multilateral wells expose the reservoir to the productive system more than others, thus increasing the productivity from a single slot. As some reservoirs depend exclusively on the natural fracturing system for oil and gas production, the planning of lateral wells increases the probability of finding and producing oil and gas from various fracture systems.

The use of multilateral completion in a single reservoir can increase the drainage efficiency. In fact, the lateral wells can be drilled in several directions to increase the area in contact with the reservoir, enhancing well productivity and reducing the number of wells needed for the development of the production field.

When an impervious barrier blocks the vertical flow of the hydrocarbons between two production areas, stacked systems can be used to produce in both areas, and overcome the obstacle in the formation.

According to the length, number, angle and distance of the secondary wells, this kind of system can increase productivity, in comparison with conventional horizontal wells. The development costs for single wells can be reduced because a small number of wells is necessary.
The decision to drill and complete a multilateral well requires the planning of an appropriate combination of drilling, casing and completion components in order to minimize problems. The choice of an appropriate completion system, as stated above, depends on the interventions required in the well, and on the expected life cycle of the well.

**Intelligent Completion Systems (ICS)**

The term Intelligent Completion System indicates the direct control of well processes. This system aims to control the flow and emission, both on a productive level and on an environmental level, operating as close as possible to the source in order to adopt the best production strategies to control well behaviour. Proximity to the source, and in particular to the production area, is one way of facilitating operations such as pressure, temperature, and flow measurement, as well as making operations such as separation and re-injection of produced water more economical.

The main reason for adopting an ICS lies in the production flexibility, the reduction of future workover jobs, and the consequent improvement in well performance. The fundamental benefit is the reduction of routine operations and occasional interventions due to the use of remote instrumentation and motorized devices in the well, such as control and/or production valves.

The most interesting aspects of ICS include: a) flow control of different production levels; b) selective closing of the levels where production is conditioned by water or gas rates greater than the established ones; c) selective water injection for assisted production on different levels; d) instrumentation for precise measurements of pressure, temperature and flow dynamics; e) devices for the separation of water, oil and gas downhole; f) remote control of production; g) instrumentation for selective testing of the production capacity of the various levels.

The archetypal ICS is geared towards wells containing areas isolated by multiple or single packers. Each packer contains well-logging devices for measuring pressure and temperature, and monitoring the flow, as well as powered choke valves allowing the regulation of production. All monitored and controlled levels are connected to the control centre on the surface by cable. This cable transmits the data gathered by the sensors in each production level, and carries the command signals to the devices located along the tubing string (**Fig. 6**).

The systems for data transmission, both bi-directional and not, from or towards the bottom of the well, usually make use of fibre-optic technology. Fibre optics present many advantages compared to traditional cable-data transmission systems, for example the ability to transmit a greater quantity of information than conventional systems with a better signal-noise relationship. Fibre-optic systems do not interfere with other systems present in the well since they do not use electric current for data transmission. They also save a lot of space, occupying from one quarter to half of the space normally required for conventional systems. This rational use of space allows for the installation of other technical instrumentation. Fibre optics are intrinsically safer than conventional systems since they are not dependent on an electrical signal to function, and are able to withstand temperatures as high as 300°C. Safety is, in fact, an important aspect of electricity supply both for fibre-optic transmission systems and for the engines needed by the actuators linked with the regulation devices in the well.

One highly interesting aspect of intelligent completion is the use of separating devices inside the well. The idea of separating oil from water downhole, and re-injecting that same water into the formation during oil production is very convenient. This technique avoids the expense of hoisting the fluids to the surface, reduces the size, weight, and cost of the...
equipment needed on surface, and reduces the processing costs in specific areas, such as offshore platforms.

The general tendency is to remove water as close as possible to the pay rock, thus creating more favourable conditions for production. Indeed, at relatively high temperatures, such as reservoir temperatures, the fluid viscosity is inferior to that on the surface, and both gas, and, if present, asphaltene, are still in a state of solution. Moreover, the oil from the reservoir has still not been subjected to intense stirring therefore emulsion is less likely to form. Finally, water removal on this level helps to limit pressure-loss along the production tubing, and therefore increases production.

3.5.3 Completion equipment

The equipment that is used to assemble completion strings in a well is numerous and varied; therefore, only the main elements will be described here.

Tubular equipment

The main element in completion is the tubing, that is the network of pipes which connect the area of the reservoir selected for production to the surface. The pipes are made of non-welded stainless steel, and are classified according to length, diameter, type of steel, weight, thickness, and according to the type of thread and joint. An alternative to the use of strings of pipes connected by joints is the use of so-called coiled tubing, which consists in a steel pipe coil around a drum that is introduced into the well by means of a special tool. This method is economically convenient because it allows us to get a completion working in very little time, and to dismantle it very rapidly. Coiled tubing can also be re-used in other completion plants. It is generally used in temporary completions to carry out long-term well tests, or where the use of a jointed tubing system would present serious problems.

Special elements are added to the tubular units that make up the production string. These are needed to carry out specific local functions, and include flow couplings, blast joints, landing nipples, circulation devices and travel joints.

Flow couplings are short pipes which are thicker than the tubing. They are used near devices that are liable to produce high turbulence within the tubing, in order to delay possible damage due to erosion. The flow couplings are generally twice as thick as the tubing, for an equal internal diameter, and are usually used with the landing nipples or the circulation devices.

The blast joints also serve to prolong the completion’s life span by protecting it from the erosive flow which comes into the well via the production string. They have a similar internal diameter to the tubing, but their external diameter is larger.

The landing nipples are thick stub pipes, turned on the inside to create blocking profiles and landing seats. These joints serve to provide landing seats for flow control devices. Other joints are used to land removable safety valves. In this case the landing nipples can differ from the standard joints by presenting a hydraulic control line.

Circulation devices are used to put the inside of the production string in communication with the annulus tubing-casing. This communication is required to circulate a fluid in the well, to treat the well with chemical products or to inject fluids into the tubing through the annulus. There are two different devices for doing this: sliding sleeves and side pocket mandrels.

A sliding sleeve is a cylindrical device with an internal sliding mechanism, or sleeve. Both the sleeve and the outer cylinder are perforated so as to provide coupled openings, and the sleeve is moved up and down by a wire-line tool. When the sleeve is brought into the open position, the relative opening is in line with the opening in the outer cylinder, and allows communication between the tubing and the casing. The sliding sleeves are usually positioned either above the uppermost packer in order to carry out circulation and pressure-balancing operations in the well, or between two packers to allow for selective production on multilevel reservoirs.

The side pocket mandrels are special devices that present a chamber parallel to the flow chamber, in which it is possible to fix devices and connect the annulus to the inside of the string without occupying the flow diameter. Their main utility is that of providing seats for gas-lift valves, but they can also be put to a different use: as a means for circulating fluids, and as an emergency device for well killing. In this case, a valve is installed, which will only open if there is major external pressure on the tubing, thus allowing the entrance of a fluid.

One very important element is the expansion joint, usually referred to as the travel joint. These joints absorb the motion of the production tubing which is due to variations in pressure and temperature. A travel joint is composed of two concentric tubes fitting into one another, and hydraulic seal units, that are placed in the internal tube to isolate the annulus between the two elements during the joint excursion. Travel joints are usually installed above the uppermost packer, to contain the tubing motion which is otherwise difficult to compensate.
Wellhead completion

The production string is connected to the wellhead by means of a series of elements that form the wellhead completion. These are the tubing spool, the tubing hanger, and the Christmas tree (Fig. 7).

The tubing spool serves to hold up the production string and to connect, at the bottom, the casing heads and, at the top, the Christmas tree. The tubing spool includes two lateral openings that allow annulus control between production tubing and production casing.

The tubing hanger is needed to support the tubing and to establish the annulus seal. The annulus is positioned in the tubing spool, and the production tubing is screwed on to it. An external gasket guarantees the seal between the production casing and the tubing.

The Christmas tree is located above the tubing spool. Its function is to consent production regulation, and to create safe conditions for workover operations inside the well. The Christmas tree is composed of two main gate valves, called the master valves, which enable the well to be closed. Above these a crossover connection is installed. Wing valves, which are fixed to the lateral flanges, are used both for production and for possible workover jobs in the well. On the upper flange there is yet another valve, similar to a master valve, and a crowning flange that is used to install the workover equipment without having to stop the flow. The absolute pressure gauge is installed on the crowning flange in correspondence with the wellhead.

The production packer

In most cases, the production string has not only one anchoring point in the wellhead, but also a second one located in the lower part, near the level to be produced. The latter is achieved by means of a packer, which also serves as a hydraulic separator between the production area and the remaining part of the well. Packers also have a number of other functions. They are used to protect the casing from formation pressure and from the fluids produced, to isolate leaks in the casing or in damaged perforations, to isolate multiple production horizons, to keep production fluids within the annulus, and to enable the use of certain artificial hauling methods.

Once the need to install a packer has been identified, it is necessary to choose the type, dimension, hole number, as well as the installation and removal modalities. Although a wide range of packer models exist, all packers have similar characteristics: every packer is equipped with a flow mandrel, packing units, a cone seat, and slips. The mandrel provides the flow conduct for production. The production tubing is installed on the mandrel, along with any other device that needs to go through the packer. The packing units enable the maintenance of different pressures between the tubing and the annulus. The cone seat sets in place the guy rings, which then grip the casing wall and prevent up and down motion on the part of the packer. The cone seat also permits the expansion of the packing units.

A primary distinction of the various packers includes a classification according to the removal possibilities they offer, and separates the permanent packers from the removable ones.

Permanent packers cannot be completely removed or reinstalled in the well; they are usually installed separately from the completion string, which is subsequently inserted under pressure on the flow mandrel of the packer. Appropriate equipment is necessary for this particular job. It is possible to install this type of packer using the production string, but to do so it must be possible to disconnect the tubing from the packer, in order to later remove the packer. The removal of this type of packer involves milling, making it impossible to reuse the packer elsewhere.

Removable packers, on the other hand, are designed to be removed and reinstalled elsewhere in the well. This characteristic means that they are
usually installed together with the production string, and are activated both mechanically and hydraulically. These packers can be removed either by exerting tension on the string, or by implementing a series of rotations that lead to the disengagement of the gripping device. The uncoupled guy rings retract to their seats, the packing units relax, and the device is ready for removal.

Another characteristic according to which packers may be classified is the presence of crossing holes. These enable communication through the packer, and can both host the completion string, and permit access and connection to any type of electronic device, or measurement equipment located beneath the packer itself. There are packers with one, two or three holes, and they are known as single, double, or triple packers. The double packers are usually used, for example, in double-string completions. In the case of single-string completions, the use of a double packer allows the transmission of electrical power from a submersed pump.

The installation of packers involves pushing the slips towards the packing units in order for them to expand. To exert this compression force between the slips and the rubber units, several techniques can be put into practice. These different modalities include string rotation, weight release, string tension, pressurizing from the inside of the string and gas expansion produced by means of explosion.

In general, the installation methods are divided into mechanical, hydraulic and electrical ones. Mechanical methods make use of techniques that involve interventions on the completion string, such as rotation or tension of the tubing, or weight release. The hydraulic method consists in pressurizing the inside of the string to activate the piston that is located within the packer, while the electrical method consists in sending an impulse to the setting device through the electric wire. The electrical impulse activates an explosive charge within the setting device in order to expand the combustion gas: the increase in pressure due to its expansion provides the necessary force for the setting of the packer.

Certain packers require the setting force to be applied continually in order to keep the packer in place. These packers are called compression-set and tension-set packers. They are both of the mechanical type, and require the setting force to be applied directly to the production string. Compression-set packers need a compressive load to be constantly applied from above. This load is usually applied by releasing the tubing weight, but can also be applied by means of a pressure differential, using the increased pressure exerted on the upper face of the packer. This is why compression-set packers are used in injection wells. In fact, if the compressive load happens to be reduced, the setting device slackens, and the packer becomes uncoupled. It is therefore important to evaluate the forces exerted on the tubing to establish whether these may lead to the uncoupling of the device.

As tension packers can be set and held in place only under tension, a tension load must be exerted by means of tubing pulling. This means that the extra pressure in the lower part of the packer increases its tightness. This type of packer is used in cases where the formation pressure of the production levels is superior to the pressure exerted on the annulus. Neutral stress or compression conditions lead to the uncoupling of the packer. Operative conditions which produce tubing expansion, for example a temperature increase that induces thermal dilatation, also produce the uncoupling of the packer.

Hydraulic, electrical or mechanical packers that are set by means of string rotation are defined as neutral, since they remain in place whether the string is under tension, in compression, or neutral.

The methods employed to bring the packer into the desired position may involve the use of cable, drill pipes or work pipes, or the production string itself. The method used for setting must be compatible with the chosen type of packer and the connection system between the packer and the tubing, and the relevant cost evaluations must be taken into account when considering alternative solutions.

There are four different methods to connect the packer to the tubing: threaded connection, anchor assembly, J-latch setting and locator setting. An anchor assembly system requires the use of short pipes with seal gaskets, and a series of grip teeth to keep the tubing locked to the packer. A J-latch setting consists in a J-shaped gripping and locking latch set on top of a series of seals, which is fixed to the packer head by means of internal or external pins. These types of connection, together with the threaded connection, promote the development of an integral packer-tubing system. The locator assembly consists in a stack of annular seals topped by a positioner. This system does not promote mechanical continuity between the tubing and the packer, which is why it allows for tubing motion, both in expansion and in contraction, against the packer.

**Subsurface Safety Valves (SSV)**

SSV are control devices that are used to interrupt well production when there is an emergency. The opening and closing of a safety valve can either be operated from the surface by means of a hydraulic control line, or directly activated by the well conditions.
SSV that are controlled from the surface are comprised of a piston on which pressure is exerted from the surface by means of the hydraulic line. This pressure causes the locking device to remain open. A spring is positioned to act in the opposite direction, thus closing the valve, should an absence of pressure occur. In most types of SSV controlled from the surface, well pressure is made to act in accord with the spring, in order to close the valve itself.

SSV controlled within the well are directly commanded by well pressure, and do not require a surface control line. In this case, the valves are armed on the surface before installation. They stay open as long as the flow conditions remain in keeping with the normal production pressure regime, otherwise they close. Given that the absence of control from the surface makes it impossible to re-arm, and therefore to re-open them, the use of these valves is limited to specific applications.

There are two types of SSV: Tubing Safety Valves (TSV), that are installed along the production tubing and used to control the tubing flow, and Annular Safety Valves (ASV), that are used to control the flow in the annular space between the tubing and the casing.

Security valves may be classified according to their shutting system, and according to how they are reused or dismantled. To be dismantled, some TSV require the removal of the tubing, while others can be dismantled without any work on the tubing, but through a wireline intervention which removes the valve from its seat using an appropriate tool. The shutting devices most commonly adopted for SSVs are balls or hinged disks; both mechanisms can be used with removable safety valves or with a wireline intervention.

An essential element that characterizes the different types of valves is the pressure-equalizing device. In fact, a difference in pressure across the valves occurs during the closing process. This must be eliminated before re-opening the valve. Thanks to the pressure-equalizing device this opening operation can be carried out by working directly on the valve. If this device is not in use, it is necessary to equalize pressure by pressurizing the tubing above with a pump or a compressor before opening the valve. Pressure-equalizing devices are extremely useful but, since they are exposed to high stress and speed levels, they can themselves become problematical during valve opening and closing operations.

This is why equalized valves are usually used for SSV which are installed and removed using wireline, whilst non-equalized valves are highly recommended for tubing retrievable safety valves.

Annular Safety Valves (ASV) are used in the proximity of the wellhead to prevent gas from getting in from the casing-tubing annular space should a wellhead failure occur. This situation may arise, for example, in a completion using gas-lift systems, or Electrical Submergible Pumps (ESP). In both cases the annulus between tubing and casing is used to either inject (in the case of a gas-lift) or to evacuate gas (in case the case of an ESP). After this, an ASV is installed, together with a production packer, a TSV, and an optional travel joint. The valves are controlled from the surface by means of control lines, to enable re-arming if necessary.

Future use of ASV depends on the development of hole-separation systems and formation-fluid re-injection for single completions.

### 3.5.4 Equipment

In choosing the equipment for a well completion it is necessary to specify which materials are adequate for the use foreseen.

Metallic tubular elements are produced in low (0.3%) carbon steel with low quantities of manganese. The increase in mechanical resistance is obtained by hardening or tempering the steel. Special steels that do not come under the API categories are used in hostile environments that require high mechanical resistance or resistance to hydrogen sulphide. The API standards that regulate the metallic materials used for completion equipment also apply to the well casing.

The equipment for standard use usually complies with the mechanical requirements laid down by the API L-80 regulation. The API L-80 also applies to corrosive or acidic environments, but does not take temperature into account. Temperature has a great influence on the behaviour of non-metallic materials such as, for example, elastomers. These deteriorate over time at temperatures above 275°C, and lose all sealing capacity. High-efficiency elastomeric compounds have higher operating temperatures, but, when used under strong pressure, require support devices to avoid elastomeric extrusions.

Interesting results arise when considering the working conditions and the type of environment in which completion equipment must function. The probability of corrosion occurring is strongly linked to the presence of both reservoir and condensation water. The water present in the production string assumes a corrosive character in the presence of carbon dioxide (CO₂), hydrogen sulphide (H₂S), and acidification fluids; it is therefore important to establish corrosiveness a priori, in correspondence...
with the temperatures in the hole when CO₂ and H₂S are present, before choosing which metallic materials to install. It should be noted that the corrosion speed increases with the water production and the decrease in the water’s pH. When the tubing becomes wettable to oil, or when water-in-oil emulsions are produced, the possibility of corrosion is strongly mitigated.

Corrosion due to CO₂ proves to be dependent on its concentration and temperature; in particular, for temperatures below 60°C, the main corrosive factor is the concentration of carbon dioxide. As the concentration of CO₂ increases, so does the corrosive effect, whereas corrosion diminishes with the increase of water salinity. At temperatures above 60°C, the deposition of iron carbonate (FeCO₃) and iron oxide causes a decrease in corrosion. In this case the rise in salinity produces an increase in the corrosive potential of the water-carbon dioxide mixtures.

Another important aspect relative to corrosion is the use of different metallic materials together. In this case potential differentials develop between the two metals that are in contact, creating a galvanic flux that consumes the metals as though they were sacrificial electrodes. It is also important to evaluate the effect of stimulation operations using acidic solutions, or injections of water is not completely de-aired, and therefore rich in oxygen.

Induced embrittlement due to the presence of free hydrogen is of crucial importance in hostile environments. In this case, exposure to hydrogen sulphide causes a non-brittle material to take on brittle mechanical behaviour, due to the penetration of hydrogen atoms within the metallic structure. This phenomenon is most common in high-pressure environments, and is accentuated when the concentration of hydrogen sulphide increases. Other environmental factors that favour the development of fractures in embrittled metals are tension stress, temperatures below 65°C and the presence of acidic waters. Conditions for embrittlement can also be caused by the chlorine ions found in hot and particularly saline waters.

In addition to metallic materials, plastic materials hold a very important place. These materials are mainly used for the realization of packing units, which are not only exposed to mechanical strain, but also to other types of stress when exposed to high temperatures and pressures, and when in the presence of both hydrocarbon and non-hydrocarbon compounds. Plastic materials are divided into two groups: elastomeric or non-elastomeric. The first group includes the well-known nitrile compounds that have proved to be particularly appropriate for the realization of gaskets and packing elements. However, elastomeric nitrile compounds have a limited field of application, since their quality is degraded in the presence of hydrogen sulphide, aromatic solvents (xylene and toluene), and heavy completion fluids, such as zinc bromides, and acids. The same quality abasement occurs at temperatures exceeding 135°C. To operate in conditions which are hostile to nitrile, fluorocarbon elastomers can be used. However, it should be noted that corrosion inhibitors made with amines, methanol, glutaraldeide, and steam will degrade the qualities of this material. Another possible solution is offered by perfluor elastomers, which present a wide field of application without showing any particular limits in performance.

The non-elastomeric plastics, on the other hand, are generally used for seal gaskets, particularly the thermoplastic materials. These present good chemical resistance, but tend to lose some of their mechanical properties when subjected to high temperatures. They are usually used in packing units, and are sometimes used together with elastomers. Thermoplastic materials are considered high performance, and are therefore used in particularly severe conditions.

### 3.5.5 Completion fluids

The definition of completion fluids is a recent occurrence in oil industry history. In the past, no distinction was made between drilling fluids and completion fluids. According to the definition, completion fluids come somewhere between drilling fluids and stimulation fluids. A strict definition of completion fluids considers them to be saline solutions or brines, which are used in completion operations such as casing perforation or gravel-pack setting. In a broader sense, completion fluids are all those fluids that come into contact with the reservoir; in fact, this definition does not refer to the type of fluid, but to the function it serves. Perforation fluids used in the drilling of the mineralised formation can be considered completion fluids. This perspective led to the development of the so-called drill-in-fluid, which can be used both as perforation fluid and completion fluid. As such, a completion fluid comes into contact with the mineralised formation, and its main function is to avoid damaging the producing capacity of the reservoir. In this light, the fluids used for the acidic washing of the wells to remove calcium carbonate and mud walls formed by drill-in fluids can be considered to belong to this category.

The brines used in completion operations are the principal fluids to be put to such use. One can also use drilling mud and degassed oils. The brines are formed...
by a watery base with a salt content that is established according to the required density, and chemical and physical compatibility regarding the formation with which they come into contact.

The density of the fluid is established so as to have control over the pressures in formation. Having defined the depth and the overbalance pressure, generally 15-20 bar, the density of the fluid is determined. This will have to be modified according to the temperature, to take into account the expansion that these fluids experience undergo when temperatures increase. Their expansion factor depends on the total saline concentration and on the salts dissolved in them. Another factor to be considered in preventing overbalance pressure is the compressibility of the fluid, although this has a less important influence.

The salts most commonly used are the chlorides of sodium (NaCl), ammonium (NH4Cl), potassium (KCl), and calcium (CaCl2), as well as the bromides of potassium (KBr), sodium (NaBr), calcium (CaBr2), and zinc (ZnBr2). Some of them are used in association, for example: calcium bromides and chlorides, and zinc bromide with calcium bromide. The densities can reach a maximum of 1,100 to around 2,500 kg/m³ at 20°C. In terms of costs, the most economical brines are the chlorides and the calcium bromide and chloride mixtures.

The brines must satisfy compatibility requirements applying to both clay formations and to the formation waters, as well as to the gases and oils that are present. The objective regarding the various clays is to avoid swelling and/or deflocculation, which in turn cause the detachment of particles from the walls. To reach this objective, minimum salinity requirements must be fulfilled, in other words, at least 3% of NH4Cl or 2% of KCl must be present. In the case of formations that present a strong proportion of clay components, it is generally preferred to replace brines with oily fluids that have high inhibiting capacities. When using saline solutions with high densities particular attention must be paid to any damage caused to the formation by solute precipitation. In fact, it has been observed that in the presence of calcium salts, precipitation occurs when density exceeds 1,700 kg/m³. In these cases it is advisable to use at least 8% of ZnBr2. It has also been noted that temperatures above 150°C influence the growth of crystals, thus favouring damage.

The compatibility of completion fluids with formation waters has a great influence on the formation of scales. Scales form when incompatible waters are mixed, when temperature or pressure variations cause solubility to vary or when water evaporates. The most common types of scales are formed by calcium and iron carbonates, calcium, barium and strontium sulphates, sodium chloride, iron sulphide and silicates. In order to prevent solute precipitation it is useful to carry out compatibility tests before choosing the completion fluid. If several different brines are used, it is recommended to verify their compatibility beforehand.

Verifying the compatibility with natural oils and gases in formation involves testing for any formation of water-oil emulsions and slime deposit, which could clog the pores and damage the formation. It is therefore considered important to test in the laboratory for emulsion formation under reservoir conditions. Should incompatibility be ascertained it can be counteracted by reformulating the completion fluid. These phenomena mainly arise where thick brines with a high degree of salinity are used. In the case of natural gas, the risk of CaCO3 precipitation when using calcium-based brines depends on the contents of the CO2.

### 3.5.6 Casing perforation

In cased hole well completions, it is necessary to drill the casing in order to restore hydraulic connection between the inside of the hole and the pay rock. This operation is carried out with the help of devices called guns, a denomination due to the original perforation method that involved the use of perforating bullets shot by short guns. The guns have the function of guiding the bullet towards the cased hole so as to perforate it and reach the pay rock, penetrating it in part. The speed reached by the bullets, about 1,000 m/s, is sufficient to perforate the tubing, the cement and the pay rock. This method is not very efficient when used in resilient formations, or when particularly strong casing materials are used. Nowadays, this method is only used when dealing with soft formations, or when it is important to obtain perfectly round holes.

Another perforation method consists in using high-pressure fluid jets containing either liquids or water-sand mixtures. The devices used make it possible to create holes or gashes in the casing, and, if necessary, to produce a cut in the casing. The main advantage of this method is the possibility of creating very clean cuts without damaging the formation. The main disadvantage is the slowness of the process, and the elevated costs it involves; it can realistically be used only for carrying out perforations on short intervals.

The third perforation method is currently the most widely used, and is called jet perforating. This
Drilling and Completion of Wells

The method consists in using explosive charges often known as jet charges, which are collocated within a support system called gun. The charges have a concave shape which, in the moment of expulsion, promotes the formation of a primary expansion chamber for the gases produced and helps to aim in the chosen direction. Jet perforation systems are composed of a series of elements that form the so-called explosive train. These elements are: a detonator that is used to activate the charges, a detonating fuse to connect the detonator to the charges and the charges to each other, and the charges themselves. The explosive train can be brought into the hole in different ways. A wireline system can be used before lowering the completion. Alternatively, coiled tubing or the production string itself can be used, in order to carry out successive operations directly in the well.

The explosives used in this perforation system are of the detonating type, that is to say materials in which combustion proceeds at a faster speed than sound propagation. Detonating explosives can be divided into primary and secondary types. Primary explosives are used exclusively in detonators because of their extreme sensitivity to ignition, and must therefore be handled with extreme care. In the oil industry they are increasingly being replaced by secondary explosives, which are used in all three components of the explosive train. They are much less sensitive to ignition, and are therefore an intrinsically safer material. In the oil industry the most utilized secondary explosives are RDX, HMX, HNS and PYX (Table 1).

The two types of detonators that are used are the electrical and the percussion detonators. When a wireline method is employed for the positioning and the execution of the perforation, the detonators used are of the electrical type. Among these a distinction is made between detonators using primary explosives, and those using secondary ones. The detonators that make use of secondary explosives are: exploding foils, exploding bridgewires, and deflagration-detonation transition detonators. The choice of the appropriate detonator depends on the energy necessary for its ignition. In fact, these detonators present a self-ignition risk due to stray currents that can occur within the electrical elements. Adopting detonators that require a lot of energy for ignition reduces this risk.

If the positioning system adopted uses the production tubing, it is preferable to carry out perforation operations using a percussion detonator. In this case, a percussion device hits a capsule containing a small quantity of explosive that provokes the ignition of the primary and the secondary explosives. The intrinsic security of this system is greater than that of electrical detonators since there are no metallic elements within the detonator. However, there is still the risk of explosion due to impact that may occur during positioning operations in the well.

To transmit detonation to the charges located along the gun the detonating fuse is used. The fuse consists of secondary explosive contained in a lining made of either metallic materials (aluminium or lead), or plastic materials extended across a woven cloth. The detonation speeds depend on the secondary explosive in use. The slower ones are achieved with HNS and PYX explosives (between 6,000 and 6,100 m/s) whilst higher detonation speeds are obtained with RDX and HMX (about 7,900 m/s).

A further way to perforate casing column is by using the jet charge method. Jet charges function in a very complex manner, but the system itself is particularly simple, consisting in explosive matter contained within a unit which is adequately protected by a special lining. The jet charge functions as follows: the ignition of the explosive produces detonation, the pressure wave generated, together with the expansion of the gases, produce the rupture of the liner following a symmetrical axis.

The shape and penetration length of the perforation depend on the geometry of the charge and the material of the liner. A cone-shaped charge produces a long thin jet that results in a deep perforation with a thin diameter. Parabolic shapes and semi-spheres produce shallow holes with large diameters. The distinction between Deep-Penetrating (DP) and Big-Hole (BH) jet perforators is based on these results. DP charges typically create holes with diameters varying between 5 and 12 mm with a penetration depth of 30-50 cm. BH charges create holes with a diameter between 15 and 40 mm, and a depth that does not exceed 20 cm.

The explosive train is kept in place by the so-called gun. There are two different types of guns: guns with a charge holder set inside a tube, and capsule systems. The first consist in a pipe sealed at both ends, containing the explosive train. This system protects the explosives from the outer environment and prevents every type of deterioration. The two existing types are: ported guns, with holes milled into the pipe and closed by special capsules, and scalloped guns, which have no holes, and a thinner pipe wall in proximity of
the explosive charges. The first can be reused several times, while the second must be abandoned in the hole. The tightness of the guns is fundamental in avoiding contact between the charges and the fluids, which would lead to damage. The ignition systems used with ported guns are electrical, with detonation from underneath. The type of ignition used for scalloped guns can be electrical, hydraulic or percussion-based, with ignition from above.

Capsule guns are formed by charges which are individually equipped with single protective capsules, and are installed on a set of cables or on a flexible plastic support. With this system, larger charges for equal tubing diameter can be used, since the space otherwise taken up by the metallic liner is available. Using this system it is possible to obtain perforations of double depth, and a 20% increase in diameter. On the other hand, the explosive train is exposed to the fluids in the well, presenting a greater risk of failure. In this situation, it is necessary to pay special attention to the tightness between the detonator and the fuse to avoid any possible contact with the fluids.

Choosing the best perforation system involves understanding which operations will be carried out in the future, in order to enhance production efficiency. For wells with a sufficient flow capacity that do not require successive stimulation, the main objective is to restore continuity between the hole and the undamaged formation. Consequently, the perforation objectives are: maximum perforation depth; phase displacement between the charges; shot density; the percentage of perforated level; and the presence of underbalance conditions during perforation, with the pressure in the hole lower than the formation pressure.

Phase displacement or phase angle is obtained by placing the charges themselves on different levels so as to avoid excessive weakening of the casing should the phase displacement be unsuccessful, and in order to be able to reach the most productive areas of the formation. Phase displacements can be of 45°, 60°, 90°, 120°, or 180°.

Shot density is an important parameter used for defining production efficiency according to the number of shots reaching the formation. Every single case must be considered when evaluating the situation. It is also important to bear in mind that the success rate for these complex perforation operations ranges from 50% to 70%.

Limiting the formation length to be produced causes a reduction in efficiency due to the necessity of forcing the flow to converge towards the perforated area.

Carrying out perforation operations in underbalance conditions helps avoid potential damage induced by explosion debris. In fact, in this situation, after the explosion, a counter-flow coming from the formation towards the hole makes it possible to purge the perforations.

### 3.5.7 Filters and drains for solid transport control

Solid transport induced in hydrocarbon production from pay rocks generally occurs in the case of non-consolidated formations and causes dangerous events with costly consequences. Most of these events are due to the accumulation of solids in the well that can lead, as an extreme consequence, to killing the well, i.e. making it impossible to produce. Another high-risk factor is the erosion of elements of the completion string, from the wellhead to the

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<table>
<thead>
<tr>
<th>Explosive</th>
<th>Chemical Formula</th>
<th>Density [kg/m³]</th>
<th>Detonation Speed [m/s]</th>
<th>Detonation Pressure [MPa]</th>
</tr>
</thead>
<tbody>
<tr>
<td>RDX</td>
<td>C₆H₆N₆O₆</td>
<td>1,800</td>
<td>8,750</td>
<td>34,500</td>
</tr>
<tr>
<td>HMX</td>
<td>C₆H₆N₆O₈</td>
<td>1,900</td>
<td>9,150</td>
<td>39,300</td>
</tr>
<tr>
<td>HNS</td>
<td>C₁₂H₁₈N₂O₁₂</td>
<td>1,740</td>
<td>7,400</td>
<td>24,100</td>
</tr>
<tr>
<td>PYX (Bis(picylamino)-3,5-dinitropyridin)</td>
<td>C₁₇H₁₇N₁₁O₁₆</td>
<td>1,770</td>
<td>7,600</td>
<td>25,500</td>
</tr>
</tbody>
</table>

(Economides et al., 1998)
surface plant, as is the accumulation of ‘sand’ in the separators, which must be removed. Problems induced by solid transport, also known as sand production, do not occur only in the well, but also inside the formation, where empty spaces may form behind the casing leading to its instability and/or collapse.

There are four methods to prevent sand from entering the well: 

1. **Reducing fluid production**: This method involves reducing the flow rate of the fluid in the hole to minimize the transport of solid particles. However, this can lead to a reduction in production efficiency.

2. **Mechanical methods**: These include the use of filters, slotted liners, and gravel packs to withhold sand and prevent it from entering the well. These devices are installed downhole and serve the following purposes: filtering, withholding solid particles, and avoiding natural solid granulate dispersion.

3. **In situ consolidation methods**: These are used to ciment the formation grains while maintaining the highest possible permeability. They are carried out using plastic materials or synthetic resins.

4. **Combined methods**: These consist of using mechanical methods together with consolidation methods.

The first method is based on the removal of the primary cause of solid transport: the speed of the flow around the well is reduced to values that do not allow solid transport to occur. It is obviously the most economical method since it does not require any investment, but it has strong repercussions on the production. Horizontal wells are a particularly interesting case. In this type of well the greater exposure of the formation to well draining leads to a lower speed in the formation, for an equivalent flow rate. The transport capacity of the fluid current is consequently reduced along with sand production. High-speed flowing is not, however, to be considered the only cause for solid transport. The formation grains can potentially be predisposed to being transported. Clearly, in non-consolidated formations this method for containing solid transport may prove to be quite ineffectual, if not damaging.

Mechanical methods are the most common type used to limit the production of sand. There are several methods, all of which use devices that are installed downhole to withhold sand and prevent it from entering the well. These mechanical devices can be filters and/or slotted liners, and serve the following purposes: filtering the formation, withholding solid particles artificially introduced, and avoiding natural solid granulate dispersion. These devices are normally used in association with a drain, which consists of granular material (with an appropriately chosen granulometry) that is placed to fill the empty spaces behind the casing and the perforation, and the filter. The purpose of the drain is to withhold solid particles both mechanically and through a reduction in the flow speed due to the increase in permeability induced in the hole.

**In situ** consolidation systems consist in providing a non-consolidated formation with an artificial cementation while maintaining the highest possible permeability. These operations are carried out using plastic materials or synthetic resins.

Combined methods consist in using mechanical methods together with consolidation methods. A drain made of resin-coated sand is used to obtain the cementation of the grains after they have been set in place.

The setting operations for mechanical sand-control systems are very articulate and complex, and require an accurate description of the single devices as well as of the operative methods. Below is a detailed overview of the single items.

To obtain an effective and efficient drain it is fundamental to choose the right filling materials. In fact, the majority of oil and service companies have adopted the API RP-58 (1995) regulation which gives recommendations for the choice and constitution of the drain. One of the most important recommendations regards choosing the correct relation between the dimension of the formation grains and the dimension of the material used for the drain. Saucier’s technique recommends choosing a relation between the average diameter of the drain grains and the dimension of the formation grains (between 4 and 8), to ensure filtering without inducing an excessive reduction in the permeability rate. This technique does not take into account granulometric distribution but only considers average dimension.

The sands used for draining are characterized by a high level of quartz and by consistent grain dimensions. The grains must be as round as possible to avoid the formation of bridges and the consequent halting of installation. Other materials can be used instead of silicate sands. These are: resin-coated sands, granites, glass beads, and aluminium oxides. These alternatives present highly spherical grains. There are various types of filters. The simplest involve the creation of longitudinal slots with openings in proportion with the dimension of the granular material used for the drain. These filters are not very expensive and have a small filtering area. They are used in wells with long production intervals and low productivity rates. In highly productive wells wire-wrapped filters are used (Fig. 8 A). In these filters a triangular wire is wrapped around a tubular element with openings in it. The filter presents an elevated filtering surface, and the space between one spiral and the next corresponds to an opening in the filter. The dimension of the openings depends on the characteristic size of the drain. There are also prepacked filters in which the chamber between the spiral filter and the tubular element is filled with granular material that may or may not be artificially cemented. Prepacked filters come in three varieties: dual wrapped prepacked (Fig. 8 B), casing external prepacked (Fig. 8 C) and with a double filter and a thin gravel pack.
The fluids used to place the drain are an equally important element in draining operations. These fluids must be able to: transport the filling materials to their place, separate from the solid fraction in order to allow the drain to form, and leave the formation without altering its permeability. These functions can be incompatible, and the selection of the ideal fluid requires special attention. Completion brines and derivates can be successfully used with the addition of polymers to increase viscosity and therefore transport capacity. The most common gel-forming agents are Hydroxyethyl-cellulose (HEC), succinoglycan (SCG), Xanthan, and Surfactant gel.

There are various methods for placing drains: a) circulation pack; b) reverse-circulation pack; c) water pack; d) frac-pack. The frac-pack owes its origin to the necessity of filling the fractures produced artificially by pressurization. Filling the fracture with granular material not only reinforces the formation, but also makes it possible to place the drain in fractures that would otherwise probably close when overpressure ceased.

### 3.5.8 Artificial lift systems

The need to use an artificial lift is an important aspect to be considered when designing a completion plant. It must be evaluated in the light of the operative life span and working conditions of the well.

There are numerous artificial lift systems, each of which has an optimal application field. The main types of lifts are: a) sucker rod pumps; b) hydraulic lifts; c) Electrical Submersible Pumps (ESP); d) gas lifts; e) Progressive Cavity Pumps (PCP). See Fig. 9.

The main purpose of artificial lift systems is to provide the fluid with the necessary energy to reach the surface and continue flowing to the primary treatment plants. The efficiency of lift systems can be defined by calculation, more specifically by dividing the power provided to the fluid by the power used by external sources such as engines or compressors. Gas lifts are the least efficient method, while PCPs present the maximum productivity, ranging from 5 to 70%.

The artificial lift system to be adopted cannot be chosen merely upon technical grounds, but must always be accompanied by an evaluation based on long-term economic convenience. This is the reason why low efficiency methods are still widely used.

Artificial lift plants with plunger pumps or sucker-rod pumps are made up of a cylinder, a piston, an aspiration valve and a release valve. The piston is connected to the surface by a string of pipes, and is activated by an eccentric system or a crank and slotted link that transforms the engine’s rotary movement into an up and down motion. During the descending phase, the valve in the piston opens and the one in the cylinder shuts. This ensures the passage of the oil from the cylinder towards the delivery pipe above the piston. During the ascending phase, the valve in the piston shuts and the one in the cylinder opens. In this manner, the piston pushes the liquid in the delivery pipe up to the surface enabling more oil to be sucked in to fill the cylinder. The pump is generally powered by an electrical or diesel engine that is connected to the surface unit by a speed reducer. This type of lift is very reliable and resilient, and is capable of lifting oil containing high percentages of sand. It presents low installation and maintenance costs and is characterized by high head, but it can only be used on reduced flows (about 6 m³/h), and presents problems when used in deviated wells.

Centrifugal pumps are composed of a rotor and a stator; the motion of the liquid is speeded up by the rotation, and then slowed down by the vanes in the stator. This operation transforms the liquid’s kinetic energy, obtaining an increase in pressure. This pressure then lifts the hydrocarbons to the surface. Generally, centrifugal pumps are installed within the...
well and are formed of several stages connected to the same rotation mast, so as to avoid suction lift. The vanes in each stage are configured so as to have peak efficiency for the flow rate concerned. As the number of stages increases so does the pump head and the quantity of power required by the engine. Given that the well diameter limits the dimensions of the vanes, the pumping rates can only be increased by increasing the rotation speed. Electric power can be provided by surface generators or through connection to the public network, and then distributed to the engines after having been brought to the adequate tension by means of a transformer. On the surface, there are electronic controllers with automatic switches or fuses for high-tension protection, manual switches, measurement equipment, and temporisers for intermittent pumping. Artificial lift systems with ESP present low installation and maintenance costs, but elevated operating costs. They have an excellent operating performance when used in deep and deviated wells (6,000 m) and promote high delivery production (80 m³/h).

A gas lift completion allows hydrocarbons to reach the surface by means of the reduction of the hydrostatic load downhole. The gas is compressed on the surface using compressors and successively blown into the well, usually through the annulus. The gas then enters the delivery pipe through holes distributed along the pipeline, making it possible to reduce the density of the fluid and bring the well to deliver. The gas lift may be continuous or intermittent. The first case is used in wells that present good downhole pressure, and allows for stronger flows. The second system is used in depleted or low-pressure wells that require a high gas cushion volume to lift the hydrocarbons. If the available quantity of gas is insufficient, the gas can be recuperated at the separator, recompressed, and sent down the well again. The valves that allow the passage of the gas can be controlled in two ways: by means of the discharge pipe, or by means of the cable. The former type have the advantage of presenting larger passages for the gas and therefore allow higher delivery, while the latter have limited passages, but can be replaced without pulling the tubing. They can be concentric, requiring the removal of all uppermost valves to enable operation on the lowermost ones, or eccentric, presenting greater external obstruction. Gas lift completions present very low installation and operating costs that can be further reduced by using a centralized compressor to feed several
wells at the same time. They are reliable and of easy maintenance, but allow a limited production flow (2 m$^3$/h at 3,000 m).

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