ARISTOTLE UNIVERSITY OF THESSALONIKI

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MSc Program "Hydrocarbon Exploration and Exploitation"

THESIS: Intelligent well completions

Completions

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Abstract

Through the years the demand for energy sources has been increased. The conventional methods of producing oil and gas are no longer sufficient to meet up with the demand. The oil and gas industry has faced several economic, geographical and technical challenges largely due to decline in crude oil prices and market volatility and there has been an increased migration to unconventional methods for the last few decades. A common solution to minimizing this problem is to increase oil production and recovery factor from new and existing oil and gas fields using Intelligent Well Completions (IWC).

This thesis analyzes Well Completions and Well Completion's methods and focuses on the new methods of Completion, the Intelligent Well Completions.

Chapter 1: Introduction

A well completion consists of a series of operations, such as tubing installation, sub-surface safety (SSSCV) installations, packer installation, perforating and sand control, Christmas tree installation, installation of lifting equipment (if required) and formation treatment (if required), that are required to enable a well to produce and to sustain the production of oil and gas following the installation and cementing of the casing. Completions are the connection between the reservoir and the surface installations. All the above will be briefly presented in Chapter 3.

Well completion is very important for the development of an oil field. The quality of the completion design and implementation plays a key role in the economic effectiveness and the expected production target of an oil field (Renpu, 2011).

The purposes of a well completion are to link the surface with the reservoir so that fluids can be produced from or injected into the reservoir, to isolate the producing reservoir from other zones, to provide a conduit for well stimulation treatments, to protect the integrity of the reservoir, especially in unconsolidated formations, and to provide a conduit to measure the changes in pressure and flow rate needed to run a well test.

The concept of well completion engineering has been little by little enriched, perfected, and updated by the progress of technology and science. Every development or exploration well is unique and faces different well completion engineering problems so engineers must apply different well completion procedures (Renpu, 2011).

Completion design includes physics, mathematics, chemistry, geology, engineering, material science, hydraulics and practical well-site experience. The best completion engineers will be able to balance the theoretical with the practical. The role of the completion designer is to take a well that has been drilled and convert it into an efficient and safe production or injection conduit (Bellarby, 2009).

The choice of the completion type must be closely coordinated with the development of the reservoir management plan. There are different methods of well completions. The main methods are:

- Open hole completions
- Cased hole completions

- Multi-zone completions
- Advanced completions (include Intelligent completions)

Chapter 2 provides an overview of well completion engineering including the main role of the well completion engineer, well planning and the concerns regarding safety and the environment during well completion procedures. The different types of well completion will be analyzed in Chapter 3.

This thesis focuses on the development of intelligent well completion which is a new advanced completion method applied in difficult and complex oil and gas fields. This type of completion will be analyzed in Chapter 4, as long as, its benefits and economical effectiveness.

Chapter 2: Well Completion

2.1 Overview

The term “well completion” describes the processes and equipment that are necessary to bring a well into production, after drilling operations have been concluded (Figure 2.1, 2.2). The quality of well completion design can increase the productivity of a well and ensure that the risks that can lead to safety hazards and/or address environmental impacts are minimized.

Completion engineer is the person that is the main responsible for the effectiveness of this process. In this Chapter the main role of the completion engineer, considerations and actions will be analyzed. The first step in completion design is well planning. In this first step, completion engineer must gather all the available information to ensure a sufficient completion design. Finally, in this chapter two of the most serious concerns for the completion engineer: safety and environmental protection will also be presented.

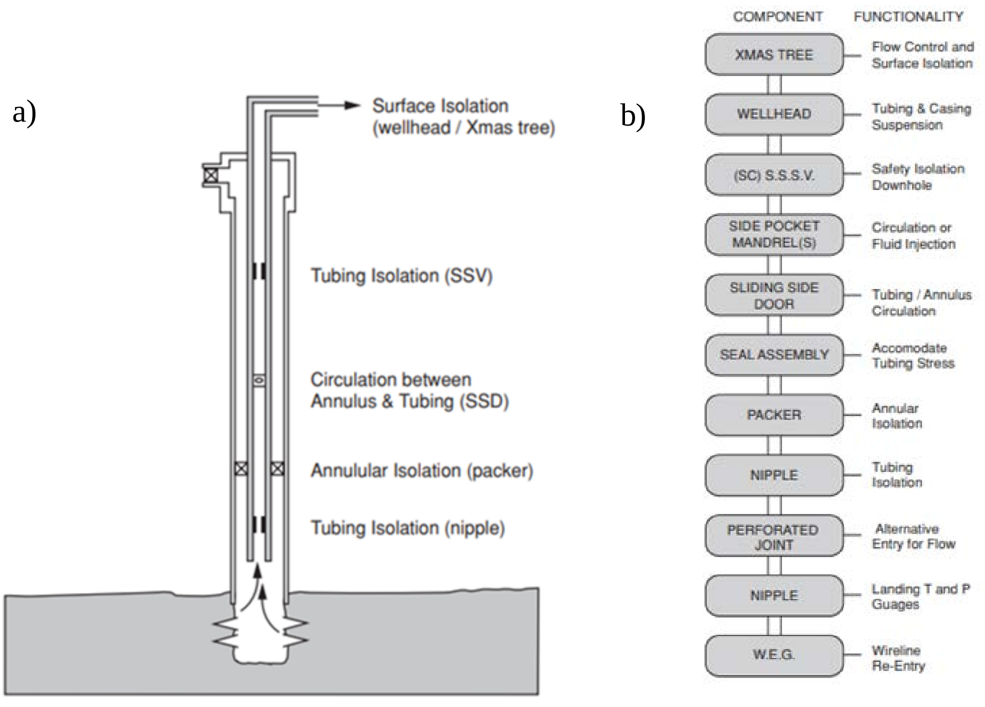

Fig.2.1, 2.2 a) Basic well completion schematic. b) General well completion string schematic (Heriot Watt University, 2011).

2.2 Well Planning

Before any production process starts, completion engineer must plan the well for completion. The most demanding aspect of drilling engineering is perhaps the well planning. It requires the integration of engineering principles, experience factors, and personal or corporate philosophies. Although well planning methods and practices may vary within the drilling industry, the end result should be a safely drilled with minimum cost hole that satisfies the reservoir engineer’s requirements for oil and gas production.

A data package should be prepared to be used on the wellsite containing all of the data needed for correlation and evaluation. This includes maps, offset well logs, the well prognosis, and any other data that the geologist believes may be useful.

Well completion design is based on data (Figure 2.3). These can be raw data or predictions what the subsurface team calls realizations. All data are dynamic and uncertain. For all available data the engineer must understand the source of the data, the uncertainty range of the data and how it might change in the future. If it is a large range of uncertainty, engineers promote completions that can cope with that uncertainty. Uncertainty can be reduced in volumetric estimations by using appraisal wells, which can also give to engineers the opportunity to try out the reservoir completion technique that most closely matches the development plan (King, 1998).

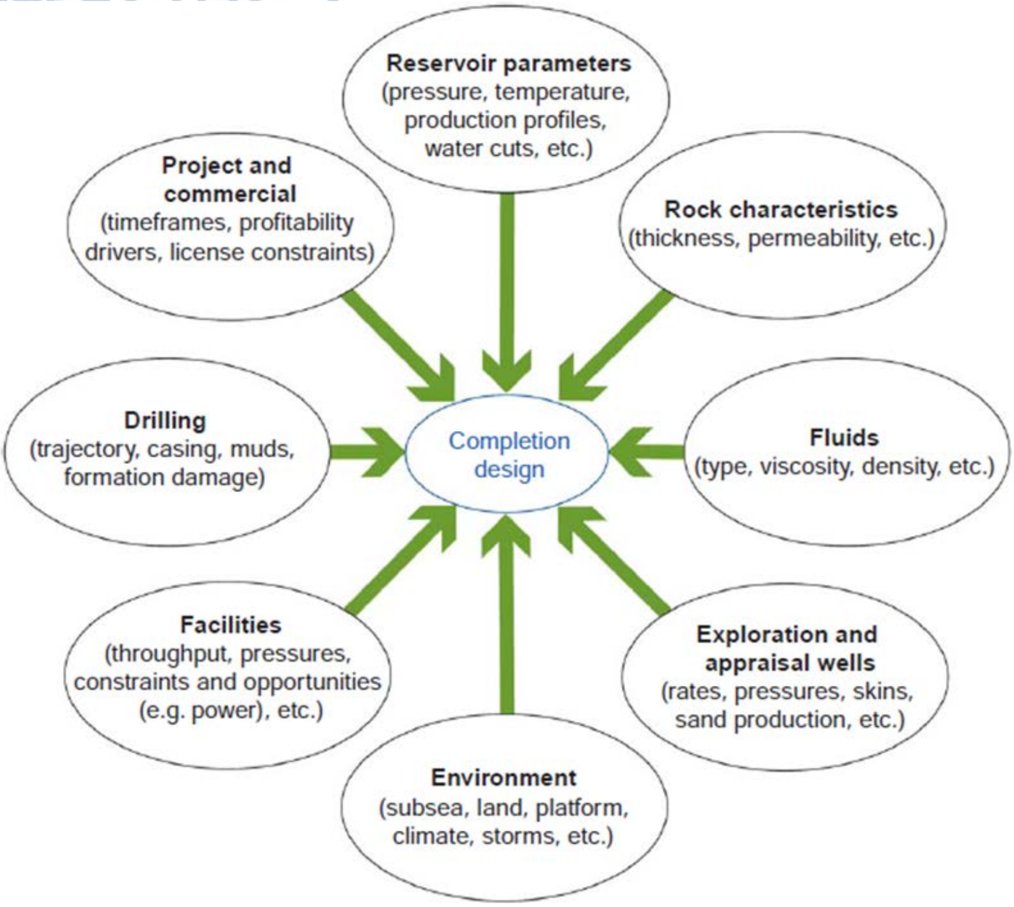

Fig.2.3 Data sources for completion design (Bellarby, 2009).

Before any operations are started on a well, for a successful well completion, engineers should construct a plan of a series of operations and steps that will take the well from initial drilling to plug and abandonment. The ideal completion is the lowest cost completion that meets or nearly meets the demands placed upon it for most of its life.

Regardless of the use of the well the method of planning is the same. For successful well planning drillers, explorers, completion and operations engineers and partner companies, foremen, equipment providers, service companies, and government regulatory officials must cooperate and exchange their information. This cooperation and information gathered at the first steps of completion could prevent expensive misunderstandings during drilling or completion of the well or significant environmental problems that could occur from improperly executed operations.

One of the most important needs is to protect the environment against pollution. All usable waters must be protected against contamination during the completion, drilling or production process. For this cause careful design and a concerted effort on the application side are required. The requirements include selection of casing that will resist against pressure and corrosive environments during the life of the well, even if a sweet well turns to slightly sour. The cement placement and elimination of any possible migration of fluids through or around the borehole must be also considered (King, 1998).

The reservoir conditions affect the completions. Reservoir considerations involve the location of various fluids in the formations penetrated by the wellbore, the viscosity, corrosiveness and the flow rate of these fluids through the reservoir rock and the characteristics of the rock itself. The factors that are most known in the area are pressure and temperature. Other factors that can be considered are the tendency to formation of scales, emulsions, asphaltenes and paraffins. The main factor in the selection of the casing size is the rate of fluid production. The starting point for well completion design is often the production rate for maximum economic recovery. Among other factors production rate should determine the size of the production conduit (Allen & Roberts, 1982).

Large casing will be used when we have expectations of a very high rate well and we decrease well costs by applying a small casing string or a small tubing string in areas with low rate. In these areas initial savings can easily be made, but the long term benefits of the well weigh in heavily for larger tubulars. There are also alternatives to conventional casing and tubing strings such as monobore completions, tailpipe extensions, velocity strings and the use of coiled tubing for faster run and retrieved tubing strings.

The topside connections and the choice of the wellhead itself are influenced by the amount of services needed on the well and the location of the well. For example, in an offshore field, for a sweet gas well with very low fluid production, the ideal wellhead is a remote wellhead or a subsea wellhead.

Multiple layered reservoirs are the most difficult parts in well planning. Multi-layered reservoirs penetrated by a well pose the problem of multiple completions in one drilled hole. These areas require processing of all the reservoirs without allowing cross flow from one zone to another. The expense of drilling and completion individual wells to isolate each zone is usually too high and it is only used in the highest rate producing areas. Other methods of effectively producing layered reservoirs or multiple reservoirs include a variety of techniques, such as multiple completions inside casing separated by packers or several strings of smaller casing cemented in one hole to provide effectively separated wells and sequenced production of reservoirs. Commingling of hydrocarbons from separate reservoirs should be done when permitted by pressures and reactants that can be formed by mixing oil or water from different zones.

The physical design parameters of the well should be dictated by the expected producing behavior of the well. Before the drilling bit selection process, the sizes of tubing and casing are set. During the tubular design, early in the design phase of the well, the use of pup joints, nipple locations, and the use of special equipment in a string, such as SSVs (subsurface safety valves) that usually need larger casing, is needed to be determined. Generally, it is preferable to minimize the number of restrictions in a producing string to prevent deposits that are often caused downstream by a flow restriction and to make sure needed tools can pass through the string (King, 1998).

Cementing operations must be carefully planned. Cementing is used to eliminate channeling of fluids. In many cases, the primary cement job will be a failure even before the cement is being pumped. In these cases an expensive squeeze cementing is required. It has been demonstrated in a number of tests that proper quality control and attention to detail can result in effective primary cementing jobs.

An area that it definitely needs attention is perforating planning and application. Depending on the needs of the well and how carefully it is designed, perforating expense can be from a few thousand dollars to over one hundred thousand dollars. A variety of processes and tools are available from underbalanced to extreme overbalanced perforating and from wireline perforating to tubing conveyed perforating.

Another fact that must be considered long before the well is drilled is the type of artificial lift that will be applied on the well. A number of artificial lift methods are available: gas lift, plunger, beam lift, jet lift, electric submersible pumps, progressive cavity pumps and natural flow. Of these lift methods, gas lift, beam lift and electric submersible pumps probably make up at least 98% of the artificial lift cases. Many wells that are on natural flow have to be artificially lifted early in their life as pressures decline or as fluid volumes increase to the point where gas drive and natural gas lift are no longer adequate. The ability to change lift methods (as fluid volumes decrease or increase) is required for well operation optimization. If the packer and casing are designed considering the changes of the lift methods, the switch of lift systems become easy (King, 1998).

Some wells have special requirements, such as sand control. The problems with the sand alone can dictate the type of completion method to increase production rates. On the other hand, reservoir fluid control problems can dictate that a less than desirable type of sand control be applied. Sand problem zones always dictate a payoff from careful well completion practices. The main concern in most sand control jobs is not the type of control, but if sand control is required and when it is required. The factors that cause sand movement change during the lift of the well. Some wells that will not experience sand production until after water breakthrough are gravel packed even from the initial completion. This is a large initial expense that can, in some cases, be delayed.

A critical factor in designing the surface and down hole equipment that makes up the well's system is the understanding of production chemistry. However, the knowledge of gas and liquid volumes, pressure and relative amounts will change over the life of a project. Hence, some flexibility must be built in to achieve a well system with low maintenance demands.

Formation damage is very common during the life of the well. Modeling can usually show a trend of formation damage and its effects but the real occurrence of formation damage may sometimes not be sufficiently predicted by any model without very exact knowledge of well behavior. The occurrence of formation damage or drilling a lower permeability formation than expected often needs the use of stimulation methods. Stimulation methods, including acidizing, fracturing, solvents and heat, can be used on almost any well provided that the tubulars and support equipment will allow the selected techniques to be implemented. If formation damage or stimulation requirement can be sufficiently forecasted early in the well's life, then cost reduction is often possible.

The lift system must be designed based on the expected rate after stimulation process and it must include: (i) the recovery of the stimulation fluid and (ii) the method this fluid flows back. The most serious problems usually occur during hydraulic acidizing and fracturing. When an acid job has begun to flow back, the pH can drop, posing corrosion issues during the recovery stage of the treatment fluid. Jobs involving proppant fracturing usually have problems because of proppant flow back with the produced fluids during the initial stage of fluid flow.

Water control is one of the problems that must be considered. The result of low pressure during hydrocarbon production is water to enter into the well. In some cases hydrocarbons are driven toward the wellbores by water and if we shut-off the water, the production rate of the hydrocarbons will be reduced. In other cases, water leaks through corroded casing, bad cement, or across fractures can flood the well with external water. If these happen, then a water control treatment is useful. Horizontal wells have often been used to successfully produce hydrocarbon without severe water production problems where bottom water drive is severe.

Since corrosion rate significantly increases during the life of the well, control of corrosion is required. The average original casing can last for twenty or more years before leaks occur. Repair may solve the problem temporarily, but leaks may often reappear in a few months. As well conditions change, special inhibitor programs are needed.

Well placement becomes critical where enhanced recovery is envisioned. In these applications the use of horizontal, vertical and deviated wells are necessary to sufficiently process and sweep the reservoir. The problem is that we know very little for the reservoir. However, today we can improve that knowledge with new techniques, such as 3D seismics and well-to-well seismics. This type of investigation can also yield extra pay zones and how those pay zones can be accessed.

All the wells that are drilled will eventually require plug and abandonment. The techniques and rules for plugging and abandonment of a well are many and variable. The isolation of the fluids within their payzone is the main concern in any completion planning and therefore the wells should be plugged in a way that the reservoir fluids will stay isolated in their reservoirs (King, 1998).

2.3 The Role of the Completion Engineer

Well completion engineering combines drilling and production engineering and yet remains a relatively independent domain. Completion engineers must act as part of a team. Although a field development team will be comprised of many people, some of the critical interactions are shown in the figure below (Figure 2.4) (Bellarby, 2009).

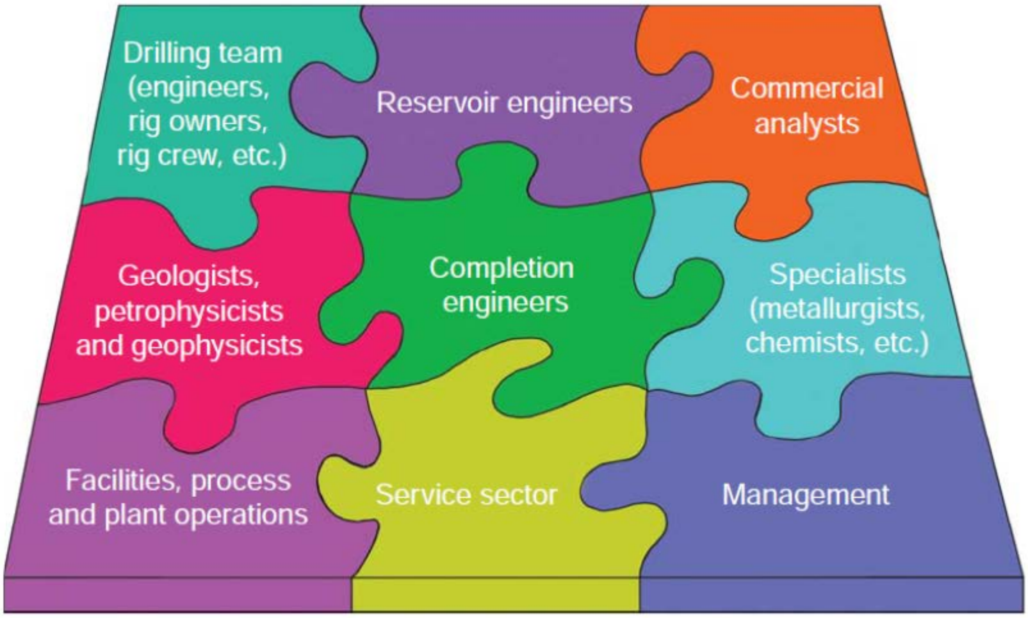

Fig.2.4 Team integration (Bellarby, 2009).

There is an inherent connection among well completion, drilling and production engineering that considers the current and future macroscopic condition of the oil field development. Drilling, well completion and production engineering must each do its own work on the well but they need to cooperate and well completion engineering must act as part of a team with the other engineers (Renpu, 2011).

A completion engineer usually needs to interact with more people than other engineers and to understand both reservoir and facilities since completions are the interface between them. Many teams are further subdivided into a facilities team, a subsurface team and a drilling team, in which completion engineers sub-team must be replaced. Whether considered as part of the drilling team, or part of the subsurface team does not really matter, as long as, they perform their tasks as needed.

A completion engineer needs get involved early in the field development plan because completion design can have a significant effect on facilities design (e.g. lift method) and drilling design (e.g. well trajectory and siting). They also influence the number and the location of the wells and the production profiles. However, in many cases, completion engineers are involved in the field planning at too late a stage. A field development team, at the starting point, consists of geophysicists, geologists, reservoir engineers, facilities and drilling engineers. By the time a completion engineer joins the team casing sizes and well locations have already been decided and some aspects of the facilities have been agreed upon, such as throughput, processing and export routes. Hence completion engineer has to fit the completion into the casing and produce the fluid to a given surface pressure. Many opportunities for production improvement are lost this way (Bellarby, 2009).

Well completion engineering is a kind of system engineering that includes drilling the well, setting casing, cementing, perforating, installing completion systems and putting the well into production (Figure 2.5). The basis of well completion engineering includes parts of the following disciplines:

(i) Reservoir engineering,

(ii) Reservoir geology, and

(iii) Petroleum production engineering.

Regarding the reservoir disciplines (reservoir engineering and reservoir geology), well completion engineering embraces reservoir types, configuration, lithology, fluid properties, porosity and fluid flow characteristics in order to select appropriate well completion mode and avoid formation damage. Petroleum production engineering lends to completion engineering the requirements of different types of wells (e.g. oil well, gas well, water injection well, etc.), production modes (e.g. commingled production, artificial lift, etc.) and technical measures necessary for maintain production (e.g. acidizing, sand control, water shutoff, etc.) (Renpu, 2011).

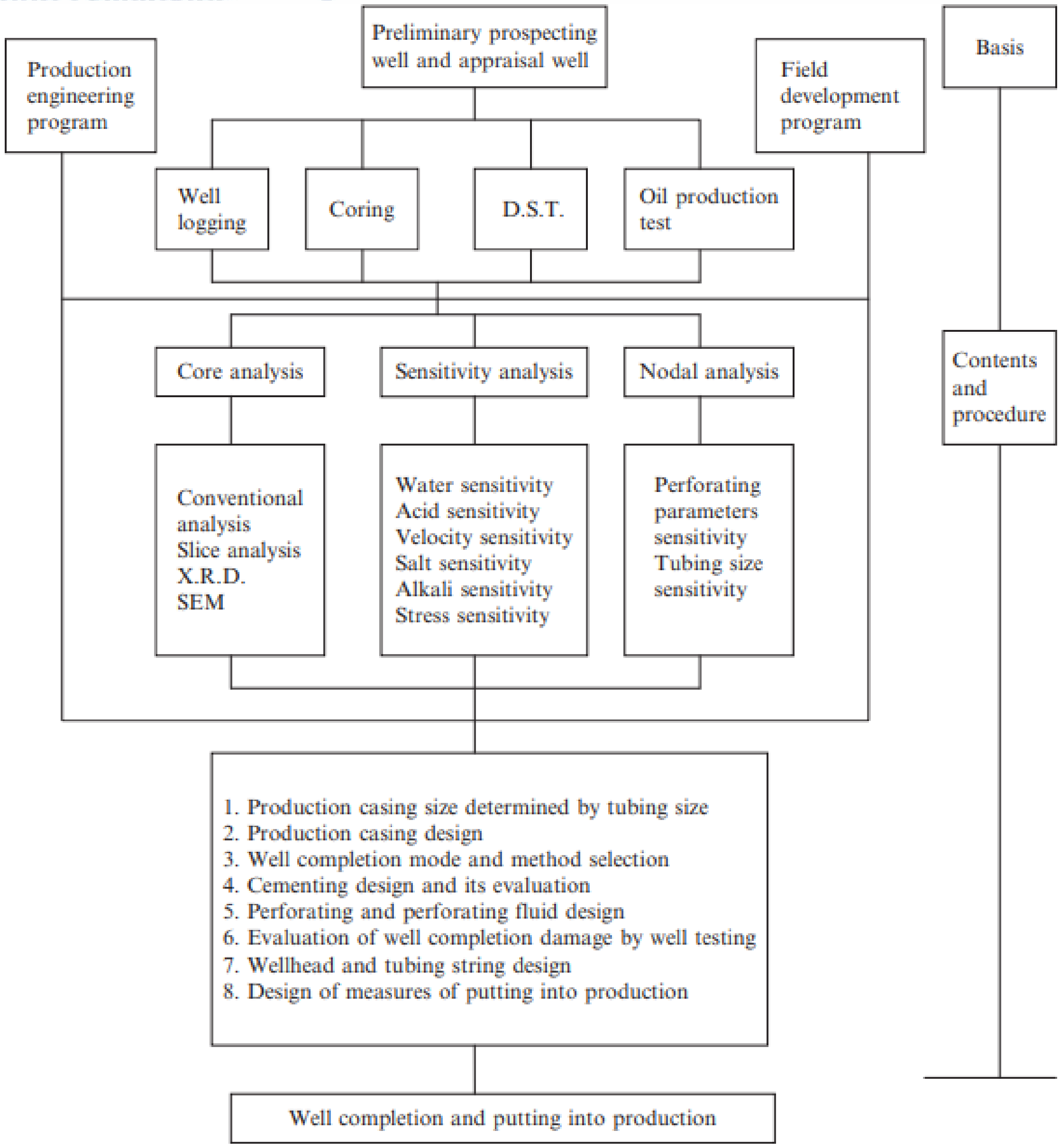

Fig.2.5 The system design procedure of well completion engineering (Renpu, 2011).

The main goals of the well completion engineering and well completion engineering system, as described above, are (Renpu, 2011):

- To minimize formation damage and unleash the natural potential of reservoir.
- To effectively produce reservoir fluids.
- To adjust the producing pressure difference, increase the flow conductivity and enlarge the drainage area, thus resulting in the augmentation of the individual well production rate.
- To assure proper conditions for the application of different oil production technologies and methods.
- To combine present and future targets in order to improve the economic effectiveness.
- To protect casing and tubing from corrosion, reduce down-hole servicing operations and prolong the well's production life.
- To design and operate the well at the maximum economic benefit with the minimum cost.

Thus, a reasonable is where the drilling ends and completions begin. This often depends on the type of completion:

- ➢ For cased and perforated wells, the completion begins once the casing or liner has been cemented.
- ➢ For open hole completions, the completion begins once the reservoir section has been drilled and the drill string has been pulled out. (Bellarby, 2009).

2.4 Safety and environment

Safety is of critical importance in well completion because of the accidents caused due to poor design or installation may be severe and fatal. The completion must be designed so as to be safely installed and operated. Safe installation will need to reference hazards such as well control, heavy lifts, chemicals and simultaneous operations.

To avoid such problems, risk assessments for all well operations, including the design of well completion, are performed. The risk assessment of well completion operations should cover all the installation procedures. Once risks are identified, they are categorized according to their impact and likelihood as shown in the figure below (Figure 2.6).

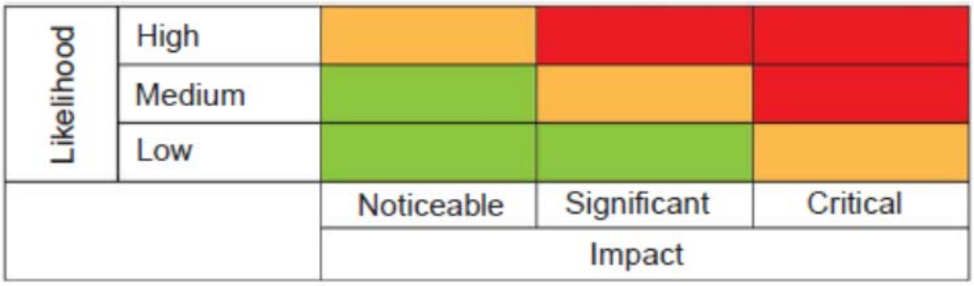

Fig.2.6 Risk categorization (Bellarby, 2009).

The majority of the companies have their own procedures for risk assessment, defining the impact in terms of injuries, cost, leak potential etc., and likelihood in terms of a defined frequency. Ideally, for all risks identified mitigation measures should be in place, but definitely for risks within the red boxes.

In some cases it is necessary risks to be quantified. These Quantitative Risk Assessments (QRAs) evaluate the risk in terms of cost versus benefit. These assessments are very useful for decisions regarding removing or adding safety-related equipment. Obviously, additional expertise with completion engineering is required for these assessments. This expertise can assist in quantifying the effect of fires, leaks, explosions, etc., on people, the environment and nearby facilities (Bellarby, 2009).

Chapter 3: Conventional Completions

3.1 Types of Completion

Well completions can either produce gas, oil and water or inject gas, steam, and waste products (e.g. sulphur, carbon dioxide, hydrogen sulphide, etc.)

The completions are usually divided into the upper completion (conduit from reservoir completion to surface facilities) and the reservoir completion (the connection between the reservoir and the well) (Figure 3.1, 3.2).

The major decisions for all completion are: (i) well trajectory and inclination, (ii) open hole versus cased hole, (iii) sand control needs and type, (iv) reservoir stimulation and (v) single or multiple zones completion (commingled or selective).

The most common types for the conventional single zone completion of the reservoir zones are:

- Open-hole completions (barefoot).
- Pre-drilled/Slotted liner completions (un-cemented).
- Cemented and perforated completions (casing or liner with annular cementation and subsequent perforation).
- Open hole with sand control screens/gravel pack.
- Cased hole with gravel pack or frac-pack. (Bellarby, 2009, Heriot Watt University, 2011).

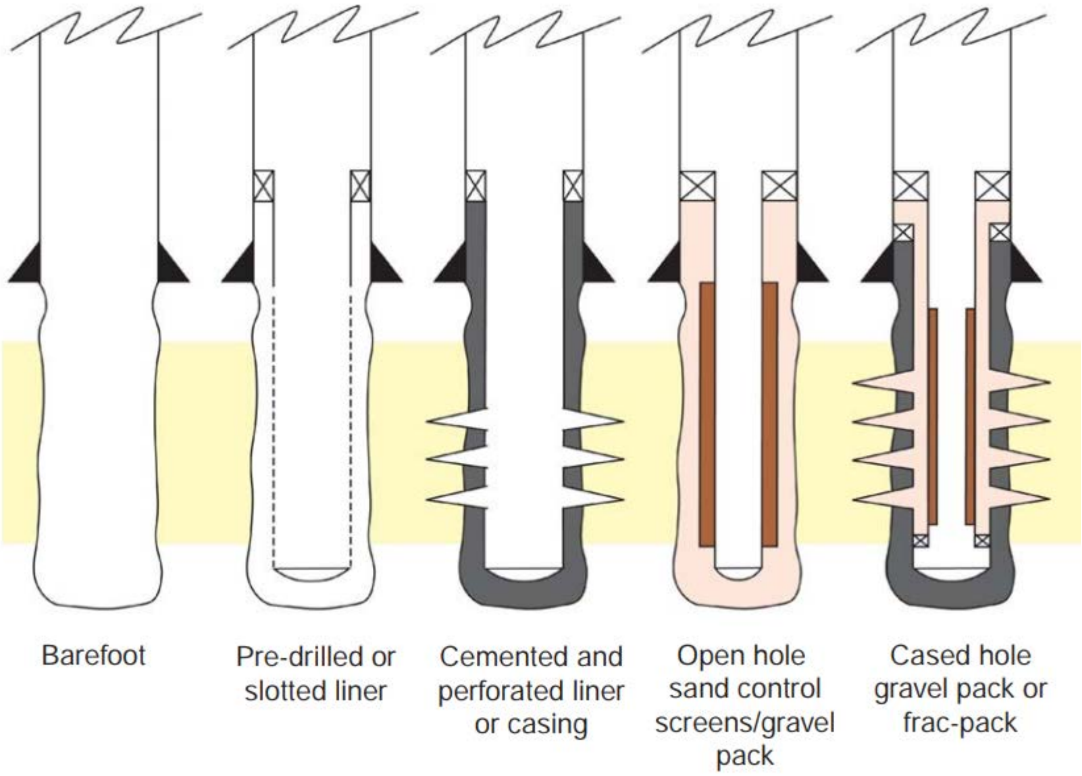

Fig.3.1 Reservoir completion methods (Bellarby, 2009).

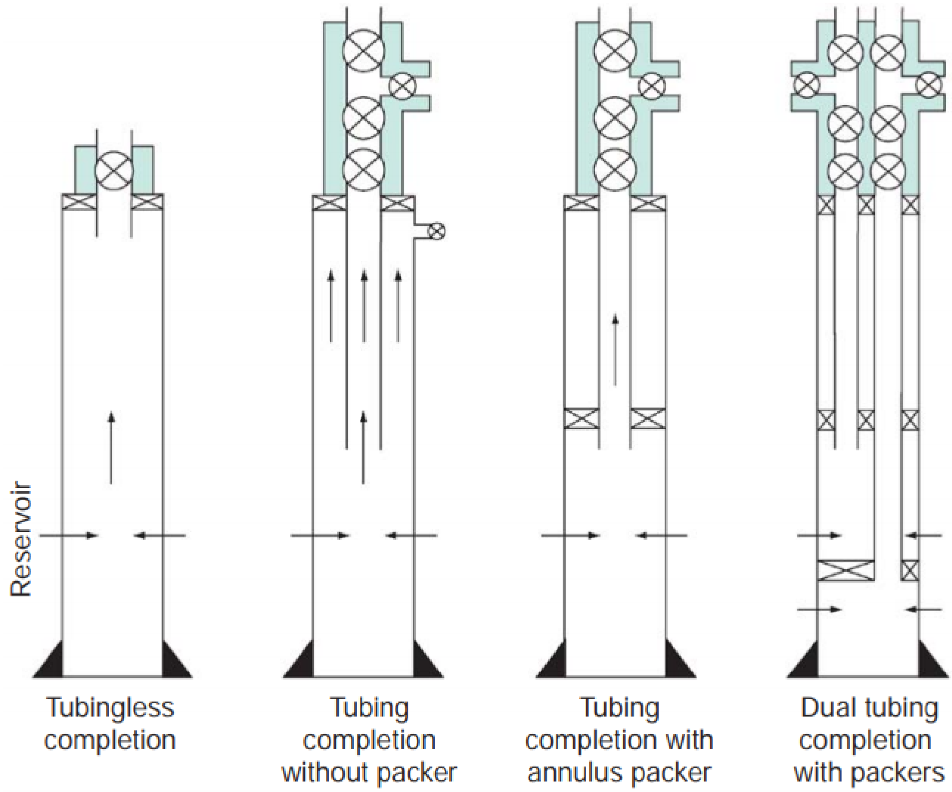

Fig.3.2 Upper completion methods (Bellarby, 2009).

3.1.1 Open Hole Completion

The primary decision on casing in the pay-zone is not of the weight or size, but whether or not to run casing at all. The simplest approach to bottom hole completion is to leave the entire drilled reservoir section open after drilling (Figure 3.3). Open hole completions represent the simplest type of completion and have some very useful features. Open hole completions are often referred to as "barefoot" completions (barefoot= no tubulars across the reservoir face) and the technique is widely applied. There are savings in both costs and time since no equipment needs to be installed.

There are 2 types of procedures for open hole completions:

1. In the first, engineers drill to the top of the oil reservoir, then they run in the intermediate casing and the well is cemented. When the cement slurry is returned to the predetermined design height and hardens, they run in a bit with a smaller diameter through the intermediate casing and they drill through the cement plug. Finally, they drill into the design depth and the well is completed.

2. In the other procedure they do not change the bit. They drill in directly through to the design depth, then the intermediate casing is run to the top of the oil reservoir and the well is cemented. They pad, during cementing, the oil reservoir with sand in order to prevent damage of the oil reservoir below the casing shoe by cement slurry. They displace the drilling fluid (which has high viscosity and low fluid loss) in order to prevent the cement slurry from settling. In some cases they set an external casing packer and cement stinger at the lower part of the casing in order to retain the cement slurry in the annulus and prevent it from settling.

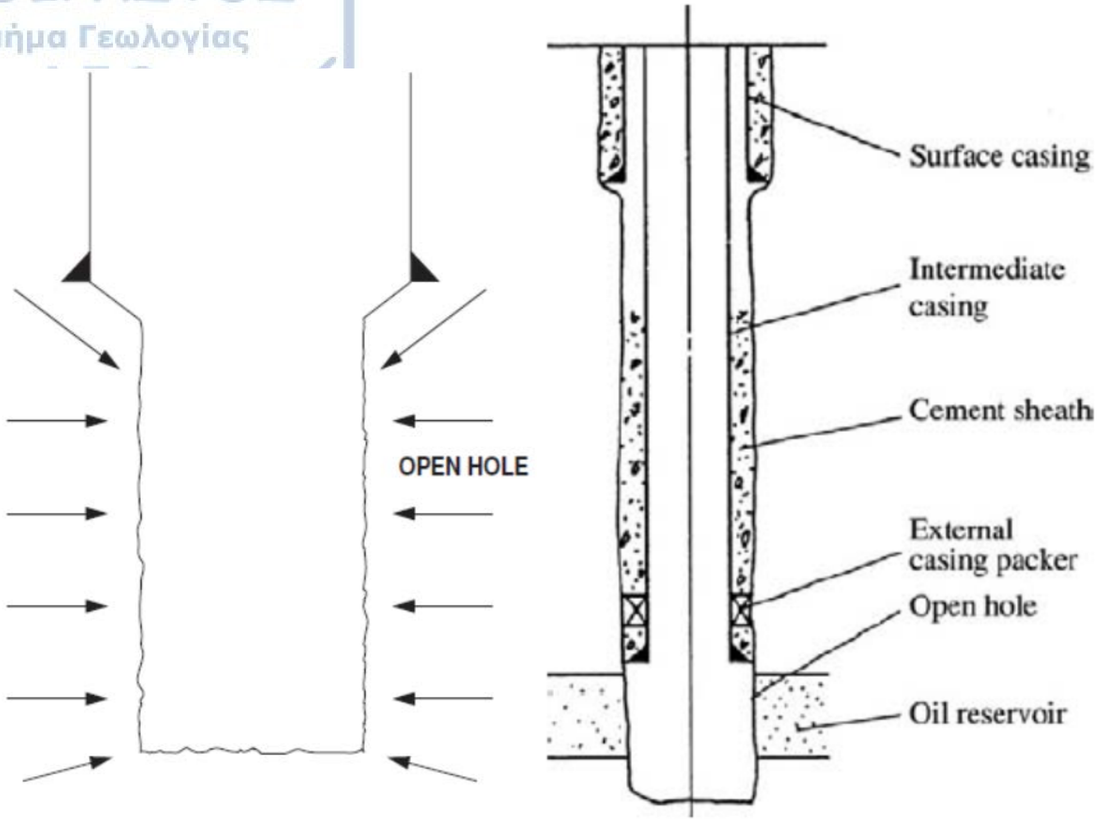

Fig.3.3 Open hole completion (Renpu, 2011, Heriot Watt University, 2011).

The major drawback of this method is the lack of zonal control for production or injection. Openhole completions are used in consolidated formations as the borehole may become unstable once a draw-down is applied to induce the well to flow. In these cases either total collapse of the formation or sand production occur. Openhole completions are particularly preferred where it is difficult to identify the net pay within the gross completion interval (e.g. alternating thin, silty/sandy sequences or naturally fractured reservoirs) and where severe filtrate losses can lead to deep damage, as in high permeability carbonates (Renpu, 2011, Bellarby, 2009, Heriot Watt University, 2011).

Openhole completions are mainly used:

- In low cost developments.
- In naturally fractured reservoirs.
- In deep, consolidated reservoirs being produced by depletion drive to ensure good contact between fracture and well.
- In some multilateral and horizontal wells with high depletion costs.

We can sum up some advantages and disadvantages/limitations of openhole completions (Allen & Roberts, 1982):

Advantages

- A low cost completion alternative.
- Adaptable to special drilling methods to prevent lost circulation into the producing zone so that to minimize formation damage.
- No perforating expense.
- With the use of gravel pack, sufficient sand control (method) is provided where productivity is important.
- Conducting loggings or log interpretation is not necessary since the entire interval is open.
- It is easier to deepen the well.
- It is easier to convert the completion to liner or perforated completion.

Disadvantages/Limitations

- Difficult to control excessive gas or water production.
- Selective fracking or acidizing is more difficult.
- Casing set "in the dark" before the pay zone is drilled or logged.
- Requires more rig time for completion.
- May require frequent clean-out in unconsolidated formations.

3.1.2 Pre-drilled/Slotted liner completions (Un-cemented)

To deal with the problems of sands collapsing and plugging the production system, engineers place slotted pipe or screens across the open hole section as a down-hole sand filter. The use of un-cemented liners as a method of sand control remains popular today in some areas (Figure 3.4).

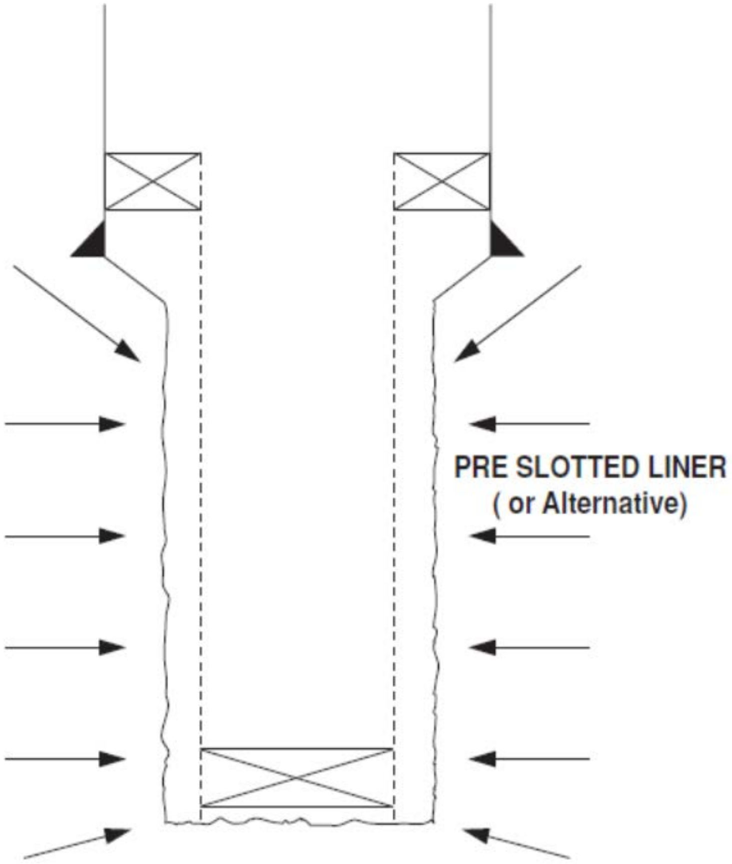

Fig.3.4 Well completed with wire wrapped slotted liner or screen (Heriot Watt University, 2011).

The liner or screen is installed to prevent sand production into the wellbore and tubing. The success of the completion in controlling sand production depends upon the screen or slot sizes and on the sand particle sizes. In order the screen to become completely effective it must totally restrain sand production, which requires that the slot size be equal to the size of the smallest particles. However, in such cases the slots may quickly become plugged and impede flow, resulting in a loss in well productivity.

This system is also used in high angle wells to prevent major hole collapse or ease the passage of logging tools. This technique has the same weakness for zonal control of production or injection as the open hole completion. However, it is also a low cost technique.

There are 2 types of procedures for pre-drilled/slotted liner completions (un-cemented):

1. Engineers drill through the oil reservoir without change the size of the bit, then they run a slotted liner at the bottom of the casing string inside the oil reservoir and casing is cemented using an external casing packer and cement stinger to isolate the annulus above the top boundary of the oil reservoir (Figure 3.5). The main disadvantage of this procedure is that we cannot repair or change the down hole liner damage. That is the reason why this procedure is generally not applied.

2. They drill up to the top boundary of the oil reservoir, then they run in the intermediate casing and the well is cemented. Then they run a smaller diameter bit through the intermediate casing and they drill through the oil reservoir to the design depth. Finally, they run a slotted liner in advance to the position of the oil reservoir (Figure 3.6). This liner is hung on the wall of the intermediate casing by the liner hanger on the top of the liner and it seals the liner casing annulus, hence the oil and gas can flow into the wellbore through the slots of the liner (Renpu, 2011, Heriot Watt University, 2011).

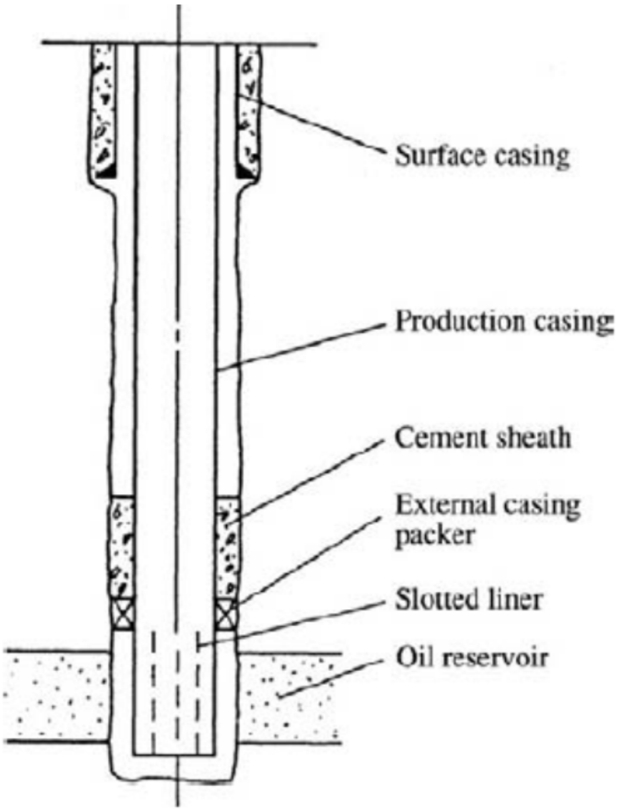

Fig.3.5 Slotted liner completion (Renpu, 2011).

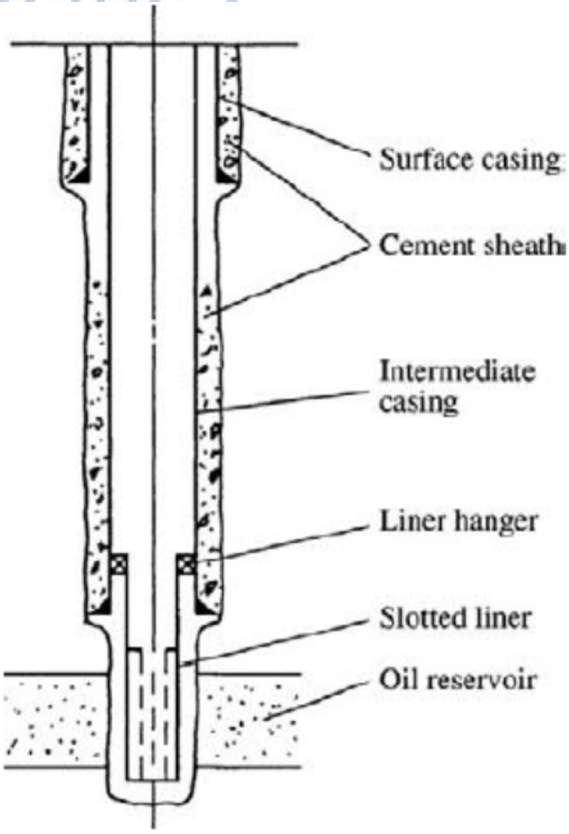

Fig.3.6 Hook-wall slotted liner completion (Renpu, 2011).

Such completions have virtually the same advantages and disadvantages as open hole completions:

Advantages

- Formation damage is minimized with new mud.
- No wireline perforation expenses.
- Log interpretation is not critical.
- Adaptable to sand control methods (gravel pack or pre-packed liner).

Disadvantages

- Difficult to control excessive gas and water.
- Selective stimulation is impossible.
- Additional rig time is required to run screen.
- Production casing is set before the pay zone is drilled.

3.1.3 Cemented and perforated completions

The final option is to install either a cemented casing string which extends back to the surface or a cemented liner which extends back into the shoe of the previous casing string (Figure 3.7).

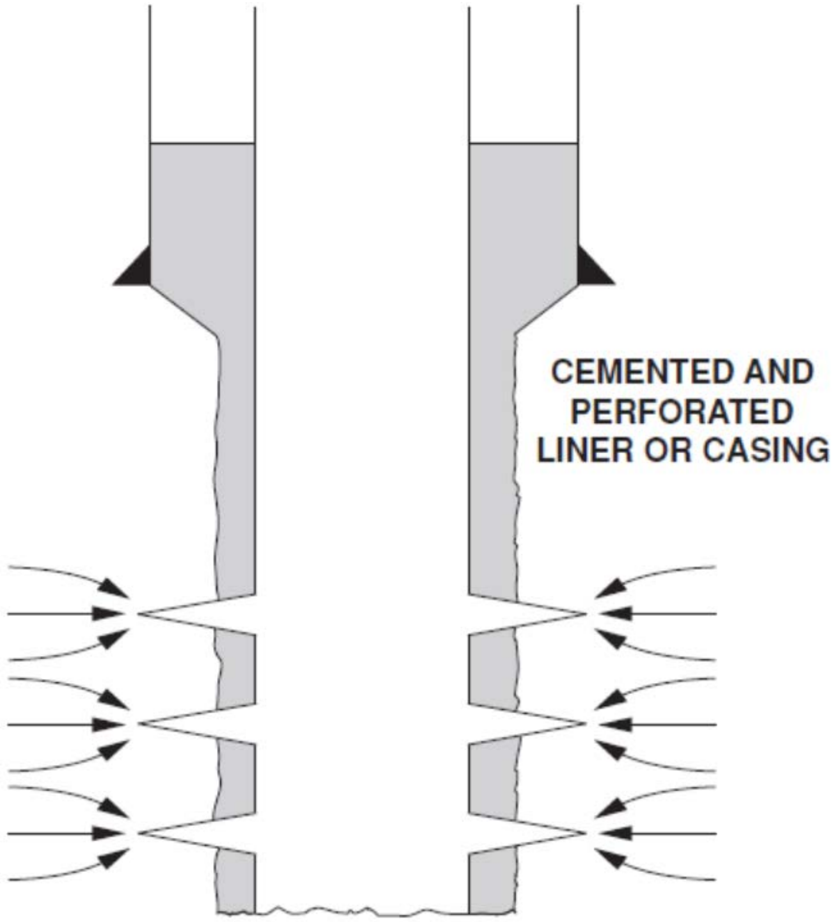

Fig.3.7 Cemented and perforated production liner or casing (Heriot Watt University, 2011).

To prevent the collapse of the wellbore, a casing string is run and act in concert with the cement sheath to isolate and separate the productive formations. The size of the casing is chosen based on the expected productivity of the well and should be designed to withstand the external and internal pressures associated with completion, any corrosive influences and the forces associated with running in the casing.

Perforated completions include casing, liner and tieback liner perforation completions.

1. In casing perforation completion engineers drill through the reservoir to the design depth, they run in production casing to the bottom of the reservoir, they cement and perforate with perforator to perforate through the production casing, cement sheath and to penetrate into a certain depth within the reservoir to make channels to permit the gas and oil to flow into the well (Figure 3.8).

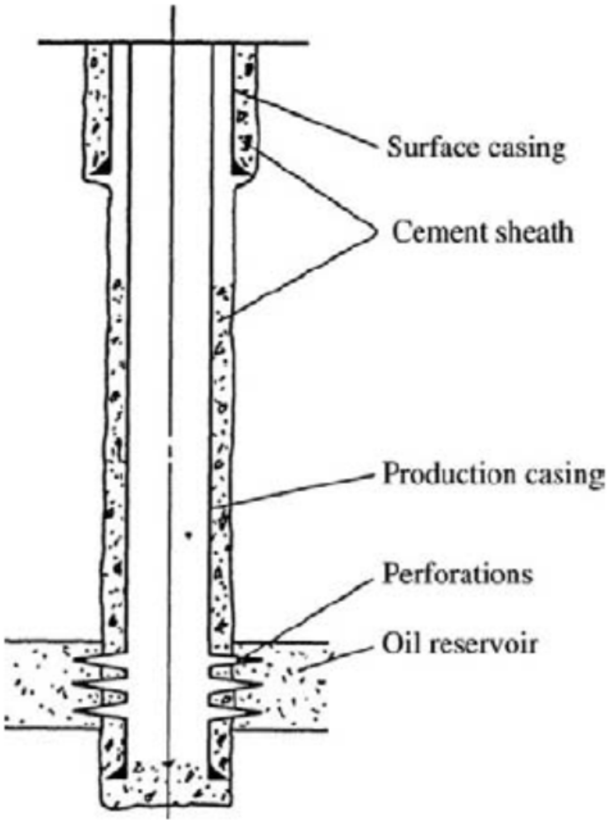

Fig.3.8 Casing perforation completion (Renpu, 2011).

2. In liner perforation completion they run in the intermediate casing and cement it after they drill to the top of the reservoir. Then they drill through the reservoir to the design depth using a smaller size bit, they run in a liner using drilling tools, they hang the liner on the intermediate casing and then they cement and perforate (Figure 3.9). Liner perforation completion is only suitable for gas and oil wells with a low or medium bottomhole pressure.

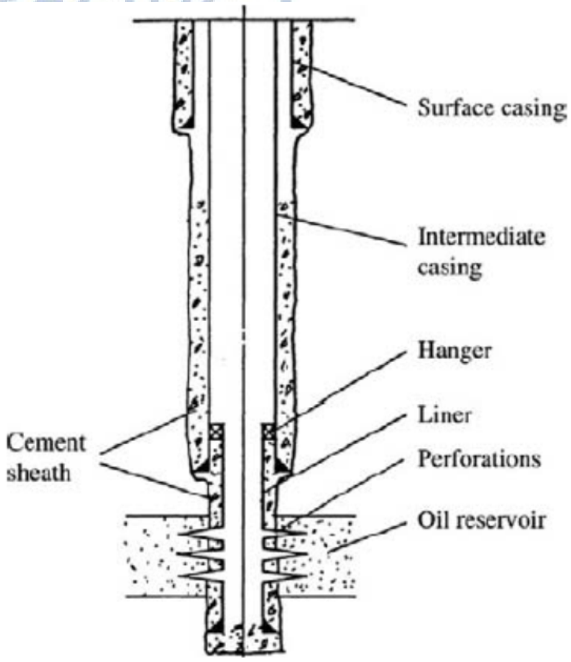

Fig.3.9 Liner perforation completion (Renpu, 2011).

3. Engineers commonly apply liner tieback perforation completion to deep and ultra-deep oil and gas wells and to high-pressure and super-high pressure oil and gas wells. The general procedure is to run liner in, cementing, run in production casing to tie back liner, cement into intermediate casing and production. Casing annulus under atmospheric pressure and return cement slurry to the surface, and then to perforate the liner (Figure 3.10) (Renpu, 2011, Bellarby, 2009, Heriot Watt University, 2011).

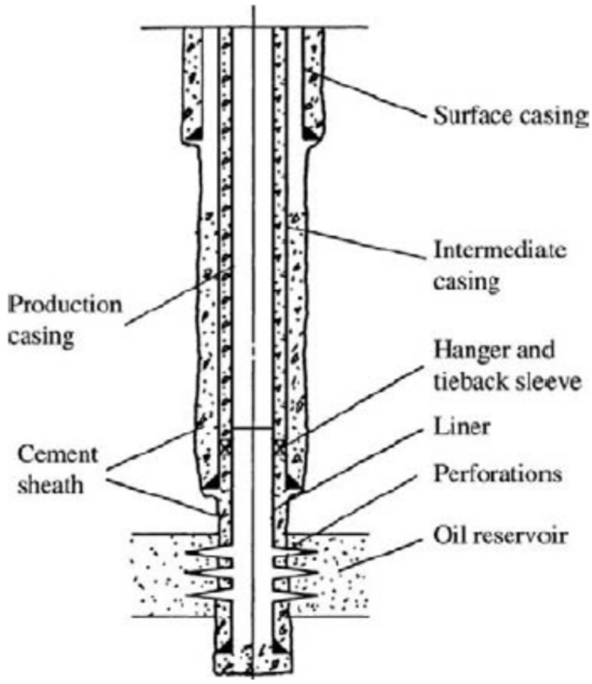

Fig.3.10 Liner tieback perforation completion (Renpu, 2011).

This technique has greater costs and time than the previous techniques. First of all, the cost of a full length of casing from the surface to the base of the well is high. Second, the cost of cementing, perforating and the additional rig time must also be added. The liner helps to reduce the required length, hence cost, of casing. However, this system presents advantages like: control the depletion of individual zones, isolate the inflow of undesirable produced fluids and control the injection of fluids into zones. These advantages are very useful to many fields and that's why this technique is the most widely applied.

To sum up the advantages and limitations of perforated completions (Allen & Roberts, 1982):

<u>Advantages</u>

- Easy to control excessive water or gas.
- Formation can be selectively stimulated.
- Full diameter opposite pay.
- Logs and formations samples available to assist in the decision to set casing or abandon.
- Easy to deepen the well.
- Adaptable to multi-completion techniques.
- Adaptable to special sand control techniques (most sands can be controlled).
- Minimum rig time on completion.

<u>Limitations</u>

- Significant perforation costs can occur.
- Log interpretation usually is critical in order not to miss commercial sands, yet avoid perforating sub-marginal zones.
- Not adaptable to special drilling techniques to minimize formation damage.
- Size is a limitation to deepen the well.

In the table below (Table 3.1) we can see the suitable completion mode depending on the geological conditions.

Table 3.1 Geological Conditions Suitable for Various Well Completion Modes (vertical well) (Renpu, 2011).

Completion Mode	Suitable Geological Condition
Perforated completion	1. Reservoir required to be separated into intervals due to complicated geological conditions, such as gas cap, bottom water, water-bearing interbed, or sloughing interbed 2. Reservoir that needs separate-zone testing, production, water injection, and treatments due to differences in pressure and lithology between separate zones 3. Low-permeability reservoir that needs massive hydraulic fracturing 4. Sandstone reservoir and fractured carbonatite reservoir
Open hole completion	1. Competent carbonatite reservoir 2. Reservoir without gas cap, bottom water, water-bearing interbed, and sloughing interbed 3. Single thick reservoir or the multizone reservoir with basically same pressure and lithology 4. Reservoir not required to be separated into intervals and treated selectively
Slotted liner completion	1. Reservoir without gas cap, bottom water, water-bearing interbed, and sloughing interbed 2. Single thick reservoir or the multizone reservoir with basically same pressure and lithology 3. Reservoir not required to be separated into intervals and treated selectively 4. Unconsolidated medium and coarse sand grain reservoir

3.1.4 Gravel Pack Completion (Open hole and Cased hole)

Gravel pack completions are mainly used in unconsolidated formations with serious sand production. At first, engineers run a wire wrapped screen to the position of the oil reservoir. Then gravel selected at the surface in advance is pumped to the annulus between the wire wrapped screen and the borehole or the casing using packing fluid, hence forming a gravel pack bed which prevent sand from entering into the wellbore and protect the borehole wall (Renpu, 2011).

In gravel pack completions, engineers usually use the wire wrapped screen instead of the slotted liner because:

1. The minimum gap width of the wire wrapped screen is 0.12mm instead of 0.5mm of the slotted liner. Hence, wire wrapped screen applicable range is much larger (the slotted liner is only suitable for medium coarse grain reservoirs).
2. The wire wrapped screen has a continuous gap formed by the wrapping wire (Figure 3.11 (a)) and there is almost no pressure drop when fluid flows through the screen. Their shape can be such that provide a certain self-cleaning action, so that slight plugging can be dredged by the produced fluid (Figure 3.11 (b and c)). The wire wrapped screen without self-cleaning action is shown in Figure 3.11 (d). The wire wrapped screen flow area is much larger than that of the slotted liner (Figure 3.12).
3. The wire wrapped screen has a stainless steel wire. This wire has strong corrosion resistance, long service life, and high economic benefits.

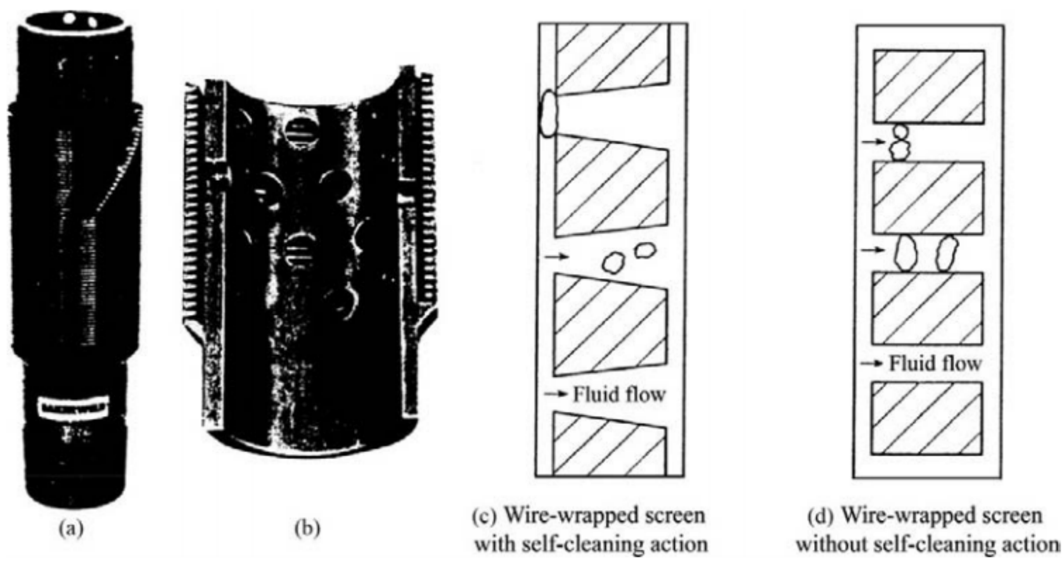

Fig.3.11 Wire wrapped screen cross section (Renpu, 2011).

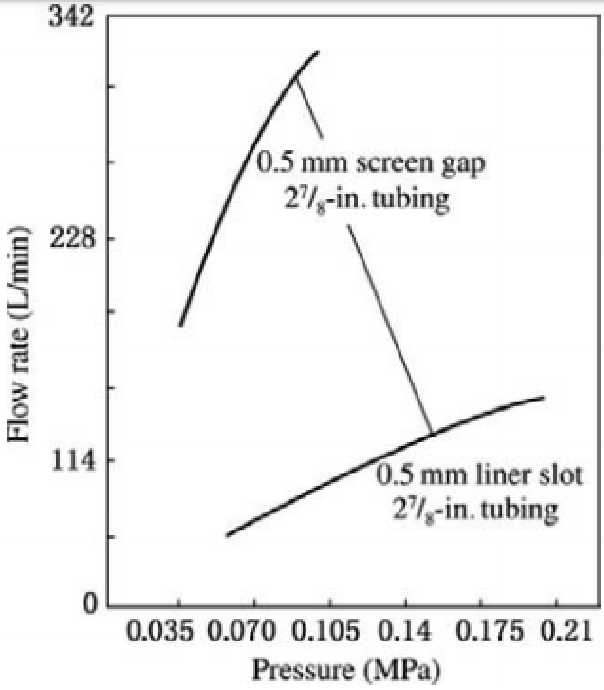

Fig.3.12 Screen liner throughput capacity comparison diagram (Renpu, 2011).

Open Hole Gravel Pack Completion

Engineers apply open hole gravel pack completion (Figure 3.13) when geological conditions allow adopting open hole and sand control is needed.

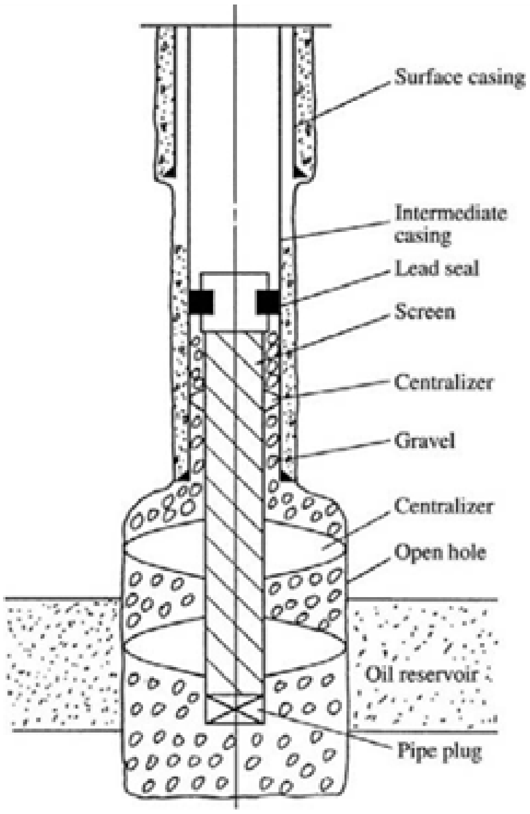

Fig.3.13 Open hole gravel pack completion (Renpu, 2011).

They drill to 3m above the top boundary of the oil reservoir, run intermediate casing, cement, drill through the cement plug with a smaller bit, drill in the reservoir to design depth, change into the under reaming expansion bit, enlarge the borehole diameter up to 1.5-3 times the outside diameter of the intermediate casing to ensure a larger annulus during gravel packing, an increased thickness of the sand control bed and an enhanced effectiveness of sand control, and then packing gravel (Renpu, 2011).

Cased hole Gravel Pack Completion

For cased hole gravel pack completion (Figure 3.14) engineers drill through the reservoir to design depth, run production casing to the bottom of the oil reservoir, cement, and then perforate the reservoir (Renpu, 2011).

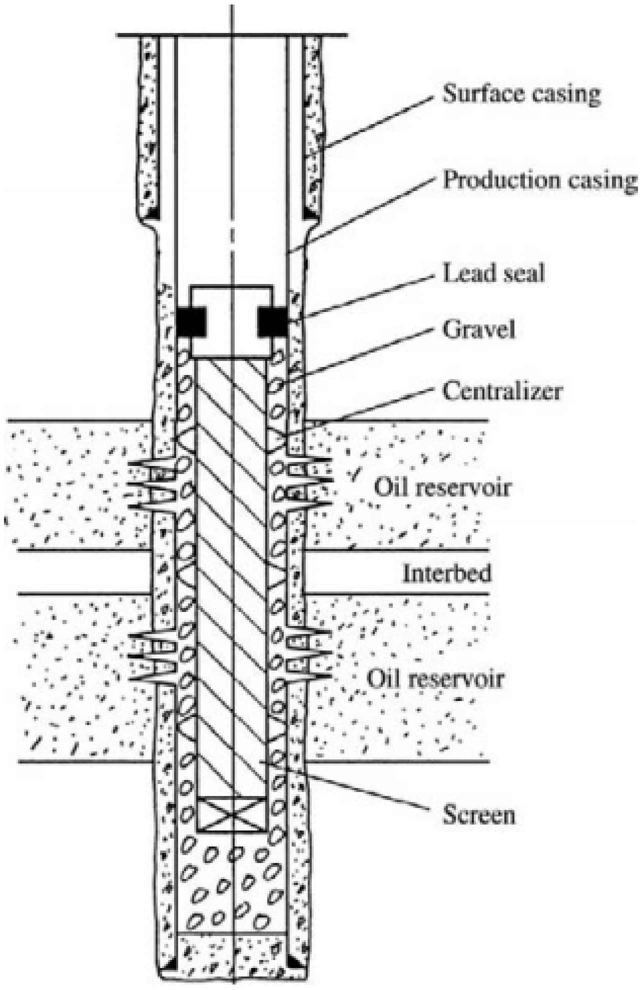

Fig.3.14 Cased hole gravel pack completion (Renpu, 2011).

In the next sections Nodal analysis (3.2) and Production logging (3.3) will be briefly presented.

Nodal analysis is a modeling tool used by engineers for many purposes in analyzing and designing producing oil and gas wells. It provides powerful insight in the design of a completion. Nodal analysis also helps engineers to achieve an optimum well design in terms of perforations, tubing size, and fluid and underbalance design, as well as to provide some of the key data inputs for the design of surface facilities. Even with limited data this process is very useful in analyzing current producing wells by identifying flow restrictions or opportunities to enhance performance.

Production logging is referred as a number of logging tools that provide the engineers with information during production operations and beyond. This information allows for efficient completion of the reservoir, increase production, diagnose production problems and lower costs. Production logging is a critical component of developing optimum modeling, completion and stimulation practices.

3.2 Nodal analysis

Through production there is a fluid pressure loss from the reservoir up to the surface caused by the resistant of porous media, well completion tubing string and the flowline. In the Figure below (Figure 3.15) we can see all the pressure losses in a well system.

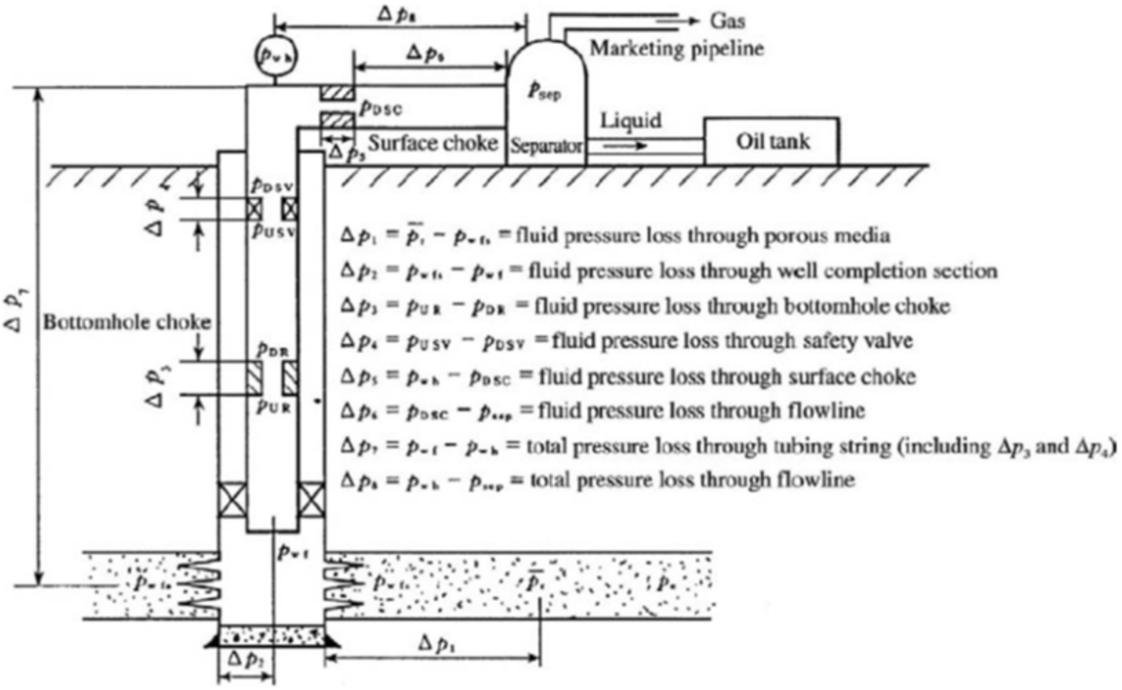

Fig.3.15 Various pressure losses in the production system (Renpu, 2011).

The whole production system can be mathematically simulated using nodal analysis method to optimize the production system of oil and gas wells. Nodal Analysis provides estimations of reservoir parameters such as: skin, permeability, reservoir pressure, and evaluation of potential stimulation treatments (primarily through the reduction in skin).

Nodal Analysis can be simplified into two parts: outflow and inflow parts (Figure 3.16). The inflow includes the flow through the porous media and the completion selection and the outflow includes the flow through the tubing string and the surface flow line. The inflow performance of a well describes the flow capacity of a well versus the drawdown pressure at a certain time for given set of conditions. Using Nodal Analysis engineers can optimize well completion selection, tubing size and choke, and determine the dynamic performance of a gas or an oil well under current production conditions, the production state when flowing stops or is turned to pumping, the moment of turning to an artificial lift and finding a way to enhance the production rate. So, in the first stage of well completion, engineers pay most attention to the IPR (Inflow Performance Relationship) curve to optimize completion parameters and tubing size.

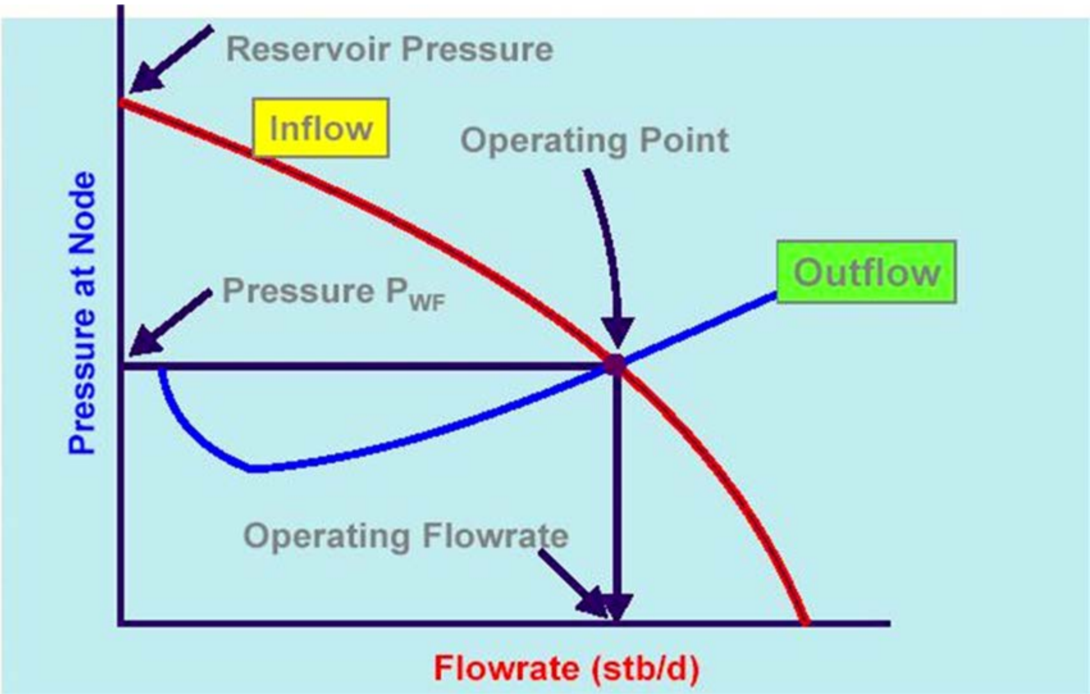

Fig.3.16 Nodal Analysis (Gusgon, 2016).

3.3 Production Logging

The main purpose of production logging is to provide information to the operator that will allow efficient depletion of the reservoir to increase production, lower costs and eliminate any danger that may occur. Accurate data from down-hole sensors will provide us an understanding of the well and reservoir characteristics.

Production logging provides the information that enables the diagnosis of well problems, as follows:

- Diagnose production problems and allocate production (or injection)
- Select zones for recompletion
- Monitor reservoir fluid contacts
- Monitor corrosion
- Monitor cement placement

Production logging has applications in well problems, well performance and well testing, and assists in determining single and multiphase flow and flow anomalies.

Logs can be separated into application classes: Open-hole logs/Cased hole logs. Open-hole logs are applied to select pay zones and estimate the type and quality of rock through which the well is drilled. Cased hole logging is used to select information for reentry of wells, evaluation of production, depth correlation and in secondary and tertiary recovery (King, 1998).

In Cased Hole Logging the following sensors can be used:

- Production Logging Tools & Potential Spontaneous (PLT & PSP) (Figure 3.17)
    - ➢ Temperature Logs
    - ➢ Pressure Logs
    - ➢ Noise Measurement
    - ➢ Flowmeter Spinner
    - ➢ Gamma Ray
- Formation Evaluation Logging
    - ➢ Pulsed neutron
    - ➢ Reservoir Saturation Tool, Cased Hole Formation Resistivity (RST, CHFR)
- Well Integrity
    - ➢ Cement Bond logs
    - ➢ Caliper logs

Analytically Cased Hole Logging applications are:

1. Evaluate completion performance
   - New wells
   - Injection wells
   - Re-completions
2. Monitor reservoir performance & variations
   - Flow profile
   - Well test
   - Completion efficiency
3. Casing/Borehole Internal Diameter (ID) Inspection (Well Integrity)
   - Electrical deform casing calipers
   - Internal calibers (microscopic)
   - Borehole televiewers
   - Casing potential profile
   - Electronic calibers or calipers
   - Induction casing thickness logs
   - Flux leakage logs
4. Fluid flow, leak detection
   - Spinner flowmeters
   - Noise surveys
   - Radioactive tracer survey
5. Formation, near well bore evaluation
   - Neutron lifetime logs
   - Photo logs
6. Diagnose well problem
   - Water entry
   - Gas entry
   - Leaks and mechanical problems
   - Flow behind casing
7. Other
   - Guidance for workover
   - Information for Enhanced Oil Recovery projects
   - Identify boundaries for field development

We can sum up the log types used depending on the survey requiered in the Table below (Table 3.2).

Table 3.2 Logs type of survey required (Kapetanios, 2017).

Survey Required	logs Types
Detect fluid movement behind casing	▪ Fluid travel log ▪ Temp. log ▪ Noise log
Locating and detecting casing, tubing and packers leaks.	▪ Fluid travel log ▪ Temp. Log ▪ Noise Log ▪ Spinner Log ▪ Flowing pressure gradient
Perforation profile Injection & production wells	▪ Fluid travel log ▪ Spinner surveys
Evaluate effectiveness of stimulation.	▪ Temp. Log ▪ R / A Tracer
Locate sand entry	▪ Noise log ▪ Temp. Log
Detect gas cap expansion	▪ All hydrogen logs ▪ Neutron Logs
Detect water injection behind casing	▪ All hydrocarbon logs ▪ Gamma Ray log
Monitoring casing corrosion	▪ Corrosion Detector ▪ Casing Caliper

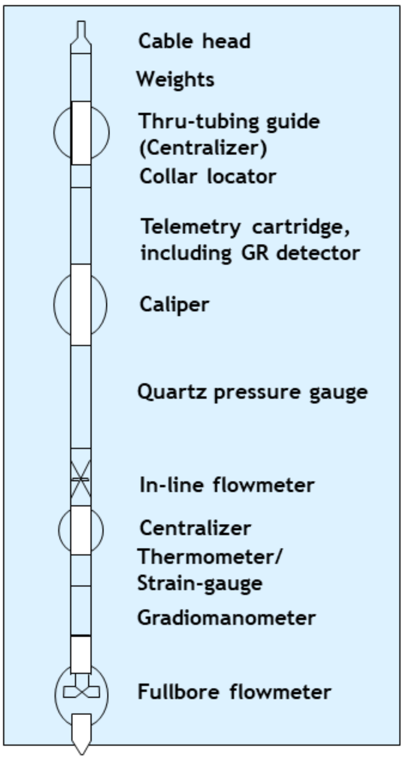

Fig.3.17 Standard Production Logging Suite (Kapetanios, 2017).

3.4 Barrier

Well barriers is the main measure that engineers can take to protect the environment. The efficient design and operation of these barriers is of vital importance for the protection of the employees on the well and the avoidance of environmental problems. Completions are part of the fundamental barrier system between the reservoir and the environment. They are also part of the well control envelope and remain so through the life of the well. The definitions diversify from company to company but the main and simple rule in well control is that 'At least two tested independent barriers between hydrocarbons in the reservoir and the environment at all times'. A barrier is any device, fluid or substance that prevents the flow of wellbore fluids (Bellarby 2009).

A well confinement barrier is defined as a set of components and/or conditions that prevents the reservoir fluids from escaping to surroundings along any potential flow path. It contains them within the confines of the well or the formation. It is also a protective measure to prevent an uncontrolled fluid release to surface through production string or from reservoir to well annulus.

Well barrier elements are:

- Primary well barrier - Normal working stage. In some situations it is the fluid column or a mechanical well barrier that provides closure of the well barrier envelope. The primary barrier is defined as the barrier that initially prevents hydrocarbons from escaping. This kind of barriers are, for example, the tubing, the mud or the Christmas tree.
- Secondary well barrier - An ultimate stage. In most cases it describes a situation where the shear ram or valve of BOP is closed. The secondary barrier is defined as the backup to the primary barrier. The secondary barrier is not normally in use until the primary barrier fails. The secondary barrier must be independent of the primary barrier, because any event that could destroy the primary barrier should not affect the secondary barrier.

Other categorization of barriers might be:

- **Surface barrier:** It is always required to connect the well to the surface facilities. The Surface barrier seals off the production/injection bores at the top part of the annulus. It consists of:
  - Christmas tree
  - Wellhead assembly
- **Structural or downhole barrier:** It is the annuli and down hole barrier for the bore of the production casing aimed at providing backup in the event of the surface barrier fails.

  Structural or downhole barrier isolates the different annuli and consists of:
  - Casing, liner and tubing strings.
  - Packers.
  - Hydrostatic columns if there is provision to monitor and top up the liquid column.
  - Cement in the annular spaces between casing strings that seals off the annuli.
  - Down hole Safety valve (DHSV) system.
  - Any plugs installed in the tubing/casing to suspend flow.

  This barrier must be routinely checked and/or leak tested.

Beside the technical barriers mentioned above in many cases there are also geological barriers.

In the Table below (Table 3.3) some examples of which primary and secondary barriers are shown used through the life of the well.

Tab.3.3 Some barrier system examples through the life of a well (Bellarby, 2009).

Example	Primary Barrier	Secondary Barrier
Drilling a well	Overbalanced mud capable of building a filter cake	Casing/wellhead and BOP
Running the upper completion	Isolated and tested reservoir completion, for example inflow-tested cemented liner or pressure-tested isolation valve	Casing/wellhead and BOP
Pulling the BOP	Packer and tubing	Casing, wellhead and tubing hanger
	Isolated reservoir completion, for example deep-set plug	Tubing hanger plug. Possible additional barrier of downhole safety valve
Operating a naturally flowing well	Christmas tree	Downhole safety valve
	Packer and tubing	Casing, wellhead and tubing hanger
Operating a pumped well not capable of flowing naturally	Christmas tree or surface valve Casing and wellhead	Pump shut-down
Pulling a completion	Isolated and tested reservoir completion, for example deep-set plug and packer or overbalanced mud	Casing/wellhead and BOP

There must be two well barriers available during all well operations and activities, including suspended or abandoned wells, where a pressure differential exists that may cause uncontrolled out-flow from the borehole to the external environment.

Wells can be produced/injected only if two independent and tested barriers are in place on each potential hydrocarbon leak path.

When one of these barriers becomes ineffective or in bad condition, the failed components must be replaced or repaired as soon as it is feasible. Risk assessment shall be made to determine the maximum allowable waiting time until the replacement or repair is made.

Well barrier design, selection and construction must follow the following principles:

- It can withstand the maximum anticipated differential pressure it could be exposed to.
- It can be function tested and leak tested or verified by other methods.
- It can be done reestablishment of a lost well barrier or another alternative well barrier.
- A failure of a single barrier or barrier element cannot lead to uncontrolled out-flow from the borehole to the external environment.

- It can be completely functional and withstand the environment which could be exposed to over time
- Its physical location and integrity status is known at all times.

3.4.1 Tubing

Tubing is the normal flow conduit which is used to transport produced hydrocarbons to the surface and fluids to the formation. Tubing with packer provides isolation of the casing from well fluids and prevent casing for corrosion damage. Furthermore, multi-completions require tubing to allow individual zone operation and production (Lake, 2007).

The integrity of tubing is vital to the safe operation of an injection or production well.

Tubing must be selected to provide the following capabilities (Heriot Watt University, 2011):

- The ID (Inside Diameter) of tubing must provide a produced fluid velocity to minimize the total pressure loss (tubing performance relationship).
- The completion string must be capable of withstanding the maximum conceivable burst (internal) pressure.
- Both tubing and coupling string’s tensile strength must be high enough to permit suspension of the complete string without tensile failure.
- Tubing must be resistant to chemical corrosive action of well fluids throughout the well life.
- The completion string must be capable of withstanding the maximum conceivable collapse (external) differential pressures between the tubing and the annulus.

Some special completions are tubingless. These are in flowing wells with relatively small size casing installed.

API has defined certain standards for tubular goods, such as casing and tubing. API has defined nine grades of steel: H40, J55, K55, C75, L80, N80, C95, P105, and P110. The letters H, J, and N are primarily to reduce verbal confusion, while others have an extra meaning: K has higher ultimate strength than J. C, L are of "restricted yield strength" with tighter specifications and P is of high strength. The numbers after the letter grading signify the minimum yield strength in units of a 1000 psi. The letter grades indicate the manufacturing process or subsequent treatment of the steel to modify its properties. In general, the higher the yield strength created by working the steel, the more susceptible it is to failure by H_2S (Lake, 2007).

The main failure modes that tubing is dealing with are:

- Burst
- Collapse
- Tension — failure of the couplings or pipe.

The most severe loading on tubing mostly occur during killing operations, well service and pressure tests. Tubing material selection requires the specification of material grade (=quality), operational parameters, dimensions, thread and connection type.

Tubing strings must have the correct size to permit the fluids to flow efficiently and to allow installation of effective artificial lift equipment. If the tubing string is too small then it may cause large friction losses and may limit production. Furthermore, it can also severely restrict the type and size of artificial lift equipment. On the other hand, if tubing string size is too large then it can cause heading and unstable flow, which results in loading up of the well and can complicate workovers.

Conventionally the outside diameter (OD) of the tubing is specified. The inside diameter (ID) is defined by the wall thickness of steel via the tubing's "weight per foot". Wall thickness will influence the tensile strength of steel and its resistance to failure with high external (collapse) or internal (burst) pressure differentials.

The greatest tensile load is applied to the joints nearest to the surface due to the weight of the suspended pipe since each joint suspends the string immediately below it.

When we design a tubing string the most important thing we must consider is the differential pressure between the external and the internal pressures. The highest burst condition is commonly encountered at the surface where the external pressure is at its minimum. The maximum design burst pressure is normally the pressure when the string is gas filled plus a safety factor which varies from 1.0 to 1.33.

When the external pressure exceeds the internal pressure collapse of tubing is occurring. This condition is normally greatest at the bottom of the well when the annulus is full of fluid and tubing is evacuated plus a safety factor which varies from 1.0 to 1.125 (Lake, 2007).

Couplings

There are generally two classes of threaded coupling (Heriot Watt University, 2011):

1. There are connections which require an internal pressure in order to produce a pressure tight seal. This type of couplings includes the API round thread and buttress connection whereby a thread compound applied to the threads must be compressed by external pressure acting on the coupling causing it to fill any void spaces within the coupling.

2. There are metal to metal or elastomeric seal connection Premium threads. This class of coupling includes the Extreme Line and a range of specialized couplings of specific commercial design.

Another classification of coupling is External or Integral couplings (Figure 3.18):

- An external coupling, such as the VAM coupling, requires that a male thread be cut on each end of the tubing joints, while the coupling has two female connections.
- An external coupling has a larger effective wall thickness in the coupling section (Dc > D) which provides higher load capacity compared to an integral coupling. The integral coupling has a male and female thread cut on opposite ends of the pipe.
- An external upset coupling uses an increased wall thickness of pipe at one end of the pipe allowing a female thread to be cut without sacrificing too much of the tensile load carrying capacity.
- A flush joint is one in which there is a uniform Internal Diameter (D = Dc) through the make up connection.
- An internal upset coupling is one in which there is a small section of decreased Internal Diameter (D > Dc) in the area of the coupling (Heriot Watt University, 2011).

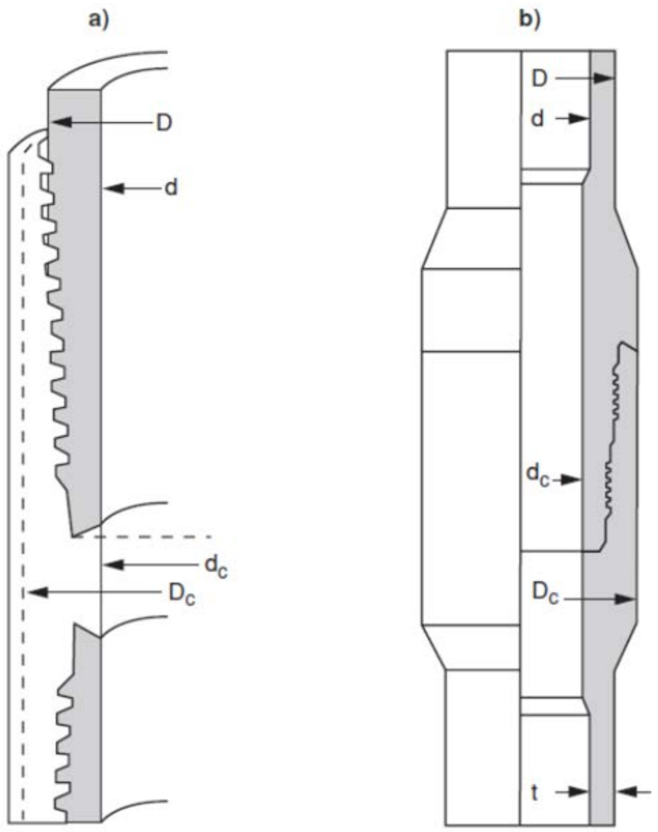

Fig.3.18 a) VAM: An internally flush coupling b) An integral, internally upset coupling (Heriot Watt University, 2011).

Anchors

Unanchored tubing in a rod-pumped well is subject to constant movement. The tubing will buckle on the upstroke and stretch on the down stroke. This is sometimes called "breathing". This movement leads to wear and fatigue problems and can result in highly inefficient use of the available pumping unit stroke. Tubing anchors are used to minimize this movement.

Tubing anchors are:

- Mechanically set anchors.
- Single or dual hydraulically set anchors.

Tubing anchors are also classified as:

- Tension anchors, which permit the tubing to elongate but not to shorten.
- Compression anchors, which permit shortening but not elongation of tubing.
- Fixed anchors.

Compression anchors reduce the breathing problems but do not prevent buckling and are therefore rarely used.

Tension anchors, which gradually "walk down" the inside of the casing as the pump starts to operate and then set the tubing at its maximum elongation, may damage the casing by repeated slight movement.

Most anchors used today are of the fixed type.

Seating Nipples

Seating nipples are used to accommodate a pump, hanger, plug or flow control device. They consist of a polished bore with an internal diameter just less than the tubing drift diameter. Commonly they also require a lock profile, especially for landing nipples. Heavy duty tubing sections, called flow couplings, are often run on either end to minimize the effects of turbulence.

There are three main types of seating nipples used as integral parts of the tubing:

- Pump seating nipples.
- Selective landing nipples.
- Non-selective or no go landing nipples.

The purposes of Seating Nipples are:

- To facilitate pressure testing and setting hydraulic packers.
- To isolate the tubing if it is to be run dry for high draw down perforating.
- To land and seal bottom-hole pump (pump seating nipple).
- To land wire-line retrievable flow controls, such as plugs, bottom-hole chokes, tubing safety valves and regulators.
- To land bottom-hole pressure bombs.
- To plug the well when the tree must be removed.
- To pack-off across blast joints.
- To install a standing valve for intermittent gas lift.
- To temporarily plug the well while the rig is moved on or off the well.
- To plug the tailpipe beneath the packer for pulling the tubing without killing the well.

A landing nipple is a short pipe, part of the tubing string, with a recess to lock or hang-off a Locking Mandrel and with a polished bore to receive a seal.

Landing nipples (Figure 3.19, 3.20) are used when there is a need to install or to hang-off the following devices in the tubing:

- A plug to pressure test the tubing.
- A plug in the tubing below packer to safeguard the well.
- A standing valve or plug during workover.
- Pressure gauges to measure bottom hole pressures.

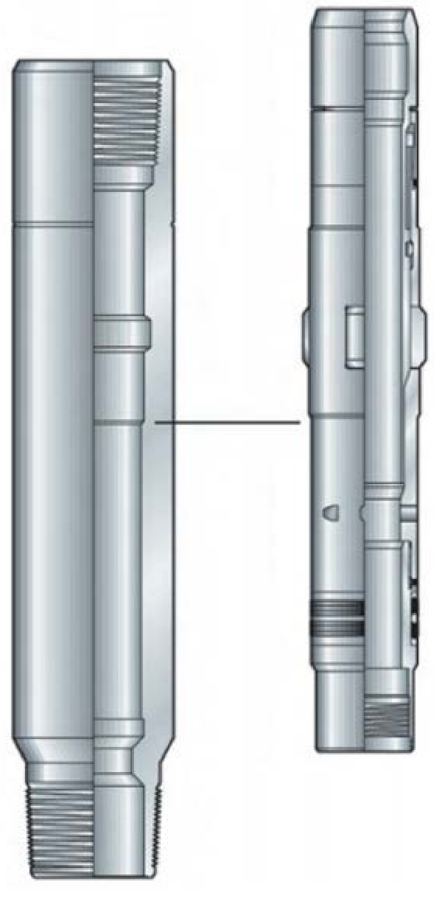

Fig.3.19 Landing nipple and locking mandrel (Lake, 2007).

Fig.3.20 Landing nipple (Lake, 2007).

Selective landing nipples are nipples with a common internal diameter. These nipples are applied when more than one nipple is required within a single string of tubing. They should be no closer than 30ft from a similar profile, and at least 10ft from any change in diameter.

No-go landing nipples are designed with an Inside Diameter that is slightly restricted to provide a positive shoulder to locate a locking mandrel. The ID should be checked against any through - tubing equipment that may be used. Commonly are located at the bottom of the tailpipe or tubing string and at least 5ft below any profile change.

It is best to include a sliding sleeve above the nipple in case debris prevents the pulling of any plug set in the nipple by regular wire-line methods. Alternatively, a mechanical perforator may be used to punch a hole above the plug.

Sliding sleeves (Figure 3.21, 3.22), also referred as “sliding side doors or circulating sleeves”, are used to obtain access from the tubing to the annulus either for fluid circulation or to allow a previously isolated zone to be produced.

They close and open with a wire-line tool. These devices are typically placed above packers. They are an essential requirement of multi-zone completions scheduled for selective production.

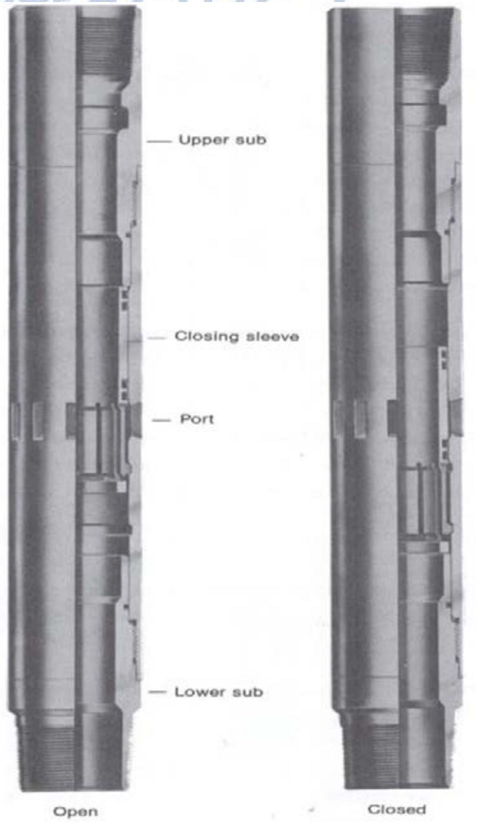

Fig.3.21 Sliding Sleeves (Bakerhughes, 2014).

Fig.3.22 Sliding Sleeve (shown in closed position) (Lake, 2007).

Uses of Sliding Sleeves are:

- Kick-off by displacing the tubing contents with a low density fluid, thereby avoiding the use of coiled tubing within the tubing.
- Well killing prior to tubing pulling job or work-over.
- Circulating out completion fluid with a packer fluid (e.g. from water to inhibited brine or from mud to brine).
- Testing (SSSV).
- Temporarily producing a selective zone into the tubing.
- They are now much easier to open and less prone to failure.
- Special elastomers are needed for some fluids.
- A ported nipple is sometimes used in place of a sliding sleeve.
- Alternatively, some completion engineers choose to apply a side pocket mandrel as a circulation point above the packer.

Side Pocket Mandrels

Side pocket mandrels (Figure 3.23) are a special eccentric nipple that can accommodate a valve parallel to the tubing to control access to the annulus. Side pocket mandrels are used to install wire-line retrievable gas lift valves, flow control valves, circulation devices and injection valves. The location of side pocket mandrels for gas lift valves will be determined by the lift gas pressure available and kickoff requirements.

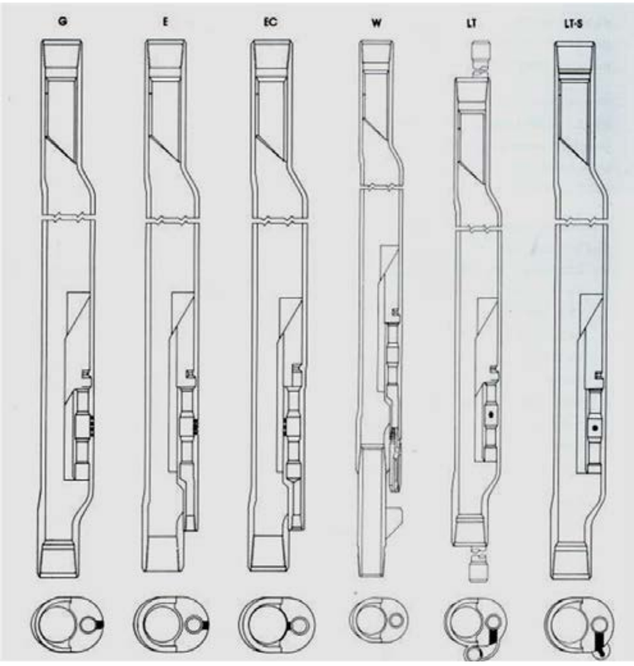

Fig.3.23 Side pocket mandrels (Greasebook, 2019).

It is highly desirable to have one or two mandrels located up to the top packer in high pressure gas well completions. These are applied to facilitate a controlled circulation kill fluid in the event the sliding sleeve is inaccessible or if corrosion inhibitor injection is required. Inhibitor may be supplied either through the annulus continuously or in batch treatments. Some operators also apply side pocket mandrels to install a temperature and pressure sensor that can transmit data to the surface through a cable attached to the outside of the tubing.

Some engineers choose to apply a side pocket mandrel instead of a sliding sleeve above the top packer. Repair of those seals in a sliding sleeve requires a work-over rig.

Blast Joints

Blast joints (Figure 3.24) are used to increase the abrasion resistance of the tubing string against the jetting action of a producing formation. Blast joints should be located on the tubing string opposite all upper perforations. Blast joints should also be used in the wellhead area where abrasive fracturing fluids may be pumped into the casing access.

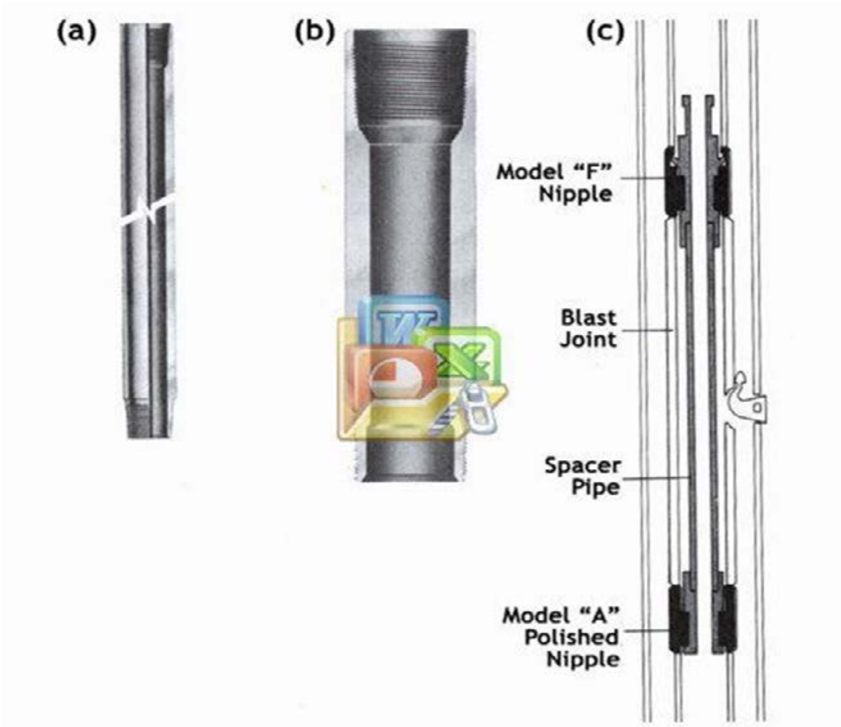

Fig.3.24 a) Blast Joint b) Polished nipples; c) schematic polished nipple run to provide at sealing surface in case of blast joint erosion (Bakerhughes, 2014).

3.4.2 Packers

The packer forms the basis of the cased-hole completion design. Packers are a sub-surface tool used to provide a seal between the tubing and the casing of a well, thus preventing the movement of fluids past this sealing point. So, packers are sealing devices that isolate and contain produced fluids and pressures within the wellbore to protect the casing and other formations below and above the producing zone. This is essential to the basic functioning of most wells.

Beside their sealing purpose packers also provide a structural purpose (anchor the tubing to casing). They are used in a variety of applications (Lake, 2007, Bellarby, 2009, Allen & Roberts, 1982):

- To improve safety by providing a barrier to flow through the annulus.
- To keep well pressures and fluids isolated from the casing.
- To protect the annular casing from corrosion caused by the produced fluids and the high pressures.
- To prevent down-hole movement of the tubing string.
- To support some of the weight of the tubing.
- To improve flow conditions and prevent heading.
- To separate zones in the same wellbore.
- To isolate sand and gravel (gravel pack packer and sump packer).
- To place treating or kill fluids in the casing annulus.
- To pack off perforations rather than use squeeze cementing.
- To keep gas lift or hydraulic power fluid injection pressure isolated from the formation.

Choosing the right packer requires knowledge of the completion and operational requirements. This gives an early design load on operational/completions engineers: get it right or risk an early workover to replace a poorly selected packer.

Packers have 4 key components: cone, slip, packing-element system and body or mandrel (Figure 3.25). The slip is a wedge-shaped appliance and it has wickers or teeth on its face. These wickers or teeth penetrate and grip the casing wall when the packer is set. The cone has beveled shape to match the back of the slip and forms a ramp that sends the slip abroad and into the casing wall when setting force act to the packer. When the slips have anchored into the casing wall, additional applied setting force activates the packing-element system and between the inside diameter of the casing and the body of the packer is crated a seal.

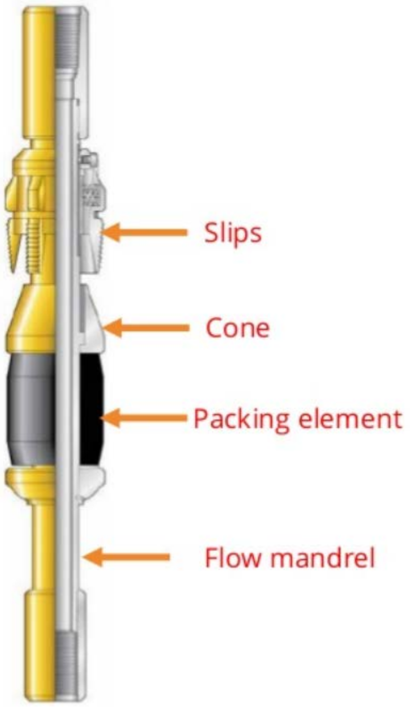

Fig.3.25 Packer components (Lake, 2007).

Packers can be classified either by their setting mechanism as mechanical or hydraulic, or by their running mechanism as tubing or wireline. They can also be retrievable or permanent.

Mechanical set packers put their slips by pushing a cone or wedge shaped tool against a set of conical slips to drive the slips outward and into the casing wall. Mechanical energy is supplied by tubing compression, tension and rotation.

Hydraulic set packer requires that the tailpipe is sealed. This is achieved with a standing valve, plug, drop ball and seat or a smart plug. The applied tubing pressure generates a differential pressure on the setting piston. A shear pin connected to the piston breaks, and the piston is free to compress the slips and element or permit the packer element to move down relative to the slips (Figure 3.26). The design of the packer slips is to hold in one direction, behaving as a hanger to resist downward movement or as an anchor to resist upward movement. The packer can be anchored from both directions, if two sets of opposing slips are used. The slip setting action tubing or pressure expands an accompanying packing element, this element expands the seals against the wall of the pipe and creates a pressure tight seal (Bellarby, 2009, Allen & Roberts, 1982).

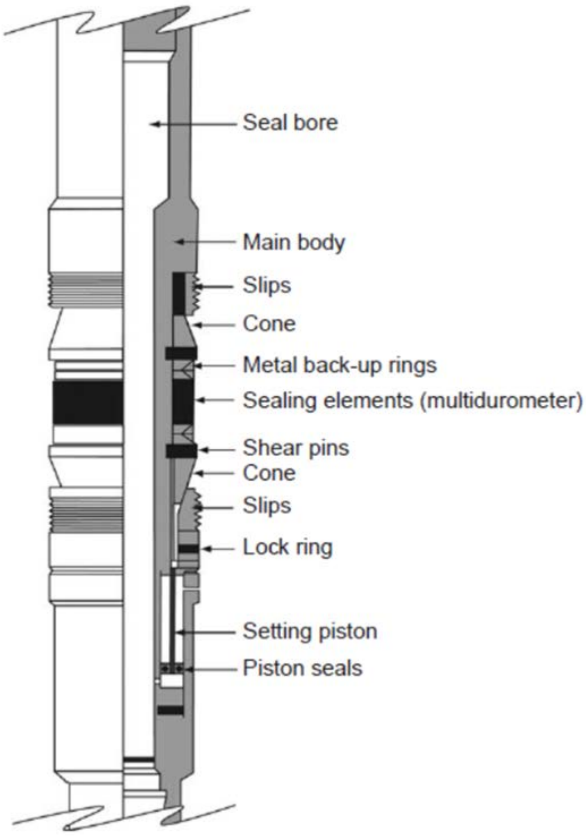

Fig.3.26 Typical hydraulic set production packer (Bellarby, 2009).

The following categories of packers will be briefly presented below:

- Retrievable
- Permanent
- Permanent - retrievable
- Inflatable

Retrievable Packers

This type of packers is run on the tubing. After setting, they can be released and recovered from the well on the tubing. It is an integral part of the tubing string, the tubing cannot be removed from the well without pulling the packer, unless a detachable packer head is used. They are designed to be set hydraulically or mechanically.

Retrievable packers are usually used for complex multiple zone and multiple string completions. Their main limitation is their limited ability to accommodate tubing stress changes without unsetting. The availability of effective slip joints and detachable heads has eased the situation.

One disadvantage of retrievable packers is that if they fail to be retrieved, they must be removed by milling. However, they are very difficult to mill. Generally, this type of packer is used under non-severe conditions (differential pressures less than 5000 psi and temperatures less than 300°F). Because of their setting mechanism, retrievable packers tend to have a restricted bore, which may restrict flow or limit wireline operations below the packer setting depth.

The different types of retrievable packers are:

i. Retrievable Tension Packer. This packer is generally used in medium to shallow-depth, low pressure/low temperature (LP/LT) conditions, injection or production applications (Figure 3.27). It has a single set of unidirectional slips. The slips grip the casing only when the tubing is pulled in tension, so to keep the packer set and the packing element energized the tubing tension must be constant. Usually these packers are set mechanically and they are released by means of tubing rotation. It does not have an equalizing (or bypass) valve to help in pressure equalization between the annulus and the tubing to facilitate the retrieval of the packer. That is the reason why this packer runs at relatively shallow depths (Lake, 2007).

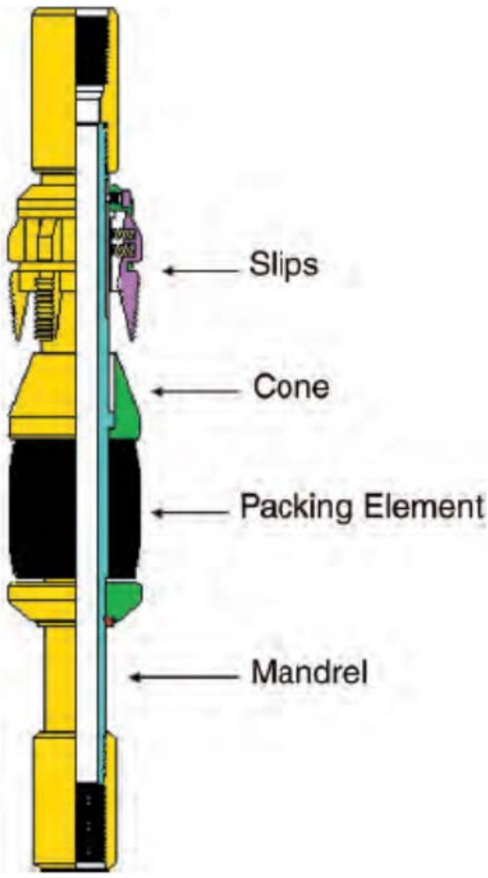

Fig.3.27 Tension packer (Lake, 2007).

ii. Retrievable Compression Packer With Bypass. These packers have a fluid-bypass valve and they are typically used for low to medium pressure/medium temperature conditions (Figure 3.28, 3.29). The retrievable compression packer is prevented from setting by means of a mechanical assembly while it is being run in the hole. When the packer has reached the designed depth, the tubing string is rotated to input the setting sequence. The drag blocks on the packer hold the packer in place and provide the resistance to set it while the tubing is being rotated.

The tubing string is lowered to close the bypass seal and set the slips, when the interconnect system is released. The constant application of slack off force activates the packing-element system and creates a seal. The additional bypass valve equalizes the pressures in the annulus and tubing and assists in releasing the packer. The valve can be opened without releasing the packer by picking up on the tubing string. Compression or tubing weight needs to be constant to sustain the pack off and keep the bypass valve closed. That is the reason why compression packers are generally not applicable for low-volume pressure-treating operations or injection wells (Lake, 2007).

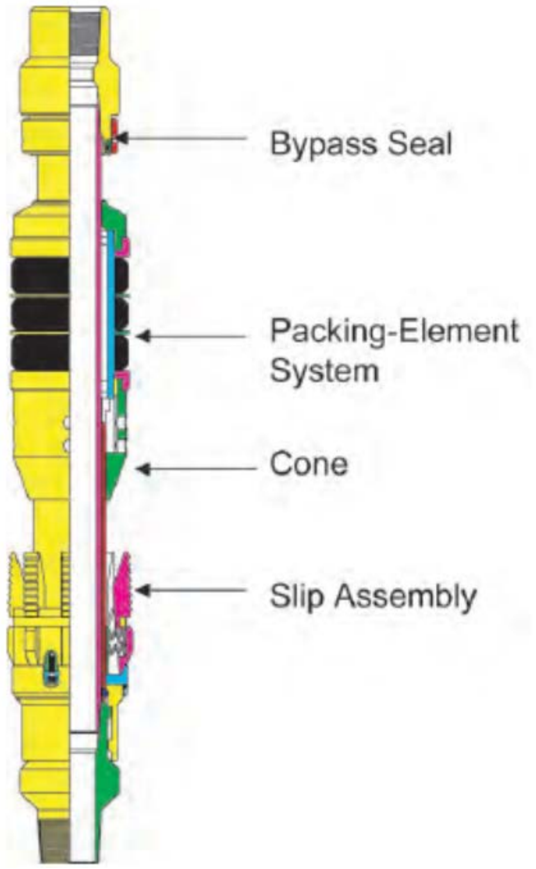

Fig.3.28 Compression packer with fluid bypass (Lake, 2007).

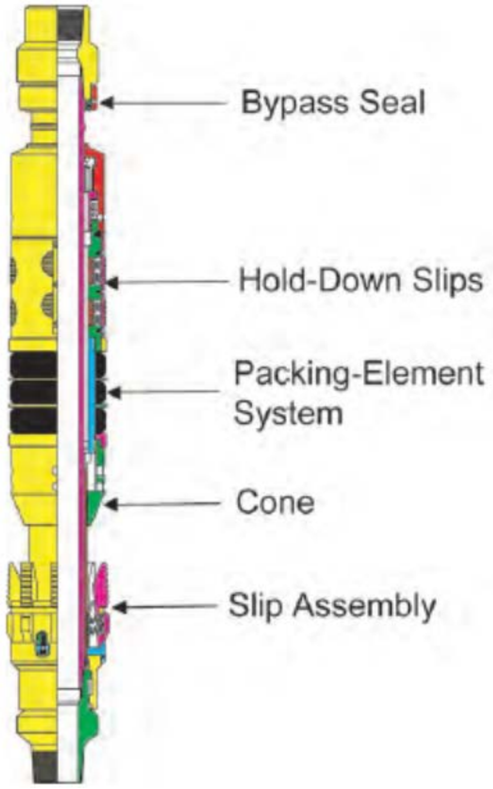

Fig.3.29 Compression packer with fluid bypass and hold-down anchor (Lake, 2007).

iii. Wireline Set-Tubing Retrievable. These packers are designed to be installed in the wellbore on electric wireline and retrieved on the tubing string (Figure 3.30). A special nipple is located on the top of the packer. It has a polished seal surface on its Outside Diameter and has j-lugs that are used to washover shoe in place or anchor a seal housing. Additionally, the polished nipple has a landing nipple profile in its Inside Diameter. The landing nipple permits the installation, if desired, of a slickline retrievable blanking plug.

The packer is run and set on electric wire-line. This wire-line provides the force by itself with no other equipment to anchor the slips in the casing wall and energize the packing element. When the packer is installed and the wire-line is retrieved, a seal housing is run in the hole on the bottom of the production tubing. The tubing can be retrieved from the wellbore at any time without disturbing the packer.

The main advantage of this system is that it can be set and run under pressure on electric wire-line in a live gas or oil well (Lake, 2007).

Fig.3.30 A set with plug in place (left) and with tubing connected and plug retrieved (right) of Wireline-set tubing retrievable packer (Lake, 2007).

iv. Retrievable Tension/Compression Set-Versatile Landing. These packers let the tubing to be landed in tension, compression, or neutral and they are the most common types of retrievable packers that are used nowadays (Figure 3.31) (Lake, 2007).

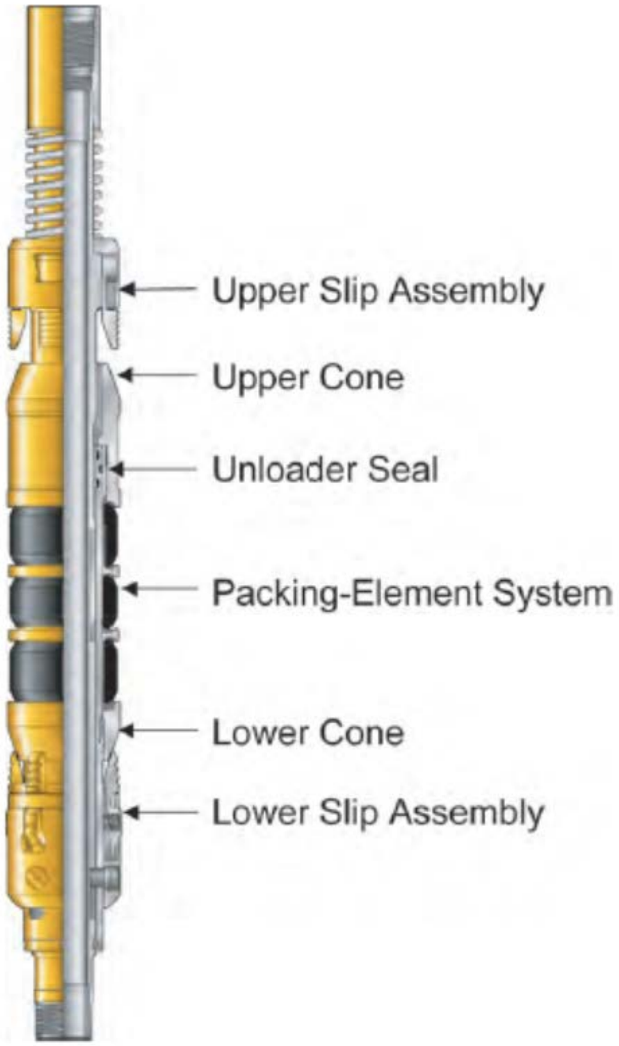

Fig.3.31 Tension/compression set versatile landing (Lake, 2007).

v. Retrievable Hydraulic-Set Packer (single+dual string). A bidirectional slip system is used in the hydraulic-set retrievable packer. This system is activated by a predetermined amount of hydraulic pressure applied to the tubing string (Figure 3.32). This pressure is achieved by a temporary plugging device that is in the tailpipe below the packer. The applied hydraulic pressure acts against a piston chamber in the packer. As a result, the force created by this action sets the slips and packs the element off (Lake, 2007).

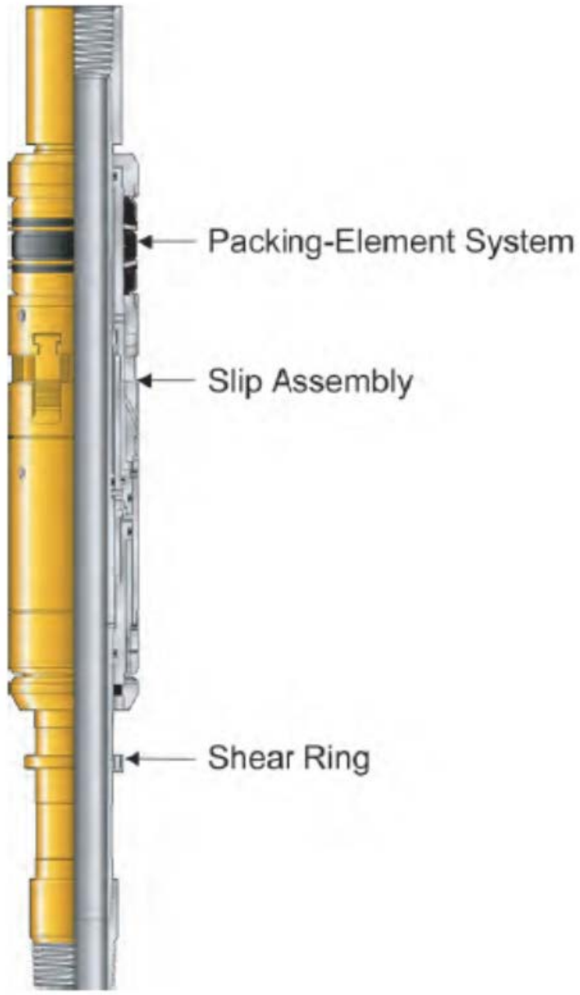

Fig.3.32 Retrievable Hydraulic-Set Packer (Lake, 2007).

Dual-string retrievable hydraulic-set packer is a “mid-string” isolation packer designed to seal off two strings of tubing (Figure 3.33). These packers allow the production of two zones at the same time while keeping them isolated. The majority of multiple-string packers are retrievable, however, there are some permanent models for use in High Pressure/High Temperature applications. Standard composition has bidirectional slips to prevent movement and maintain pack off with the tubing landed in the neutral condition.

The multiple-string retrievable packers are mostly set hydraulically on the ground that tubing manipulation required to set a mechanical packer is not desired or not feasible in a dual-string application (Lake, 2007).

Fig.3.33 Hydraulic-set dual-string packer (Lake, 2007).

Permanent Packers

A permanent packer is independent of the tubing and may be run on tubing or on wire-line. The tubing can be released from the packer and can be pulled, leaving the packer set in the casing. It can subsequently be run back and resealed. The packer acts as an integral part of the casing. It is usually referred to as production packer or retainer production packer.

It cannot be recovered as such, but it can be destructively removed. In case that the packer includes a tailpipe and must be recovered, a mill out extension is required on the packer for the “catch sleeve” or "packer picker" on the mill to engage. In other cases, after milling, it may be adequate to simply push the packer to the bottom of the casing.

The upper part, down to the slip, is required to be milled at a permanent packer. The slips can then collapse inwards and the packer pulled. These packers are generally reliable once set (Figure 3.34).

Fig.3.34 Permanent sealbore packer (Lake, 2007).

A permanent packer can be set using an electric wire-line setting tool, a hydraulic setting tool run on drillpipe or tubing or by a combination of rotation and pull (Bellarby, 2009).

Permanent packers have the following applications:

- High formation, treating, or swabbing differential pressures.
- Pulling the tubing without unseating the packer.
- Converting the packer to a temporary or a permanent bridge plug.
- High bottom-hole temperatures.
- Tubing operating stress variations would not be accommodated with a retrievable packer.
- A retrievable packer would have an inadequate bore.

Permanent - Retrievable Packers

A recent arrival, this type of packer has the same characteristics as the permanent packer, but it can, when desired, be released with a special pulling tool and recovered.

Inflatable Packers

This type of packers comprises a flexible sealing element that can be expanded hydraulically using cement or completion fluid (Figure 3.35). They are used as open hole packer in Drill Stem Testing or when the casing is damaged. They are also used as external casing packers in stimulating horizontal wells.

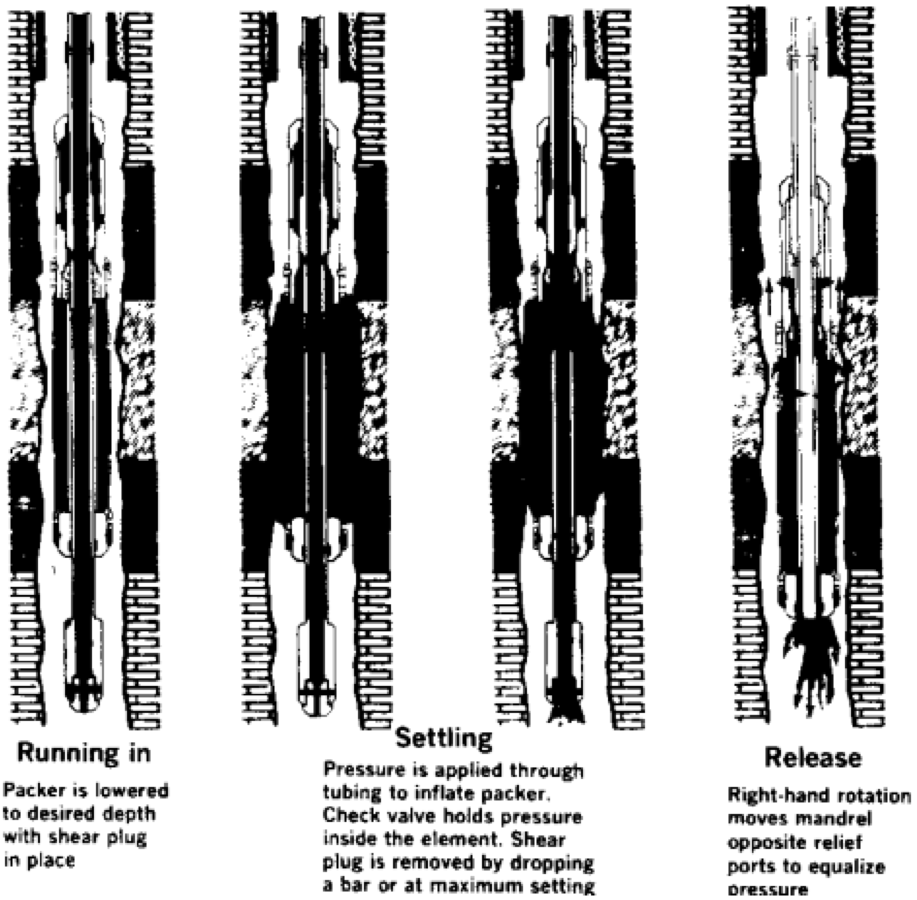

Fig.3.35 Open-hole inflatable packer (Allen & Roberts, 1982).

3.4.3 Wellhead/Xmas Tree

Wellheads are the connection point for the surface flow lines and the tubulars and they are the surface pressure control point in almost every well operation. They usually have working pressures of 2000-15,000 psi or greater. They must be chosen to meet the temperature, pressure, corrosion, and production compatibility requirements of the well.

Wellhead assembly is applied for hanging down-hole casing and tubing string, sealing casing-casing and tubing-casing annuluses, injecting gas, steam, water, and chemicals and acidizing and fracturing. It is the most crucial equipment for safe production.

There are three sections at a wellhead (Bellarby, 2009, Heriot Watt University, 2011):

-The outer cemented casing string, commonly either the surface string or the conductor pipe, is fitted with a slip type or threaded casing head.

-The head which supports the BOPs (Figure 3.36, 3.37) during drilling and the rest of the well head (Figure 3.38) during production.

The BlowOut Preventer or BOP is a large assembly of valves and rams at the top of a well that can be closed in case the drilling crew loses control of formation fluids. By closing BOP valves (commonly operated remotely via hydraulic actuators), the drilling crew often regains control of the reservoir and procedures can then be initiated to increase the mud density until it is possible to open the BlowOut Preventer and retain pressure control of the formation.

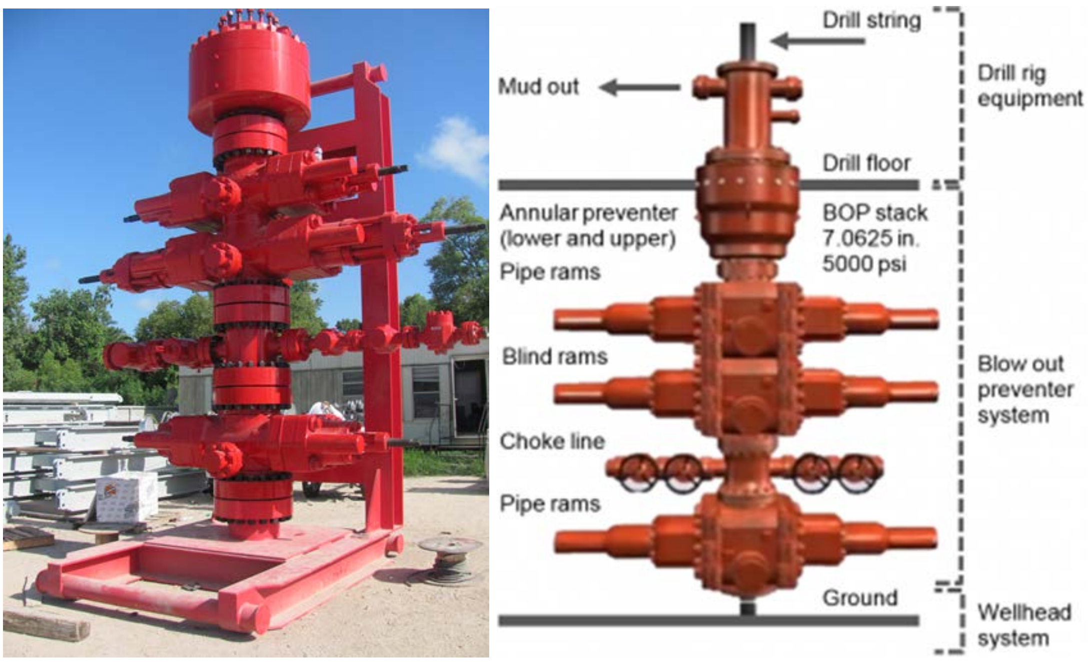

Fig.3.36, 3.37 Blowout preventer (Pipingonline, 2019, Geodesicdrilling, 2019).

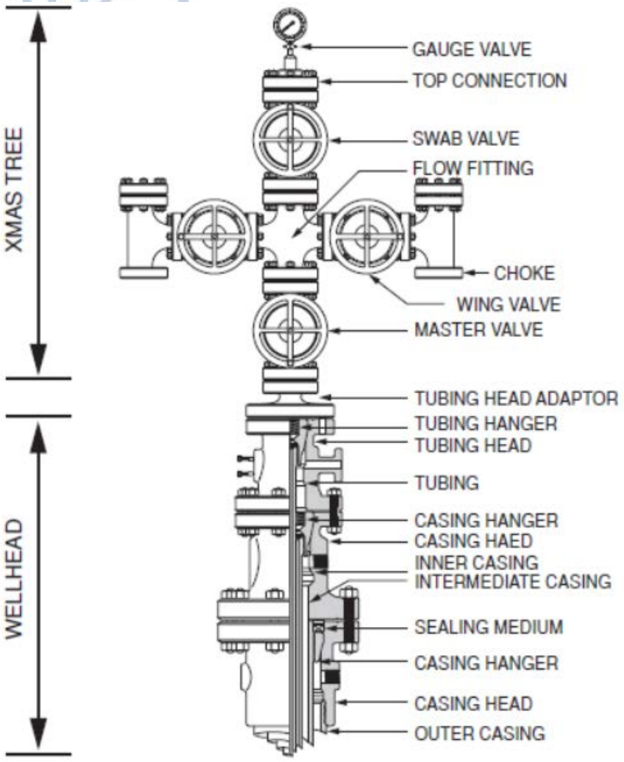

Fig.3.38 Simple wellhead assembly including casing spools and Christmas tree (Heriot Watt University, 2011).

On the side of the head there is a port that permits the communication with the annulus when another casing string is run. A casing spool is used for every additional casing string. At each end the spool has a flange. The bolt pattern, the diameter of the flange and the seal assembly are a function of the spool size range and the pressure rating. The tubing is isolated and hung in a tubing spool. On the side of the spools there are ports which provide annulus communication. Each spool has alignment screws for aligning the tubular in the center of the spool.

-The Christmas tree is the final section of the wellhead. The tree is set on top of the tubing hanger spool. The tree holds the valves that are used in well operation. Its main purposes are to isolate the well from adjacent wells, provide the primary method of closing in a well, connect a flow line and provide vertical access for well interventions. The Christmas tree valves provide flow control of the fluids produced from or injected into the well. The Christmas tree is generally installed on the wellhead after the installation of the production tubing has been completed.

The master valve of the Christmas tree is always completely open when the well is producing or when a workover is in progress. The master valve's working pressure rating must be adequate to handle full wellhead pressure. The master valve can be closed without killing the well when the upper part of the Xmas tree must be replaced.

In some wells such as those with very HP (P>5000 psi) or hazardous wells there are usually two master valves: one for backup in case there are leaks in the main valve. The choke is the only device that is used to reduce the production of flowing fluids.

Christmas trees can be conventional or horizontal, set on platform or land or on subsea floor.

The main difference between horizontal and vertical trees is the position of the valves (Figure 3.39). Vertical tree has the master valves in the vertical position and in line with the tubing. On the other hand, horizontal trees have the master valves horizontal and away from the production/casing bore.

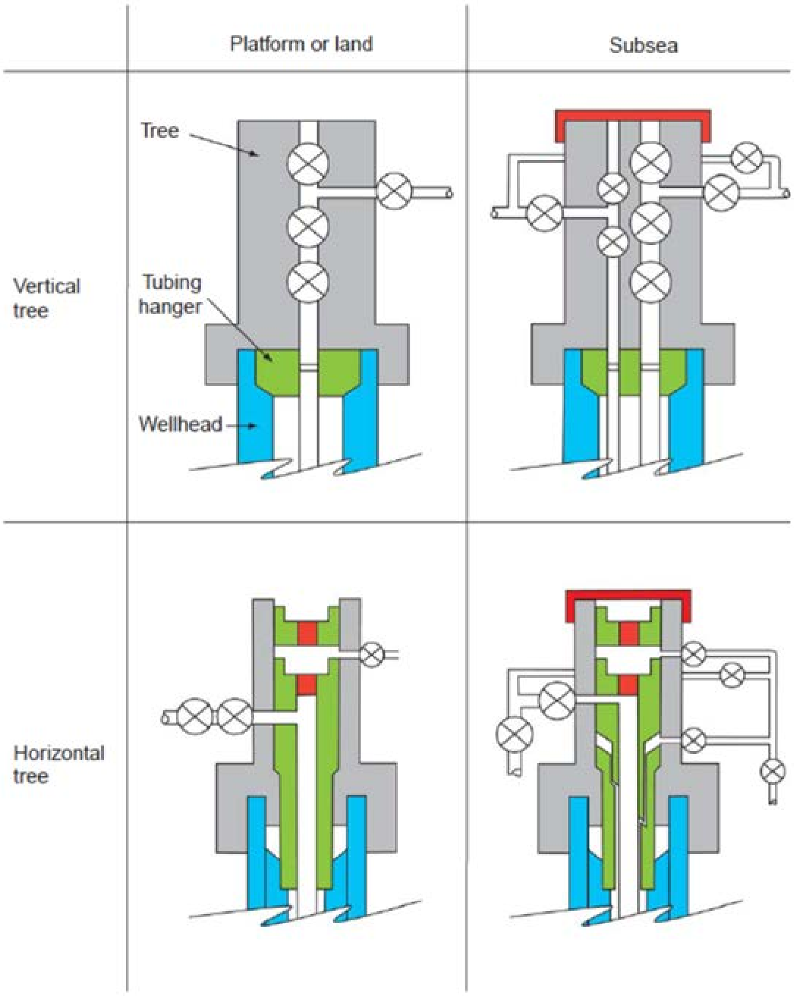

Fig.3.39 Typical vertical and horizontal tree valve configurations (Bellarby, 2009).

The BOP in horizontal trees is set above the tree and the tree is installed prior to running the completion. Usually tree plugs need to be run before the Blow out Preventer

(BOP) can be removed. The plugs must be positioned inside the tubing hanger or be of full bore. In Table below (Table 3.4) the sequencing of tree installation of vertical and horizontal trees is shown.

Table 3.4 Sequencing of tree installation of vertical versus horizontal trees (Bellarby, 2009).

Conventional (Vertical) Tree	Horizontal Tree
Drill and case tophole sections. Install BOP on top of wellhead. Drill and case remainder of well. Run reservoir completion. Run and test upper completion. Tubing hanger sits inside wellhead. Install sufficient barriers in the well to allow the safe removal of the BOP. Remove BOP. Install and test Christmas tree. Pull barriers.	Drill and case tophole sections. Tree can be run with BOP or at any convenient stage (e.g. casing shoe) thereafter. Tree installed on top of wellhead. Install BOP on top of Christmas tree. Drill and case remainder of well. Run reservoir completion. Run and test upper completion. Tubing hanger sits inside Christmas tree. Install plugs inside the tree to allow the safe removal of the BOP. Remove BOP.

A conventional platform or land tree commonly comprises of two master valves, a swab valve and a wing valve. An additional second wing valve can be used for pumping operations such as chemical or stimulation treatments. For many platform wells, one of the master valves and the wing valve are hydraulically actuated. This valve is connected to the platform shut-down system. The swab valve is manually operated in most of the cases. The figure below (Figure 3.40) presents an example of a high-pressure land tree and its valves.

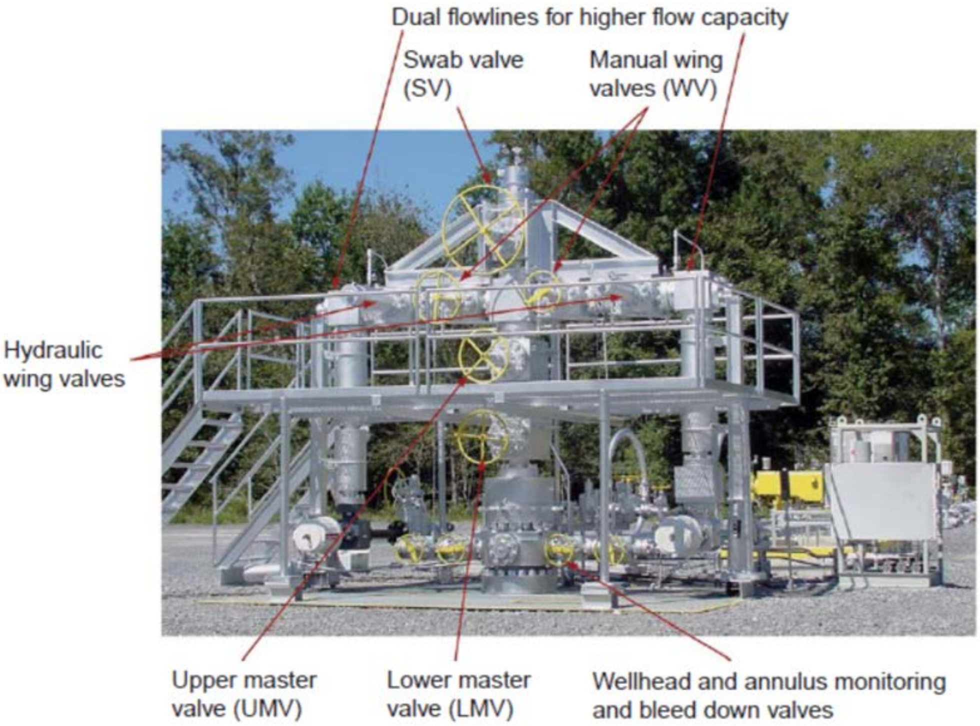

Fig3.40 High-pressure land tree (Bellarby, 2009).

Subsea Christmas trees

The wellhead in subsea wells sits on the bottom of the ocean at depths ranging from less than a 100 ft. to over than 2500 ft. Access is much more difficult here than in an onshore well. Hence a subsea completion requires a well to be of low maintenance, mostly a sweet flowing oil or gas well. The wellhead for these wells has to be self-contained units with controls that can be manipulated by remote action at the well head by a remotely operated tool (ROT), by diver or remotely operated vehicle (ROV) (Figure 3.41).

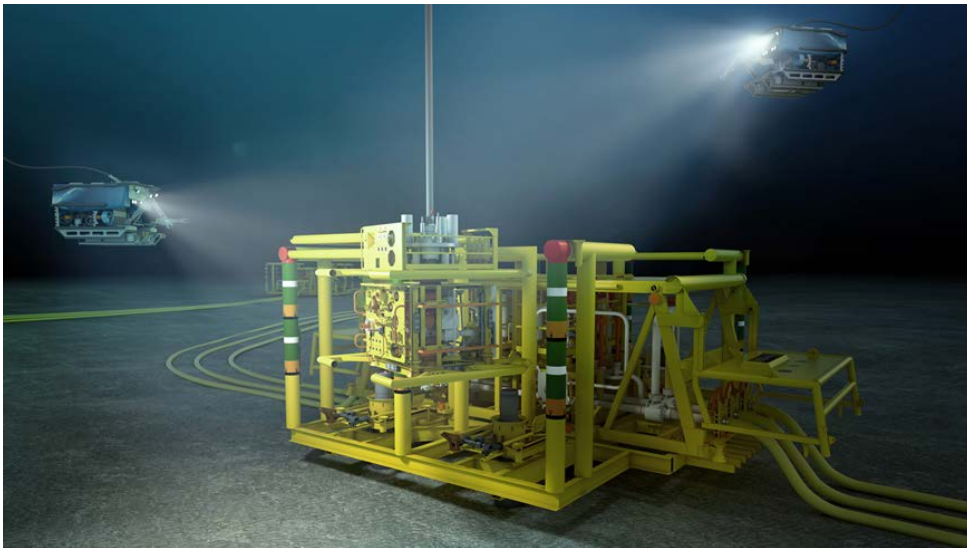

Fig.3.41 Subsea Christmas tree (Akersolutions, 2019).

The main difference between platform/land and subsea wells is the need of annulus access through the tree. The annulus access is required for pressure monitoring, gas lift and bleed down of annulus fluids.

The tubing hanger and the tree are dual bore for a conventional vertical subsea tree (Figure 3.42): an annulus access bore with associated master valve and wing valve. A XOV (crossover valve) lets annular fluids to be bled into the flow line. A conventional subsea tree must have access to both the annulus and production bores. This is why a dual-bore riser has to be used.

The horizontal subsea tree (Figure 3.43, 3.44) uses a single-bore riser. The fluids of the annulus can be bled off through a concentric port in the tubing hanger and continue through an annular master valve on the side of the tree. There is no requirement of plugs on the annulus flow path (Bellarby, 2009, King, 1998).

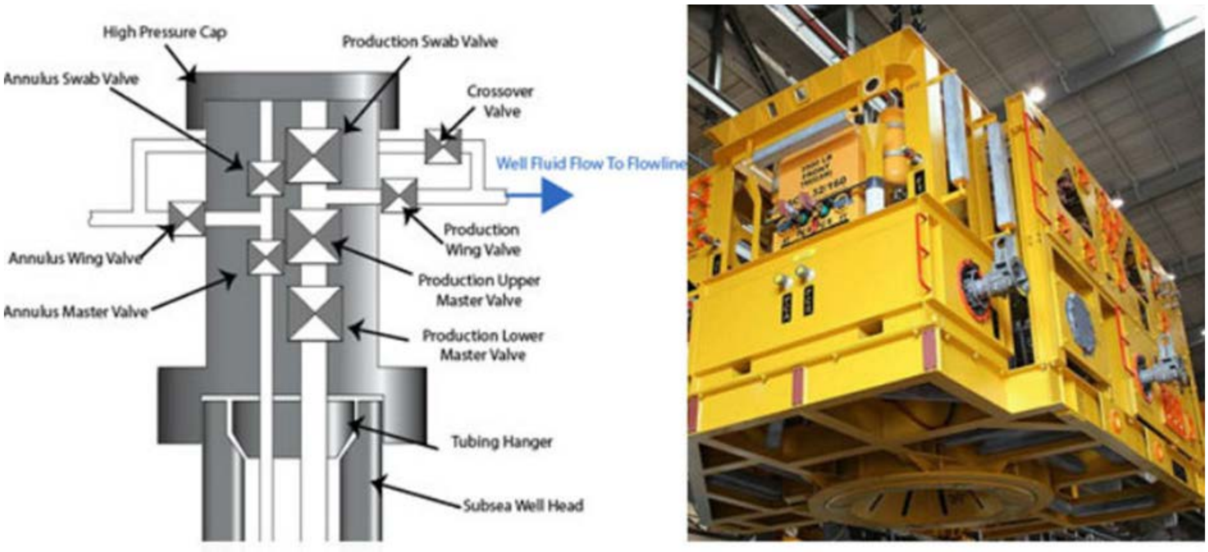

Fig.3.42 Vertical subsea Christmas tree (Bellarby, 2009).

Fig.3.43 Horizontal subsea tree with tubing hanger (Bellarby, 2009).

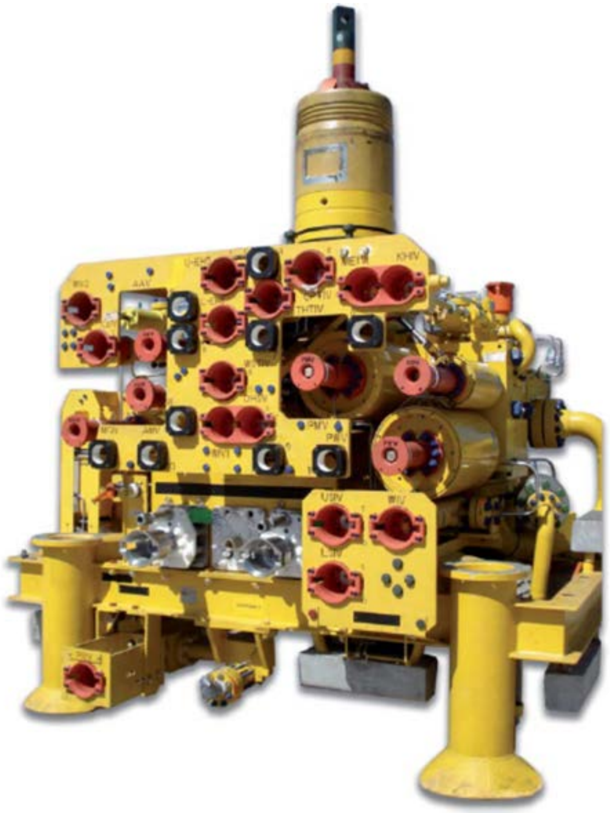

Fig.3.44 Horizontal subsea tree (Bellarby, 2009).

3.4.4 Subsurface Safety Valves

The subsurface safety valve automatically shuts-off the flow of the well, in case of a catastrophic failure of the wellhead should occur, to avoid disaster. They must be installed in every offshore well capable of flow, at onshore locations in high pressure or sour gas wells located in close proximity to housing, public roads, or rock slide areas. These requirements are often dictated by government regulations. There are generally two types of down hole safety valves (Lake, 2007):

1) Subsurface-controlled safety valves (SSSVs)
2) Surface-controlled subsurface safety valves (SCSSVs)

1) Subsurface-controlled safety valves (SSSVs)

These are usually deep set valves whose operation is directly controlled by the well stream. They are normally wireline retrievable since they must be reset from time to time, especially as well conditions change. They are designed to be open normally, but to snap shut if the tubing pressure dips below a threshold or the flow rate exceeds a preset limit (Figure 3.45, 3.46).

Fig.3.45 Open and close Subsurface-controlled safety (Bakerhughes, 2014).

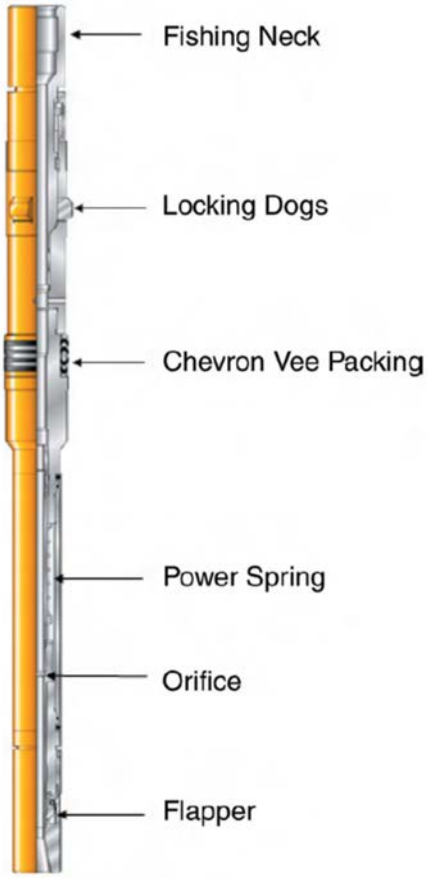

Fig.3.46 Subsurface-controlled safety valve (Lake, 2007).

The valve can be a ball, flapper, or stem type. It is reopened by raising the pressure on the downstream side in excess of the closed-in bottom hole pressure. Setting this type of valve need an accurate knowledge of well behavior, temperature, and flow conditions.

The major advantage of these valves is that they are cheap and can be set deep in the well below the packer, protecting both the tubing and the annulus.

The main disadvantages are the servicing and design requirements, the restrictions to flow capacity and flexibility and the risk of inadvertent reopening as a result of fluids lost into the wellbore.

2) Surface-controlled subsurface safety valves (SCSSVs)

The SCSSV is a fail close valve that is kept open by a high pressure control line. Pressure will leak off and the safety valve will close, if the control line is severed in an event that damages the wellhead or tubing (Figure 3.47, 3.48).

The control line is commonly connected to an emergency shutdown system to provide automatic closure during not safe or alarm conditions (such as detection of gas or fire).

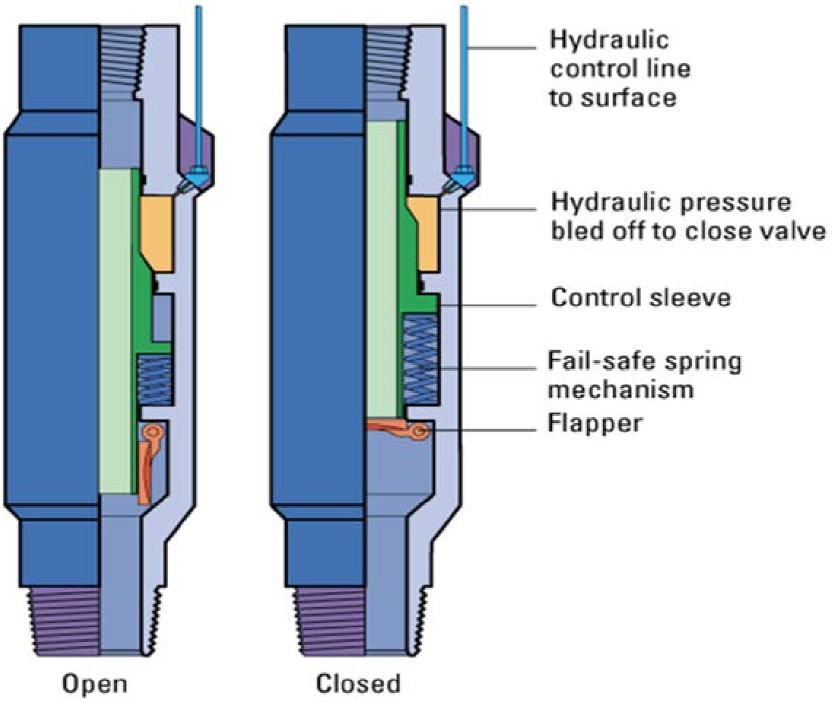

Fig.3.47 Open and closed SCSSV (Bellarby, 2009).

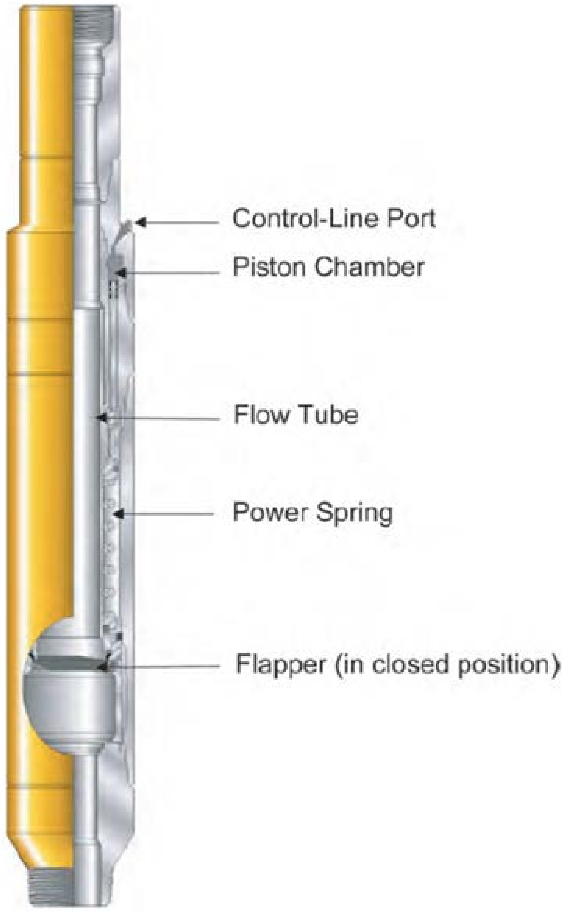

Fig.3.48 Surface-controlled subsurface safety valve (SCSSV) (Lake, 2007).

There is often a control panel with pressure gauges and control valves for all the wells on an offshore platform. Surface controlled valves are the type of down-hole safety valves most favored today. The regulations require the use of this type of valve in all offshore wells and onshore sour wells capable of flow.

There are two basic types of SCSSVs (Allen & Roberts, 1982): Wire-line retrievable (TFL retrievable) and tubing retrievable (Figure 3.49, 3.50).

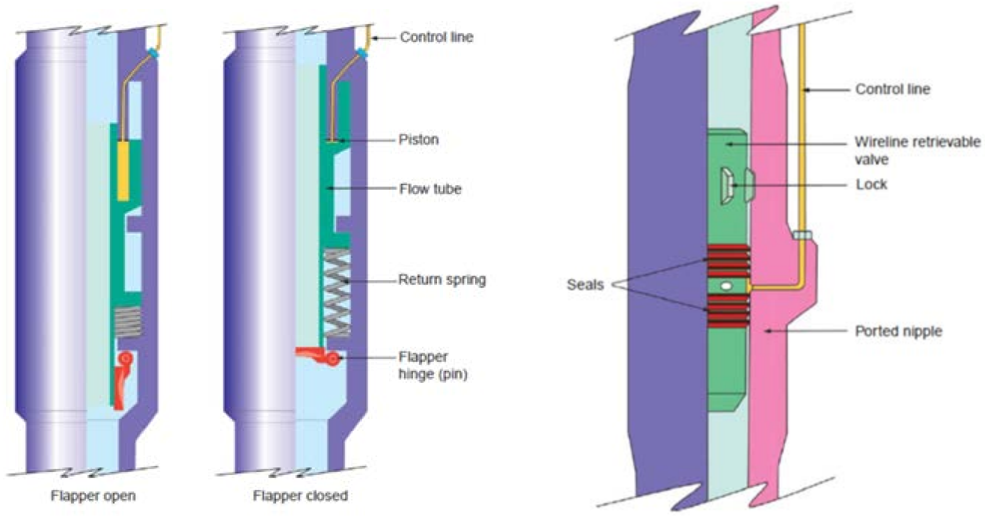

Fig.3.49, 3.50 Tubing (left) and Wire-line (right) retrievable down-hole safety valve (Bellarby, 2009).

In the first one, wire-line retrievable valve, surface-controlled subsurface safety valves landing nipple is installed in the tubing string. This is commonly a landing nipple with a port through which the control line enters between a set of packings on the SCSSV. This type of valve has a service life of eighteen to twenty four months and therefore requires easy wire-line access.

The main disadvantages of wire-line retrievable surface-controlled subsurface safety valves are the short service life, the restricted through-bore, the fact that the valve has to be pulled for deep wire-line or through tubing work, turbulence in the flow stream increases pressure loss and erosion problems and we are forced to rely on a lock to make sure that the valve is not blown out of the well on closure.

On the other hand, in tubing-retrievable SCSSV the initial cost is relatively low and servicing can be undertaken with minimal disruption of production. The tubing retrievable SCSSV is an integral part of the tubing string. It generally has a larger through bore than the wire-line retrievable valves and has a full bore diameter. It has a much longer service life (five to twenty years, depending on the design and the materials selected). Tubing retrievable valves with all metal to metal seals are available for severe environments.

Since most valve failures are caused by elastomer problems and since tubing-retrievable valves need a rig entry for repair work, these valves are often backed up with a nipple section positioned to accept a wire-line retrievable valve. Service procedures have been developed for installing the insert valve using both TFL and wire-line techniques.

The Surface-controlled subsurface safety valve may incorporate a ball valve (Figure 3.51) or a flapper valve (Figure 3.52) (Heriot Watt University, 2011).

Ball valves are usually considered more robust and can sometimes cut wire-line when they are closed across the valve. However, they are prone to damage by improper operation and sand.

The simpler flapper valve has the advantage of always being re-opendable (mechanically if necessary) should it become stuck in the closed position.

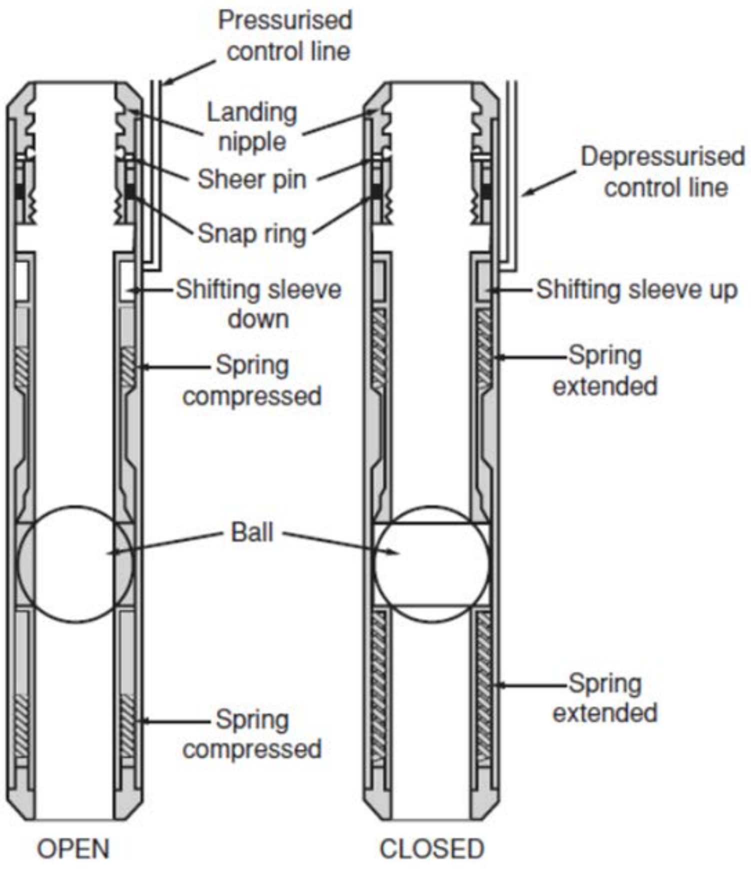

Fig.3.51 Ball type SCSSV (Heriot Watt University, 2011).

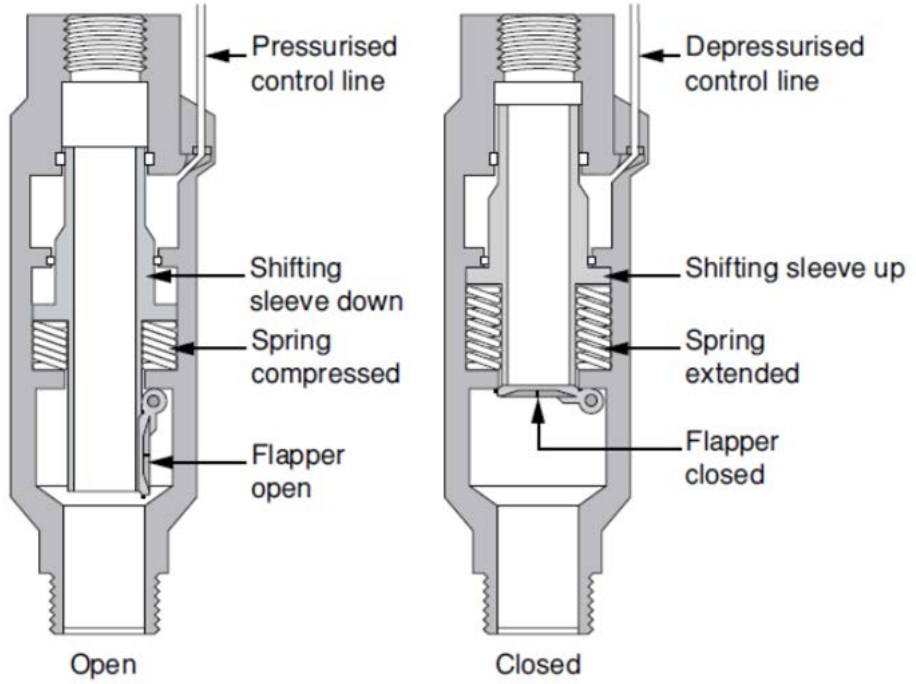

Fig.3.52 Flapper type SCSSV (Heriot Watt University, 2011).

The recommended safety valve's setting depends on the company's philosophy and operating procedure. Many companies like to set the safety valve beyond the kick off point so that it can be applied to shut in the well during the top-hole drilling or during kick off of an adjacent well. Other designers do not prefer to subject the valve to significant bending and therefore prefer its installation nearer to the surface. Valves are generally set at least 150ft below surface or sea floor.

Bottom-hole chokes and regulators

A bottom-hole choke is a flow-control device that is landed in profile seating nipples. The bottom-hole choke reduces flow in the tubing string and controls the production from different zones. It can also be useful for preventing freezing of surface controls. The bottom-hole choke assembly is comprised of a set of locks, packing assembly, packing mandrel and choke bean.

They are often used for:

- Limiting the rate at which a well could produce.
- Limiting the surface operating pressures in high pressure wells.
- Limiting the drawdown rates on wells that have a tendency to produce sand.

- Taking maximum advantage of the formation temperature to avoid hydrate formation during choking of a high pressure gas stream at surface temperatures.

Chokes are designed to give a constant rate. Regulators give constant choking or pressure differential. The other safety device that is often used in injection wells is a simple check valve that will permit injection but not production. This device may be used to prevent backflow of water and formation sand, should injection cease. All of these devices are normally wire-line retrievable.

3.5 Sand Control

Conventional well completions are usually used in sand reservoirs which are soft formations, so generally produce formation sand and fines with fluids. Sand production can reduce well productivity, erode equipment and plug wells.

Some of the main consequences of sand production are (Lake, 2007):

- Accumulation down-hole.
- Accumulation in surface equipment.
- Erosion of surface and down-hole equipment.
- Collapse of the formation.

It is very important for a completion engineer to predict if a well will produce without sand and if sand control is necessary. There are several techniques to predict if sand control is necessary, but none of them are universally acceptable or completely accurate.

The engineer must consider the operational and economic influence to determine whether sand control is required and in most cases with limited data. The decision is complex and difficult, since sand-control techniques, e.g. gravel packing, are expensive and may reduce well productivity if not performed properly.

Another fact that must be considered is the formation strength. The compressive strength of the rock has the same units as the pressure difference between the reservoir and the well, so the two parameters may be directly compared and can determine drawdown limits for specific wells.

We can use sonic logs as a way of addressing the sand production potential of wells. The porosity is related to formation strength and the sonic travel time. Furthermore, there are several other formation properties logs, such as density and neutron logs, which are indicators of formation hardness and porosity. The formation porosity can be used as a guide to decide whether sand control is needed. Usually, in case formation porosity is greater than 30%, the necessity for sand control is high because of the lack of cementation. The uncertainty for sand control requirement usually exists when formation porosity is between 20 to 30%. Below 20% porosity sand control is not probably required.

Through production a pressure drawdown is usually a sign of sand production. Sand production cannot occur if there is small pressure drawdown around the well.

The most sophisticated approach used by an engineer to predict sand production is the Finite Element Analysis of geomechanical numerical models developed to analyze fluid flow through the reservoir in relation to the formation strength.

There are many techniques to reduce sand production from wells. The method used depends on the specific conditions of the site, operation practices and economic considerations. In summary, the most used techniques are (Lake, 2007):

- Maintenance and Workover. A passive approach to sand control.
- Rate Restriction. Restricting the well's flow rate to a range that minimizes sand production.
- Selective Completion Practices. Produce only from sections of the reservoir that are able to withstand the anticipated drawdown and apply perforations only to sections of the formation of the higher compressive strength which allows higher drawdown.
- Plastic Consolidation. Injection of plastic resins. These resins are attached to the formation sand grains. Inject resins quickly under highly overbalanced conditions, which are surged into the formation at rates that will place the resin before the formation has a chance to fail. There are 3 commercially available types of resins: epoxies, furans and phenolics.
- Resin-Coated Gravel. Involves pumping the gravel into the well to completely fill the perforations and casing. We can use two types of resin-coated gravel treatments: a dry, partly catalyzed, phenolic resin-coated gravel or a wet resin (epoxies or furans).
- Stand-Alone Slotted Liners or Screens. They are applied as the sole mean of controlling formation sand production and they act as a filter.
- Gravel Packing. It is comprised of placing a slotted liner or screen in a well opposite to the completion interval and placing gravel concentrically around it.

3.6 Multiple Zone Completions

There are some wells with 2 or more pay zones that need separate handling due to the different zone pressures or the incompabilities of fluids. In these cases multiple zone completions are used and the reservoirs are drilled from a single well and produced separately. Each reservoir has its own pressure regime and its own GOC (Gas-Oil Contact) and WOC (Water-Oil-Contact) (King, 1998).

In multiple zone completions we can have commingling flow from different zones in which fluids from more than one reservoir flow into a single tubing string. There is also the segregated multiple zone completion where multiple production conduits are installed within the same wellbore and each tubing controls the production of one reservoir. This allows for alternate zone well completion strategy where each well is completed on more than one reservoir (Heriot Watt University, 2011).

Multiple completions have often increased mechanical problems with the equipment because of setting two or more packers of and running two or more strings of pipe. In most of the cases the equipment used is very specialized and the completions are tailored for each well.

These completions can be side-by-side tubing completions or a concentric tubing completion. The conventional side-by-side dual tubing is more common, however concentric duals have higher flow rates in some applications and need special running techniques to make and break joints.

The packers used in the multiple completions are customized to the requirements of the individual well and they are usually hydraulically set. The pressure set packers are the most popular due to the difficulty in rotating side-by-side dual strings. Mechanically set packers are used sometimes as the top packer in the multiple packer series. The packers are either permanent or retrievable.

Other special equipment used in multiple completions is (King, 1998):

- Special BOP rams for work over.
- Shear release joints or collects between the packers on the tubing, for pulling off in case the lower packer sticks.
- “Y-block” connections, which allow the use of Electrical Submersible Pumps (ESP) and wireline operation.

- Heavy wall tubing blast joints over the tubing across from high velocity productive formations to reduce outside tubing erosion.
- Sliding sleeves or telescoping unions for minor adjustments in spacing out tubing during packer setting.
- Oriented perforating in the short string, to miss the long strings.
- Special artificial lift assemblies.
- Dual polish bore receptacles in deep wells.

3.6.1 Dual-Zone Completion.

When we want to produce 2 zones simultaneously while keeping them isolated from each other, we usually use the dual-zone completion method (Figures 3.53, 3.54). The most common use of dual completion is in stacked reservoir sequences in low to moderate flow rate, shallow water wells (Bellarby, 2009).

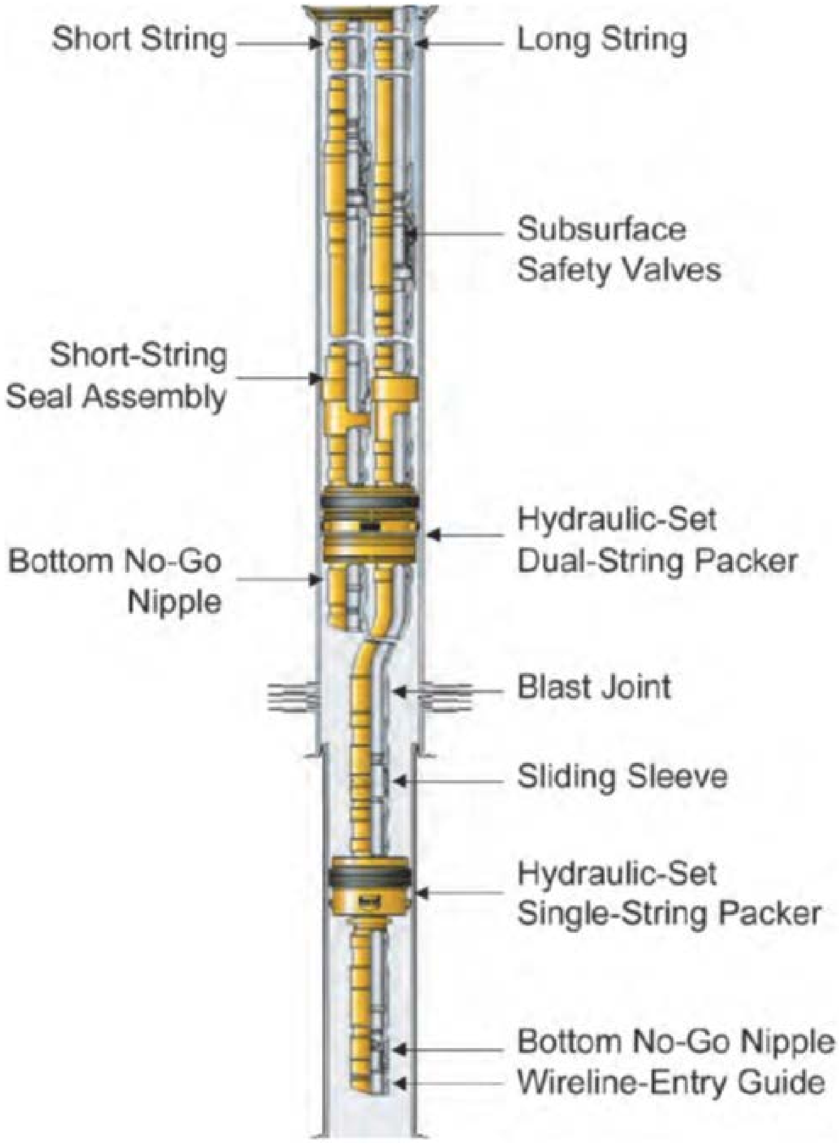

Fig.3.53 Parallel-string dual-cone completion (Lake, 2007).

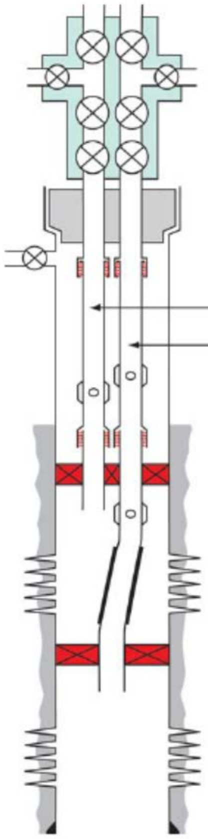

Fig.3.54 Typical dual completion (Bellarby, 2009).

These completions are used where independent injection or production is required. The typical dual completion consists of two strings of tubing. The strings are run from the surface to the dual packer. One string ends at the dual packer while the other extends from the dual packer to the lower single-string packer. The upper zone string is referred to as the “short string” and the other, which produces the lower zone, is referred to as “long string”.

If the pressure is equal and the cross flow during the completion stage is not an issue, a hydraulic-set packer is used as the lower packer and the completion runs in a single trip. On the other hand, when the pressures are unequal and the cross flow is an issue, the lower single-string packer is commonly a seal bore packer which is applied with a temporary plug in place for controlling the well before perforating and running the upper completion. The two zones stay separated by the plug until the upper completion is installed and the wellhead is flanged up (Lake, 2007).

Below the lowermost packer and the dual packer on the short string, a profile seating nipple is run to accept a blanking plug to set the packer and to give well control. Across the perforations of the zone between the packers a blast joint is positioned to limit the risk of erosion damage from well fluids and produced sand to the long string. Between the packers a sliding sleeve is positioned for aid in case of circulating kill-weight fluid in the hole or circulating lighter gas or fluid in the tubing strings to bring the well into production. Above the dual packer on both strings profile seating nipples should be run for testing tubing for well-diagnostic purposes or well control (Lake, 2007).

The main difficulties in dual completions are difficulties to integrate them with sand control reservoir completions and difficulties to perforate the upper interval. Inside the large-diameter casing the small-diameter tubing may create high stresses, doglegs and difficulties with through tubing access. We also can have limited access to the upper interval and water shut-off within the interval. The complicate artificial lift needs tubing pressure operated valve and the installation steps are generally complicate too.

3.6.2 Multiple-Zone Single-String Completion

This is the simplest multipurpose completion type. It consists of one flow stream through the wellhead valves and perforations above a single packer (Figures 3.55, 3.56). The casing-tubing annulus is exposed to one of the fluids.

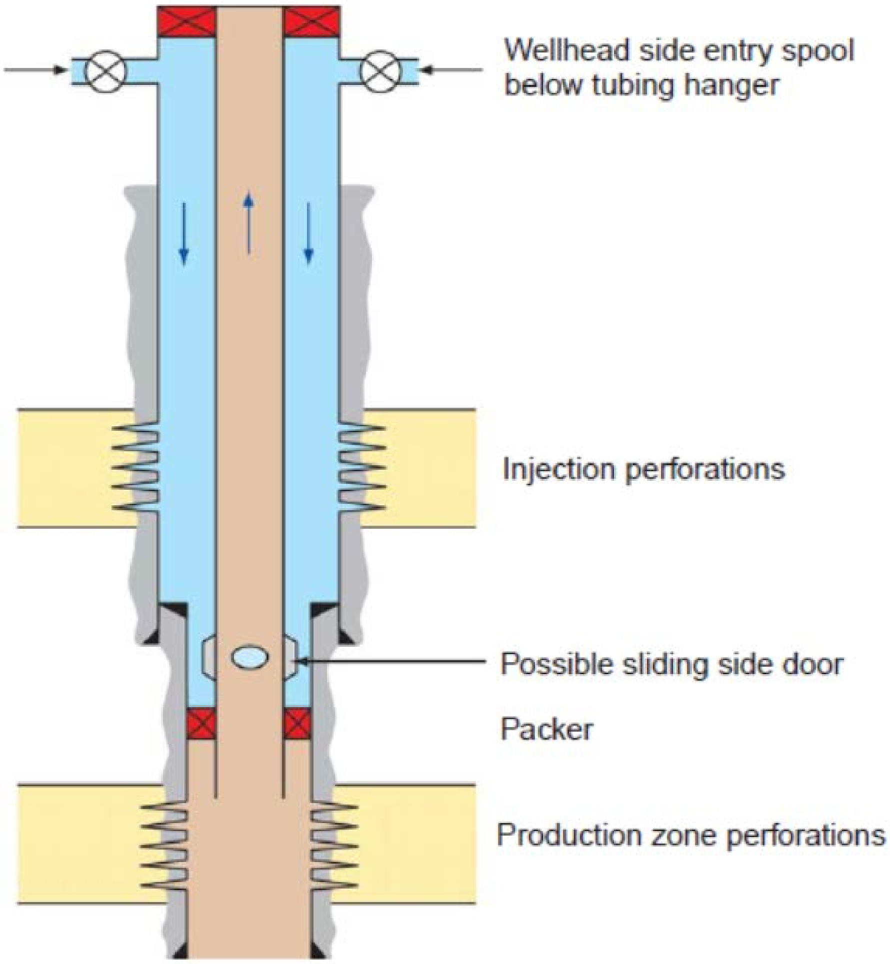

Fig.3.55 Example of single string completion with single packer (Bellarby, 2009).

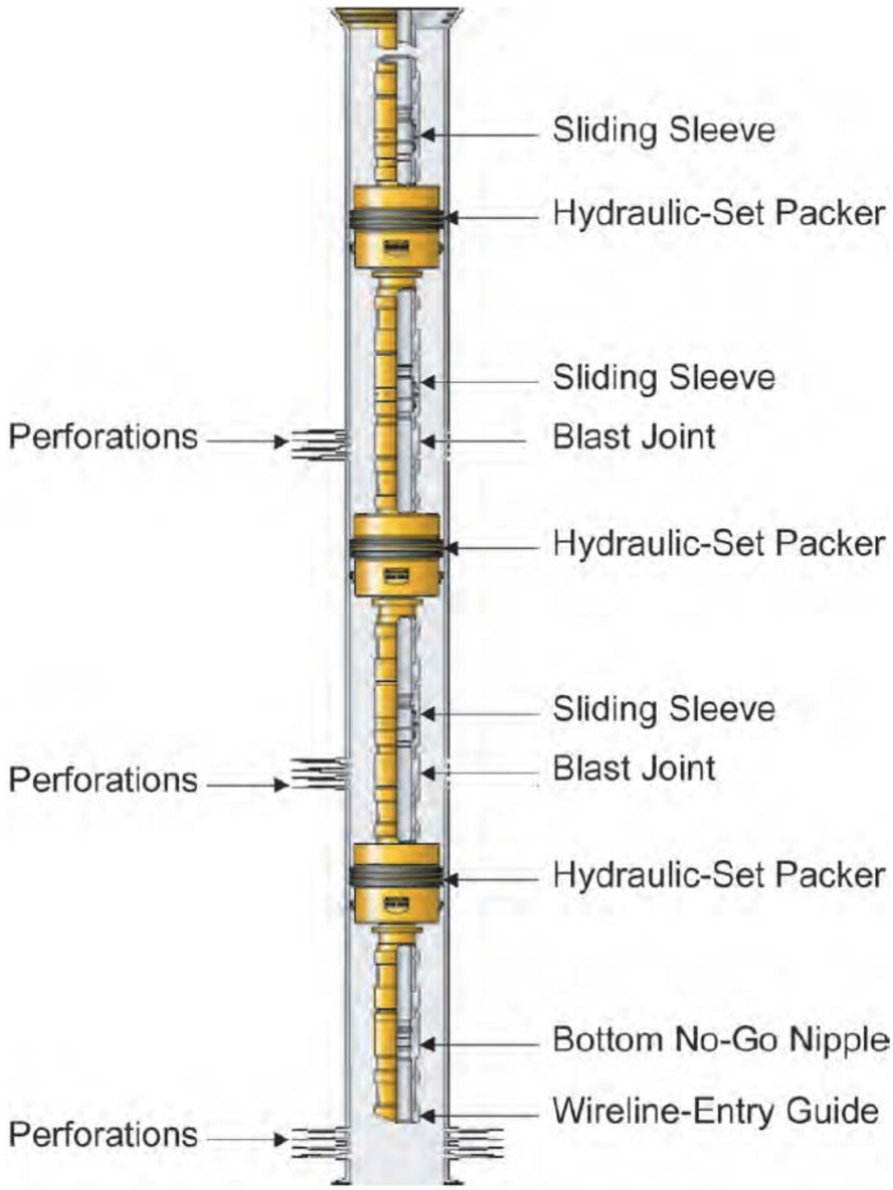

Fig.3.56 Example of Multiple-zone single-string selective completion (Lake, 2007).

Usually hydraulic-set single string retrievable packers are used and allow for all the well zones to be completed at once and produced commingled or individually. Between each isolation packer, sliding sleeves are positioned. The number of packers and sliding sleeves depends on the well and there are no limits. The more complex the completion designs the more the costs. This completion type usually increases workover costs significantly.

Below the lowermost packer a profile seating nipple is run to accept a blanking plug to set the hydraulic-set packers and to give well control for the lower zone. Between each packer for zonal isolation we position sliding sleeves. Between the isolation packers blast joints across the perforations are also positioned to reduce the erosion damage from well fluids and produced sand to the tubing string. Above the uppermost hydraulic-set packer we may position a gas-lift mandrel with a dummy or a sliding sleeve to aid in circulating lighter fluid or gas in the tubing or circulating kill fluid in the hole to bring the well into production (Lake, 2007, Bellarby, 2009).

The main disadvantage of these completions is that for oil production with water injection, the injection zone is usually below the production zone, so they require annular production which is usually not acceptable because of the lack of barriers and concerns about casing corrosion. They may also require large-capacity annulus safety valves.

Chapter 4: Intelligent Well Completion (IWC)

4.1 Overview

In this chapter completion methods in complex reservoirs (horizontal wells, extended reach wells and ultra-deep wells, multilateral wells, and intelligent wells) will be analyzed. These are considered to be the advanced completion methods. The development of intelligent well completion (IWC) is also examined as this is the new advanced completion method applied in difficult and complex oil and gas fields nowadays. The benefits and the economical effectiveness of IWC will also be briefly examined.

4.2 Advanced completions

Oil and gas companies have changed the conventional way of Exploration and Production over the years because of the demands for new technologies in new more complicated well systems. These technologies have made possible to reach new well shapes and increase the efficiency of oil production. Some of the wells that we apply advanced completions are:

- Horizontal wells.
- Extended reach and ultra-deep wells.
- Multilateral wells.
- Intelligent wells.

Using these completions in the last decades we access inaccessible reserves, increase the recovery factor and increase well flow rate.

Such advanced wells are more complicated and require an accurate reservoir description with adequate data. The main benefits of these completions are the following (King, 1998):

- They reduce operating expenditure per barrel of oil produced.
- They reduce the capital expenditure per barrel of oil produced.
- The reservoir properties at the field’s lateral limits are evaluated by logging while drilling techniques.
- They accelerate initial field production build-up and reserve recovery.

The main difficulty that arises from using this ‘unconventional’ completions is the increased complexity which requires a more strict validation well design because of the greater potential risks. Extra difficulties and challenges arise when using advanced completions including extra constraints when engineers operate these wells.

4.2.1 Horizontal wells

Horizontal wells are high angle wells, at an angle of at least eighty degrees, drilled to enhance reservoir performance by placing a long wellbore section within the reservoir and retrieve oil and gas in situations in which the shape of the reservoir is abnormal or difficult to access (Figure 4.1).

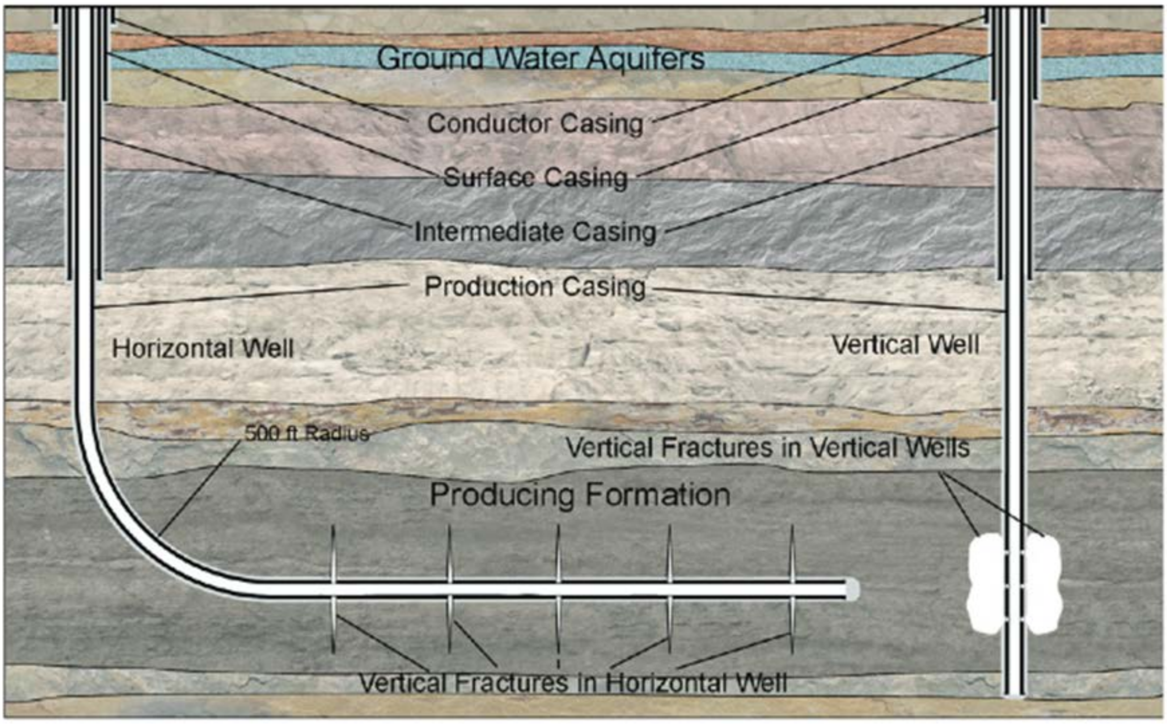

Fig.4.1 Example of a Horizontal and Vertical Well (National Academies of Sciences, Engineering, and Medicine, 2019).

The main advantages of horizontal wells are (Renpu, 2011):

- They reduce water and gas coning problems by reducing drawdown in the reservoir for a given production rate, so that remedial work needs in the future are also reduced.
- The pressure drop around the wellbore is reduced.
- They increase production rate (greater wellbore length in the pay zone).
- Sand production is reduced.
- Lower fluid velocities around the wellbore are achieved.
- They increase overall reserves recovery because of the larger and more efficient drainage.

The primary objective of horizontal wells is to increase reservoir available area from a single location. They can be drilled by common used drilling equipment and their trajectory is achieved either in a single stage step out to form a short radius or in a two-stage step out which can result in a long horizontal and highly deviated portion, of 4000 feet or more (Bellarby, 2009).

In short radius lateral drilling hole angles between 1.5" to 3" per foot are build. In long reach conventional directional drilling hole angles at 0.1" per foot maximum are build.

When engineers are planning a horizontal well they must consider that the formation permeability can vary widely depending on the flow direction. It is also influenced by the depositional environment, bedding planes, sediment sorting and size, geochemical reactions, fractures and sediment reworking.

There are many potential problems in horizontal wells, such us (King, 1998):

- Fluid exit control and entry control and stability of the wellbore as a system are challenged by a variety of reservoir properties.
- Sealing off the upper zones in the bending area when turning the well horizontally as a new well or as a recompletion.
- The shape of the hole through the turnout area is a problem for just setting the liners.
- Difficulties in tool passage when the departure area contains a dogleg from a missed drilling run or a combination angle which turns down and sideways at the same time.
- Logging tools with knuckle joints are needed.
- Losses of drilling mud from the hole to natural fracture systems in the near wellbore area.
- Cleaning horizontal holes from cuttings.
- Heading can be a serious problem when water is standing in the well.
- Across the whole wellbore, solids and liquids drop out quickly and flow may only moves in a portion of the wellbore, when the flow rate from the well is not sufficient to make turbulence.

Horizontal Well Completions are usually one or two times longer than conventional completions and they are significantly more expensive and complex considering the other production technology requirements, such as zonal isolation, sand control, selectivity for gas or water shut-off and stimulation operations which are correspondingly complex. There are three types of horizontal well completions:

1) Open hole barefoot completions (Figure 4.2).

Advantages

-Low cost.

-Large internal diameter.

Disadvantages

-Risk of hole collapse.

-Difficult to abandon.

-No sand control.

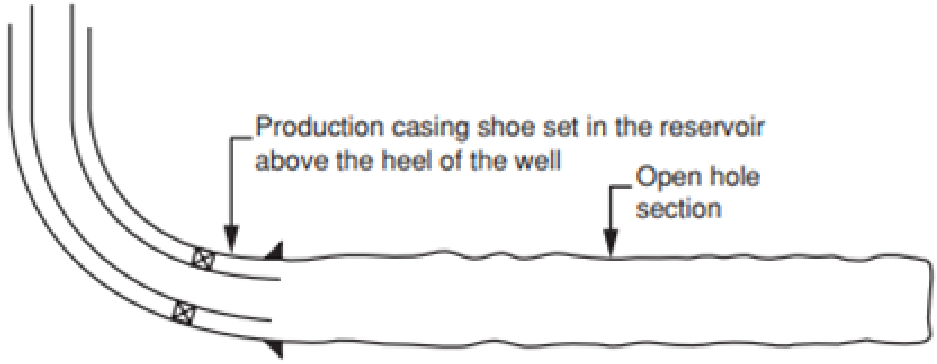

Fig.4.2 Open hole completion (Heriot Watt University, 2011).

2) Open hole liner completions (Figure 4.3).

Advantages

-Liner provides access for wireline or coiled tubing.

-Maintains access if hole collapses.

-Provides sand control of wire wrapped screen installed.

Disadvantages

-Isolation and selectivity problematic.

-Difficult to abandon.

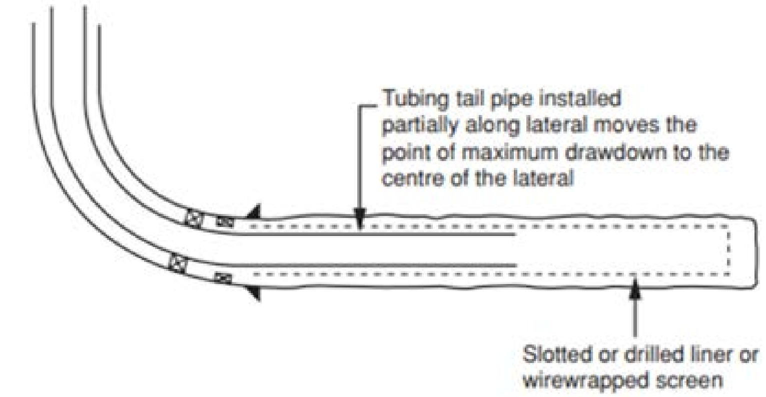

Fig.4.3 Open hole liner completion with (optional) extended tubing tailpipe (Heriot Watt University, 2011).

3) Cemented and cased completions (Figure 4.4).

<u>Advantages</u>

-Provides zonal isolation.

-Allows multiple hydraulic fracturing treatments.

-Can be completed as a "smart" well.

<u>Disadvantages</u>

-Higher cost.

-Achieving a good cement bond requires good practices.

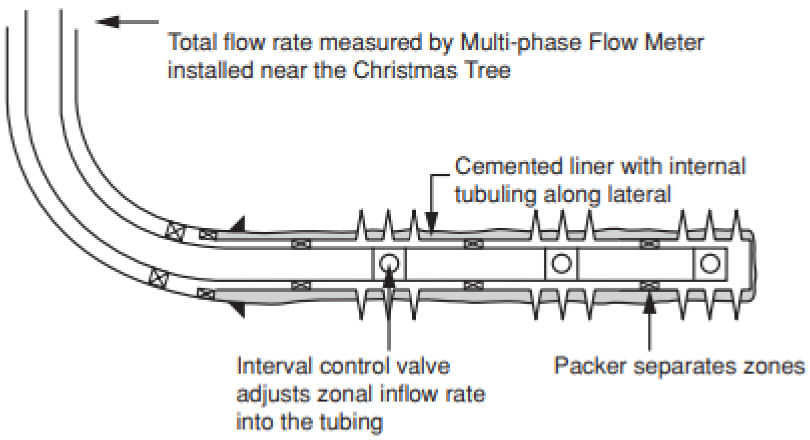

Fig.4.4 Selective completion divides the lateral into three zones (Heriot Watt University, 2011).

Horizontal well applications are summarized in the figure below (Figure 4.5).

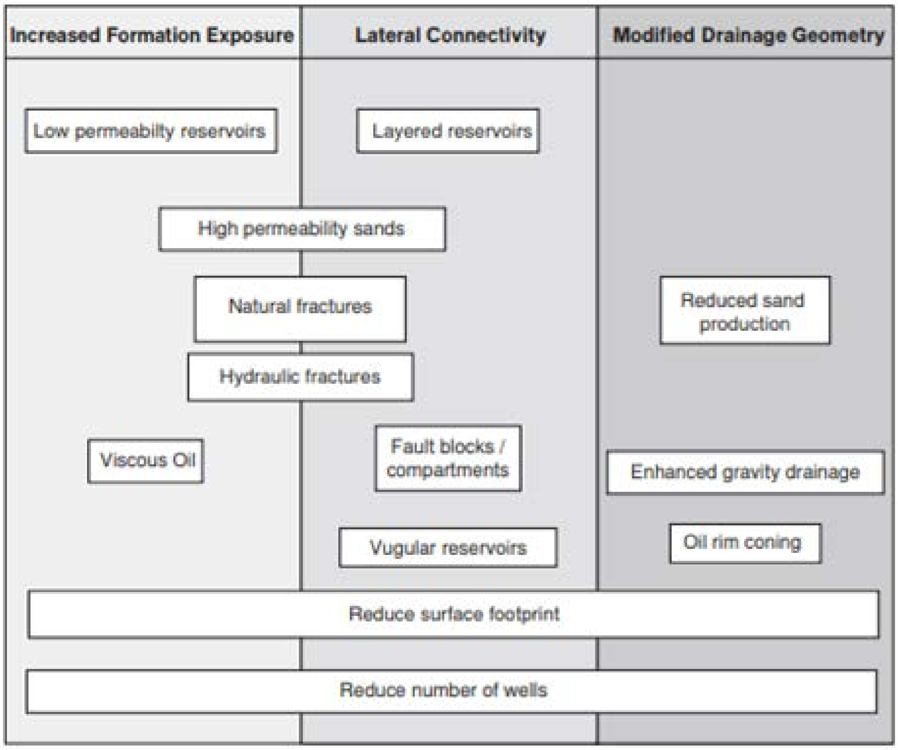

Fig.4.5 Horizontal well applications (Heriot Watt University, 2011).

4.2.2 Extended Reach Drilling (ERD)

Extended reach wells are extremely long and shallow vertically wells which have a horizontal displacement (HD) to True Vertical depth (TVD) ratio of at least 2:1 up to the current maximum of 13:1 (Figure 4.6). The value of this ratio depends on the Vertical Depth, the drilling conditions, the equipment and the technology capabilities (Heriot Watt University, 2011).

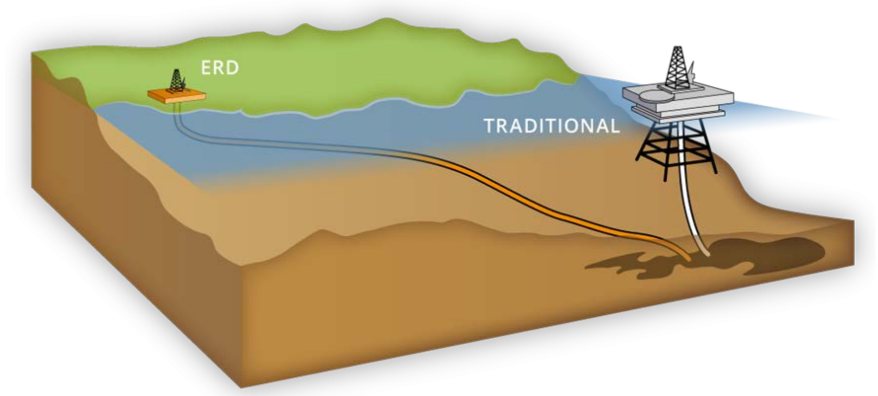

Fig.4.6 Example of Extended vs Traditional Reach well (Pngfuel, 2019).

Extended reach wells are used to distant reservoirs to decrease the infrastructure and operational footprint that would otherwise be required to access the resources.

The main constraints we must consider when we use extended reach wells are:

- The risks due to the increased length and complexity of each well.
- The limitations of the availability of appropriate drilling rigs.
- The higher investment per well.
- The completion limitations due to long distance of reservoir and the completion length within the reservoir.
- The flow monitoring and interventions unless we use "Smart Wells".

Although ERD are technically challenging and expensive, they can add value to drilling operations because they can make it possible to reduce costly subsea equipment and pipelines, develop near shore fields from onshore, use of satellite field development and reduce the environmental impact by developing fields from pads.

Multilateral completion system is analyzed in the following section because it is one of the main techniques that are used in Intelligent Completion systems with the Intelligent Well Completion (IWC) technology in order to isolate and monitor multiple wells and test and control each lateral well from one wellbore.

4.3 Overview of the Intelligent Wells

The first intelligent well appeared in the late 1980s. A down-hole temperature and pressure meter was run in, achieving reading out data at the surface and real time monitoring of the down-hole temperature and pressure of the oil well.

Next, intelligent wells appeared after the 1990s. This well could control the down-hole flow rate. Data of down-hole pressure, temperature and flow rate were acquired at the surface using an electric or hydraulic control system.

Since 2004, there were more than 130 intelligent wells worldwide. Furthermore, more than 200 wells had down-hole remote control devices by which down-hole gauges and tools can be controlled remotely from the surface and more data of reservoir production parameters can be acquired (Renpu, 2011).

Nowadays, the application of IWC (Intelligent Well Completion) technology has solved many problems in fields where Conventional Completions have been producing at rates significantly below potential values. IWC technology also responds to problems such as overlooked and discarded marginal reserves on the ground that the technology required for profitable exploitation has been expensive, elusive and unproven (Figure 4.7).

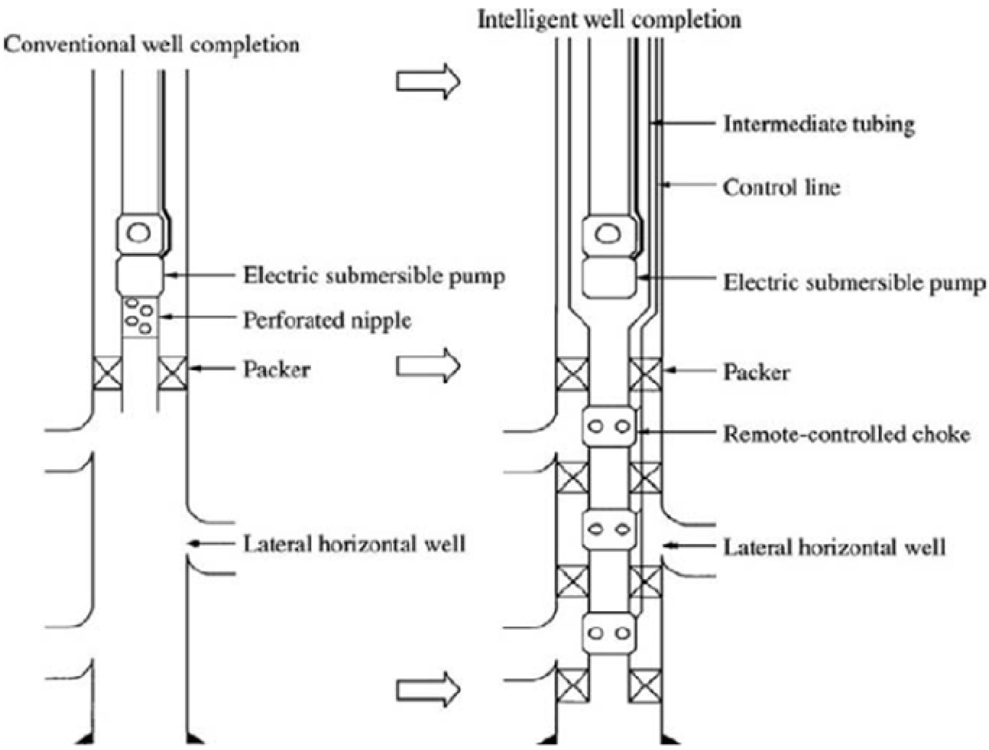

Fig.4.7 Hole structures of conventional and IWCs (Intelligent Well Completions) (Renpu, 2011).

An IWC (Intelligent Well Completion) system is a permanent system capable of collecting, transmitting, and analyzing wellbore production and reservoir and completion integrity data, and allowing remote action to better control well, reservoir and production processes. Intelligent Well Completion can be explained as the type of completion that is based on the strategy of using "real time" well monitoring and closed loop capability to increase the final recovery of reserves. This is achieved by running gauges down-hole to monitor "real time" data per zone in order to make proactive (preventive) rather than reactive (corrective) decisions. Thus, the recovery factor of gas and oil reservoirs can be enhanced, the times of down-hole operations can be decreased and the operating management of oil and gas field production can be optimized (Gao et al, 2007).

An intelligent well can be a multilateral (monitoring multiple wells), a single (monitoring multiple zones within a single well) or a commingled (monitoring multiple reservoirs or layers) well. It can be drilled horizontally, vertically or inclined.

Intelligent well completions are suitable for fields which have 2 or more reservoirs that could be produced simultaneously (often at different depths) but these reservoirs could have different fluid characteristics, petrophysical properties and/or different pressures. Because of the subdivision by some fluid units inside the same reservoir with different petrophysical properties, differential replacement occurs (some fluid units build up their pressure faster than others) when injecting fluids for pressure support or differential depletion occurs (some flow units deplete faster than others) during the production process. EOR (Enhanced Oil Recovery) strategies are among the most complicated, successful but expensive methods for maximizing final recovery of reserves. In these projects it is highly desirable to reduce costs.

Intelligent well completions (IWC) involve a combination of sealing elements and inflatable packers, Inflow Control Devices or Valves (ICD), and down-hole sensors (Figure 4.8, 4.9). The intelligent well completion (IWC) system consists mostly of the following components (Renpu, 2011):

1. Surface SCADA (supervisory control, alarm and data acquisition) system interface.
2. Down-hole control network.
3. Under water control network.
4. Removable, switchable and open degree adjustable down-hole tools.
5. Separate zone packers with bypass.
6. Down-hole sensors of temperature, pressure, flow rate, density and water cut.

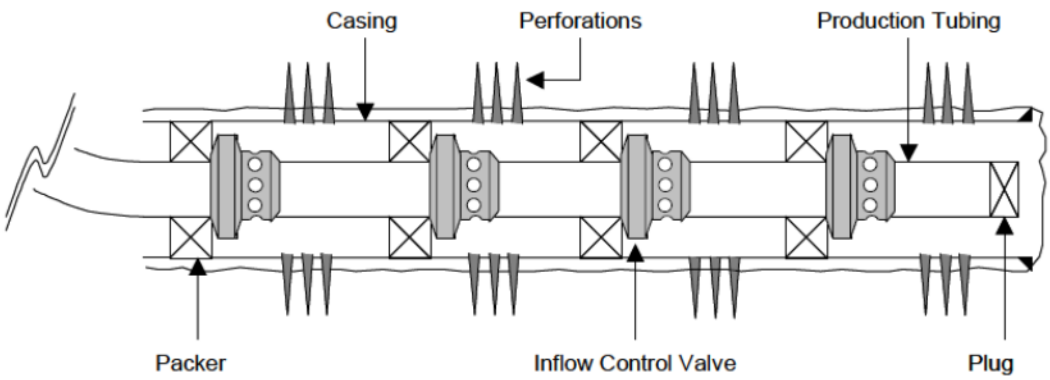

Fig.4.8 An Intelligent Well Completion System (Naus et. al, 2004).

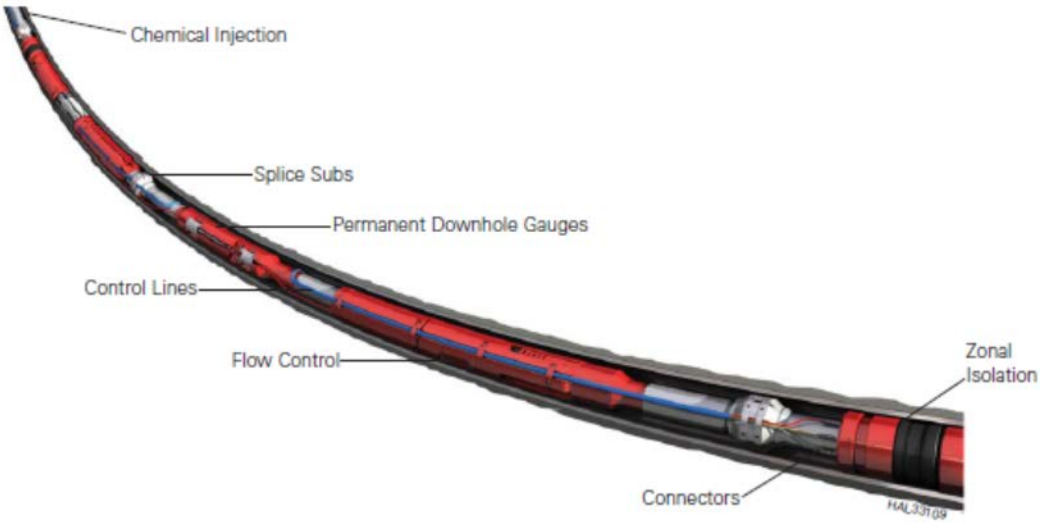

Fig.4.9 Intelligent Completion System Installation (Halliburton, 2019).

The main benefits of IWC application technology are (Tirado, 2010, Sun et al., 2009, Zhu & Furui, 2006, Chukwueke & Constantine, 2004, Arashi, 2008):

- Elimination or reduction of extra wells, intervention procedures and surface facilities.
- Reduced OPEX (Operational Expenses).
- Reduction in the water cut.
- Extend the life of wells and reserves.
- Maintain gas and oil production peak.

- Control cross flow elimination and Back Allocation of commingled production for economic exploitation of marginal reserves.
- Control valves can be activated remotely.
- Regulate injection rates, thus maximizing injection sweep efficiency.
- Replacement or Augmentation of Wireline services, particularly in inaccessible ERD (Extended Reach Drilling) wells.
- Reduce Non-productive Time and Rig down time.
- Reduce geological uncertainty by more accurate reservoir characterization.
- Measurement and transmission of reservoir properties in real time for better reservoir management.
- Reduce risk of personnel accidents, because of the reduced requirement for their presence on the well site.

The only disadvantage of IWC is that their cost is higher than that of the mechanical systems.

4.4 Intelligent Completions Assembly

4.4.1 Commingled flow

This is the flow when we produce through a single production conduit from two or more separate zones. This production has high economic benefits, especially in the profitable production of marginal fields.

In the majority of fields, wells cross more than one hydrocarbon bearing layers and the operator must decide if to apply commingling techniques or to produce each layer separately. In that case and when the conventional sequential production yields to a lower recovery factor and a poor production profile, the best choice is the application of IWC technology which solves these problems, eliminates intervention requirements and allows for shutting and opening each zone remotely from the surface control unit when it is needed (Reed et al, 2012, Konopczynski et al, 2003).

4.4.2 Multilateral Wells

Multilateral completion systems (Figure 4.10) are the systems that allow for drilling and completion of more than one wellbore within a single wellbore. Usually consists of three or four single open-hole laterals, each one acting as a single well, with variances in productivity and permeability from lateral to lateral. The number of laterals depends on the number of targets, risk analysis, depths/pressures and well-construction parameters.

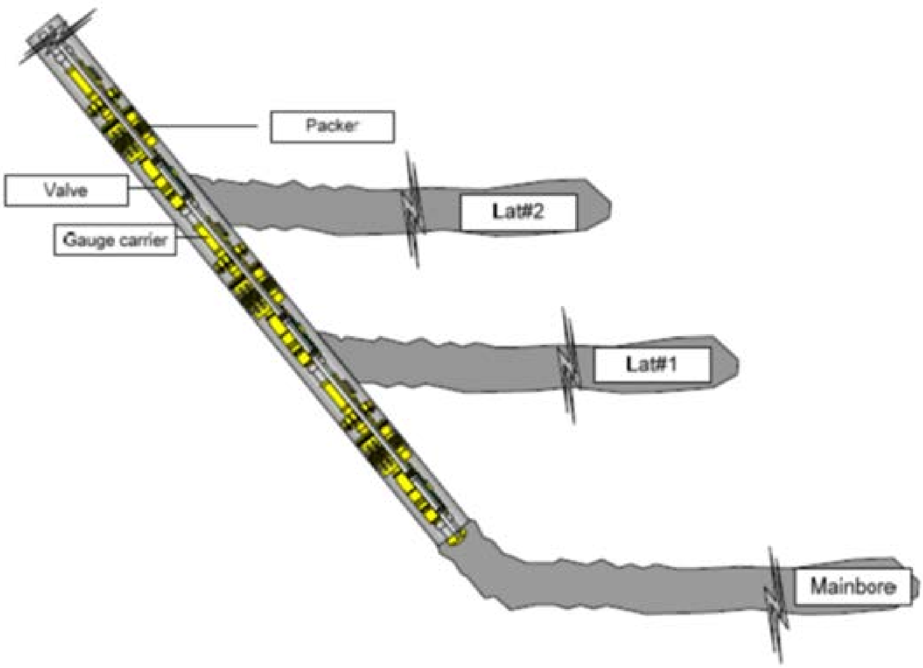

Fig.4.10 Multilateral well (Sun et al, 2009).

This type of completion is advantageous because it reduces the overall cost of hydrocarbon production on the ground that it allows accessing from a single surface, multiple reservoirs locations and improving reservoir drainage. The advantages also include higher production, decreased water and gas coning, the possibility of draining relatively thin formation layers, better sweep efficiencies and increased formation's exposure to natural fracture systems (Lake, 2007, Quereguan & Grossmann, 2011).

The application of Intelligent Well Completion (IWC) technology to multilateral wells gives the operators the ability to isolate, monitor, test and control each lateral from one wellbore and gives the engineers the ability to maintain peak in oil and gas production, extend the well's yield life and reduce or avoid water coning.

In 1997, the various degrees of multilateral systems have been categorized by the Technology Advancement of MultiLaterals (TAML) (Figure 4.11), establishing the six-tier classification. The Technology Advancement of MultiLaterals system for multilateral-well classification is based on the type and the amount of support provided at the lateral junction. This categorization is very helpful for operators because it simplifies the recognition and the comparison of the functionality and risk-to-reward estimations of one multilateral completion design to another. Higher TAML level means higher cost and complexity (Bellarby, 2009).

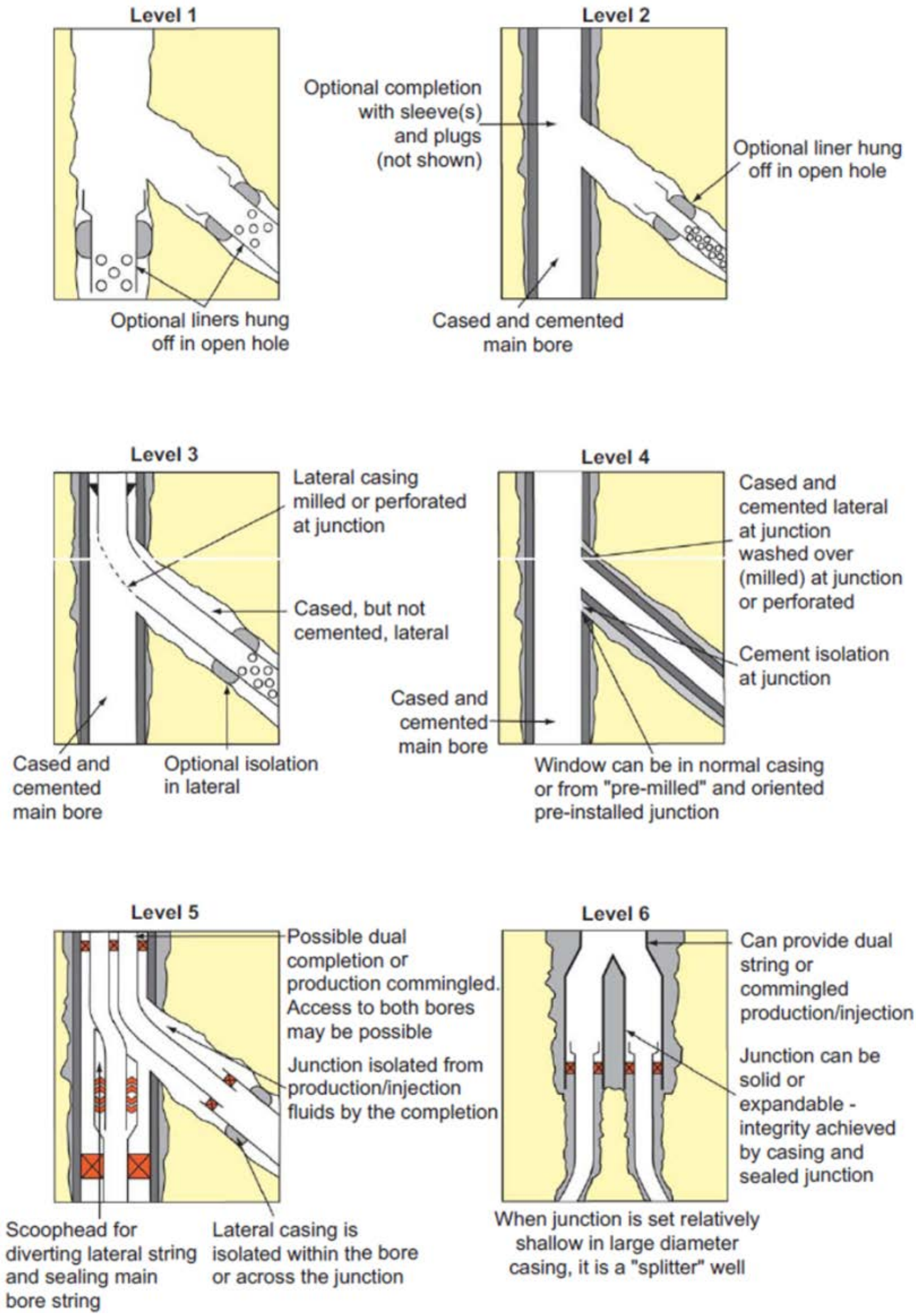

Fig.4.11 TAML multilateral classification system (Bellarby, 2009).

The six TAML levels are analyzed below (Lake, 2007):

TALM Level 1

This is the most fundamental multilateral system. It consists of an open hole main bore with multi drainage legs (Figure 4.12). The junction is with no hydraulic isolation or mechanical support, so the integrity is based on the natural borehole stability. In some cases in order to aid the hole to remain open during production a slotted liner is landed in the lateral or in the main bore. This level's production is commingled and the selective control or zonal isolation is not possible.

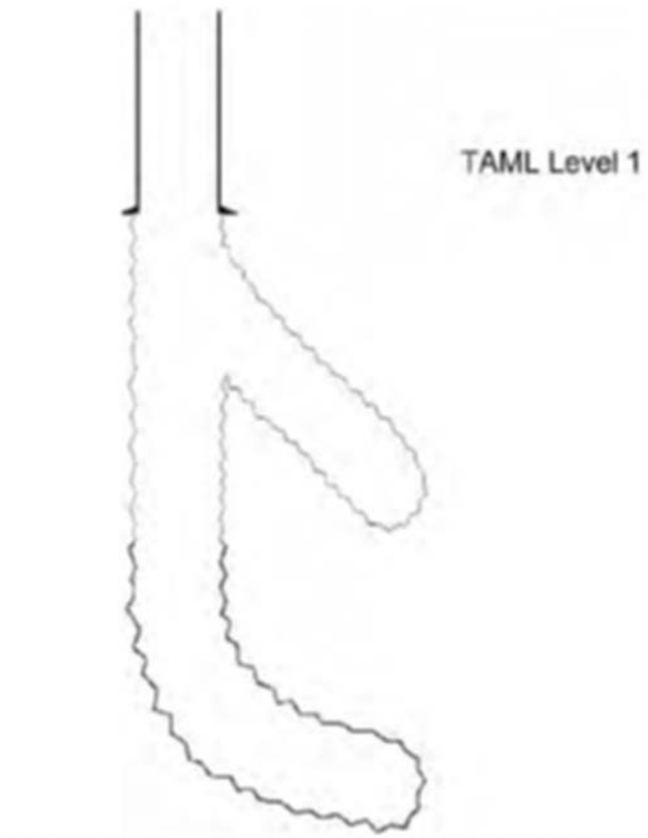

Fig.4.12 TAML Level 1 (Lake, 2007).

TAML Level 2

It is the same as TALM level 1 with one difference: The laterals are drilled off from a cased and cemented main bore (Figure 4.13), so that the chances of borehole collapse are minimized and also to provide hydraulic isolation between zones.

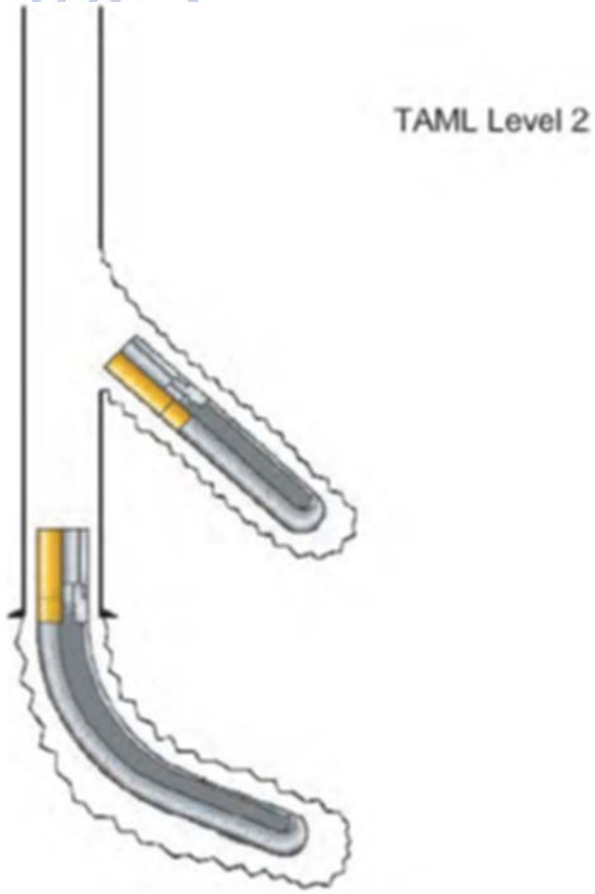

Fig.4.13 TAML Level 2 (Lake, 2007).

TAML Level 3

The TAML Level 3 system has a cased and cemented main bore with an openhole lateral like level 2, but it also has a screen or a slotted liner which is placed in the lateral branch and is anchored back into the main bore (Figure 4.14). With this system we have mechanical support but we don't have hydraulic isolation and the zones must be commingled. We cannot re-entry into the main bore below the junction. This type of well allows to easily access the lateral for coiled-tubing assemblies.

Fig.4.14 TAML Level 3 (Lake, 2007).

TAML Level 4

The TAML Level 4 system offers both a cased and a cemented main bore and lateral (Figure 4.15). This provides mechanical support to the lateral, but pressure integrity is not offered by cement at the junction. This is the reason why it cannot withstand more than a few hundred psi of differential pressure. We install packers above and below the junction in the main bore to provide zonal isolation and selectivity. These systems allow for coiled-tubing interventions, both into the main bore below the junction and as well as into the lateral.

Fig.4.15 TAML Level 4 (Lake, 2007).

TAML Level 5

This system is the same as to level 4 since both have a cased and cemented main bore and lateral, which gives mechanical integrity. In TALM level 5 system pressure integrity can be reached by using packers and tubing string to isolate the junction (Figure 4.16). We place single-string packers in the main bore and lateral below the junction and they are connected by the tubing string to a dual-string isolation packer which is located above the junction in the lateral and the main bore. We can produce each zone independently or commingled.

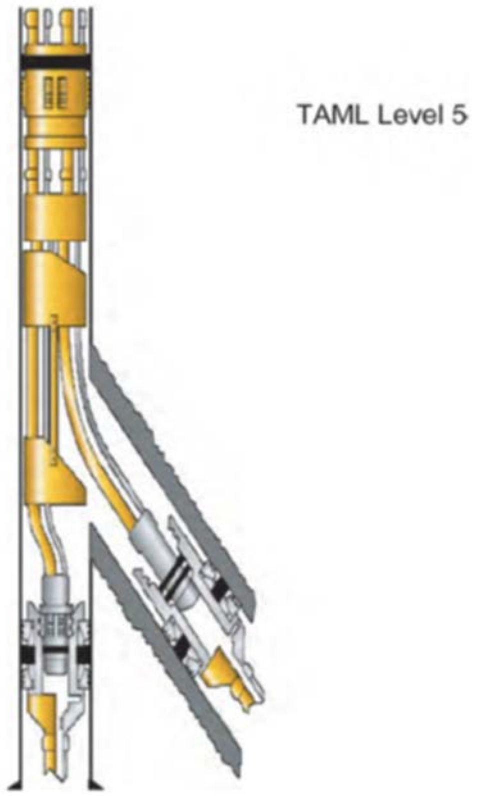

Fig.4.16 TAML Level 5 (Lake, 2007).

TAML Level 6

This system has pressure and mechanical integrity, using the casing to seal off the junction (Figure 4.17). This system employs a pre-manufactured junction: Either the junction is re-formed down hole, or two separate wells are drilled out of a single main bore and the pre-manufactured junction is assembled down hole.

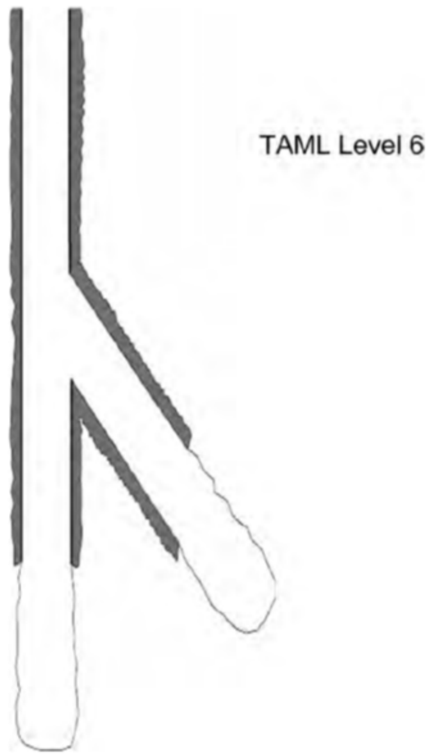

Fig.4.17 TAML Level 6 (Lake, 2007).

When we decide to use the multilateral system we must consider (Bellarby, 2009):

- The benefit vs. cost of a single well vs. a multilateral.
- If isolation from the formation is required at the junction.
- If the junction is positioned within the reservoir section or above, since if it is positioned in a sand production prone reservoir, the junction isolation with cement can be acceptable but adds risk, especially for the long-term.
- The hole size requirements, except of levels 1 and 6.
- The reservoir completion requirements.
- If production or injection fluid control from or into each lateral is required.
- If access to both branches is required.
- The way that the laterals are going to be constructed and if isolation of one branch before drilling another is required.

4.4.3 Layered Reservoirs and Horizontal Wells

A horizontal well has a higher production yield than a vertical well. We can apply Intelligent Well Completion to isolate sections of the wellbore and adjust fluid influx at each isolated section to obtain equal production. Intelligent Well Completion application is even more advantageous in ERD (Extended Reach Drilling). Extended Reach Drilling is an advanced technique that applies the concepts of horizontal and directional drilling to achieve horizontal well departures and reservoir contacts that exceed conventional directional drilling.

The degree of monitoring and control, however, depends strongly on the type of completion installed (ESP, cemented, screen, etc.). An IWC system provides temporary isolation of layers while surveys are performed. Furthermore, we can obtain zonal flow data constantly from individual sensors or by controlling the position of the interval control valves to alter or isolate the flow from specific layers (Figure 4.18) (Lake, 2007, Sun et al., 2011).

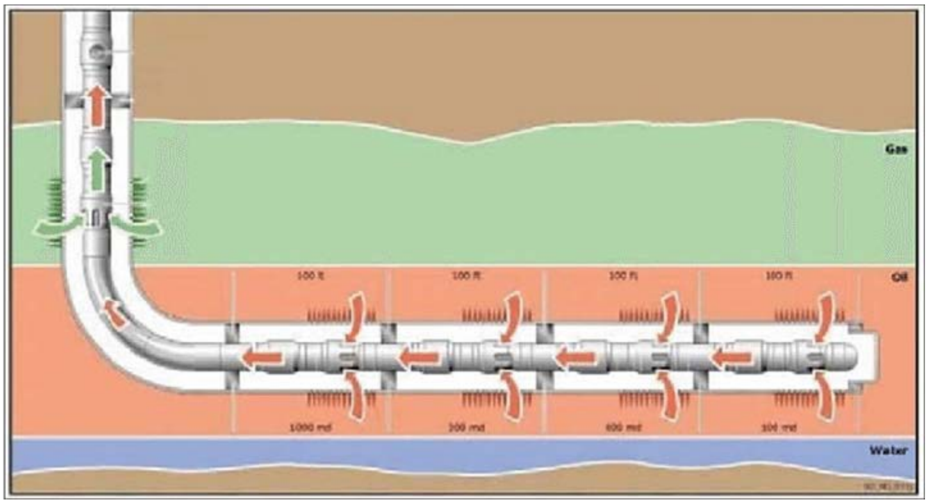

Fig.4.18 IWC Horizontal Well (Yousef, 2018).

Remote completion control provides zonal data with no additional operational cost and allows for remedial action to be taken rapidly in the form of choking, zonal isolation or treatment. This form of monitoring and immediately action and control increases recovery and production.

4.4.4 Inflow Control Devices (ICDs)

ICD or ICV (Inflow Control Devices or Inflow Control Valves) are considered as key equipment in IWCs (Figure 4.19, 4.20). They are surface controlled chokes that are applied to regulate and restrict production. Inflow Control Devices are commonly of two types, binary (open and close control) or variable (intermittent, stage-wise control). They create a pressure difference between the production string and the annulus to regulate flow at each zone, shutting off zones, and they can also be used to shut in a layer for Pressure Build Up operations. ICVs are more effective and accurate than sliding sleeves in choking flow application. We can determine the position and the type of Inflow Control Valve by applying Nodal analysis and reservoir simulations. ICDs can be operator controlled or automated. They can be operated electrically or hydraulically and they can be variable from open to close or may operate in multiple incremental steps (Cullick, 2010).

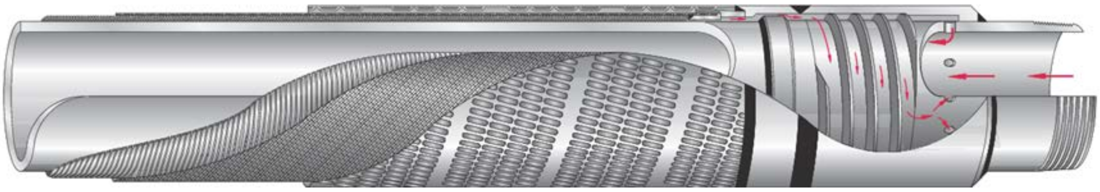

Fig.4.19 Inflow Control Device (Bellarby, 2009).

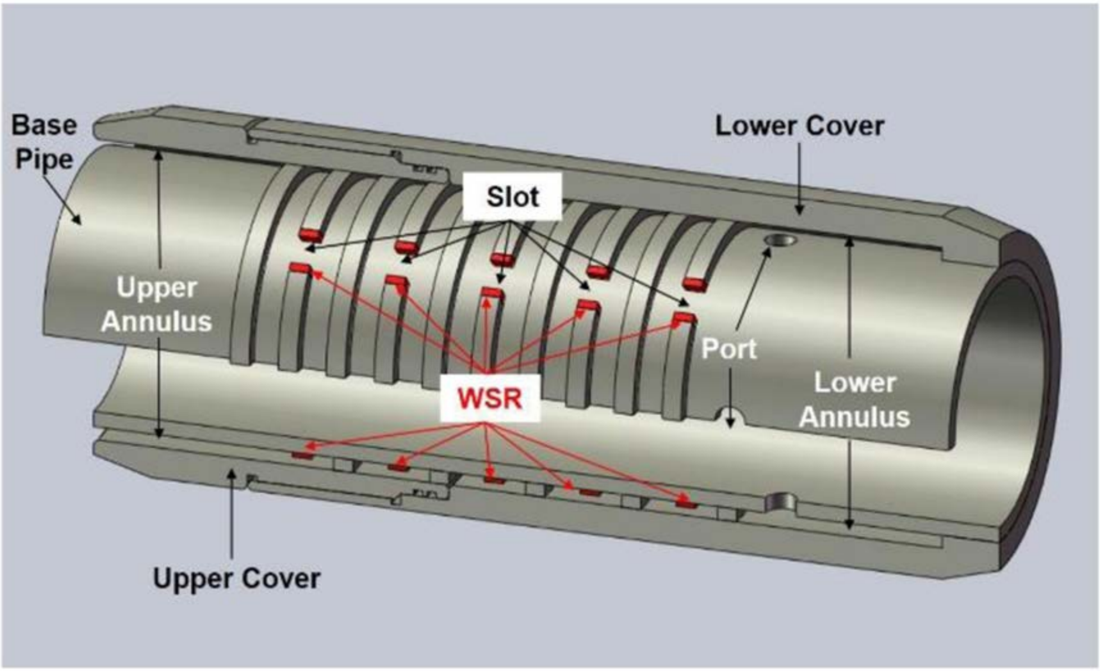

Fig.4.20 Structure Diagram of Novel Autonomous Inflow Control Device Design (Zeng, 2014)

4.4.5 Downhole Flow Control

Intelligent well completions with downhole flow control can be operated remotely from the surface. They are also equipped with multiple downhole gauges. Downhole flow control is particularly problematic with most types of sand control.

Remotely operated downhole flow control has additional cost and risks but the benefits are significant. Some of these benefits are (Bellarby, 2009):

- Remotely replacing through tubing interventions such as gas or water shut-off. This remote action of downhole valves is applied immediately without having to use intervention equipment or the rig.
- Improving the ability to clean up a well. For instance, the toe of a long, high-angle well can be selectively produced, hence provides a greater draw down and better clean up characteristics than a commingled producer.
- Reducing the cost and the risk of zonal isolation. This allows more active and regular reservoir management, thus could increase hydrocarbon reserves.
- Allowing zonal well testing by sequencing intervals open and closed.
- Giving many options for placement of chemicals (e.g. acids or inhibitors). For instance, selective acid stimulations can be performed or scale inhibitors deployed solely into intervals at risk of scaling.
- Increasing reservoir information. For instance, reservoir communication between zones can be assessed by shutting in one interval and flowing adjacent zones.
- Allowing intervals to be swing producers (alternating one interval with another).

The typical installation steps of a three-zone downhole flow control completion (Figure 4.21) are shown below as an example of a common downhole flow control installation in cased hole wells. These steps are the follows (Bellarby, 2009):

I. The liner is run and cemented. An efficient cement job is essential, especially between the intervals.
II. The well is displaced and cleaned to a fluid suitable for perforating in.
III. The well is perforated commonly with tubing conveyed guns. In some cases, the well can be perforated underbalance and flowed to surface for maximum productivity. For that it is needed a full well test spread for a subsea well. For a platform well, the well can be used as a temporary producer.

IV. The perforations are killed with a non-damaging, ideally solids free fluid such as a gel.

V. An optional clean-up trip is run to circulate out any remaining debris that could obstruct running the downhole flow control completion. The perforating process does not usually produce internal burrs so a polish mill should not be required.

VI. The single trip permanent completion is run and set.

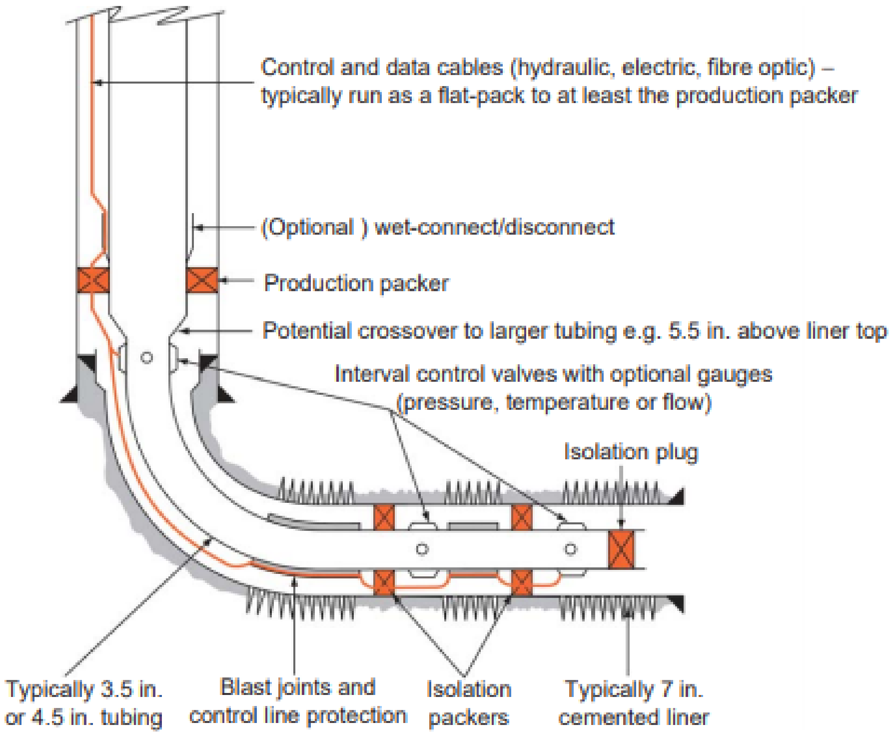

Fig.4.21 Typical downhole flow control in cased hole completion (Bellarby, 2009).

The main problem of downhole flow control operation is that must be run past perforations at least one packer. This fact requires that all or most of the perforations to be made prior to running the completion with resulting formation damage and well control concerns plus additional rig time to run, clean out, fire, and kill the perforations. In some cases it is used side-string perforating systems (Figure 4.22) (Bellarby, 2009).

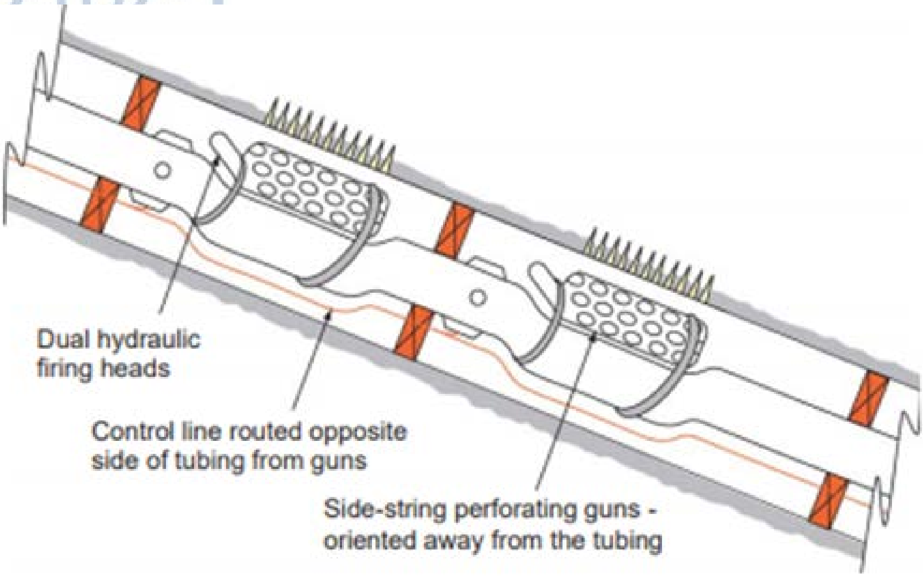

Fig.4.22 Downhole flow control with side-string perforating (Bellarby, 2009).

Side-string perforating guns reduce formation damage and rig time. Once the packers have been set, they can be fired hydraulically (dual firing heads) and in sequence (if required). If the guns are fired hydraulically, engineers must take care to avoid hydraulic lock when the packers are set. They can avoid hydraulic lock by setting the packers from the bottom up with the interval control valves open. For that it is required control line set packers. Side-string perforating has some disadvantages such as the reduced gun size that can be run beside the completion tubing and the eccentric nature of the perforations. Engineers can fire the guns either by firing all the intervals simultaneously (all the control valves open) or by selective firing, using the produced hydrocarbons to create an underbalance fluid, but closing the intervals already perforated. Downhole flow control is well suited to multilateral wells.

4.4.5.1 Downhole flow control in wells with sand control

For cased-hole gravel packs and frac packs, stacked packs can incorporate downhole flow control. The main disadvantage is the reduced sizes required for the screens, liner, tubing and control lines. This disadvantage can reduce the number of intervals to two (Figure 4.23).

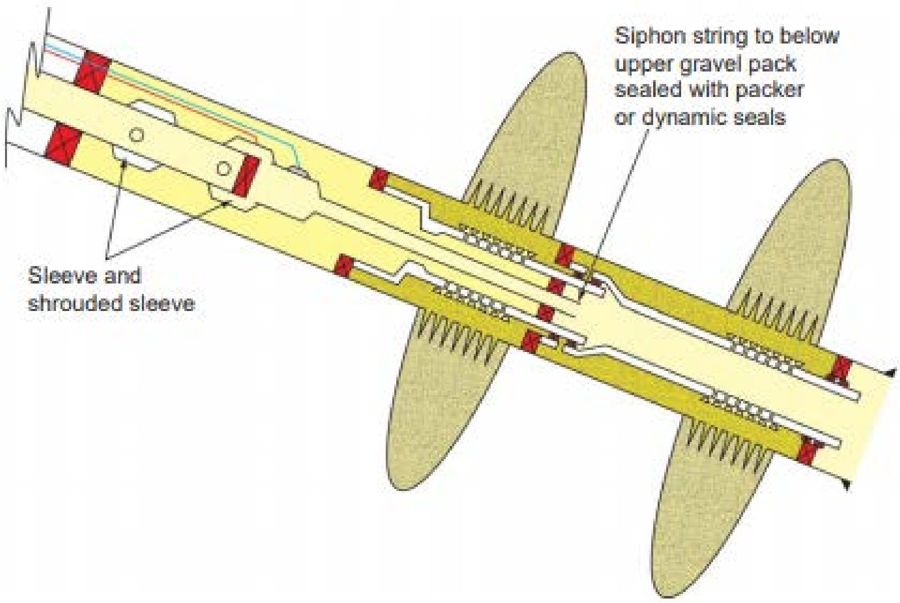

Fig.4.23 Stacked cased hole gravel packs with downhole flow control (Bellarby, 2009).

These restrictions of the size are the reason why the application of downhole flow control in areas such as the Gulf of Mexico, where cased hole gravel packs are common, is limited compared to other areas such as the North Sea, where the most wells are non-sand control and open hole completions.

The usual sizes of these completions are 9 5/8" casing with 5 or 5.5" base pipe screens with 3.5" siphon string. The interval control valves can be 4.5 or 5.5" inside the 9 5/8"casing. If alternate path gravel packing is not required, the base pipe screen size can be increased. An essential risk of these completions is that the upper completion has to be run with at least the upper gravel pack open. A formation isolation valve can keep the lower gravel pack isolated. Packers and large-diameter components are included in the upper completion. The multiple control lines can compound a well control problem. In order to reduce this problem, a further trip can be made with a packer, stinger and formation isolation valves. Both flow paths are isolated by formation isolation valves for running the upper completion. Then they are opened using pressure cycles with the valves (Figure 4.24).

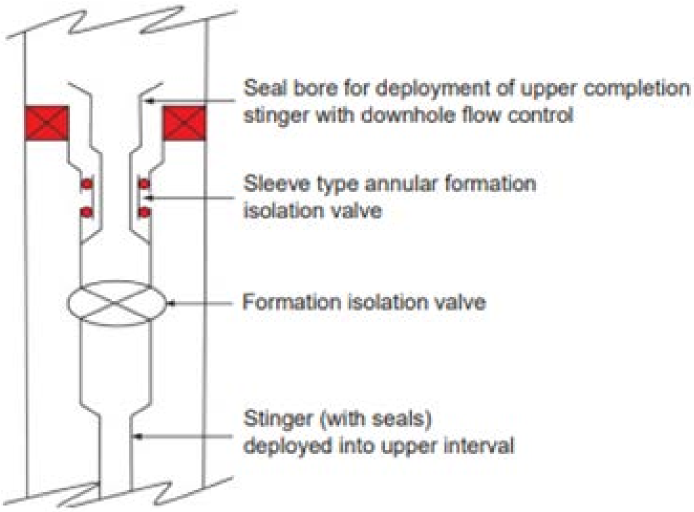

Fig.4.24 Formation isolation valves used in conjunction with downhole flow control (Bellarby, 2009).

These valves can be used in conjunction with or without sand control, with open or cased hole completions. Alternatively, engineers can apply multiple, pressure-actuated formation isolation valves as part of the base pipe of the screens or a downhole wet-connect and run the valves independent of the upper completion (Bellarby, 2009).

A wet-connect requires additional complications (e.g. for space and stress) and they are not very reliable. Screen type completions can use a solid base pipe screen and change the annular flow below or above the interval. Hence, there are no needs for a siphon or stinger. This allows a single trip completion for a cased hole gravel pack (interval control valves, screens and upper completion in one trip). To gravel pack the intervals, further trips are still required and close the gravel pack ports post packing. The figure below (Figure 4.25) shows an example of running multiple packers, screens, and the upper completion in a single trip.

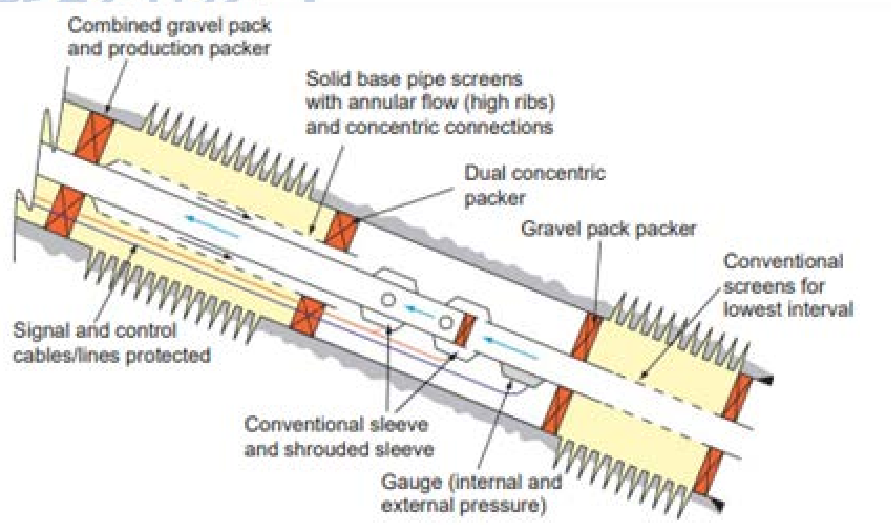

Fig.4.25 Downhole flow control with solid base pipe screens (Bellarby, 2009).

For open hole sand control completions, the options are almost the same as the cased hole. External casing packers or swell-able elastomer packers achieve isolation between intervals. Multiple interval control valves could be used to aid clean up and skew the flow distribution as required, where zonal isolation is not achieved (Figure 4.26).

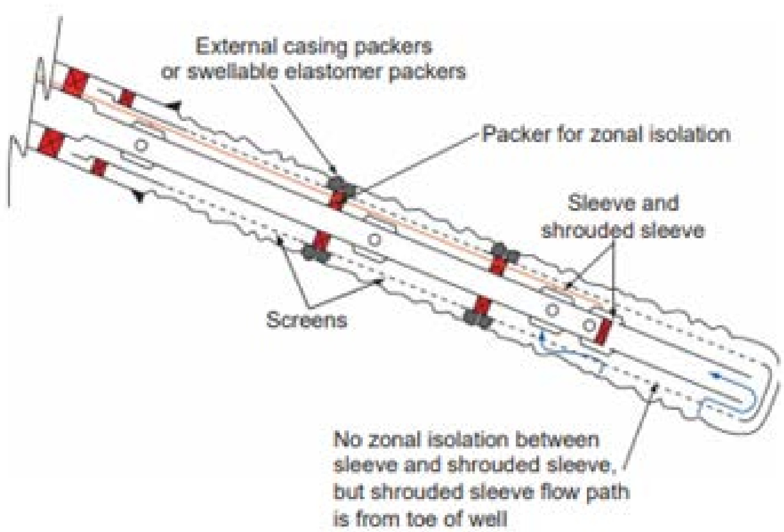

Fig.4.26 Downhole flow control with open hole sand control (Bellarby, 2009).

Swell-able elastomer or hydraulically set open hole packers are used with ‘Beta Breaker’ valves, which leave the annulus between the packer and open hole unpacked. Then the packers seal against the formation and provide the location for the stinger to seal or set in similar to Figure 4.26.

4.4.5.2 Valves and control systems

Valves can either be all-electric, electro-hydraulic or hydraulic. A sleeve type valve is used to control flow from the annulus to the tubing. A ball valve or shrouded sleeve can be used to control tubing flow. Engineers should choose, position and operate all types of valves to avoid problems such as wax, asphaltene, scale, and erosion. The common interval control valve is a directly controlled hydraulic valve (Figure 4.27). This valve can be positioned fully closed or fully open.

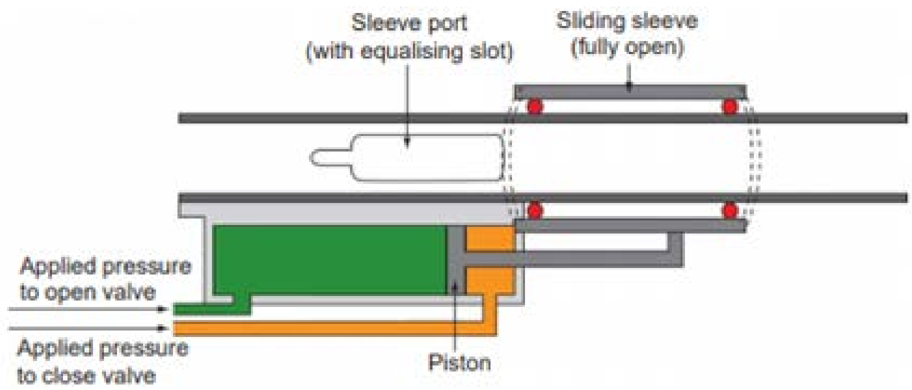

Fig.4.27 Directly controlled hydraulic sliding sleeve (Bellarby, 2009).

To open or close the sleeve it is required a differential pressure enough to overcome piston and sleeve friction. Scale, asphaltene or other downhole deposits may increase the required differential pressure but the force used to close or open the sleeve can be large, depending on the piston area. This may be sufficient to cut through these deposits, but is far from guaranteed. A hydraulic sleeve in the fully open and nearly closed position is shown in the figure below (Figure 4.28).

Fig.4.28 Hydraulically actuated sliding sleeves (Bellarby, 2009).

If the hydraulic system leaks and the valves cannot be operated remotely by the hydraulic system, many downhole flow control valves can be actuated by a landing nipple profile and either slick-line or coiled tubing. If the hydraulics are plugged, then hydraulic lock will prevent movement of the sleeve regardless of the amount of jarring. This is why two control lines are required to control one valve. It is usual to use a common line for multiple valves, commonly the 'pressure to close' control line. The figure below (Figure 4.29) shows four valves. If an engineer wants to open all the valves, then pressure is applied to the green, purple, blue and orange lines but not to the red line. If he wants to open valves two and four, but the other two left closed, then pressure is applied to the purple and orange lines, but not the green, blue or red lines. If he wants to close all the valves (to set packers or for pressure test), then the pressure is applied only to the red line.

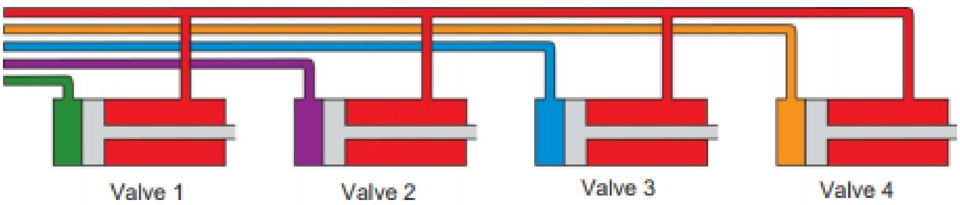

Fig.4.29 Multiple directly controlled hydraulic sliding sleeves (Bellarby, 2009).

Usually, the control lines are in surface or subsea control system. The boundary for the number of control lines is typically the tubing hanger. Running multiple control lines in a flat-pack is a little more complex than running a single hydraulic line. Flat-packs can contain bumper bars. It can be impossible to accommodate through the hanger and tree or wellhead the multiple hydraulic control lines for interval control lines, plus a gauge cable, chemical injection and the safety valve control lines. To reduce the number of control lines, there are available digital decoders. Digital decoders convert pressure signals applied down multiple control lines into applied pressure for a single valve. The figure below (Figure 4.30) shows an example of three control lines, which can control up to six on/off interval control valves.

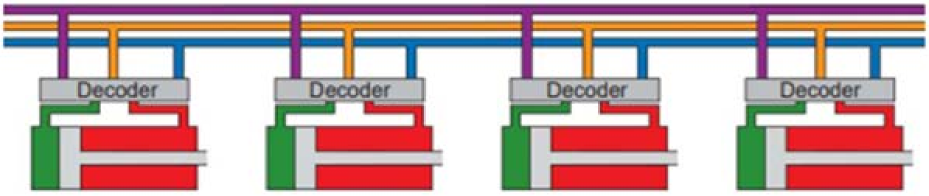

Fig.4.30 Using pressure sequences to control multiple hydraulic sliding sleeves (Bellarby, 2009).

Engineers can reduce the number of lines and increase the options for valve control and numbers by adding electric control to the completion. A single hydraulic line and a single electrical cable can be used to effectively control any number of valves, including multi-position valves. All-electric downhole flow control can be used in some applications and has the advantage of requiring only a single cable.

4.4.5.3 Control lines and control line protection

Electric cables and hydraulic control lines require protection. Downhole flow control lines and cables are exposed to aggressive and variable fluids, erosion and vibration. There are control line materials, such as metals and encapsulation, which are suitable for exposure to reservoir and intervention fluids. To reduce vibration, the encapsulation is critical. Typically, encapsulation is colour coded, keeping track of which colour cable corresponds to what function. No further protection is required when cables or lines are exposed to low-velocity fluids flowing parallel to the cable. When fluids flow directly through the tubing (e.g. adjacent to perforations) blast joints are recommended. They are important coupling stock in conventional tubing lengths. Blast joints can be modified to provide protection for the control and data lines. There are downhole flow control completions which do not require cables or lines adjacent to areas of inflow (Figure 4.22).

These control lines should be protected, when are adjacent to inflow. The methods to achieve this are two:

1. The first method uses an aligned connection with grooves and a cover plate (Figure 4.31). There are available plenty of proprietary aligned connections. Bolting the cover plates in place needs time and risks loose bolts falling downhole.

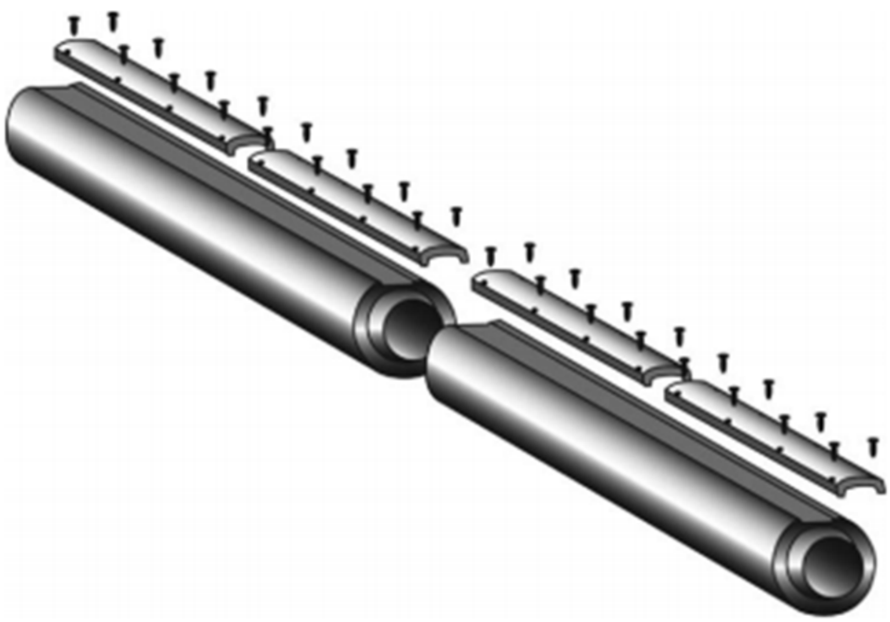

Fig.4.31 Example of aligned connections with cover plates (Bellarby, 2009).

2. The second method uses an independent cover plate that is held in place with cross-coupling protectors (Figure 4.32). Clearly, this method provides less protection, but is easier to install and procure. For control lines and cables adjacent to screens can be procured with an integral groove for the positioning of the control lines. Alternatively, it can be used a cover plate. Control lines should be protected whether in gravel packed or standalone screen environments.

Fig.4.32 Installing a control line protection plate (Bellarby, 2009).

4.4.5.4 Packers, disconnects, expansion joints and splice subs

The difference between downhole flow control packers and conventional production packers are:

- Downhole flow control packers require penetrations for multiple control lines.
- Downhole flow control packers are exposed to reservoir and intervention fluids below and above the packer. The packer should be resistant to any such intervention fluids.
- They require set when the tubing below the packer is not necessarily free to move.
- The packers can be exposed to loads from below the packers.

With electro-hydraulic systems or digital controllers hydraulic pressure can be diverted in a one-off operation, to set the packer. Control line connections should be made up and tested prior to transport to the wellsite. This is aided by the use of splice subs (Figure 4.33). Usually they are positioned above each packer. The splice sub provides a protected groove for the location of the control line connections.

Fig.4.33 Splice sub and hydraulic connector (Bellarby, 2009).

It is possible to connect above the packer, an expansion joint that includes control lines and cables wrapped in a shroud. They would be connected between the packer and any disconnect and the splice sub.

4.4.6 Downhole Sensors

Sensors used in Intelligent Well Completion are installed down-hole for the purpose of measuring parameters, such as: temperature, pressure, flow rate and seismic waves (Figure 4.34) (Naldrett & Ross, 2006). Downhole Sensors may be in the form of down-hole gauges or optical fibers. The measurements provided by the sensors provide data, which are interpreted to give the required information. Fiber optics systems have replaced electrical systems and present higher reliability and higher temperature capacity capable of efficient operation in difficult environments (Lake, 2007).

Control Device Performance

With downhole zonal flow-control device we can have full closure in one or two minutes or less, depending on the starting position, for build-up surveys to obtain build-up data and fast opening for drawdown analysis. Opening speeds can be reduced by sand-production considerations.

Fiber Optics

The fiber-optics system has been developed to provide direct conversion of down hole measurements into optical signals. It has effective immunity to temperature degradation. Development of resonating crystal optical pressure sensors produces a transducer that gives an optical output varying with pressure. Later developments in optical sensors have resulted in the down hole deployment of fiber Bragg-Grating sensors configured within transducers to measure flow, temperature, pressure and seismic data. Packaging and integration of optoelectronic conversion tools into electrohydraulic subsea-control infrastructures have been successfully completed and they can be considered mature (Lake, 2007).

Near-Wellbore Sensing

Electromagnetic resistivity arrays have been successfully deployed into wells for determination of fluid-front movement and monitoring near-wellbore effects. Integration of these sensors with automated sequencing of down hole control devices to give better water-flood control is now a short-term option (Lake, 2007).

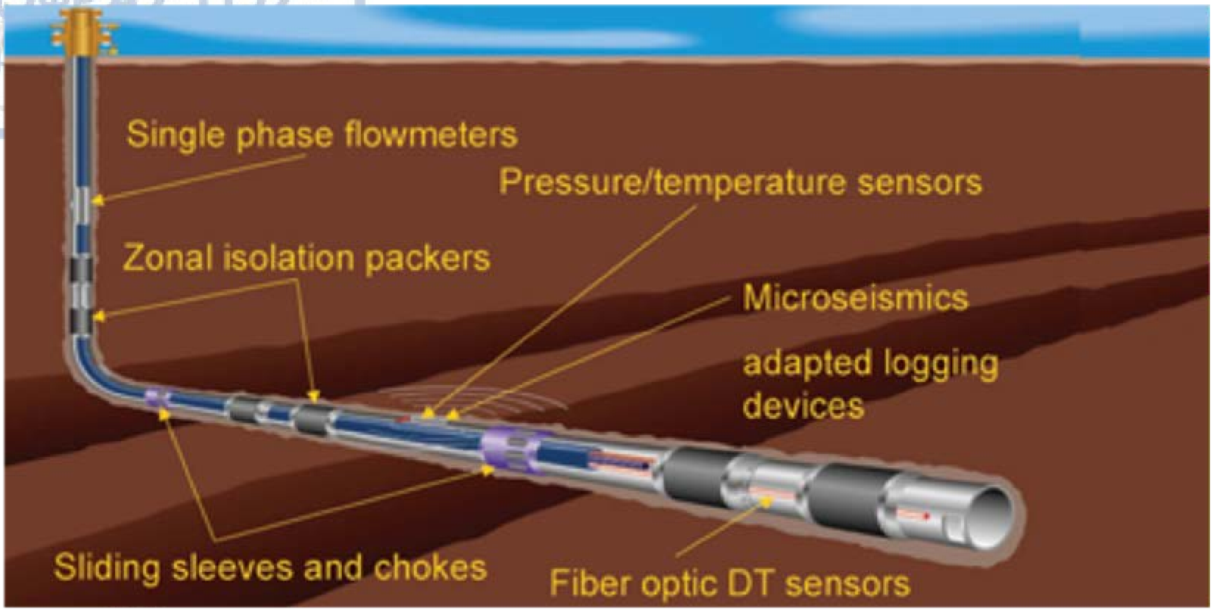

Fig.4.34 Intelligent Well Completion’s Sensors (Frontender, 2019).

4.5 Risks and Reliability

The demand for improvements and upgrades for more reliable intelligent well systems have been studied extensively. The researchers for this demand have mostly focused on the design phase, using techniques and tools to improve system longevity (Naldrett & Ross, 2006).

Some of the common risks in IWC include wellhead penetrator and cable/line failure, especially during installation. Longer-term system failures include erosion on cables which are exposed across producing ports and intervals and, temperature effects on electronics, wear and tear, and seizure of moving components. So a balance must be found between careful control of moving parts and ensuring that systems are regularly cycled to avoid seizure. Procedures and supporting control software must be developed to ensure optimum system use (Lake, 2007).

Based on reviews of past experiences, some of the challenges IWC are facing are:

- Uncertainty in the price of Oil and Gas.
- Requirements for substantial amount of rig time and expertise for the installation and testing of Intelligent Well Completion.
- Expensive adoption of IWC to mature fields.
- The challenge of choosing the right "People", employing the right "Process" and applying the right "Products".
- Lack of reservoir evaluation tools for effective modeling of the IWC components and expected operation.
- Identification of potential and suitable candidates for IWC.
- Reliability of down-hole sensors and valves.

4.6 Economics

To effectively rationalize the extra capital cost of Intelligent Well Completion installation, asset development teams are usually required. The rationale for cost effective Intelligent Well Completion application is subjective and can only be justified on a case by case basis. A cost effective operation does not always mean a lower cost. Reduced intervention cost savings will result from a successful system. Sometimes, Intelligent Well Completion is more expensive at the onset. This is compensated for by higher fluids production, reduced water cut and a limited necessity for future well intervention.

For subsea operations, a cheaper alternative to full rig intervention is provided by monohull vessels, but rising rig rates will also affect monohull charges. These costs are naturally increased for ultra-deep water developments. For platform wells, intervention cost is much lower, but this usually depends on the drilling sequence activity level, possibilities for concurrent access, seasonal effects, whether the installation is equipped with a rig and whether the installation is normally manned. In a study of a common North Sea oilfield, the major challenge with proper economic justification of Intelligent Well Completion applications is the unavailability of ideal modeling and software tools. These tools are needed to show to the management that there could be an increased and accelerated economic benefit by Intelligent Well Completion adoption.

In all cases, the economic benefits of IWC must be balanced against alternatives, which are mostly conventional completions operated with normal intervention techniques.

The figure below (Figure 4.35) demonstrates the relative values for different aspects of intelligent-completion application.

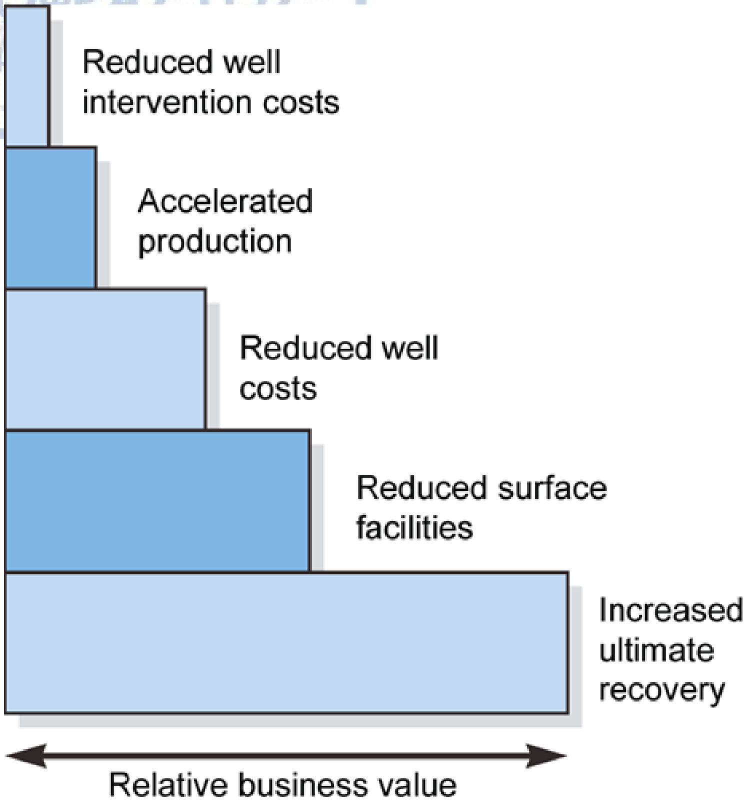

Fig.4.35 Intelligent Well Completion (IWC) relative business value (Shell Intl. Exploration and Production, Lake 2007).

Chapter 5: Conclusions

Through the years various types of processes have been applied to complete and produce hydrocarbons from reservoirs after drilling. Demand for processes which increase the recoverable reserves and reduce costs, because of interventions, has been increased. This fact has brought about the latest well completion technique which is the IWC (Intelligent Well Completion).

Intelligent well completion is an integrated package featuring complicated design and including control tools, inflow or conformance control devices, down-hole monitoring systems, and also control and emergency shut in systems. This comprehensive package enables automation and optimization of reservoirs or target developments at a local level, as well as standalone or remote control operations.

It is obvious that Intelligent Well Completion provides reliability and flexibility, but the most essential aspect of this technology is its ability to adapt to the changes of well conditions, either these changes are part of a planned reservoir exploitation strategy or an unplanned event. It must be noted that an Intelligent Well Completion is the key component of an exploitation strategy to maximize final recovery of reserves through maximum control, real time monitoring and closed loop capability. Finally, Intelligent Well Completion can help operators take the right decision at the right time by minimizing uncertainty levels.

To sum up the main advantages of Intelligent Well Completion system are:

- Well production can be enhanced.
- It is highly beneficial in Enhanced Oil Recovery (EOR) operations.
- It can automate as much of the production process as is achievable.
- It can maximize production and minimize costs.
- It can recover production from existing and future proved reserves.
- It provides monitoring and control.
- It can reduce water cut and diminish necessity for future well intervention.
- It can reduce or eliminate extra wells, surface facilities, and intervention procedures.
- It can reduce operational expenses (OPEX).
- It can maintain oil and gas production peak.
- It can extend the life of wells and reserves.

- It gives automate regulation of flow by downhole ICVs, controlled from remote locations.
- It can reduce geological uncertainty by higher reservoir characterization.
- It reduces non-productive time and rig down time.
- It gives real time measurement and transmission of reservoir properties for better reservoir management.
- It reduces risk of personnel accidents, since the requirement for their presence on the well site is reduced.

To sum up the main disadvantages of Intelligent Well Completion system are that:

- It is an expensive and complicated well procedure.
- Substantial amount of rig time and expertise is required for the installation and testing of IWC.
- Oil and gas prices are uncertain.
- It is difficult to find expertise employments for Intelligent Well Completion process.

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