Institute of GeoEnergy Engineering

School of Energy, Geoscience, Infrastructure and Society

G11PT

Production Technology: Lecture Notes

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Produced by Heriot-Watt University, 2023

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Production Technology G11PT

Acknowledgements

This material has a long history of being prepared, delivered and routinely updated by a big team of academics and graphics experts across the University for many years. We would like to acknowledge the assistance and contributions from colleagues in preparing this and support material. The latest version was prepared by Dr. Khafiz Muradov based on the notes by Prof. David Davies, Khafiz Muradov, et al., with the help of Drs. Morteza Haghighat Sefat, Ismail Labed, Jim Somerville, and many others.

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CHAPTER 1: WELL COMPLETIONS

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LEARNING OBJECTIVES

(All Examinable)

Having worked through this chapter the Student will be able to:

- Describe the basic well completion design principles and decision areas involved.
- Evaluate for a given reservoir scenario the bottom hole completion options and make a recommendation based on well integrity and reservoir management requirements.
- Identify, evaluate and recommend functional capability of completion strings for a variety of situations.
- Explain the principles of the tubing grade selection, and the calculations involved.
- Describe the purpose and generic operating principles for major completion equipment components.
- Assess well safety requirements and capabilities inherent in well design. Identify potential failure mechanisms/operational problems with equipment.
- Outline the basic logic behind the completion installation practices, and be able to propose a conceptual installation program for a given well completion.
- Describe the options, and their inherent constraints/advantages, for producing multiple reservoir units.
- Propose general completion options for producing two, three or more zones simultaneously.
- Assess and recommend geometrical configurations for drilled wellbores for both production and injection applications.
- Describe the application of horizontal wells.
- Describe the requirements for and operational principles of intelligent well completions.
- Evaluate for a given reservoir scenario the advanced well completion options and make a recommendation based on reservoir management requirements.
- Understand the basics of Multi-Lateral technology and list its applications.

1. INTRODUCTION

The development of a hydrocarbon reservoir requires wells to be drilled and completed to allow the structure to be depleted. The role of the production engineer in this context is to maximise oil and gas production (or water injection) from these wells in a safe, cost-effective manner. This includes well completion design, where the term 'completion' generally means the production or injection interface between the reservoir and surface: the way the well is constructed across the reservoir (a.k.a. bottomhole completion), as well as the tubing string transporting the fluids in the well (a.k.a. completion or production/injection string), etc. (See Figure 1)

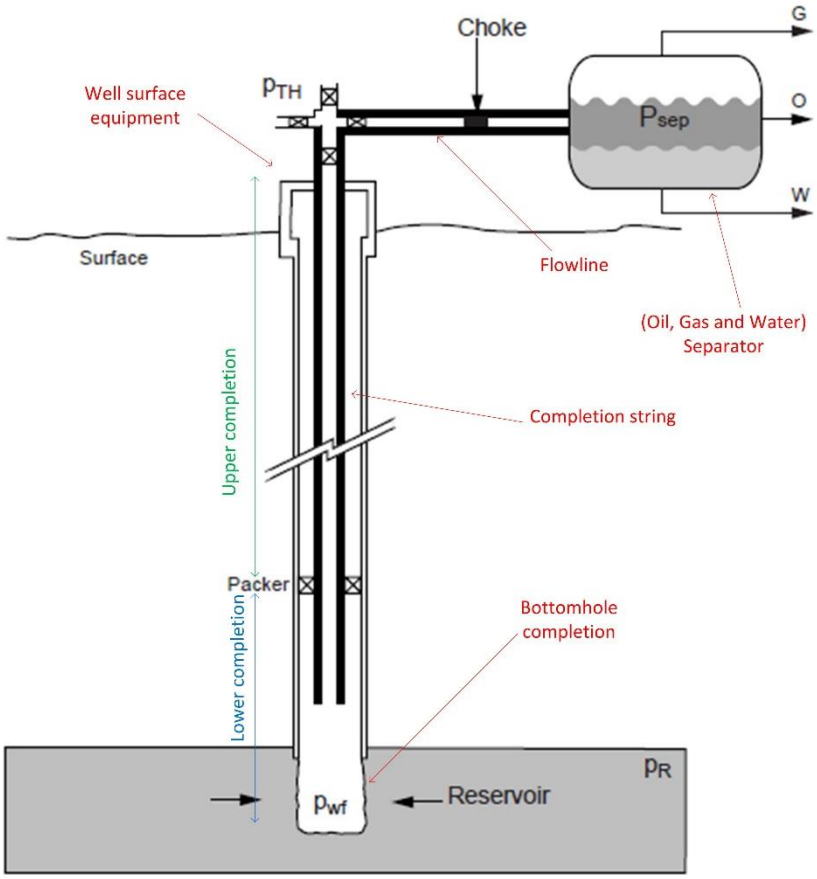


Figure 1: Production Well System

➢ *Feel free to attempt the 'Setting the scene' tutorial 1 at this point*

The design and completion of both production and injection wells must:

- Provide suitable production/injection performance.
- Ensure safety (which mostly means ensuring that both pressure and fluids are contained within the well system and do not escape in an uncontrolled manner).
- Maximise the integrity and reliability of the completion over the envisaged life of the completed well. (Envisaged life normally spans several decades, but can be much longer. In 2012, the oldest, still producing oil well was completed in 1861!). As a minimum, this often implies adherence to the standards (e.g. Norwegian NORSOK, American Petroleum Institute API, International ISO, etc.) and policies specified by the company or government agencies.
- Make it as cost-effective as possible, or more precisely minimise the total costs per unit volume of hydrocarbons produced which implies minimisation of the total costs of initial completion, as well as of maintaining production and remedial measures (the latter costs often prevail during the field life!). *Note*

how this does not mean constructing 'cheap' wells. Generally well construction costs vary in the range of millions of US dollars (on-land) to tens or hundreds of millions (offshore)).

- Other criteria for particular wells can be case-specific (e.g. control sand production) depending upon the particular reservoir characteristics or development constraints.

The completion design involves four principal decision areas that together provide a conceptual design (Figure 2):

- Specification of the bottom hole completion technique
- Selection of the production conduit in the wellbore
- Assessment of completion string design and the facilities/components (a.k.a. 'jewellery') it contains
- Evaluation of expected/desired well (flow) performance

The first three areas will be the subject of this chapter.

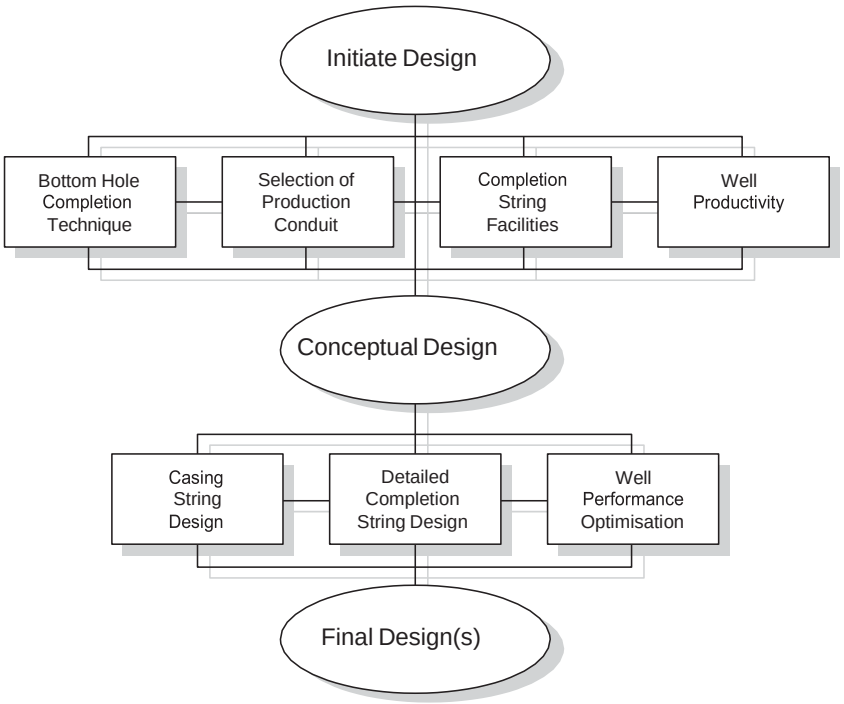


Figure 2: Completion design strategy

➢ *At this point feel free to relate the above decision areas to the well design objectives (also listed above) and discuss particular design decisions a completion engineer may face. You may revisit this once you have read this chapter.*

This conceptual design process is initiated on the basis of data from exploration wells, quite often well before the production/injection wells are drilled. Considerable uncertainty may exist as to the validity and accuracy of that data. Thus a number of alternative designs for well completions will normally be selected and contingency designs may be developed. The detailed design evaluation and costing of the selected completion concept will then be undertaken to specify and order all equipment and materials. Design adjustments are not uncommon once the well is drilled and tested, subject to the materials available on site.

It is essential that an interactive approach is adopted at both the conceptual and detailed design stages. This is necessary due to the diversity of design data, e.g. reservoir rock and fluid properties, production constraints, etc. and the range of disciplines which have inputs into the decision making process, e.g.

drilling engineers, reservoir engineers and production technologists. Such approach is becoming more common.

➢ *At this point feel free to select an arbitrary well design aspect, e.g. the production interval's wellbore diameter or trajectory, and discuss: input from what disciplines may be involved in designing it.*

2. BOTTOM HOLE COMPLETION TECHNIQUES

The oil or gas has to flow through the reservoir rock to reach the drainage location of individual wells and, in doing so, a loss in pressure will occur within the fluid. This ***reservoir pressure drop***, or, as it is sometimes called, the "***drawdown***", is principally dependent upon the reservoir rock and fluid characteristics.

At the junction between the reservoir and the individual wellbore, the fluid has to be able to leave the formation and enter the wellbore. A major completion decision has to be made as to the way in which fluid connectivity between the formation and the wellbore is to be provided. In some cases, where the drilled hole through the pay zone is used for production, the entire cylindrical surface area of the borehole is available for fluid entry from the reservoir. In other cases, after drilling the hole through the pay zone, the hole is lined (a.k.a. 'cased') with a steel tube known as casing/liner and a cement sheath installed by cementing between the drilled hole and the outer diameter of the casing to ensure wellbore stability and isolate the drilled-in formations. Then, since fluid connectivity will not exist, specific entry points (holes) for the reservoir fluid through the casing wall are provided by perforating. The number, location and characteristics of these perforations will influence the fluid flow and the associated pressure loss. The pressure drop generated by the perforations and other near wellbore completion equipment is known as the bottomhole ***completion pressure drop***.

Therefore, generally two major alternative approaches for the completion of the reservoir zones are:

- Open hole (OH) completion (which can optionally be equipped with a pre-perforated / slotted liner, Figure 5)
- Cased hole (CH), cemented and perforated completion.

Both of them can optionally further be equipped with e.g. a sandscreen, a smart (a.k.a. intelligent) completion, or a gravel pack completion.

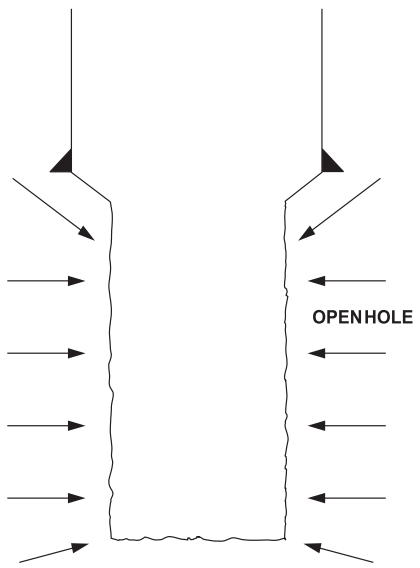
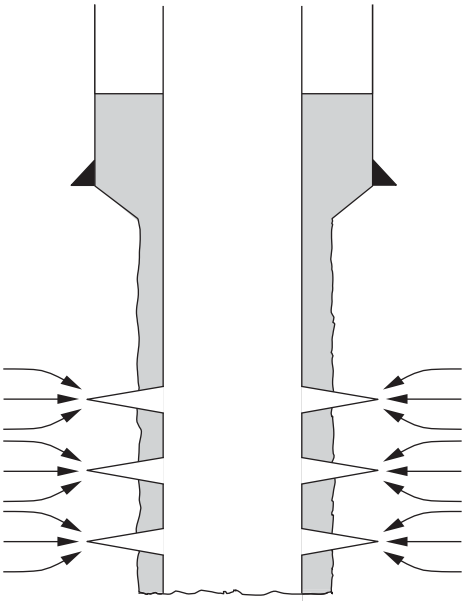


Figure 3: Open hole completion.



CEMENTED AND PERFORATED LINER OR CASING

Figure 4: Cemented and perforated production casing or liner.

2.1. OPEN HOLE COMPLETION

The simplest approach to bottom hole completion is to leave the entire drilled reservoir section open after drilling (Figure 3). Since no equipment requires to be installed there are savings in both costs and time. However, since the entire interval is open to production it does not provide selective control over fluid flow. Such control is important in the cases of early water breakthrough, water coning, etc. where the well essentially turns into a water production well while the oil sweep efficiency decreases. This lack of zonal control for production or injection is the major limitation on the application of this technique.

Another limitation is that the open hole completions can only be applied in consolidated formations as otherwise the borehole may become unstable. In such cases either total collapse of the formation or the excessive production of sand may occur.

Open hole completions often add value in naturally fractured, consolidated reservoirs (many of which are carbonate ones) in the cases where production from the fractures is beneficial. Open hole is also often a completion of choice in complex trajectory wells: e.g. horizontal or multilateral wells, - where it may be difficult to install other options.

Note that some modern completion equipment, e.g. smart completions or sandscreens equipped with OH swellable (elastomer) packers, can achieve some degree of zonal control in OH wells.

2.2. CEMENTED AND PERFORATED CASING/LINER

The more robust, yet more expensive, option is to install either a cemented casing (which extends back to surface, Figure 4) or a cemented liner (which extends back into the shoe of the previous casing string where it is suspended on a hanger). (Selective) perforating subsequently provides paths for fluid to flow to/from the wellbore and formation.

The integrity and selectivity of the completion depends on an effective hydraulic seal being provided in the casing-formation annulus by the cement placed during the primary cement job. The absence or failure of the cement can lead to either fluid migration behind the casing to surface, into another zone or

into perforations from which it was assumed to be isolated. It may be possible to regain annular isolation or close off unwanted perforations by a remedial cement squeeze operation.

Though costlier, this completion has the generally essential ability to control the depletion of individual zones, isolate the inflow of undesirable produced fluids and control the injection of fluids into zones. This is achieved by setting flow control or isolation equipment / plugs in such wells. This makes it the most widely applied bottom hole completion technique.

Expandable casing or liner can also be used though are much less common. Such casing of a softer steel grade can be mechanically or hydraulically enlarged to fit the wellbore wall (that additionally can be 'underreamed' to enlarge it with a special drill bit). Extra isolation can be achieved by adding elastomers to the outside wall. Such completion (including monobore wells) increases the wellbore diameter for improved mechanical access, wellbore stability, and flow throughput and can be beneficial in deep and/or long wells.

- *At this point feel free to compare the common completion techniques.*

2.3. OTHER TYPES OF BOTTOM HOLE COMPLETION

In many situations it is common to install additional equipment in either OH or CH bottomhole completions, including:

- slotted or pre-perforated liners in OH completions (Figure 5) to prevent major hole collapse or facilitate the passage of logging tools. Slotted liners (with very small, laser- or fine saw- cut slots) can also provide some degree of sand control by retaining some (large) sand particles on the outside.
- sandscreens (wire-wrapped, prepacked, premium, expandable, etc.) in OH and CH completions to prevent sand production into the wellbore and tubing more efficiently.
- gravel packs in OH and CH completions where the space between the sandscreen and formation is packed with special, pre-sorted sand (a.k.a. 'gravel') as a more efficient filter for the reservoir sand control.
- smart completions in OH or CH wells where the production/injection interval is zonated and the zonal flow is controlled (and sometimes monitored) in real-time by permanently installed, flow restriction devices.

Combinations of the above options (e.g smart completions with screens or base-pipe supported sandscreens) are also used. External casing packers or swellable packers can nowadays also be added to all the above options (subject to the installation risks) to enable zonal flow control.

More on several of these completion types can be found in other parts this course.

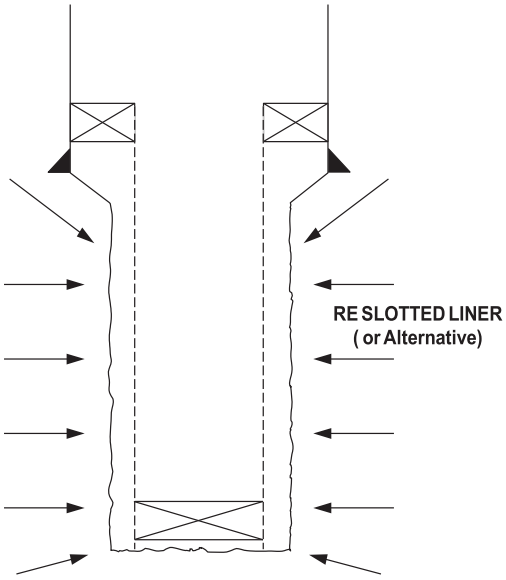


Figure 5 Well completed with a wire-wrapped screen or a slotted liner.

- *At this point feel free to propose a field production situation where you believe one completion option would be more advantageous than others, and provide reasons.*

3. SELECTION OF THE FLOW CONDUIT BETWEEN THE RESERVOIR AND SURFACE

There are several options for fluid flow to surface in a production well, or to the formation in an injection well. The considerations which may influence the choice include cost, flow stability, ability to control flow and assurance of well safety and integrity of the well by minimising casing corrosion or erosion.

In principle, the following alternatives exist for a single zone (upper) completion:

1. Tubingless casing flow (option 1 in Figure 6).
2. Tubing completion without packer, such as the casing and tubing flow case (2a). *Alternatively, the casing flow (i.e. the flow in the tubing-casing annulus) can be isolated at the wellhead (2b).*
3. Tubing-only flow with downhole annular isolation (option *3*).

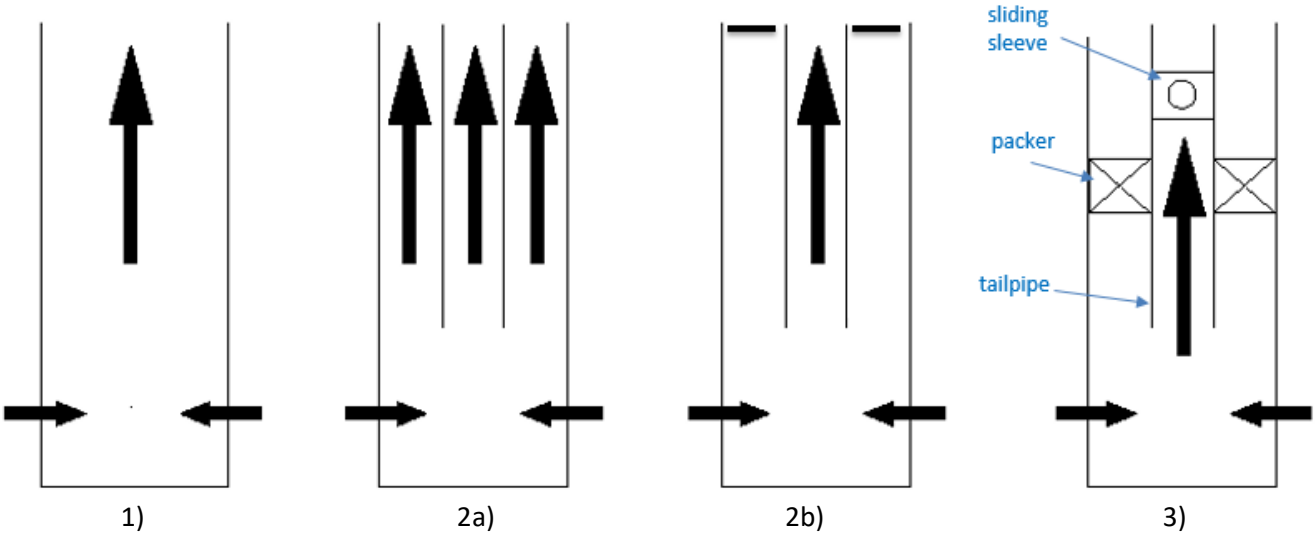


Figure 6: Alternative production conduits for a single zone.

It's easy to see that in the first two options (1 and *2*) the casing is exposed to the produced fluid, potentially resulting in casing corrosion, if H_2S or CO_2 are present in produced fluids (which they normally are) or casing erosion. Since the casing is cemented and is not replaceable, its repair may be problematic if not impossible, so the well production life may be significantly shortened. The other problem with these first two options is that some or all of the wellbore fluid should be squeezed into the formation when the well needs to be killed (i.e. filled with heavy fluid the weight of which will create bottomhole backpressure sufficient to stop inflow) during routine well workovers. This can severely damage the formation and reduce well productivity. Also, in the second '*alternative'* option 2b. i.e. the one with tubing-only flow because the annulus is closed at surface: the gas from the production fluid may start accumulating in the annulus, eventually expelling some portions of this gas into the tubing causing gas slugging (a.k.a. annulus heading) resulting in unstable, cyclic flow. For these reasons the third option, i.e. the tubing completion with downhole, annulus packer is most commonly used. *Note that the first two upper completion options can still be used in the situations where the above problems are minimal, or temporarily.*

The tubing string is normally long enough to end shortly above the top of the production/injection interval. It can be replaced when damaged. The packer is normally installed as close to the bottom of the tubing string as possible to minimise the casing exposure and the volume of trapped gas as explained above. A common packer is basically an elastomeric packing around the tubing pipe, expanded to isolate the annulus. The annulus above the packer is filled with non-corrosive 'packer' fluid (e.g. treated water, diesel, etc.). A short 'tail-' pipe may be suspended below the packer to improve flow and host some equipment close to the production interval, e.g. a plug preventing fluid flow into the formation during circulation. A circulation device (e.g. a sliding sleeve or door) needs to be installed closely above the packer. Such device can be opened by e.g. wireline to allow well kill/startup (or kick-off) circulation between the tubing and the annulus. *These components will be described and illustrated later in this chapter.*

- *At this point feel free to propose a well production situation where you believe one upper completion option would be more advantageous than others, and provide reasons. Discuss what information and conditions are generally needed to select an upper completion technique.*

4. COMPLETION STRING FACILITIES

The tubing (a.k.a. completion or production/injection) string, suspended on the tubing hanger from the wellhead, is made up of (steel pipe) joints few inches in diameter and each some 30 ft long. They are joined together with threads or couplings to form the tubing string of the required length: either precise (e.g. if the string has to fit between the given wellhead and pre-installed packer locations) with the length adjusted by shorter, 'pup' joints; or approximate when the packer is run into the hole integrally with the tubing string and can be set once the string is in place. The tubing string has to be designed for the well to achieve appropriate flow performance (or 'well deliverability') while also being able to reasonably resist corrosion and erosion (this affects selection of the steel grade) as well as to contain high pressure fluids and withstand expected stresses (this affects selection of the steel grade and pipe thickness, and the joint coupling type). Various devices (a.k.a. facilities or jewellery) can be integrated into the string the same way as the pipe joints.

There are many capabilities which can be included in the string design. Some of these capabilities are essential (e.g. a circulation device like a sliding sleeve when the packer is installed) such as those providing operational security or safety, whilst others (e.g. a pump) provide improved performance or flexibility. However, an increased degree of flexibility provided by the completion normally results in a complex completion design with a large number of components. Such inbuilt complexity compromises the reliability of the completion string. The design process should thus initially identify the minimum functional requirements. Any additional options are then assessed on the basis of incremental complexity versus incremental benefit.

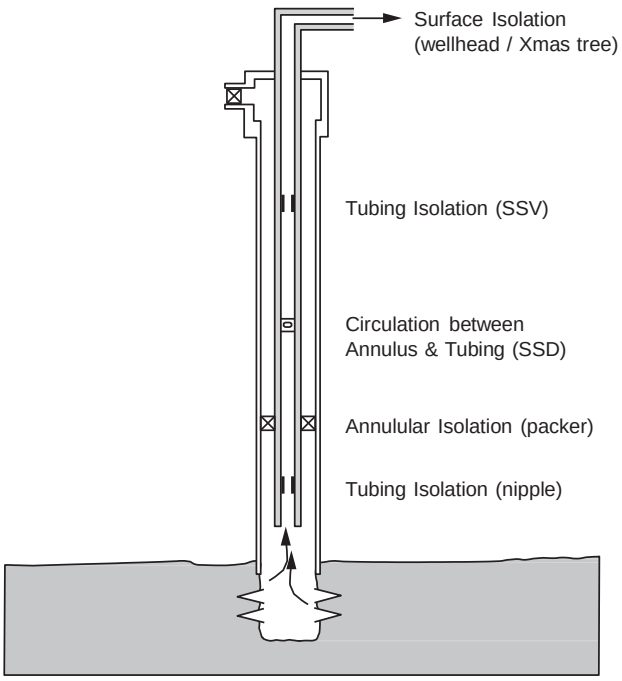


Figure 7 Basic well completion schematic.

4.1. BASIC COMPLETION STRING FUNCTIONS AND FACILITIES

The basic facilities provided by a completion string must allow it to continue the production or injection of fluids over as long a period as possible without the necessity of a major intervention to conduct well repairs. Further, the design must ensure safe operation of the well at all times and also reliably allow for its shutdown in a variety of situations. The completion string, production casing and wellhead must act as a composite high-pressure system which prevents the unintended escape of formation fluids and pressure i.e. all flow must be up the production tubing and the wellhead equipment (e.g. Christmas [a.k.a. 'Xmas' or production] Tree) into the surface processing facilities.

The following qualities are considered to be essential for the majority of completion string installations to allow the well to be produced in a safe and controlled manner:

(a) The ability to contain the expected flowing pressure as well as the highest hydraulic pressure which may be employed in well operations. Fluid should flow to surface (in production wells) or the reservoir (in injection wells) at the target rate with minimal flowing pressure loss and optimal flow stability.

(b) Minimum reservoir fluid contact with the production casing by isolating the annulus between the production casing and the tubing.

(c) The ability to perform downhole shut-in either by remote control or by automatic activation if there is a detrimental change in the well's flowing conditions, or an emergency.

(d) A means to establish circulation between the annulus and the tubing.

(e) The ability to block the tubing by installing of a plug. This allows pressure testing of the tubing etc.

- *Think of the situations when extra capabilities are required.*

The above allows the completion string to produce in a safe, controllable manner. The tubing string design aspects related to the above, essential facilities are briefly described below. These aspects include tubing functions, material selection and stress analysis, as well as basic well components.

4.2. PRODUCTION OR INJECTION TUBING

The integrity of the tubing is vital to the safe operation of a production or injection well. The specification of a production tubing must be carried out based upon the mechanical and hydraulic operating conditions envisaged, the proposed operating environment and "life of well" considerations. The tubing must be specified to provide the following capabilities:

(1) The inside diameter of the tubing must provide suitable well production or injection flow rate with acceptably small pressure loss (the tubing performance relationship).

(2) The tensile strength of the string (both for tubing joints and couplings) must be high enough to allow suspension of the complete string load without tensile failure.

(3) The completion string must be able to withstand the maximum conceivable internal (or burst) or external (or collapse) pressure. Additional effects like tubing bending in deviated wellbores, buckling between fixed tubing points (e.g. between the packer and wellhead) due to e.g. thermal expansion; cyclic movement ('breathing') due to e.g. periodic fluid pumping, etc. must be accounted for if expected.

(4) The tubing must be resistant to corrosion which may arise because of fluid contact in the wellbore. Such corrosion, especially localised (e.g. typical cases of point or pitting corrosion) might also ultimately accelerate string failure by one of the loads and stresses mentioned above.

Each of the above aspects of tubing selection are discussed below.

4.2.1 TUBING DIAMETER

Conventionally the (average) outside diameter (OD) of the tubing is specified. The inside diameter is often derived by using the specified, average wall thickness of steel via the tubing's "weight per foot" (lbs/ft) e.g. [5½" OD tubing 23 lbs/ft]. It is then easy to recalculate the weight into thickness, or look up the corresponding thickness from a tubing specifications handbook/database. The tubing's weight specification makes it easy to calculate the tubing string's weights and loads.

The wall thickness will influence the tensile strength of the steel, as well as its resistance to failure under high internal (burst) or external (collapse) pressure differentials [P_{inside_tubing} - $P_{outside_tubing}$].

A curious fact: the joints with the diameter of 5 ½ in. and bigger were mostly used as casing in the past, whereas nowadays in high production wells they are often used as tubing joints while still sometimes termed as 'casing'.

4.2.2 TUBING STRESSES

Each joint of tubing will suspend the tubing string below it, so the top joints may be suspending thousands of feet of tubing or tens of tons of load. The maximum allowable tensile load of a joint of tubing increases with the tensile strength of the steel and with the wall thickness of the tubing (or the "plain end area"). *For this reason it is not uncommon to use 'tapered' tubing string designs where wider/thicker tubing joints are installed at the top, and (progressively) smaller at the bottom, subject to the subsequent tool access and flow performance requirements.*

There are several standard grades of steel, including H-40, J-55, C-75, L-80, N-80 and P-105. The numbers after the letter grading signify the yield strength in units of a thousand psi, which is close to the maximum force per unit area at which the pipe deformation is normally allowed since it is still elastic. The letter grades indicate the manufacturing process, subsequent treatment, or additives (in alloys) of the steel to modify its properties, e.g. the C and L grades are heat treated.

Essentially, the grade defines the steel's strength as well as resistance to corrosion. More corrosion-resistant steels are normally (much) more expensive. Also, in general, the higher the yield strength created by working the steel, the more susceptible it is to corrosion, so a careful compromise between the strength, cost, and corrosion resistance must be selected. The steel specifications may be further varied along the

tubing string length, e.g. in the tapered design as explained above, or varying steel grade to have the corrosion-resistant joints only in the depth intervals where the high-level corrosion conditions are expected. Careful transportation and installation of the tubing joins and couplings is also important: rust, scratches and deformations notably increase the risk of tubing failure.

In addition to the tensile stresses, it is important to consider the pressure differential between the tubing (internal) and annulus (external) pressures, since the (much) higher internal pressure can potentially result in the tubing burst, while the (much) higher external pressure may result in the tubing collapse. Either way this pressure differential, along with the tensile stress, will affect the total stress field acting on the tubing. Note that similar to the tensile stress, the tubing-annulus pressure differential also changes with depth (e.g. at the top of the tubing producing gas the internal pressure is likely to be much higher than the external pressure in the annulus filled with packer fluid. This situation is likely to be opposite at the bottom of this tubing string).

- *At this point think of several production and completion scenarios (e.g. a gas production well with the tubing string anchored (fixed) at the packer location; or a water injection well) and discuss how the tubing tensile stress and the internal and external pressure profiles may look like. Where are the areas most prone to tensile failure, collapse, burst? Also discuss the possible temperature profile and how this may affect the stresses.*

Tubing stress analysis is often essential in the well completion design to ensure the tubing will withstand all the expected loads. Sometimes the analysis may be omitted if e.g. a proven, 'photocopy' design is used for multiple wells in a field, or the well conditions are expected mild at all times, etc. Tubing stress analysis is performed using numerical (software) or analytical calculations for a variety of possible, extreme, well flow scenarios (at realistic temperatures) expected in a given well: e.g. well production, well shut-in, evacuated tubing, gas lifted production, tubing leak, accidental packer un-setting, tubing drag during installation/pull-out, injection of hydraulic fracturing fluid, tubing buckling, pressure test, annular pressure buildup (APB) due to e.g. thermal expansion of the confined packer fluid, etc. The required tubing metallurgy yield proposed by the stress analysis is often increased by safety factors varying from 1.0 to 2.0 depending on the standards for the given stress type: tensile, collapse, burst, etc. Temperature corrections to the expected yield are also normally applied.

A side note: specialist tubing designs are also available, e.g. thermally insulated or Vacuum Insulated Tubing (VIT) where the tubing is composed of two concentric pipes with vacuum in between for better thermal insulation (the same principle as for thermal cups and thermoses). This may be important in the cases like steam injection, wells in permafrost, production in the wells with 'flow assurance' issues like a risk of high wax or hydrates deposition rates at low temperatures, etc.

4.2.3 TUBING STRESS ANALYSIS

Apart from running tubing stress analysis to select the right tubing size and grade, it can be used to assess the risks of running it in/out or accessing it, as well as to assess loads on various other completion string components: wellhead, packers, seals, etc. This is also important to ensure the packers can be set at a design location, the seals stay intact, the tubing string is not locked up in place due to drag or bends, etc.

Current software tools allow the complete calculation of the profile of tri-axial (i.e. 3D, see Figure 8) stresses acting on the tubing and string components, even including the geometry effects like tubing bending, buckling, ballooning, etc.

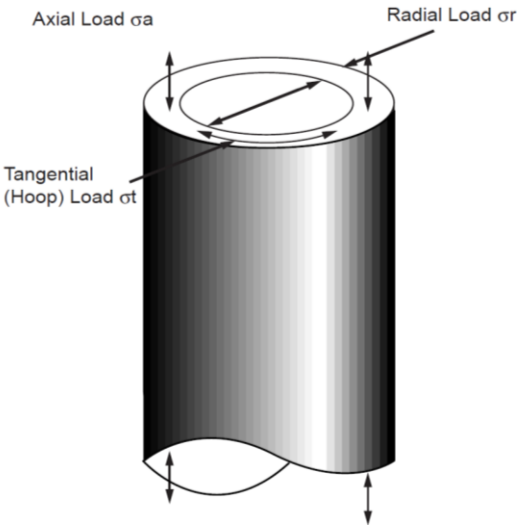


Figure 8: Tri-axial loads

The basic understanding of the loads calculation is illustrated below by some simplified problems.

Consider a tubing string suspended from a tubing hanger in a vertical, brine-filled wellbore.

- The weight of the tubing causes the tensile, axial load linearly decreasing downward as a product of the tubing (specific) weight and suspended length.
- The piston (buoyancy) force in the brine will relieve some of this load by causing a (smaller) force acting upward on the tubing edge from below, equal to the product of the wellbore pressure at the bottom of the tubing and the average cross-sectional area of the tubing. *For this reason this force also acts on the tubing at the depths where its average diameter changes: e.g. on tubing cross-overs (i.e. tubing joints changing the diameter between sides in e.g. tapered wells), packers, anchors (i.e. tubing string components used to fix the tubing string to the casing at a defined depth without sealing the annulus), seal assemblies, etc. This force may even be high enough to e.g. get a packer unseated or move a seal.*

As mentioned, inclusion of multi-dimensional stresses makes the problem more difficult. For instance, consider a routine, tubing pressure test where a plug is set in the tubing and the tubing pressure above the plug is increased. (Meantime the annular pressure is measured: its response (buildup) to the tubing pressure rise means there is a tubing leak.) There is now an extra, downward load acting on the tubing due to the high pressure acting on the plug from above, while also high internal (or burst) pressure in the tubing causing its expansion (ballooning). This (radial) ballooning along with the (axial) tensile stresses move the tubing load into the burst-tension, 2D stress regime. The tubing 2D strength envelope should be designed to withstand such scenarios. An example of the tri-axial loading ellipse is shown in Figure 9.

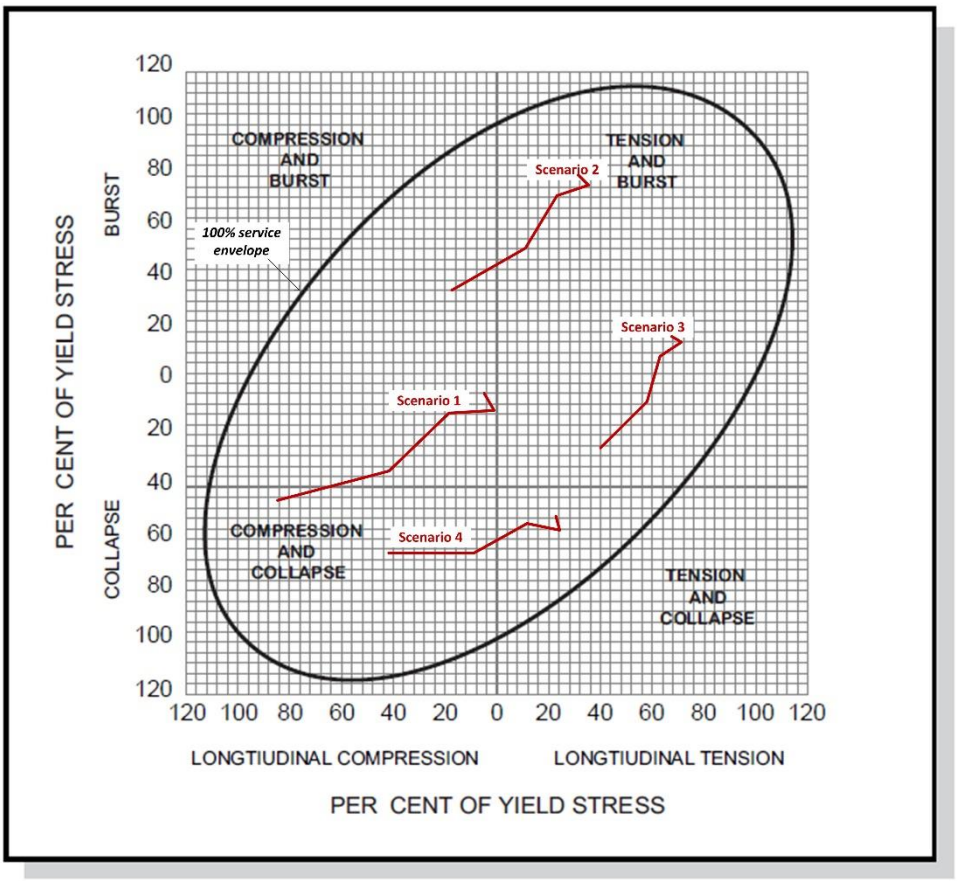


Figure 9: Tubing stress scenarios and load ellipse. The lines represent the stress profile along the tubing string in various scenarios

All in all, a map of extreme stress scenarios expected in a well during production/injection, installation and workovers is modelled and then the tubing and tubing string components (i.e. couplings, mandrels, valves, etc.) are selected so that their permitted stress envelopes (either modelled or provided by the manufacturer) cover all these conditions by a safety margin. *Similar maps may be additionally constructed for e.g. packers, seals, anchors to make sure the expected loads acting on them are within their operational envelope and will not un-seat them.*

- *Think of what well conditions may correspond to different cases in Figure 9.*
- *At this point feel free to attempt the load calculation tutorials (Tutorials 2).*

4.2.4 CORROSION

In-well corrosion can have serious consequences, including: well abandonment in the case of casing or sandscreen leak/failure (alternatively, a heavy workover to patch* – **i.e. to insert a pipe with isolation/packers or special glue on both ends* - the leak may sometimes be possible though risky); patch or replacement of a leaking tubing; higher pressure losses for fluid flow in the corroded tubing; cross-flow due to casing, packer, or seal leaks (may be fixed by patches or additional packers / seals / cement bridges); etc.

- *At this point try identifying the potential location of these leaks on a well diagram (e.g. on* Figure 7*) and discussing how this can be fixed.*

There are several principal types of corrosion encountered in oil and gas production wells, namely:

(a) ***Acidic Corrosion*** – due to the presence of ('sour' gas) H_2S or carbonic acid (formed from 'sweet' gas CO_2 and water) dissolved in the produced water or the organic acid content of the hydrocarbon fluid.

(b) ***Sulphide Stress Cracking/Hydrogen Embrittlement*** – another mechanism due to the presence of H_2S in the well fluids flowing from the reservoir, when hydrogen can migrate into the metal lattice (to 'poison' it) making it brittle, causing dislocations and even 'blisters' and cracks. *H_2S can also be generated by bacteria in stagnant fluids, e.g. in the poorly-treated casing-tubing annulus fluid (a.k.a. 'packer' fluid) or in the reservoir, which by the way also means the H_2S level can increase during the production life making this corrosion problem to become more serious with time.*

The severity and rate of these types of corrosion depends on the fluid flow pattern (e.g. stagnant fluid, stratified flow, etc.) and acidity (reflected by pH). pH, on the other hand, is itself a function of the H_2S or CO_2 partial pressure (i.e. the H_2S or CO_2 molar fraction in the flowing gas multiplied by the gas pressure), temperature, fluid composition, etc. Total acid number reflects the acidity and corrosiveness of the fluid. For simplicity, H_2S or CO_2 partial pressure values are sometimes used as primary criteria for expected corrosion risk, with possible further corrections to the corrosion rate applied due to the expected fluid temperature, chlorine content, pH, flow pattern, erosion rate, etc. Naturally, since the fluid pressure, temperature, and possibly composition change along the well depth, some parts of the tubing string may be in a higher corrosion risk area than others.

Corrosion can be further exacerbated by erosion due to the presence of produced solids if the well is produced at too high a flow velocity. This is because the corrosion- or inhibitor-generated film on the metal surface, that protects it from (further) corrosion, may be taken off by erosion notably increasing the corrosion rate and loss of metal (i.e. of the pipe wall thickness).

Corrosion due to the presence of oxygen (i.e. rust) may also happen if there is a wellhead leak or venting problem, or e.g. in injection wells if the injected water is not properly deoxygenated, etc.

Stress corrosion causes metal loss and cracking in the presence of chloride or bromide-rich brines and/or, oxygen, in the locations of high tensile stresses acting on the pipe.

Some other, typically less aggressive, types of corrosion exist: e.g. casing corrosion due to exposure to the formation water where the cement sheath is not completely sealing, etc.

It is common to use (expensive) corrosion-resistant alloys when high corrosion (either sweet or sour) service is expected. The additives in such alloys include chromium (Cr), nickel (Ni), molybdenum (Mo), etc. For instance the alloy with 13% Cr, a.k.a. 13Cr, is common to use in standard to moderately sweet (i.e. high CO_2 content, not very high temperature) service. More expensive alloys, like (2Mo-5Ni) 13Cr ones, are suitable for high CO_2 and H_2S concentration conditions at higher temperatures. Numerous API and proprietary grades, brands, alloys and duplex steels exist to cover the range of production conditions. Many manufacturers provide metallurgy selection charts based on the range offered by them. Figure 10 is an example of a completion metallurgy selection chart illustrating how more complex and expensive alloys are required as the partial pressure of hydrogen sulphide and carbon dioxide increases. High reservoir temperature and chlorine content can further affect the selection process.

- *At this stage feel free to attempt Tutorials 3.*

Alternatively, corrosion inhibition can be applied e.g. by using tubing liners, by tubing coating with plastics, or by either continuous or periodical injection of liquid inhibitors into the flow stream that are primarily designed to cover the tubing wall with a corrosion-resistant film. The inhibitors are normally injected downhole via small control (a.k.a. capillary or macaroni) lines of less or about an inch in diameter, installed in the annulus and connected to e.g. a chemical injection valve located in the production string at

the designed depth. *At surface, the flowlines and structures can also have cathodic protection, achieved by charging them to prevent corrosion.*

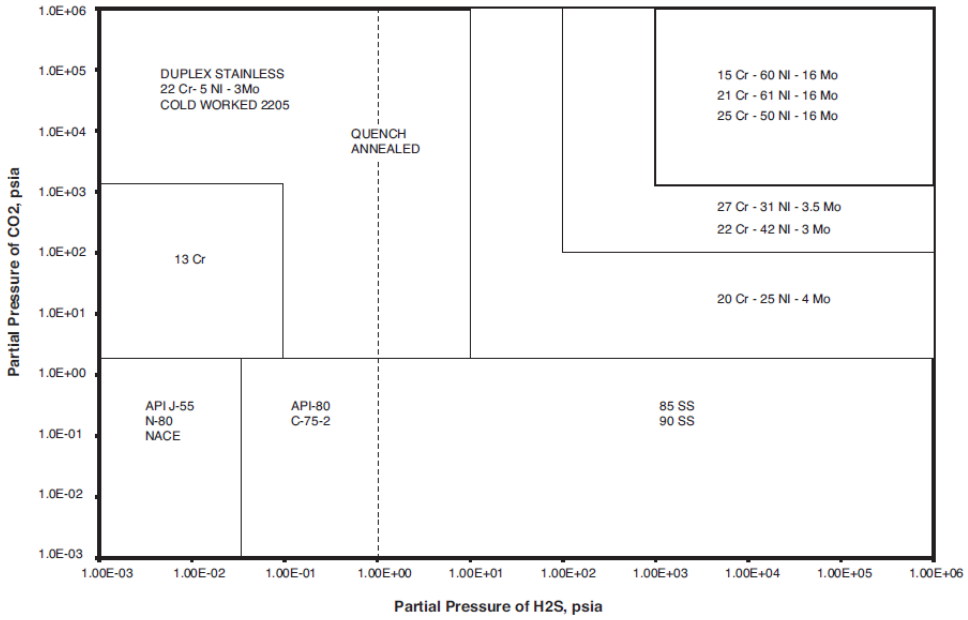


Figure 10. An example of a Completion Metallurgy Selection Chart

4.2.5 COUPLING TYPES

Couplings are used to connect tubing joints. They can be classified as being Integral or External:

- An external coupling such as the VAM™ coupling (Figure 11a) has two female connections on either end to join tubing joints that have male threads. An external coupling has a larger effective wall thickness in the coupling section (Dc > D) normally giving it higher load capacity compared to an integral coupling. The internal diameter of the coupling is normally the same as for the tubing (i.e. d_c=d a.k.a. 'flush' coupling), making it uniform inside for better flow performance and tool access.
- The integral coupling (Figure 11b) is part of the tubing joint that has a male and female thread cut on opposite ends of the pipe. The bigger coupling diameter outside (a.k.a. external upset where Dc > D) and/or inside (a.k.a. internal upset where d > d_c) is often required to maintain the load capacity.

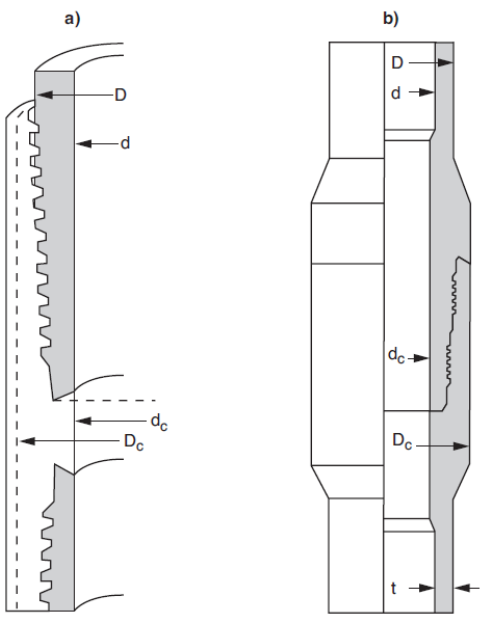


Figure 11 a) VAM: An internally flush coupling. b) An integral coupling.

Note that for the reason of having upsets in e.g. tubing couplings, mandrels, valves, landing nipples etc. the well completion diagrams always identify not only the average tubing internal and external diameters, but the physical minimum (or 'drift') and maximum diameters than can e.g. restrict tool or control line access in the tubing or annulus.

Various API and proprietary coupling types exist, e.g. the long- threaded and coupled (LT&C) connections or premium- threaded and coupled ones, with possible individual features for better seal or load capacity (e.g. with tapered threads, shoulders, etc.).

The couplings must also provide effective seal between the tubing and annulus to avoid leaks. Generally, this can be achieved two ways:

- Connections which require internal pressure to produce a pressure tight seal. For instance, this can be achieved by the thread compound (e.g. 'dope' like grease or other lubricant) trapped between the threads once the joints are screwed at a defined torque. Such seals are common in conventional wells, while may be inappropriate where high tubing-annulus pressure differentials are expected, e.g. in gas wells, gas-lifted wells, high-pressure high-temperature (HPHT) wells, etc.

- Metal to metal or elastomeric seal connections, such as premium threads. This class of coupling includes the Extreme Line as well as a range of specialised couplings of specific commercial design, e.g. Hydril™ or VAM™ designs. The couplings do not always utilise the threads to give the pressure seal but allow torque to be applied to bring together (well-matching) seal shoulders or a tapered surface within the coupling. Elastomeric or plastic rings can be added to improve the seal.

The selected coupling type is often additionally tested for its seal and load capacity at the expected conditions.

4.3. COMPOSITE COMPLETION STRING

As mentioned, the completion string must provide multiple, essential and/or important, functionalities including the ability to circulate in order to kill or kick off the well, to test and shut-in the well, to isolate annulus, etc. *(As far as the circulation is concerned – it can be either in the reverse mode: from annulus to tubing, or vice versa in the direct one. To kill the well a heavier control fluid e.g. brine is used whose weight is sufficient to create a high back pressure at the bottomhole. To kick the well off a lighter fluid is used e.g. oil, diesel, nitrogen).* This is achieved by integrating components into the completion string. The purpose and functionality of some major components is discussed below.

Figure 12 summaries the basic completion components and their functions.

- *Try suggesting where these components might be located in the well (starting from top down) based on what functions they serve.*

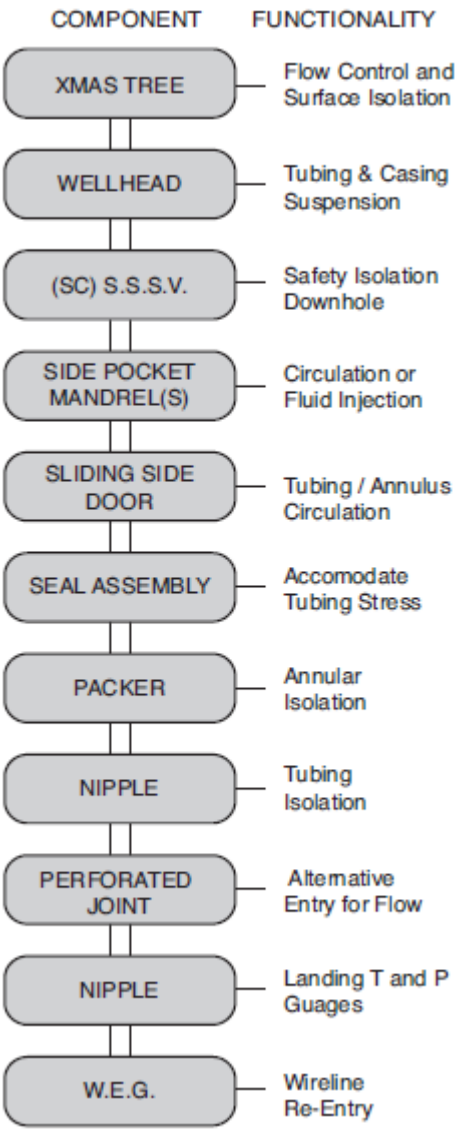


Figure 12: Schematic view of a generic well completion string.

5. COMPLETION STRING COMPONENTS

The detailed design of the completion string involves selection and specification of all its component parts. There are many potential components available, each one has numerous variants and each equipment supplier has their own particular designs. In practice many companies use a single preferred supplier or have considerable experience with specific types of components. Also, the equipment is specified as a certain size and with a certain type of threaded coupling. Hence, tubing completion equipment is fairly standard and comparable between different suppliers.

Equipment selection should be done on the basis that the component will provide a specific facility necessary for the successful performance and operation of the well under a range of operating scenarios, e.g. a mandrel may be a necessity in some wells to host a corrosion inhibitor valve. Each component however adds vulnerability and undesirable complexity to the completion, e.g. the mandrel may fail or leak. This must be compensated for by the fact that the component is necessary or provides desirable flexibility. One approach to discussing whether a particular well completion is "fit-for-purpose" is to evaluate the facilities that each component provides. The design is thus justified on a "needs" basis and the benefits of flexibility can be assessed against the drawback of incremental complexity. Further, a completion failure risk matrix is often prepared listing the risks and consequences of the completion components failure, and possibly the mitigation measures.

- *Discuss what consequences various failure events may have, e.g. packer failure, mandrel leak, tubing leak via coupling, inability to open the sliding side door. What measures you think can be applied in these cases?*

Each component in Figure 12 will now be discussed below in relation to its purpose in production operations. Its generic operating principle and functionality will be discussed, without much focus on (numerous) variations and particular brands.

5.1. WELL SURFACE EQUIPMENT: WELLHEAD AND XMAS TREE

The **wellhead** provides the basis for the mechanical construction of the well at surface (or at the seabed for subsea wells). Typically, a relatively short and wide pipe (conductor) is driven into the ground or installed in a pre-drilled hole, and the wellhead is screwed or wielded on top of it to provide:

- Suspension of all (subsequent) individual casings and tubulars, concentrically installed in the well and suspended from the wellhead via casing and tubing hangers.
- Hydraulic access to the annuli between the casings to e.g. allow cement placement; and between the production casing and tubing for e.g. well circulation, lift gas injection, annulus (a.k.a. 'casing') pressure monitoring, etc.
- Ability to install a surface closure/flow control device on top of the well. This can be e.g. a blowout preventer (BOP) stack whilst drilling or e.g. the Xmas tree for production or injection.

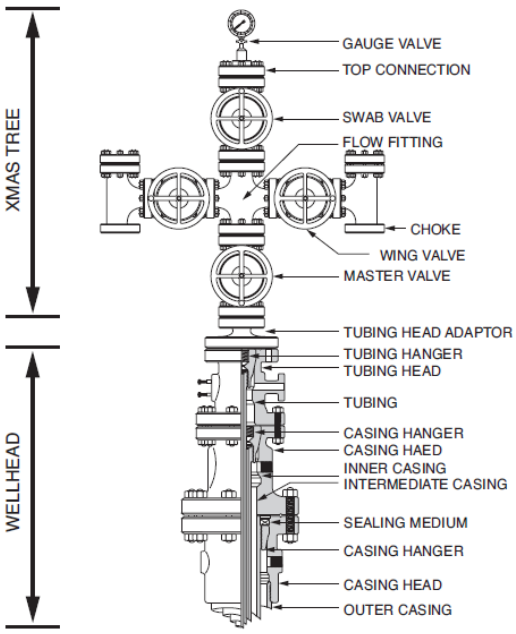


Figure 13: Conventional wellhead assembly and Christmas tree.

As seen in Figure 13, once every next casing is inserted into the previous one its hanger and spool are added on top, necessitating the (sometimes complex and unsafe) reinstallation of the BOP as well. Wellhead systems like Compactspool™ (or UNIHEAD™) are available that avoid this problem.

Offshore wells may need the wellhead, if located at the seabed and not on the platform, to additionally connect to the casing extension strings (using mudline hangers) guided from the seabed template to the drilling facility (e.g. a platform), where the BOP is subsequently installed. After drilling, Xmas tree can be installed either also on the facility (connected to the wellhead via a 'riser' pipe) or at the seabed (for subsea wells). The 'dry-tree' wells can be accessed from surface any time while the 'wet-tree' ones have their wellhead facilities at the seabed and are accessed during the planned well intervention campaigns. (In the past some seabed wellheads and Xmas trees were placed in a watertight housing at atmospheric pressure and were also called 'dry').

The **Xmas (or production) tree** is essentially a surface plumbing installed at the wellhead with flow outlets and valves providing flow control of the fluids produced from or injected into the well. *In some cases e.g. in rod-pumped wells the Christmas tree may be replaced with alternative flow control equipment e.g. a stuffing box.*

There are a number of Xmas tree designs e.g. Figure 13 shows a vertical tree with two wing valve outlets, e.g. one connected to the production line is used normally and the other is used when temporary injection (*e.g. of a stimulation fluid, see chapter 8*) is needed. In typical production all but one wings are optional and may be replaced with a cap. Additionally, the third, top outlet (with a swab valve) provides vertical access into the tubing for insertion of wireline or coiled tubing tools into the well. The lower valve is the master valve. It controls all hydraulic and mechanical access to the well. All outlets have valves which may be manually operated or are remotely controlled valves (e.g. electrically and/or hydraulically) operated from a control room. Well safety often requires the master valve (MV) to be duplicated, or even to have more than two master valves.

Alternative to the conventional, vertical tree technology, horizontal trees are now also used. Traditionally they were preferred in subsea wells, though nowadays are sometimes also installed in platform wells and on-land. The horizontal tree valves are off-centred, located (horizontally) on the tree outlets, which allows positioning the BOP on the tree and drilling/completing through the tree, making these operation easier and safer. However, additional routines like installation/retrieval of tubing plugs to remove the BOP can be required.

Various modification of the Xmas tree and wellhead designs exist, e.g. to allow installation of multiple non-concentric tubings, or running in control or fibre-optic lines, or to have annulus isolation valves, etc.

The Xmas tree and wellhead have to be pressure rated (and tested) to well withstand the expected pressures in the well in various operating scenarios.

5.2. ANNULAR PRESSURE SEAL

As explained above, annulus isolation is required in production wells for reasons of tubing flow stability and protection of the production casing from corrosion, and/or to prevent high pressures being exerted on the wellhead and possibly giving rise to burst of the production casing. To minimise the volume below the packer and the length of casing exposed to well fluids, the packer is normally set quite deep in the well.

Additionally, packers can be used for many other reasons, including zonation of production/injection interval (e.g. in smart or multiple-completion wells) to enable flexible zonal flow control, or in selective small interval well testing or stimulation (using coiled tubing or drill string), or to isolate an interval or a leak (with a straddle packer), etc.

This tubing-casing annular isolation is normally achieved by installing a ('production') packer at the bottom of the completion string which is lowered into the wellbore with an elastomeric element in the retracted position. At the prescribed depth, the element is set by extrusion or inflation to fill the annular space between the tubing and the annulus.

A typical production packer design is shown in Figure 14a. The packer is anchored in position by pushing the steel teeth of the slips into the casing wall while the pack-off is accomplished by expanding or extending the elastomer element outwards from the packer body until it seals against the casing wall (Figure 14b).

(*A side note. Other devices: anchors, often resemble the packer design, except there is no elastomer – they fix the tubing in place while keeping the annulus open. This is often needed in e.g. wells equipped with pumps as will be explained later in this course).*

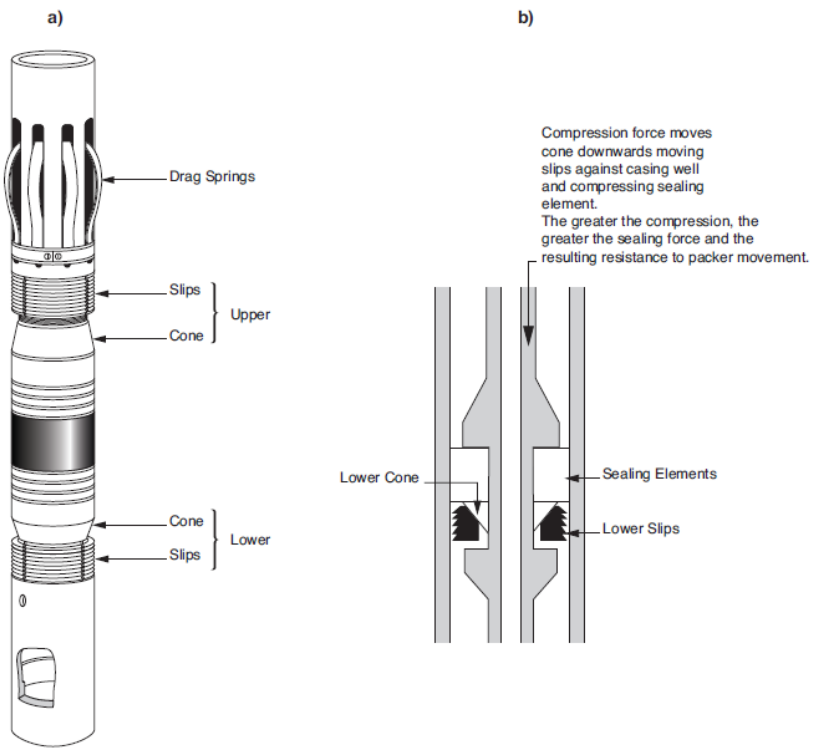


Figure 14 a) Permanent packer. b) Schematic view of setting a compression set packer.

Depending on a particular application, the packer can be either:

- **A Retrievable Packer** The packer can be run as an integral part of the tubing string. It is run to the setting depth where the setting mechanism is actuated.
- **A Permanent Packer** is cheaper and often more reliable, but cannot be so easily retrieved. It is usually run and set separately, either with or without a tailpipe. It often can be run on a wireline or coiled tubing. The tubing string is subsequently run and connects to the packer seal assembly to achieve a pressure seal. Retrieval of such packer, if at all required, would involve milling away the packer's internal sleeves to allow the rubber element to collapse and the packer debris either caught and retrieved to surfaced or left in the wellbore (i.e. fall in the sink hole – *the wellbore interval below the production zone* - if there is one).

The compression and extrusion of the rubber element during the setting of packers can be accomplished by a number of mechanisms, including:

- **Mechanically** set e.g. by rotation of the tubing string.
- **Compression** or **Tension** using the suspended weight of the tubing. A cone mechanism transfers the string weight to the packer to compress the rubber element (Figure 14).
- **Hydraulic** setting utilises hydraulic pressure inside the completion string, or the pressure differential between it and the annulus. E.g. in the latter case the tubing string is plugged below the packer, then the tubing pressure is increased so that at some threshold pressure the tubing fluid (be it completion fluid, drill mud, or even cement) moves the packer's slips anchoring it in place, and then squeezes (via a sleeve) or inflates the elastomer element.
- **Electrical** The packer (plus tailpipe) assembly is lowered into the casing on an electrical conductor cable. A small explosive charge is detonated at the required setting depth, actuating the setting mechanism (e.g. inflating by explosion gas).
- **Swellable elastomer** These special elastomers are designed to increase in volume when exposed to oil (oil-swellable packers) or to water (water-swellable packers) provided the fluid temperature and composition are favourable. They are run in the opposite fluid (e.g. the oil packers are run in brine) and take time (days or weeks) to swell when subsequently exposed to the swell-causing fluid.

Some of the above mechanisms (e.g. the hydrostatic pressure-actuated mechanism, or the compression-actuated one) may result in premature packer setting when run into hole. Also, in horizontal or deviated wells running a casing or tubing with multiple downhole packer(s), e.g. as part of smart well completion, may result in it getting stuck. This risk must be considered and/or modelled in completion planning.
Retrieval of retrievable, e.g. of the hydraulically-set retrievable, packers can be actuated by e.g. pulling the tubing which would shear a set of (softer metal) pins releasing the high-pressure fluid from inside the packer and thus letting the slips un-set and the elastomer contract, which basically reverses the setting process. *(The pins and damaged parts can be later replaced, and the packer re-used).*

As discussed above, the packers should be selected to withstand the expected differential pressure (between the annulus above and the annulus below the packer) at various well operating scenarios. Some types of packers have limits on the upward or downward acting differential pressure.

- *For instance, discuss what direction of differential pressure may unseat the packer in* Figure 14*b. At what well conditions can this differential pressure be high?*
- *Attempt Tutorial 4*

Some packers can accommodate 'feed-through' control lines or connectors. This is useful when e.g. a hydraulic, electric or fibre optic line(s) has to run through the packer into the lower completion (e.g. in smart wells); or when a by-pass tube is installed to host an annular safety valve.
There are also more complex, dual or triple -bore packers that can accommodate two or three non-concentric tubing strings in e.g. multiple tubing string completions described later in this chapter.

5.3. SEAL BETWEEN TUBING AND PACKER

Some completion designs seal and latch (anchor) the tubing string to the packer (Figure 15a). However, changes in the flowing temperature and tubing pressure can cause elongation or contraction of the tubing string. This may result in buckling or tensile failure of the tubing string locked between the packer and wellhead. Alternatively, (dynamic) seal assemblies (Figure 15b-f) can be designed to allow tubular movement (which could even be in the range of 40 ft) to compensate for (thermal or otherwise) expansion and contraction of the tubing. Most of these seal assemblies also allow (upper) tubing detachment and (re-)insertion to ease its installation and retrieval.

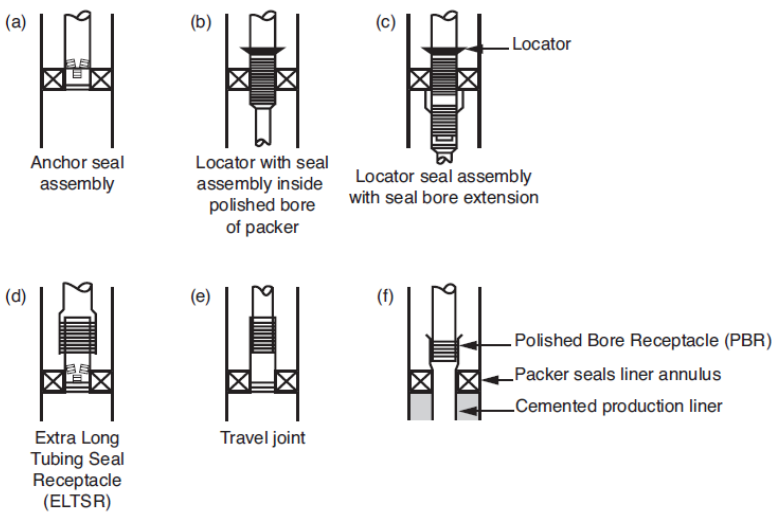


Figure 15 Schematic views of example tubing seal assemblies.

Dynamic Seal Assembly designs include:

- **Polished Bore Receptacle (PBR)** type (Figure 15b,c,f): This consists of a series of standard elastomer seal elements which are run inside the smooth (polished) bore of the packer. The length of the polished bore is sufficient to ensure the seal when the tubing experiences the maximum expected amount of expansion or contraction.
- **Expansion Joint** type like the Extra Long Tubing Seal Receptacle (ELTSR) in Figure 15d. The major difference from PBR assemblies is the outer cylinder is attached to the tubing string, whereas the inner cylinder is latched into the packer.

These types of seal assemblies also allow installation and retrieval of the upper tubing string without the need to retrieve the (often permanent) packer and its tailpipe. This makes the tubing replacement operation easier during well workovers.

- **Travel (or Slip) Joint type** (Figure 15e) can be added to the tubing string as e.g. a telescopic joint that allows some limited extension. This can also be useful for instance when accommodating the tubing string's expansion or contraction, or when spacing out the completion string.

As mentioned, the seal in such assemblies is achieved by a combination of elastomeric and plastic elements installed between the receptacle and the tubing string. These elastomers can have different geometry (e.g. an O-ring design, a 'T' or a 'V' (chevron) -shape seals, etc.) to improve their reliability in dynamic assemblies. The elastomer and plastic materials have to be selected carefully as different materials have different applicability when exposed to high temperature, fluid containing H_2S and CO_2, aromatic hydrocarbons, etc.

5.4. SUB-SURFACE SAFETY VALVES (SSSV)

It is advisable, and in most cases mandatory, to have a secondary means of closure for all wells capable of natural flow to surface. This may be used e.g. when it is not possible to close the Xmas tree valve (e.g. due to damage, repairs, or lack of access), or there is a leak or emergency at surface, etc. *(In general, in naturally flowing wells it is essential to have a policy of at least two 'barriers' preventing the reservoir fluid from escaping to surface at all times; e.g. during drilling these are the drilling mud (whose weight creates sufficient backpressure) as a primary barrier and the BOP as a secondary; during production these are often the Xmas tree and the SSSV).*

Therefore, an additional valve to shut off flow is located beneath the wellhead as part of the tubing string. This Sub-Surface Safety Valve or SSSV design is based upon two different control philosophies:

(1) Remotely or Surface Controlled Safety Valves (SCSSV) whereby closure and opening of the valve is actuated using a surface control system which feeds hydraulic pressure directly to the downhole valve assembly via an annulus control line. One common type – a flapper valve – is illustrated in Figure 16. High pressure in the control line keeps the valve open and is maintained by surface facilities. In the case of emergency or control line leak the high pressure is lost and the spring moves the flapper to close.

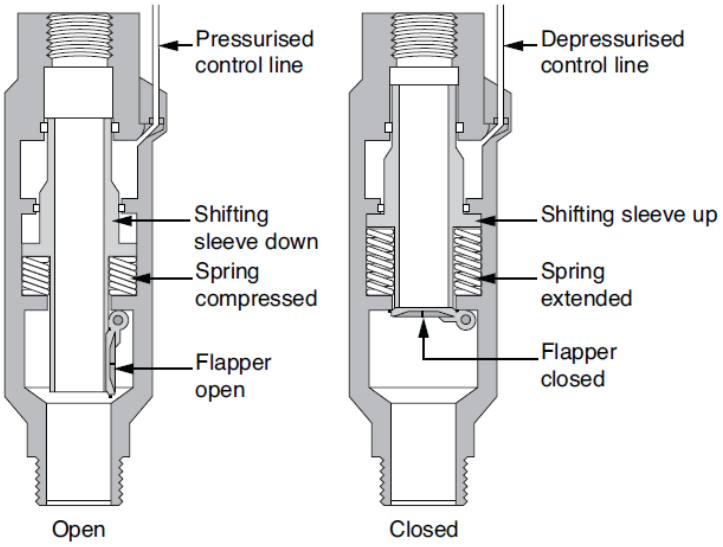


Figure 16 Flapper type Surface Controlled Sub Surface Safety Valve.

(2) Direct or Sub-surface Controlled Safety Valves (SSCSV) which are designed to close when downhole well conditions of pressure/flowrate vary from pre-set design values. These valves are often referred to as "storm chokes". They are less reliable than the surface-controlled ones and are normally used as a contingency or temporarily e.g. until an inoperable SCSSV is fixed.

By the means of installation and retrieval, SSSVs can also be classed as 'tubing retrievable' TR (i.e. they are integrated into the tubing string) or 'wireline retrievable' WR (i.e. the valve landing nipple is run as an integral part of the tubing while the internal valve assembly is subsequently run and retrieved on wireline cable or coiled tubing). In the latter case the retrieval and replacement is easier (subject to the problems with scale and solids build-up on the valve), but the valve flow area is smaller which can restrict production and/or result in excessive erosion.

The SSSV setting depth is often within the top few hundred feet of the completion string. It is selected neither too shallow (where they can be subject of interference with the surface equipment, or can be in the scale or hydrates deposition risk zone) nor too deep (where there may be a problem of controlling them if the leaking control line fills with brine).

One of the problems with the flow shut-in using SSSVs, plugs, sleeves etc. is that there may develop a very high pressure differential across the valve or the plug during the well shut-in. This may result in a difficulty to re-open the valve (e.g. imagine what happens to the Figure 16 flapper opening force when the pressure below the closed flapper is thousands of psi higher than the one above), and in the case of e.g. plugs: in a high force acting on the plug once it is unseated (this force trying to eject the plug out of the well like a bullet out of a gun). For this reason pressure equalisation capacity can be added into such devices, e.g. a small additional, in-built by-pass tube with a valve can be added that can be actuated to provide communication across the (thus termed 'self-equalising') SSSV or the plug to gradually equalise the pressure until the SSSV or the plug can be opened or released. (However, such self-equalizing valves can be found to be less reliable.) Alternatively, the tubing above the SSSV/plug can be first pressurised until its pressure is equal to the pressure below.

In addition to the SSSVs in the tubing it is sometimes required to additionally install annular safety valves (ASV) to have an extra barrier in the annulus for higher safety. For this, basically a packer with a fed-through by-pass tube is installed at a shallow depth, and a safety valve is added to this by-pass tube. This is for instance important in offshore wells where gas lift is used (during which the high-pressure lift gas fills the annulus) so that in the case of a well shut-in only a small volume of pressurised gas –the one

trapped in the annulus above the ASV - is exposed to the wellhead (*as an example see e.g. completion number 6 in Tutorial 5*).

Safety valves should be periodically tested to ensure they are not damaged by e.g. scale build up or erosion, and can shut-off production with the minimum allowable leak. The testing routine and frequency are defined by either government or company standards.

5.5. SIDE POCKET MANDREL

Side pocket mandrels (SPMs) are often added into the completion string for various reasons. An SPM (Figure 17) contains an off-centre pocket with ports into the annulus to host a valve or a gauge. Meantime the completion string remains open to flow or tool access. A valve, which controls the fluid flow between tubing and annulus, can be installed in the pocket. When such flow is not needed a temporary 'dummy' valve, closing the port, is installed. Alternatively, a gauge (for on-line or offline monitoring of pressure, temperature, etc.) can be installed; or a rupture (a.k.a. burst or shear or dump) disc valve that opens at some threshold pressure or applied force.

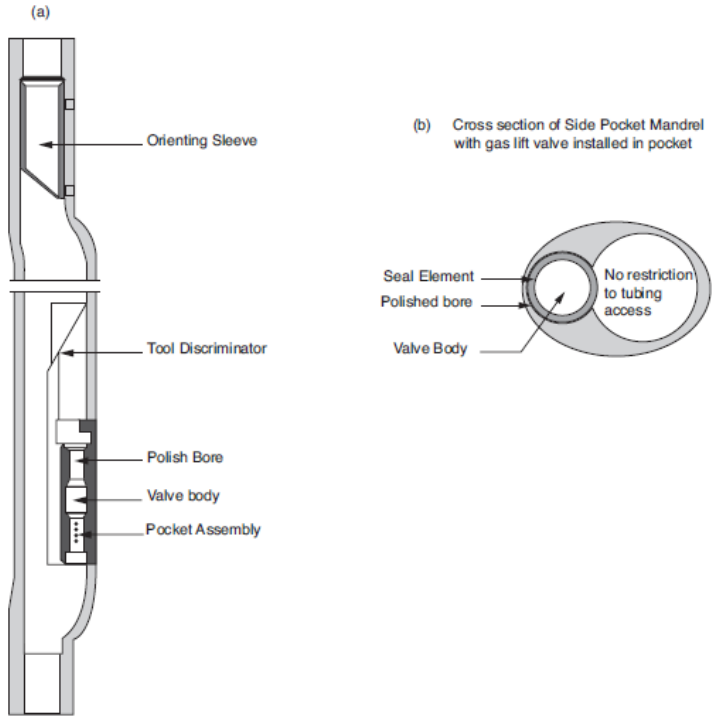


Figure 17a and b: Side Pocket Mandrel with valve installed.

Some of the flow control valve types installed in SPMs include:

- *Gas lift valves* are set to open to, shut or throttle the gas flow between the annulus and the tubing.
- *Chemical Injection Valves* allow controlled injection of production chemicals, such as corrosion inhibitors, etc. into the tubing from the annulus or control line.
- *Circulation* of fluids to or from the annulus into the tubing is achieved by installing a valve with a bursting disc which can be sheared. The shear valve can be later replaced by wireline.

The installation and recovery of the valves or gauges from the side pocket mandrel is achieved by a relatively simple and fast wireline operation (that can also be done on a live well if needed) with a tool that can help detect the SPM in question, anchor itself in position, orient the arm towards the mandrel, and then either latch onto the valve or gauge to retrieve it or to install one in place.

5.6. CIRCULATION DEVICE

The majority of naturally flowing well completions include one of the following devices to provide circulation (e.g. in order to kill the well) between the annulus and tubing:

- Sliding side door (SSD) or sliding sleeve (SS)
- Side pocket mandrel (SPM) with a circulation valve
- Ported nipple that can allow tubing-annulus communication once the mandrel covering the port is moved e.g. by wireline.

They can all be opened when required (e.g. by a wireline or coiled tubing operation on a live well) and subsequently closed. *An (unwelcome) alternative is to use a tubing punch or a perforation gun with a low power tubing perforator charge to perforate the tubing. However, this is only used prior to a tubing removal workover during which, among other things, the damaged tubing joints are replaced.*

The conceptual design of the sliding side door is shown in Figure 18. The SSD permits communication between tubing and annulus. It consists of two concentric sleeves, containing slots or holes, with elastomeric seals between them. The inner sleeve can move up or down by wireline or coiled tubing tools (*e.g. by jarring – a sudden move of the tool up or down, as explained later in this course*). This movement aligns the inner and outer openings.

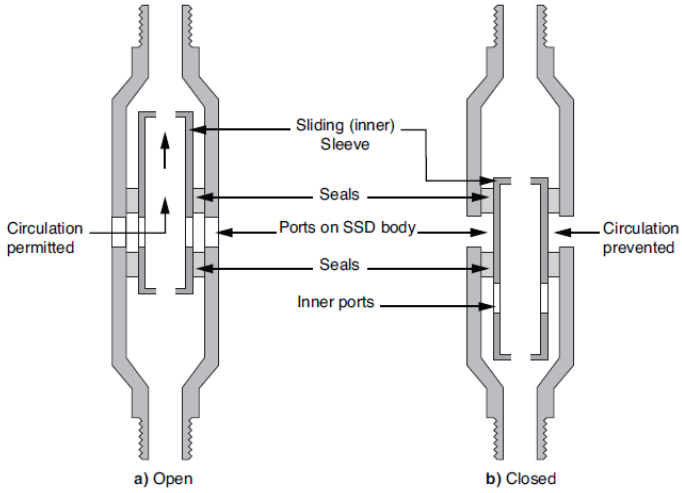


Figure 18 Conceptual design of a Wireline Operated Sliding Side Door

Another application of SSDs and SSs is to allow flow from zones in multi-zone completions.

Solids or scales in the seal area or the effect of well deviation and the resultant inefficient jarring can cause failure to close the sleeve. A separation sleeve can be run which will land inside the sliding sleeve and seal it.

5.7. LANDING NIPPLES

In addition to safety valves, a further means of physical isolation of the reservoir can be installed at one or more places in the tubing. The isolation is normally provided by lowering a plug on wireline down the inside of the tubing string until it lands and locks into an appropriate landing nipple which was incorporated into the design of the tubing string at the appropriate depth.

A landing nipple (an example of a selective one is shown Figure 19) is a short, tubing accessory with an internal profile which can accommodate and secure a mandrel run into its bore on wireline or coiled tubing. It provides a:

- Recess to mechanically lock the mandrel in place using a set of expandable keys
- Pressure seal between the internal bore of the nipple and the outer surface of the mandrel.

The nipple therefore offers a landing/locking profile and a seal bore into which the mandrel (e.g. a plug or other equipment) may be selectively installed.

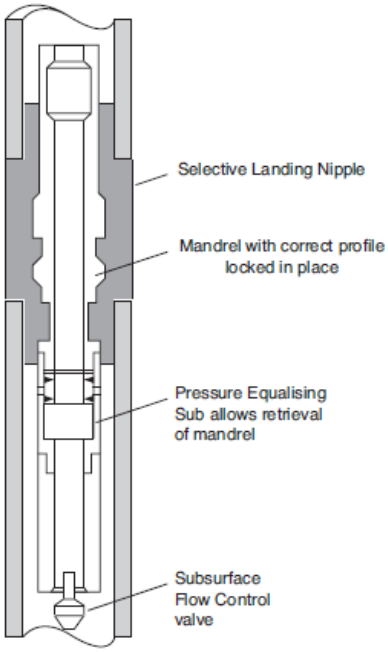


Figure 19 Subsurface flow control mandrel in a selective landing nipple.

Nipples are installed at various points in the string with a possibility to:

(1) Host plugs for isolation or plugging of the tubing string for completion pressure testing, well shut-in, workover, or for hydraulically setting packers.
(2) Allow communication between the tubing and the annulus when the nipple has a port(s).
(3) Host a safety valve
(4) Host a siphon or velocity string or a choke for regulation or throttling of the tubing flow.
(5) Host downhole pressure and temperature recording gauges.

➢ *Discuss where in the well the nipples can be installed for the purposes listed above*

The landing nipples maybe selective or non-selective. A selective nipple will only allow the corresponding mandrel to lock into place. A non-selective (or no-go) nipple has a no-go profile that stops any tool bigger than the no-go size.

The general methods of obtaining selectivity in a landing nipple system include:

(a) Selectivity based upon a variable internal profile. Only the mandrel with a matching profile can fit into it.
(b) Selectivity associated with the setting tool. The tool is actuated to set the device in the nipple.
(c) Selectivity based upon pre-spaced magnets. The magnets recognise the tool and actuate e.g. a small charge to lock the device in place.

5.8. FLOW COUPLING

Many of the tubing accessories, e.g. landing nipples or SSSVs, installed within a tubing string, will cause a restriction to flow. The resulting fluid flow convergence and divergence effects associated with entry to and exit from the nipple system will cause increased turbulence, especially in high-rate wells. This turbulence can lead to substantial abrasive erosion of the tubing wall. In this case flow couplings (Figure 20b) are often installed above and below the restrictions. They are essentially tubing joints that have an increased wall thickness as an extra allowance for erosion.

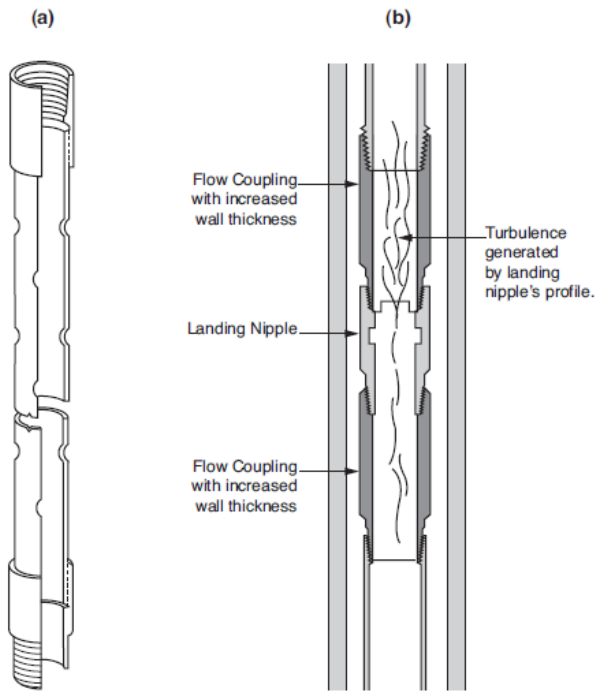


Figure 20 a) Perforated flow tube b) Flow coupling.

- *At this stage feel free to explain the design of the completion string presented for an example, conventional well in* Figure 21

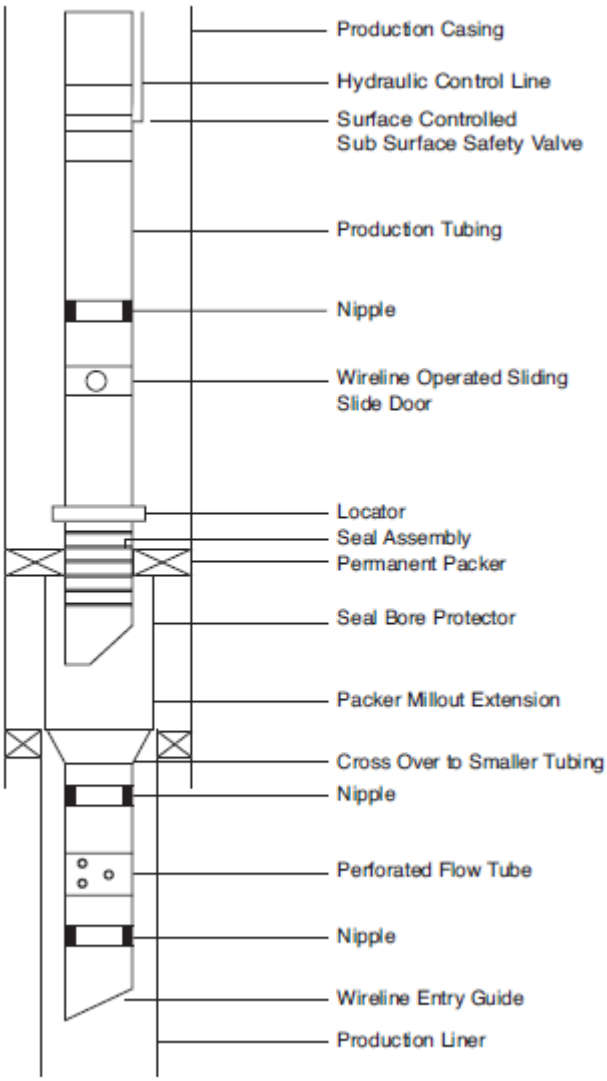


Figure 21: Single zone completion example

5.9. TAILPIPE ASSEMBLY

As mentioned, it is often preferred to have tubing extension below the production packer (see e.g. Figure 21). Such 'tailpipe' is normally suspended on the packer (and often reaches close to the top of the production/injection interval, seldom deeper), for instance in order to:

- 'Sting' into the production liner to ease the wireline tools running in the production interval and their retrieval (so that the tools do not get stuck in the interval between the liner and the packer);
- Have the nipples to host a plug for packer setting or tubing testing and/or for reservoir isolation during e.g. a workover (upper nipple of the tailpipe in Figure 21); or to install a pressure/temperature gauge close to the production interval for accurate well testing (lower nipple in Figure 21).
- Have a perforated flow tube (see Figure 20a) to allow flow if a gauge is installed in the lower nipple;
- Have a wireline entry guide (essentially a tubing joint with a funnel-like opening) at the very bottom of the tailpipe to ease the access and retrieval of the wireline tools into the tubing.

The tailpipe size is normally designed to have sufficient flow velocity in it to ensure most of the (largest) sand particles and/or water droplets are carried out by the flow and do not accumulate at the

bottomhole, causing negative, sand bridging (restricting flow) or water loading (creating back-pressure) effects.

This concludes the list of basic, generic equipment installed in well completions. Many other fit-for-purpose completion equipment exist, e.g. artificial lift-related pumps, valves and other accessories; well workover and stimulation – related components; bottomhole completion installation related equipment; smart well flow control completion; etc. Many of them will be discussed in other sections of this course.

- *At this stage review the (Tutorial 5) well completion examples and discuss their design features and objectives.*

6. COMPLETION INSTALLATION PRACTICES

Completion installation practices and procedures vary depending on the completion string design, bottomhole completion type, number of production zones, type of equipment, etc.

- *Discuss how these options may influence the installation procedure. E.g. consider a) perforated bottomhole completion with the perforation done either before or after the completion string is installed, or b) the difference made by having a retrievable packer run on the tubing string, or a permanent packer run on wireline.*

A brief description of an example routine to run the completion shown in Figure 21 is provided below for illustration. Assume the case where the perforation is performed via wireline-conveyed, (through-)casing guns before the completion string is installed.

6.1 Example installation program of the completion in Figure 21

The overall installation strategy is shown in Figure 22.

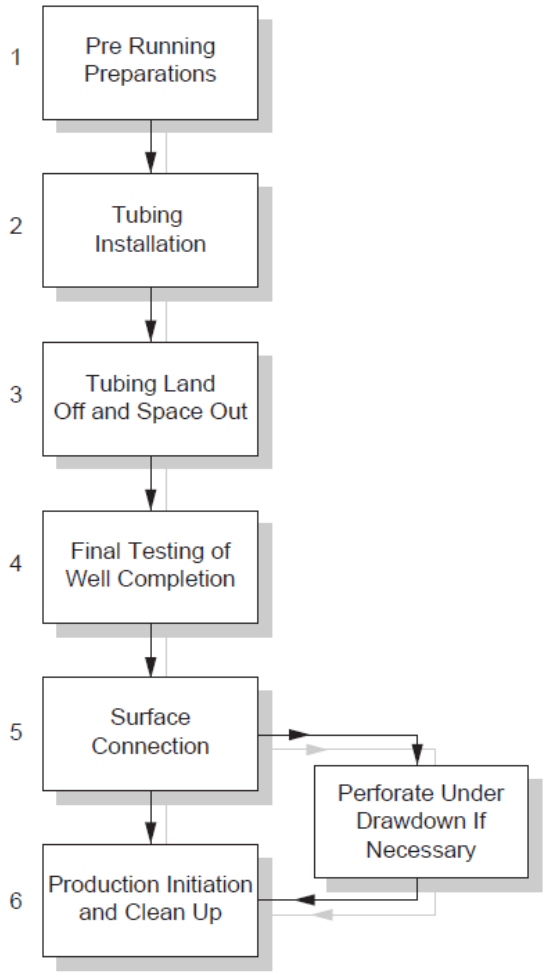


Figure 22: Overall strategy for completion installation

1. This completion is installed once the well has been drilled, (openhole) logged, cased and cemented. The tubing head spool is added to the wellhead, the BOP is put back in place and the system is pressure tested. A drill string is run to check the top of cement and, if there is cement left in the wellbore, to drill it out. Then a control string with scrapers, junk catchers, circulation subs etc. is run to clean the casing walls and preferably circulate out major debris and other junk. Afterwards the drilling mud is displaced with the completion fluid (usually a clean, compatible, low corrosivity and oxygen, solid-free brine with possible biocide and hydrate inhibitors); detergent and solvent stages may be added during displacement for better clean-up, as well as small viscosified fluid volumes ('viscous pills') to improve the drilling mud displacement. The well is logged to check the cement bond quality, and possibly match the position of the casing collars (with a Casing Collar Locator CCL log) to the formation properties (with e.g. a Gamma Ray GR log) for later completion and/or perforation gun positioning. The gun and CCL and/or GR are run on the wireline and positioned across the net pay interval, which is perforated and then this wireline assembly is retrieved.
2. A 'gauge ring' (*a.k.a. 'gauge cutter' – described in Chapter 2*) tool is run on wireline to make sure the well casing is unobstructed and there is access for the packer. Then the CCL/GR logs (for positioning) and the packer with its tailpipe are run on the wireline and set in place. Alternatively, the packer can be run on the drillpipe or coiled tubing (e.g. if too heavy for the wireline). Once the packer is set, the tailpipe may be plugged to reduce the fluid loss into the formation and the associated formation damage. Afterwards the tubing string is run into hole, with the special care paid to the threads, the makeup torque and the amount of grease applied when assembling the string. By then, the tubing joints and components should have already

been measured, tested, numbered, and often pre-assembled into 2-3 joint-long modules to speed up the installation trip. The tubing string may be regularly pressure tested during the tripping.

3. Once the tubing string hits the packer no-go (which is detected by the reduction in the tubing string weight), it is lifted and spaced out with pup joints to have the needed length to fit between the wellhead and the packer seal assembly. The control line (to the SSSV) is run together with the tubing string, clamped to it. Finally, the tubing hanger is screwed on and the string is set in the wellhead.
4. The BOP is replaced with the Xmas tree (for this period, a temporary check valve or a back pressure valve [BPV] can be installed in the tubing as a second barrier to flow. *A check valve allows flow only in one direction, in this case only downward*). The system components are pressure tested and the SSSV is opened.
5. The flowlines and chokes are connected to the Xmas tree.
6. The completion fluid at this stage can be replaced with a different, packer fluid or light-weight fluid that will later initiate the flow. The SSD is closed and the tailpipe plug, if there was one, is removed. The flow is initiated by gradual reduction in the tubing head pressure (by gradual opening of or 'beaning up' the surface choke). The well may take time to clean up until the completion fluid from the string is fully displaced by the production oil and/or gas.

- *Discuss the reasoning behind the above-listed steps, and what may be different if a different completion is installed.*

- *Discuss what changes in the above routine if the completion is installed underbalance (i.e. when the wellbore pressure is **lower** that the reservoir pressure to avoid fluid loss and subsequent formation damage)?*

Needless to say, the completion installation program must be developed and approved well in advance, with objectives, risks, and contingency actions explained. The crew must be briefed, and the installation process carefully recorded and reported.

7. ADVANCED WELL COMPLETIONS

On top of the conventional wells described above, there are many other, less common (but no less important) well completion options. They may differ in the way the well is constructed (e.g. horizontal or multi-lateral wells), and/or what completion is used (e.g. multiple-zone completions, smart wells, etc.), or both. In other words such wells (termed 'advanced' in this course material) require some specialist drilling or completion equipment and expertise. They are often more expensive, require higher 'front-end' load (i.e. more detailed risk analysis, careful design and planning, long-term production forecast) offset by the fact that they can result in higher profit by accessing complex reserves, improving oil or gas sweep, and producing at higher rates often with lesser need for well intervention.

Some common examples of advanced wells: multiple-zone completions, horizontal wells, multi-lateral wells, and smart wells, are briefly described below.

The other common attributes of (any) well completion or stimulation, such as artificial lift, sand control completions, matrix acidizing or hydraulic fracturing, are discussed separately, later in this course.

7.1. MULTIPLE-ZONE COMPLETIONS

Multiple zone completions are often employed where more than one distinct reservoir layer is intersected by a single well and there is an intention, or legal requirement, to produce from or inject

into these layers separately. Each reservoir has, by definition, its own pressure regime and, if present, their own Gas-Oil-Contact GOC and Water-Oil-Contact WOC.

Essentially, there are three conceptually different ways to develop such reservoirs:

- By **Comingling the Flow** from various zones in which the fluid from more than one reservoir simultaneously flows into a single tubing string (like e.g. the completion in Figure 21). This is the simplest way where no zonal control at the completion level is applied.

- By **Segregated, Multi Zone Depletion:** multiple production conduits are installed within the same wellbore (as e.g. in Figure 23d for two-zone, dual-tubing completion. *Triple-tubing completions for three zones also exist*). Each tubing controls the production of one reservoir. Alternatively, the tubing and annulus are used as separate conduits for production and/or injection as e.g. shown in Figure 23a,b *(note that all the risks discussed earlier of using the annulus for production, and thus exposing the casing, still apply.)*

- With **Alternate Zone Well Completion Strategy:** each well is completed on more than one reservoir (see Figure 23c). This makes it possible to control which zones produce (via the same tubing) and which are shut-off. *Additionally, installation of flow control devices instead of SSDs in such wells makes them smart wells, where it is possible to control production from every zone separately either in real time or with a pre-set setting.*

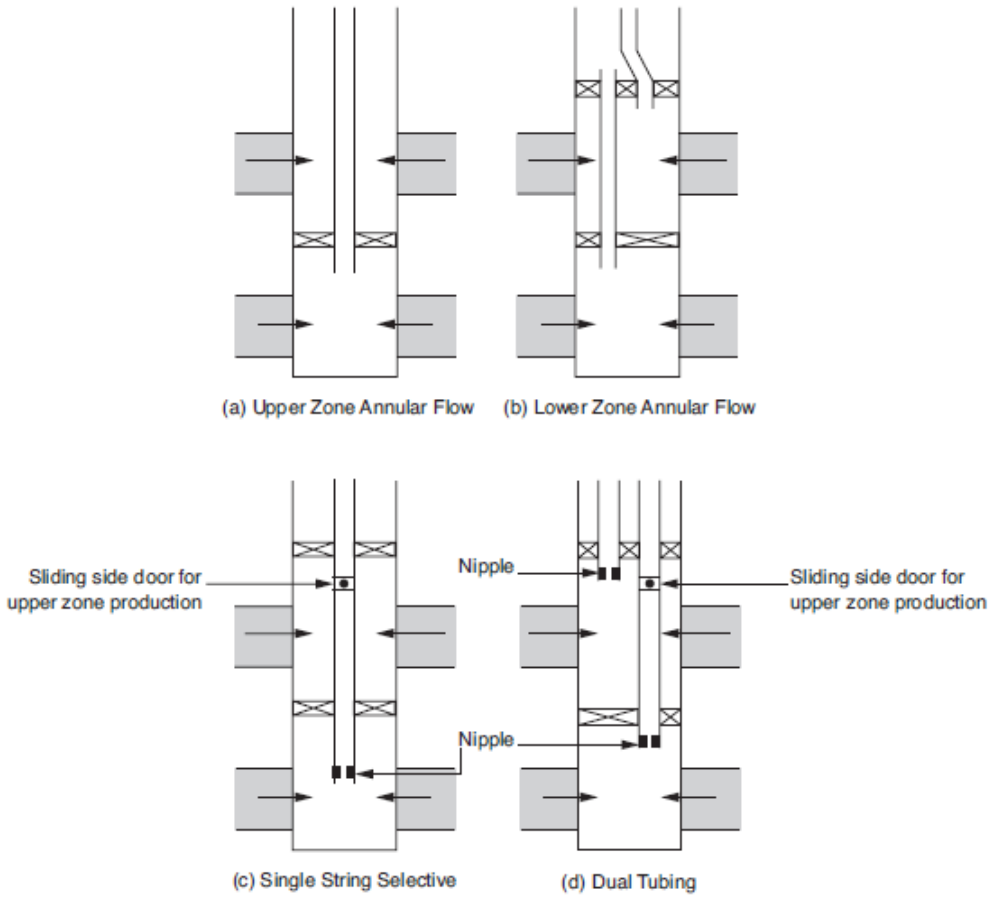


Figure 23 Options for single and dual string, two zone completion

With so many well design options available nowadays to implement either of these strategies, it is important to select the right one in the context of the major pros and cons of them, including:

a) Co-mingled flow:

Advantages:

- The total number of wells and the capital investment is minimised since each well provides a drainage point in every reservoir
- The production plateaux for each reservoir should be reached faster since the amount of drilling is minimised

Disadvantages:

- The mixing of produced fluids in the wellbore can be disadvantageous if fluids from one or more of the reservoirs significantly differ in their composition including H_2S, CO_2, water, gas, as well as density, sand concentration, etc. This complicates the fluid lift, processing and transportation.
- Variation in individual zone pressures and permeability can lead to a back pressure effect where the high bottomhole pressure 'does not let' the less productive or lower pressure reservoirs to produce at full potential
- Control of the production from an individual zone is not immediately possible, as well as of zonal injection ('placement') of chemicals during e.g. well stimulation.

Well work-over is required to locate and isolate offending zones (e.g. the ones producing too much water or sand), which is sometimes difficult, risky, non-frequent, and can be quite expensive an operation (especially in subsea wells).

b) Segregated, multiple zone depletion

Advantages:

- The production rate and duration of flow on each zone can be independently controlled.
- Changes in the production characteristics of one zone will not influence the others.
- Selective stimulation or remedial work of each zone is possible.
- Continuous depletion monitoring of each zone is possible.

Disadvantages:

- Each zone requires its own tubing string and/or annulus; increasing the length of production tubing and other completion equipment required (such as dual packers, dual wellhead accessories, dual tree, etc.). This increases the complexity, risk, and cost of the well completion and operation.
- The reduced tubing sizes may significantly reduce the total flow capacity of the well (both in the case of parallel and concentric tubings).

These disadvantages quite often outweigh the advantages of such completions.

NB: The completions where the annulus or tubing is used for injection into one layer, while the remaining tubing or annulus is used for production from another layer, are often called 'multipurpose completions'.

c) Alternate zone strategy

Advantages:

- Some level of zonal flow control is provided.
- Selective stimulation or remedial work of each zone is possible.
- Each well is mechanically relatively simple minimising the risk of failure due to complexity.

Disadvantages:

- For the case when generally only one zone is producing at a time (e.g. due to differential pressure depletion, or different zonal fluid compositions, or seasonal gas production), a greater number of wells have to be drilled and completed to achieve the same degree of depletion control and reservoir management. Hence higher costs and slower production.

The modern trend of equipping such wells with smart completion allows simultaneous production, flow control and monitoring from multiple zones making them quite attractive for multiple-zone development scenarios.

The choice of the zonal depletion strategy depends on many parameters, including:

- Offshore or Onshore Development

Offshore developments have a higher well cost and thus favour a reduced number of wells, making such wells good candidates to be advanced. This particularly applies to subsea wells that additionally favour completions with lesser need for (costly) interventions.

- Areal Size and Number of Reservoir Zones

When a large or geologically complex field is being drilled out from a limited number of locations (e.g. from a few platforms or on-land drill sites/pads), the wells have to be drilled deviated (for instance S-shaped as in Figure 24) to access all the reservoir reserves. The installation of dual- or triple-tubing completions is problematic in high angle wells.

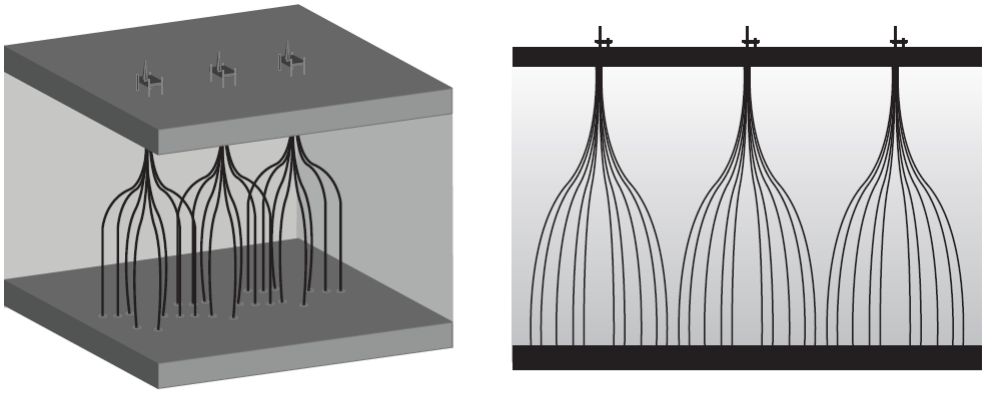


Figure 24: On- and off-shore fields developed with vertical completions from S-shaped wells. *(S-shaped wells are often used when a reservoir is drilled from a certain location, and the wells are designed to have vertical bottomhole completion, e.g. to aid their further hydraulic fracturing or for other reasons).*

- Variation in the Reservoir Rock and Fluid Characteristics

The degree to which the drawdown or composition on one zone might suppress production from other zones may influence the choice of completion.

- Field Management Philosophy

The need to control and monitor production from or injection into multiple reservoirs or blocks may be dictated e.g. by the government policies. Also, the careful zonal control and monitoring can significantly improve recovery and project economics in the reservoirs with complex geology (e.g. compartmentalised or blocked), multiple small fields, etc.

7.2. IMPROVED OIL RECOVERY

The developments in well drilling technology allowed the cost-effective drilling of new well trajectories that increased the efficiency of oil and gas production by increasing the reservoir recovery factor. These new trajectories eventually led to the development of new completion designs along with the technologies required to create and cost-effectively service them during the life of the well. These new well construction technologies are collectively known as "Improved Oil Recovery" (IOR).

N.B. IOR employs well drilling, completion and servicing technologies. It should be distinguished from

EOR ("Enhanced Oil Recovery") where the reservoir's recovery factor is increased by altering the reservoir fluid displacement processes at the pore level, for example by injecting polymer solutions, Carbon Dioxide, surfactants, etc.

Some of the IOR completion technologies are briefly described below.

7.3. HORIZONTAL WELLS

Horizontal wells have become an extremely popular development option. Horizontal well nomenclature is brought in Figure 25. As shown, horizontal wells are frequently drilled parallel to a fluid contact or reservoir / non-reservoir rock contrast. The vertical distance to that contact is called the "standoff".

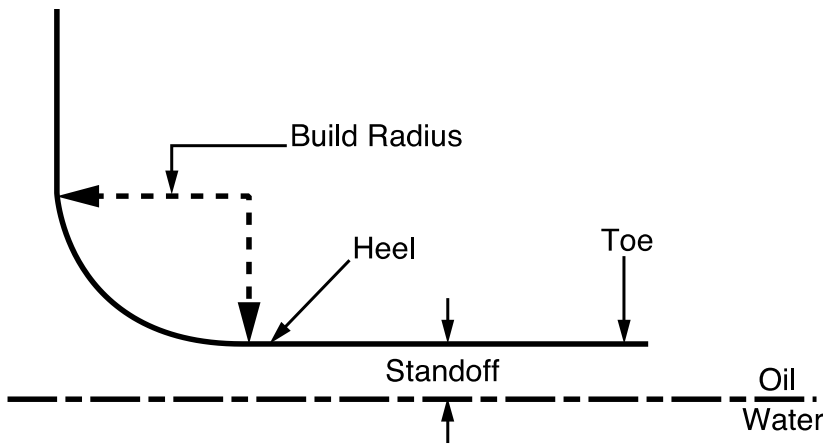


Figure 25: Horizontal well nomenclature

Note that horizontal wells are not strictly horizontal. E.g. by design they may follow the dip angle of a formation layer, while by construction the imperfect directional drilling control results in trajectory undulation though it can be considerably within ±0.5 m in the vertical direction when using the "measurement-while-drilling" MWD and "logging-while-drilling" LWD technologies. *During production, this undulating well geometry causes problems with water collecting in the low points and gas at the high points. Severe slugging (irregular well production with rapid, large changes in the phase fractions of the produced fluid) results when the deviation of the well trajectory from the horizontal increases and the production rate decreases. ('Lazy wells', i.e. the wells that take time to clean-up and reach the production rate level after a shut-in, also quite often have complex trajectory and similar problems.)*

The measured depth along the horizontal section can well be in the range of several kilometres. The limit on its length is actually often set by the reservoir management or completion installation requirements (e.g. the production casing can get stuck in a short build radius or undulating wellbore) and well access (by wireline or coiled tubing tools) considerations; but not necessarily drilling difficulties. As far as the horizontal well bottomhole completion is concerned, the same options and considerations apply as for vertical wells discussed earlier: the openhole completion and the cased-and-perforated one, with their variations such as with sandscreens or gravel packs or smart completions etc.

7.3.1 APPLICATIONS OF HORIZONTAL WELLS

Typical Horizontal well applications are summarised in Figure 26.

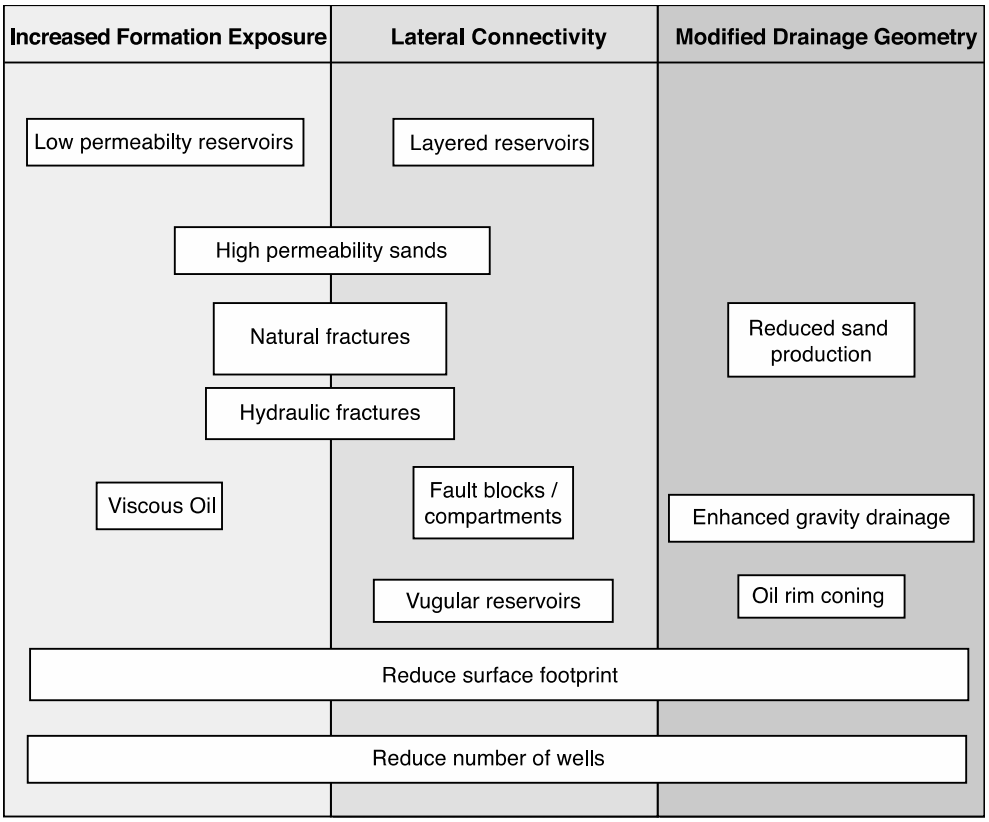


Figure 26: Horizontal well applications

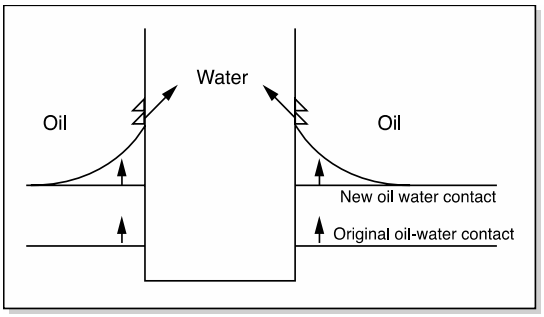
These applications include:

a) **Low permeability reservoirs**. **Viscous oil reservoirs. Oil-rim reservoirs. Reservoirs with a risk of high sand production** (i.e. the ones with weak sand zones causing high concentration of sand in the produced oil, which results in the well and flowline erosion, damage, and sand plugging).

   Horizontal wells are suitable for these applications because they have a longer production/injection interval in the reservoir (compared to vertical or deviated wells) resulting in a higher reservoir exposure (or contact), and thus their productivity is higher making it possible to either

   - produce at a higher flow rate (than a vertical well) at the equivalent drawdown, or
   - produce at the same target rate (as for a vertical well) but at a lower drawdown. Lowering the drawdown is often required, e.g. to control/reduce water or gas coning/cresting or sand production.

Figure 27(a) shows how the drawdown distorts (pulls) the water-oil contact next to the vertical wellbore. This allows the water to reach the well's bottom perforation despite it being placed some distance above Oil-Water contact. A similar phenomenon, often called cusping, draws the gas downwards from the gas cap towards the top perforation of a vertical well {Figure 27 (b)}. Horizontal wells experience an equivalent effect called 'cresting' (Figure 28b). Formation of such cone or crest, with a subsequent breakthrough of unwanted fluid (water or gas), is negatively affecting oil production.



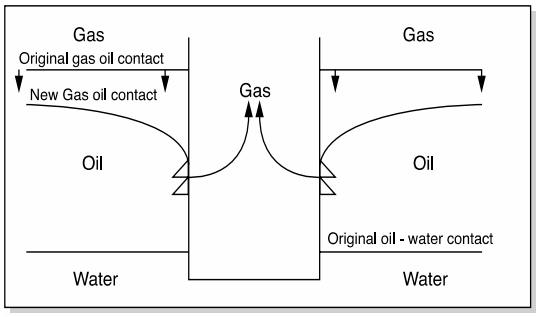


Figure 27: ***(a)*** *Water "coning".* ***(b)*** *Gas "cusping".*

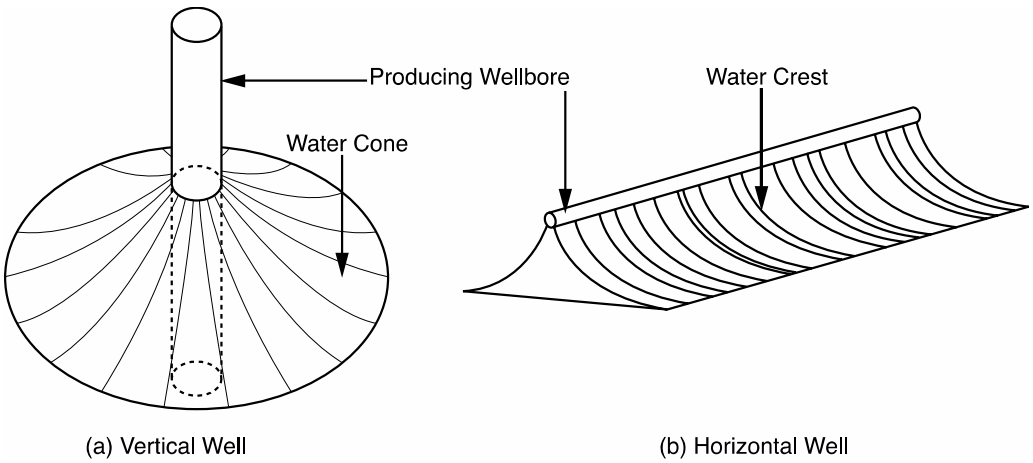


Figure 28: Production-induced water coning in a vertical well and cresting in a horizontal well

Clearly, the greater the distance of the horizontal well above the Water-Oil-Contact the greater the allowable drawdown before water production from the aquifer occurs. That's why the horizontal well standoff is carefully selected to both ensure suitable well productivity and slow down water cresting. The situation is more complex in oil-rim reservoirs (where a relatively narrow oil column is trapped between the aquifer below and the gas cap above) where the standoffs from both the gas and water contacts have to be just right for efficient oil drainage. Similarly, the lower the drawdown the slower crest propagation (and at some conditions it can even be halted or avoided).

Lower drawdown also means lower stresses acting on the reservoir rock during production. In many cases this prevents or significantly limits the rock failure and/or sand particles transport towards the wellbore, reducing sand production. This also improves wellbore stability (so that it does not collapse).

b) **Natural and hydraulic fractures.**

The efficient drainage with a horizontal well strongly depends on the reservoir vertical permeability because the reservoir fluid has to flow and converge vertically to the horizontal well. Reservoirs with low vertical permeability, e.g. shale-sand laminated formations, may not be good candidates for horizontal wells. To solve this problem, and to generally increase the well contact even further, the horizontal well can additionally have either artificial (e.g. hydraulic) fractures, or penetrate natural fractures (if there is a network of such fractures in the reservoir. Such networks are common in e.g. carbonate reservoirs), provided these fractures are good for oil production (i.e. they do not extend to an aquifer or a gas cap or water injection wells, all of which can flood the production well with water or gas via the fracture). In this context:

- Hydraulically fractured horizontal wells, especially with multiple fractures (Figure 29), are crucial in tight sand (i.e. very low permeability, < 0.1mD) and shale (i.e. extremely low permeability, nano-Darcy) oil and gas fields. So much so that in the 'unconventional', shale gas fields often only the Stimulated Rock Volume (SRV) between the well's hydraulic fractures can realistically be drained.

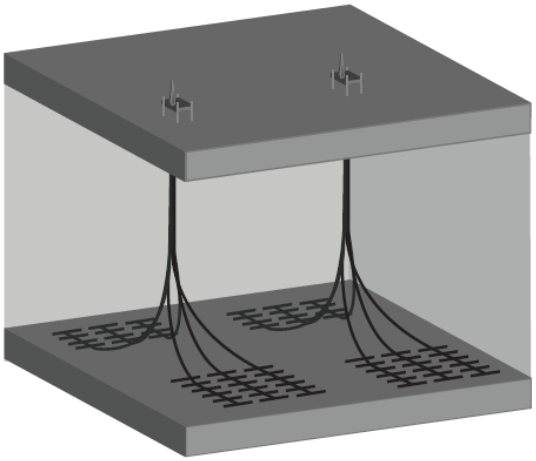


Figure 29: Horizontal wells with multiple fractures

- Naturally fractured reservoirs (such as many carbonate reservoirs, and Coal Bed Methane CBMs, etc.) are common. Their rock (or matrix) permeability is often too low for commercial production rates, so connecting the wellbore to and producing from the fractures is key.
- When such reservoirs are deeper than several hundred meters, these fractures are often oriented generally vertically. In this case, a horizontal well drilled perpendicular to the orientation of the open fractures has the best chance of intersecting them (compared to a vertical well), subject to the fracture density (Figure 30). For the same reason such wells are often left open hole (with or without a slotted liner depending on the competency of the reservoir rock) to make sure the penetrated fractures are not accidentally cemented or unperforated.

  The same conclusion applies in vugular (porosity) reservoirs, i.e. the reservoirs having regions with vugs, cavities, voids -type porosity, and these regions have a better chance to be accessed by a horizontal well.

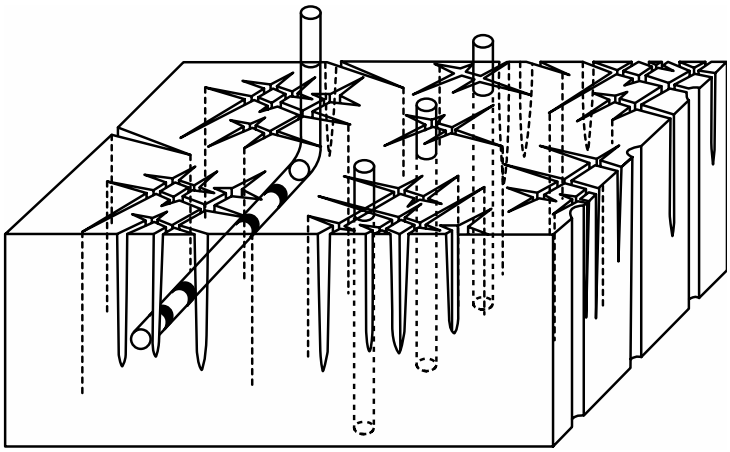


Figure 30: Vertical wells have a good chance to avoid the vertical fractures while horizontal wells drilled perpendicular to the fracture orientation connect many open fractures.

c) Layered and compartmentalised (blocked) reservoirs.

The horizontal well can also be used to connect reserves separated by a sealing layer of shale or in different fault blocks (Figure 31), provided it is cheaper than to drill a separate vertical or deviated well per each layer/block.

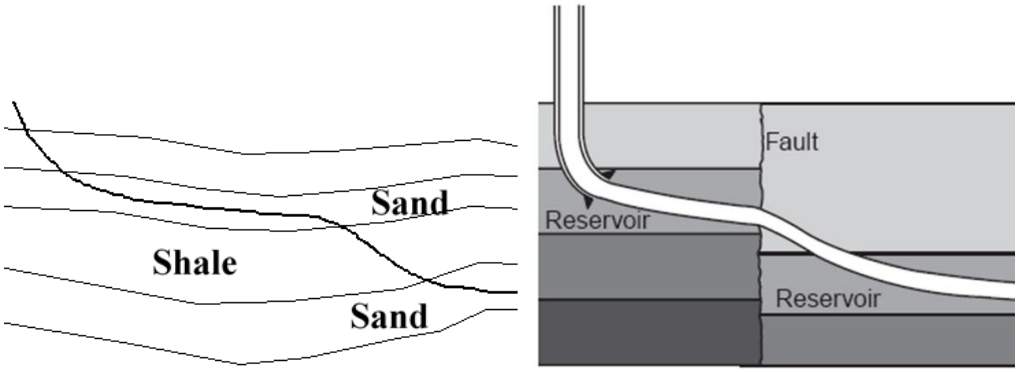


Figure 31: Reserves separated by a sealing shale layer or a fault may be produced by a horizontal well *(the sands in the left example could also be penetrated by a vertical well, but the horizontal one has a better, longer contact in these thin sands offering better productivity).*

Good quality seismic and an understanding of the field's structural history are required here. The reservoirs in different fault blocks may have significantly different initial pressures or the pressures may diverge during exploitation. Management of the inflow from the separate blocks using an intelligent well may be beneficial.

Either way, in all of the above cases horizontal wells generally improve drainage and sweep efficiency when drilled in the right direction e.g. parallel to the contact, or along the reservoir boundary, or perpendicular to the natural fractures, or towards unswept reserves (these unswept 'sweet spots' can remain due to them e.g. being bypassed by the advancing injection water), etc. This makes these wells a powerful tool in reservoir management for improved reserves access and drainage. They also improve reservoir monitoring having higher reservoir contact and as such providing more information about the reservoir via logging while drilling, core, openhole logging, production monitoring, etc.

N.B. For the reason of accessing unswept reserves it is also sometime practiced to drill out horizontal branch(es) (a.k.a. 'sidetracks', see Figure 34) from depleted or dry wellbores in mature fields, to access the regions of remaining reserves, subject to the completion and drilling limitations.

7.3.2 SOME FURTHER TYPES OF HORIZONTAL WELLS

A few types of horizontal wells are worth mentioning:

- Extended Reach (Drilling) Wells have a Horizontal Displacement to (True) Vertical Depth (TVD) ratio of at least 2:1.
- Maximum Reservoir Contact (MRC) wells are the wells with the reservoir contact longer than 5 km. This may be a horizontal well that long, or a multilateral well with the combined length of all its laterals that long.
- 'Snake wells' term is used by some operators to describe horizontal (or more complex trajectory, 'designer') wells producing from multiple, small-reserve fields or blocks with the ability to control and monitor zonal production.

7.4. SMART (OR INTELLIGENT) WELLS

Horizontal and multilateral wells often experience the problem of producing from different zones (layers, reservoirs, blocks…) that can strongly interfere due to different water or gas cuts or pressures, thus adversely affecting well production and the recovery factor. Ability to conveniently control zonal flow rates in such wells, without the need for well intervention, in many cases is highly beneficial. This particularly applies to subsea wells the intervention campaigns of which are complex, expensive and non-frequent.

Smart well completion installed in such wells offers zonal, downhole flow control capability. This is achieved by dividing the production/injection interval into several zones with packers, and installing flow control devices in each zone (Figure 32).

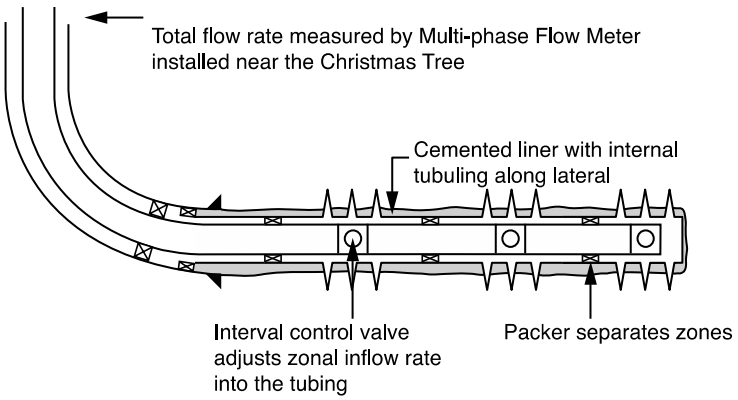


Figure 32: A three-zone intelligent well equipped with interval control valves

These devices by control can either be active (such as Interval Control Valves ICVs) the flow area of which is controllable in real-time from surface by hydraulic or electric lines, or passive (such as Inflow Control Devices ICDs) i.e. permanently pre-set to a certain flow control regime. ICDs often are merely joints offering restricted flow from annulus into tubing, e.g. by the means of orifices, narrow tubes, or nozzles. It is important to select the right restriction level (or 'strength') of the ICD design since it cannot

be changed after installation. *ICDs and ICVs can also be installed in injection wells for a more efficient allocation of injected water between zones.*

A more recent technology of Autonomous Inflow Control Devices and Valves (AICDs and AICVs) is a passive one with an extra degree of freedom: these devices are able to autonomously recognise and react to unwanted fluids (e.g. water, or also gas in oil wells) by increasing flow resistance.

In the wells equipped with ICVs it is also common to install downhole monitoring sensors to inform the operator in real-time what each zone is producing and therefore which one needs control. These sensors commonly include Permanent Downhole Gauges (PDGs) and/or fibre-optic sensors such as Distributed Temperature Sensors (DTS), Distributed Acoustic Sensors (DAS), pressure and temperature gauges. *The other benefits of having permanent downhole sensors include: reservoir monitoring, well completion monitoring, sand production allocation, etc.*

Intelligent well completions (IWCs) can be installed both in cased holes (as in Figure 32**)** or in open holes. In the latter case, either External Casing Packers (ECPs) or swellable packers are used for well zonation.

Additionally, sandscreens (and in some cases even gravel packs) can be added to protect the completion from excessive sand production.

Smart wells were originally developed as an answer to the problem of reservoir management in horizontal wells. Reservoir management has the objective of ensuring that the reserves of each flow unit are efficiently extracted with a minimum of unwanted fluids (e.g. water). This requires the ability to close-off perforated intervals and/or open new perforated intervals, operations that are all more difficult in a horizontal well, and even more expensive in a subsea well. More efficient reservoir management is achieved by IWCs.

As mentioned, smart wells also reduce the frequency at which well workovers are required; avoiding the increased costs and risks, such as formation damage, associated with conventional workover methods.

7.5. HORIZONTAL WELLS USED IN STEAM ASSISTED GRAVITY DRAINAGE (SAGD)

Viscous oil reservoirs are difficult to develop because their oil viscosity is hundreds or thousands times higher than that in conventional (light or medium) oil ones. Such oil has very low mobility and as such the well productivity is very low. Solvent injection (to dilute the oil and thus decrease its viscosity) can be used to improve production, though the use of thermal recovery methods is more common in these cases. These methods aim to increase the reservoir temperature, which significantly decreases oil viscosity. The methods include internal combustion, electric heating, and much more commonly: the use of steam. The steam (or sometimes a diluent instead) can be used to periodically circulate in or inject into the production well, followed by back production of the hot water and oil ('huff and puff', cyclic injection methods); or for continuous steam injection in injection wells (steam flood), etc. and, more commonly, in Steam Assisted Gravity Drainage (SAGD).

In SAGD, dual horizontal wells with 5 - 10 m vertical separation (Figure 33) are used for heavy oil production from relatively shallow (often ~ 600 m TVD) reservoirs. *Slant well drilling, where the wellhead is installed at an angle of 45°, can be used to minimise the deviation angle through which the well has to be turned.*

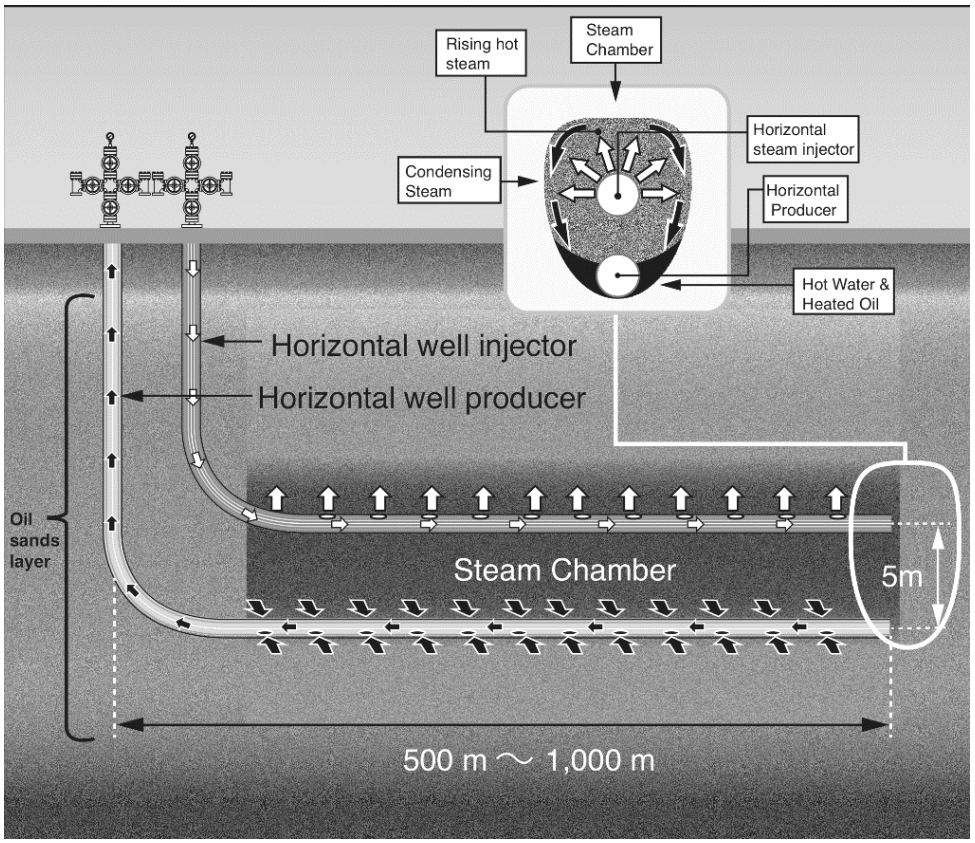


Figure 33: Steam Assisted Gravity Drainage employs a doublet of Horizontal Wells to recover high viscosity oil

The steam is injected into the top well, accumulating and heating the ever-increasing rock volume around it (called 'steam chamber'). The heated, less viscous oil flows down the boundaries of the chamber (partly due to gravity) to the production well at the bottom. The wells are often left openhole and completed with slotted or pre-perforated liners, alternatively with screens. Thermally insulated tubing is sometimes used to keep the fluids hot while injecting/producing.

Alternative to thermal recovery methods, Cold Heavy Oil Production with Sand (CHOPS) method is sometimes an efficient alternative. In this case the (often vertical) well is allowed to produce with high volumes of sand, without thermal methods. The wellbore is equipped with a slotted or pre-perforated liner or is cased and perforated to avoid wellbore collapse. High sand production causes the reservoir around the wellbore to dilate and form cavities, and thus the wellbore to enlarge, improving the well productivity. The well completion and artificial lift have to be designed to survive high sand production.

7.6. A NOTE ON MATERIAL SELECTION IN ADVANCED WELLS

It is clear now that many advanced well completions are exposed to quite hostile environments. E.g. in thermal recovery wells this is steam injection causing completion metal yield and experience high-temperature service; in CO_2 injection wells (e.g. for EOR purposes; or to store CO_2 in an aquifer or in a depleted reservoir instead of releasing it to air mindful of climate change) this can be CO_2 –caused corrosion, dissolution or other damage; in high-pressure high-temperature (HPHT where P_R>15000 psi, T_R> 350° F) wells this is obviously severe HPHT service; in Water-Alternating-Gas (WAG) injectors that periodically inject water followed by gas to improve sweep: these are big changes in the wellbore pressure and temperature, etc. In all these cases the specialist, non-conventional completion, metallurgy, cement type, elastomer type, etc. is often required that is able to withstand these conditions. Other than that, such wells' completion design principles are not very different from the ones described earlier in this chapter.

7.7. MULTILATERAL WELLS

7.7.1 MULTILATERAL WELL COMPLETION PRINCIPLES

A multi-branch well is defined as "a well which has more than one vertical, inclined or horizontal hole drilled from and connected back to the 'mother' wellbore". This section focuses on multi-laterals in which the branches are horizontal or close to horizontal in the reservoir. See an example in Figure 34 where a horizontal lateral connects to the vertical motherbore. This lateral increases the well reservoir contact in the top, low permeability layer allowing the well to efficiently produce its reserves.

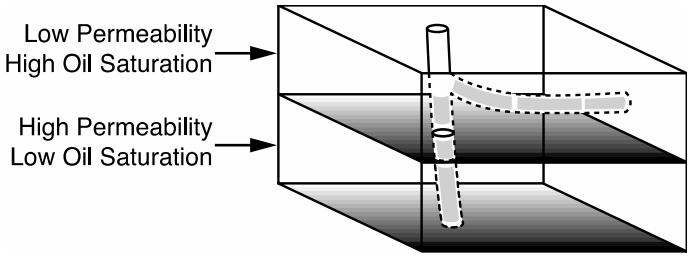


Figure 34: A multilateral well example

The main reason for drilling a multi-lateral well is to improve reservoir drainage even though the initial well cost is higher. The increased reservoir contact results in higher production rates and improved sweep which eventually brings higher return on investment. However, the risks and experience of constructing a multilateral well, compared to several equivalent conventional wells, must be factored in.

Multilateral wells have various levels of sophistication in their completion design, from simple openhole sidetracks to the wells where the branches could be re-entered or isolated selectively. This particularly applies to the construction of the multi-lateral junction to achieve zonal isolation and allow re-entry. The sophistication of the well completion at the junction is commonly classified into six levels proposed by the 'Technical Advancement for Multilaterals' (TAML) joint industry group. These range from TAML Level 1, where both the motherbore and the lateral are left openhole at the junction (this makes sense if the rock at the junction is strong and non-permeable) and the production from both branches is commingled, to TAML Level 6 where both branches are cased and cemented and there is an option for selective production. An example of TAML Level 5 junction is presented in Figure 35 where the motherbore is cased and cemented while the two laterals are openhole completed with slotted liners and the ability to control production from either lateral: the top lateral can be shut-off by closing the SSD installed at its mouth, while the bottom lateral can be shut-off with a plug. *(Intelligent completion could have been used here for the same objective).*

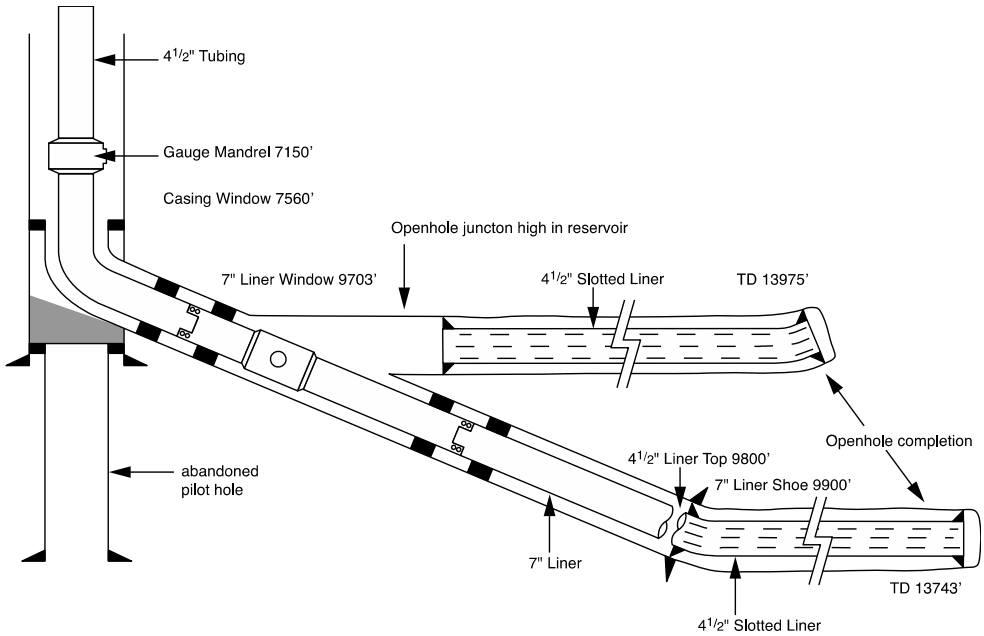


Figure 35: A multi-lateral completion example

There are many constraints in multi-lateral well design related to the operation of sidetracking out of the primary wellbore and the shape of the target reservoir(s). For example, the laterals have a smaller diameter than the motherbore, and sometimes have quite short build radii. Thus, the laterals may have different lengths and different completions as a result of such geometric constraints. If the primary wellbore is highly deviated then the azimuthal separation between the laterals will be restricted. The process of multi-lateral well design often involves iterations between (directional) drillers, geologists and reservoir engineers before a satisfactory solution is found.

Many factors influence the decision of whether to deploy a multi-lateral. They can be used in new or existing fields; it being helpful to have some experience of constructing horizontal wells in the area. In some cases, a lateral can be drilled in a new direction to acquire exploration/appraisal data and depending on its success, either be retained for production/injection or abandoned.
Similar to the zonal production interference in horizontal wells, the laterals too can interfere e.g. when they are

- Producing from the same reservoir and are competing for the drainage area;
- Producing from different reservoirs or blocks that have different water or gas cuts or pressures. This may result in the laterals interfering in terms of back-pressure or cross-flow in the wellbore.

Thus the positioning of the laterals in the reservoir will be critical and it may be necessary to provide intervention possibilities to facilitate reservoir management.

As for the positioning, the three basic geometries of Multi-Laterals are (Figure 36):

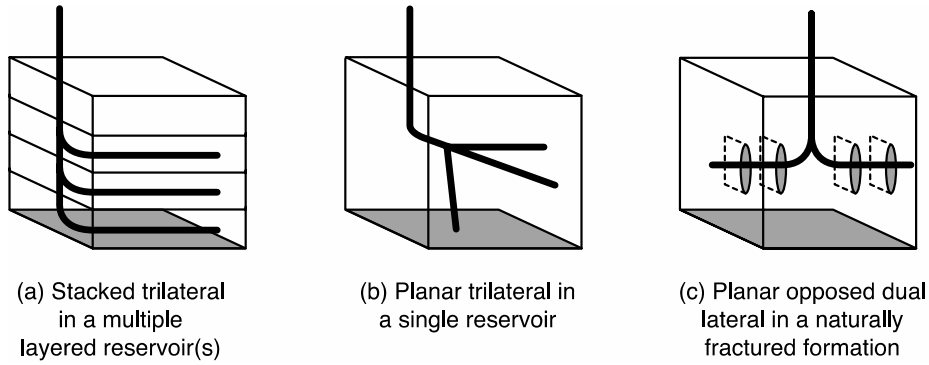


Figure 36: Multi-lateral well designs.

a) Stacked configuration (Figure 36a) is used for developing a non-communicating, layered reservoir. It is also useful in a single massive, low permeability reservoir where there is a long period of transient production before interference between the laterals becomes significant.

b) Planar configuration (Figure 36b) is often used in naturally fractured reservoirs where there is some uncertainty about fracture orientation. Three laterals at an angle of 45º result in almost certain intersection of the fractures at a reasonable angle to the original well, unless the spatial distribution of fractures is highly clustered.
Alternatively, planar branches can be added to produce from a non-fractured reservoir for the sake of higher reservoir contact, higher production rate and faster recovery. The branches can e.g. be arranged in a 'fishbone' style (like in Figure 36b) or a 'fork' style (when they are parallel at the toe like e.g. the top and bottom laterals in Figure 35).

c) Dual-opposed configuration (Figure 36c) has the advantage of giving the largest drainage area for a given length of horizontal wellbore with a minimum distance the fluid has to flow to reach the heel (and hence minimum pressure losses in the wellbore).

7.7.2 BENEFITS AND APPLICATIONS OF MULTI-LATERAL WELLS

Technical advantages of multi-laterals rest on their greater reservoir exposure at a lower cost. The economic benefits of multi-lateral wells arise from the fact that the conduit (i.e. the motherbore) from surface to the reservoir only has to be drilled and cased once. Multi-laterals can have a major impact offshore by increasing the production and pay section exposure for each slot available from a fixed platform or subsea template (*such templates have a limited number of slots for wells*). Multi-Laterals reduce the capital cost since the target rate ca be achieved with fewer wells, and the cost of platforms and templates is related to the number of slots; allowing marginal fields to be transformed into economically viable developments.

The same effect can benefit onshore developments by reducing the pad size of the drilling location due to having fewer wells per pad. Costs will be reduced simply through having fewer wells, as well as a smaller "footprint" on surface.

There are economic disadvantages that need to be recognised at the planning stage. Risk is now being concentrated into a smaller number of wells, so a loss of a single well will result in significant production losses. In the longer term there may be additional operating costs due to uncertainties in the reservoir and mechanical performance. E.g. some branches may experience premature water or gas breakthrough and require a difficult shut-off operation.

Multi-laterals generally entail greater risk. The construction (i.e. drilling and completion) of multilaterals has higher risks and requires specialist equipment and expertise. It also introduces new difficulties in well control and also in impairment and cleanup of individual branches. Well intervention will be more difficult and reservoir monitoring and management that requires such intervention is often limited in scope.

There are numerous applications of multi-lateral wells. Many of them are similar to those listed earlier for horizontal wells, and for similar reasons. Popular examples include:

- Viscous oil reservoirs have a productivity that is, in general, constrained by poor oil mobility, i.e. the ratio of oil [Permeability/Viscosity] is low. This is combatted, along with the associated high drawdowns, by maximum formation exposure.

- Layered reservoirs can be efficiently exploited using the stacked multi-lateral configuration (Figure 36a). Care must be taken to evaluate the degree of interaction of the laterals in the completion. If the pressure regimes are significantly different then it may be necessary to install separate tubings or a "smart" completion with downhole flow control values.

- Naturally Fractured and Low Permeability Reservoirs

  Tight sand (low permeability) and naturally fractured reservoirs can be exploited using planar configurations with two or more laterals being used (Figure 36b,c). For tight, unfractured reservoirs a number of branches at various angles will be appropriate, increasing the reservoir exposure cost effectively. For the naturally fractured case it depends on how well the branches cross the maximum number of fractures.

- Faulted and compartmentalised reservoirs are good candidates for multi-lateral application, especially if some of the compartments have reserves below the level at which an individual well could be justified. In drilling such wells, knowledge of the fault locations and experience of drilling in the fault zone will be important. A high-resolution, 3D seismic survey with good well control will make well placement easier.

- Depleted or mature reservoirs are candidates for multi-lateral well application especially when the pace of development in the various zones is different. Figure 34 shows two zones, one with good permeability, of low oil saturation while the other has a lower permeability and a greater oil saturation. The high permeability layer can produce quite well through a vertical wellbore but the low permeability one is better suited for a horizontal wellbore. The aim is to produce comparable oil rates from each lateral.
  Alternatively, the sweet spots in the mature fields can be mapped (e.g. by 4D seismic and/or reservoir model history matching) and sidetracks from the existing wells can be drilled to reach these spots.

- Reservoirs where low drawdown is preferred (e.g. for the reasons of water or gas coning control, sand production risk, etc.). Multilateral wells (especially MRC wells) have high productivity and so can produce at the target flow rate and low drawdown.

8. RECOMMENDED READING

1. "Petroleum Well Construction" by Economides, M.J., Watters, L. T. and Dunn- Norman, S. Published by John Wiley & Sons Ltd. Library of Congress No. TN871.2P487 1988 and ISBN 0 471 96938 9

2. "Well Completion Design" by Bellarby, J. Volume 56 of Developments in Petroleum Science. First Edition published by Elsevier in 2009. ISBN 978-0- 44-53210-7 and ISSN 0376-7361

3. "Well Completion and Servicing" by D. Perrin, Editions Technip, Paris, 1999

4. "Well Control for Completions and Interventions" by H. Crumpton, Elsevier, 2018

CHAPTER 2: WELL SERVICING

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LEARNING OBJECTIVES

(All Examinable)

Having worked through this chapter the Student will be able to:

- Explain the need for well servicing and intervention, and their benefits.
- List and describe the equipment and operational concepts involved in wireline, coiled tubing and hydraulic workover interventions.
- Describe the typical applications of wireline, coiled tubing, and snubbing interventions.
- Describe well pressure control, tool conveyance problems, and safety issues associated with the different types of well interventions.
- Explain the reasons for and principles of the tubing retrieval.
- Analyse a given well problem and propose the optimal intervention program to rectify it.
- List, locate and describe the measurements routinely taken in wells. Explain their applications.
- Explain the objectives of production logging. Propose the logging tools suitable for these objectives.
- Describe the production logging tools' types and measurement principles. Explain how these measurements are related to the fluid and formation properties as well as to flow phenomena.

1. INTRODUCTION

A production or injection well may be designed for maximum efficiency but will always be subject to failure or declining performance. These problems can be attributed to either:

(1) Mechanical malfunction or the need for redesign of the completion equipment to adapt to changing reservoir conditions

(2) Changes in reservoir performance or flow characteristics as a result of reservoir dynamics and recovery mechanism.

Problems on wells can largely be associated with one of three areas, namely:

(1) The reservoir
(2) The completion string
(3) The wellbore

Normally, presence of a problem on a production or injection well is evident by information gathered at surface, in relation to flowrate, pressure, flowing fluid composition, etc.

- *Feel free to suggest such problem identification scenarios.*

Well Servicing implies carrying out routine interventions aimed at collecting information about the well and reservoir status, and at rectifying the above-mentioned problems. Before a problem can be rectified on a particular well, the nature of the problem has to be investigated and clarified, often by taking in-well measurements by the means of production logging and other types of in-well monitoring. Once this has been accomplished the options available to the company to intervene to correct the problem can then be drawn up and evaluated. Sometimes a relatively simple, wireline or coiled tubing intervention (e.g. to change a valve, open a sliding side door or clean out a sand fill) is sufficient. Otherwise, a more complex intervention (i.e. a 'workover') to deal with the well and reservoir problems may be needed. It is also crucial to make sure that the option selected to correct the problem will yield the best probable economic benefit to the company.

The benefits of well servicing could include:
(a) Enhancement or restoration of safety
(b) Reduction in operating costs
(c) Acceleration of the production revenue
(d) Increase in the ultimate recovery

In this chapter we will discuss the well intervention types, the problems associated with the completion string, and briefly the production logging methods. *As for the problems associated with the reservoir deliverability: many of them are often solved by stimulation (e.g. hydraulic fracturing or acid injection) or (re-)perforation which are discussed separately, later in this course.*

In general, the problems associated with the completion string can be classified as follows:

- Problems which arise in the tubing bore and which can be corrected by concentric through tubing operations (e.g. using wireline, coiled tubing, or snubbing units). These problems may include: scale buildup or sand fill requiring cleaning; need for equipment exchange and/or operation, etc.

- Problems which necessitate the retrieval of the completion string from the well (e.g. a component failure/leak or tubing collapse/leak that cannot be rectified otherwise).

Note that some operations may not need well access, e.g. the ones like adjusting the surface choke, or replacing a Xmas tree valve, or testing an SSSV or a surface-safety valve (SSV).

➢ *Feel free to attempt Tutorial 1 a) and b).*

2. WIRELINE INTERVENTIONS

The majority of well completions use wireline techniques for basic well maintenance. These involve light operations, which are relatively low-cost and fast, that can be carried out on live wells (which results in no or little production loss during well intervention nor problems with the kill fluid damaging formation or loading the well), need minimum, lightweight surface equipment, and in many cases can eliminate the need to pull the completion string (which is an expensive, 'heavy' workover operation) by operating equipment in the well and/or by replacing the components which have failed (provided this equipment is wireline-retrievable). Use of wireline will, in many cases, be a quicker, more economical alternative to mobilising a drilling or workover rig to pull the tubing string to replace faulty equipment. However, the wireline operator at the surface is physically very remote from the downhole location where the tool must operate. This remoteness coupled with the uncertainty of cable stretch (especially important in deviated wells) and the small diameter of the tools makes wireline a technique which requires highly skilled personnel in order to be effective. Nevertheless, incorporation of wireline operated equipment into the completion string design provides an increased degree of flexibility in terms of well operations and servicing capability.

Typical wireline applications are:

- Well logging.
- Installation of completion equipment prior to running the production tubing e.g. a packer and a tailpipe assembly.
- Installation or retrieval of equipment within the tubing string e.g. valves, pressure gauges, etc.
- Operation of downhole equipment to either divert or shut off fluid flow e.g. open a sliding side door or install a bridge plug.
- Removal of (rather soft) materials, which have built up in the tubing string, such as wax, debris or sand.
- Well kick-off e.g. by swabbing.
- Adjustment of the completion interval e.g. by perforating.

A wireline operation involves lowering a tool into the tubing to perform a specific function. The tool forms part of a tool string suspended on either a single strand wire ('slick wireline' or 'slickline') or, a braided (or multi-strand) cable. In some operations, such as logging, an electric line ('e-line') can be used e.g. for continuous logging tool powering and/or surface read-out. (An e-line is also a braided cable that has one or several conductive strands). *In some cases nowadays one or more fibre-optic lines can be added to the cable to allow continuous measurement of e.g. distributed or discrete temperature or acoustic noise.*

2.2 Wireline Tool String

In the completion string servicing operations the wireline tool string (Figure 1), connected to the wireline by a rope socket, normally consists of (top down):

- One or more stems (*essentially equivalent to a sinker bar*), the high weight of which helps lowering the tool into the well under pressure– otherwise the tool string can be ejected out of the well. *(Generally in all types of well interventions, including wireline, coiled tubing, etc. an assessment of the loads, piston and buckling forces on the string is important. For instance, when running a coiled or snubbing tubing into a live well at high tubing pressure, initially pushing may be needed (during the 'snubbing' phase for 'pipe light' conditions) till the 'balance point' depth from which the weight of the string in the well is high enough to go down on its own ('stripping' phase for 'pipe heavy' conditions).)*

➢ *Feel free to relate this phenomenon to the load calculations provided earlier in this course.*

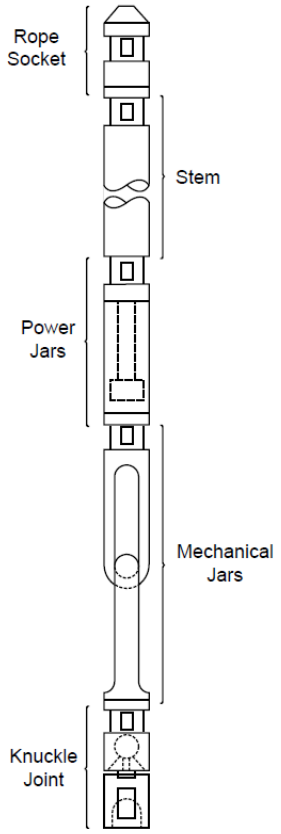

Figure 1: Schematic of a Wireline Tool String

- One or several jars. Their jarring effect (making it jolt upwards or downwards) is what often activates the mechanism that will carry out the required, mechanical tool action (e.g. valve setting or retrieval, scraping, shearing a pin in a tool, etc.). *Alternatively, a cable with an electrical conductor to generate an electric signal can be used to initiate the required action.* Since the operation of all wireline equipment is affected by mechanical impact, it is essential that the tool string can deliver the weight of the stem bar as a jolt or jar to the operating tool. This is accomplished by placing a set of jars immediately below the stem. Most frequently used, mechanical jars (spang jars or tubular jars), as depicted in Figure 1, are employed and these can be used to create a jarring force applying a hammer blow in either the upwards or downwards direction. The action is such that these jars are sometimes referred to as stroke jars. Hydraulic jars and accelerators can be added, though they normally allow only upward strokes.

- Optionally, a knuckle joint can be added (along with kick-over tools) for the cases of e.g. performing installation to or retrieval from side pocket mandrels, and similar tasks.

- Specialist equipment required for the job in question, e.g. a valve, a plug, a sensor, a gauge cutter, a swage, a wireline spear, a sand bailer (that collects sand filling the well), a brush, a scratcher, a caliper (measuring the internal diameter), a tubing puncher (to perforate the tubing e.g. when the sliding sleeve is stuck), a lock mandrel (to carry a tool), etc. A few examples are shown in Figure 2: a) a gauge cutter is run first before any intervention operation to make sure the tubing is not obstructed, and to possibly remove scale buildup (provided it is sufficiently soft); b) a swage may be needed to open a partially collapsed tubing (there is a risk of the swage itself getting stuck though); c) in the cases where 'fish' (i.e. any item blocking the well) is a wireline tool with a broken wire that has entangled (i.e. has formed a 'nest'), a wireline spear (or 'grab') may be able to grab it. Many more wireline tool types are used depending on the job. The jobs can be generally classified as:
    - checking and cleaning;
    - taking measurements;
    - setting, pulling, or operating tools.

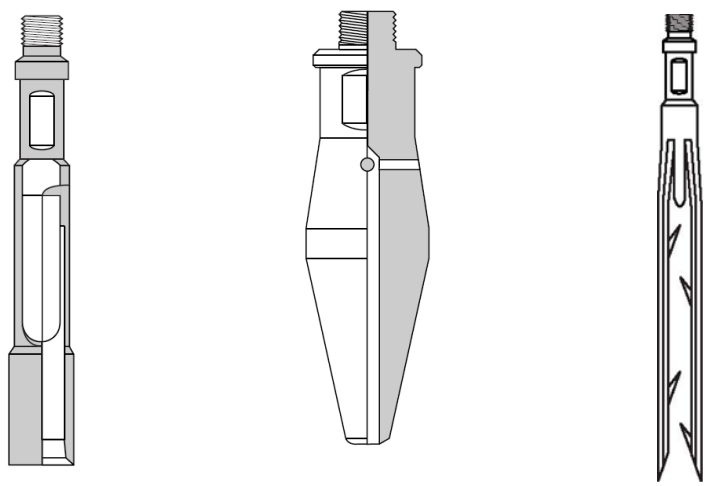

Figure 2: a) Gauge Cutter; b) Swage; c) Wireline spear

2.2 Surface Equipment

Wireline's greatest asset is the ability to conduct operations on a "live" well i.e. the one where communication exists between the reservoir, the wellbore and the top of the tubing. Hence high pressure is present at the Xmas tree during a wireline intervention and the surface wireline equipment must allow to insert the tool string into the live well and to prevent pressurized well fluid from escaping into the environment.

The components of a conventional wireline system are shown in Figure 3. A BOP (a.k.a. a 'wireline valve') and a lubricator (a tubing string made up of one or several tubing joints) supported by a gin pole are attached to the Xmas tree. The wire is supplied by a winch. The lubricator (Figure 4) has a stuffing box (for slickline operations) or a grease injection head (for a braded cable) on top ensuring the wireline is sealed, and a pressure release valve at the bottom to bleed the high pressure off the lubricator after the tool is returned to the lubricator and the swab valve or BOP is closed.

Essentially, when operating on a live well the tool string is inserted into the lubricator and connected to the wire. *(Hence the lubricator's length is one of the factors that limit the length of the tool string.)*. The lubricator with the toolstring inside is then mounted on the Xmas tree. Then the swab valve is opened and the tool is lowered downhole. The well pressure and fluid are contained within the lubricator.

- *Feel free to propose the sequence of steps needed to remove a wireline tool string from a live well.*

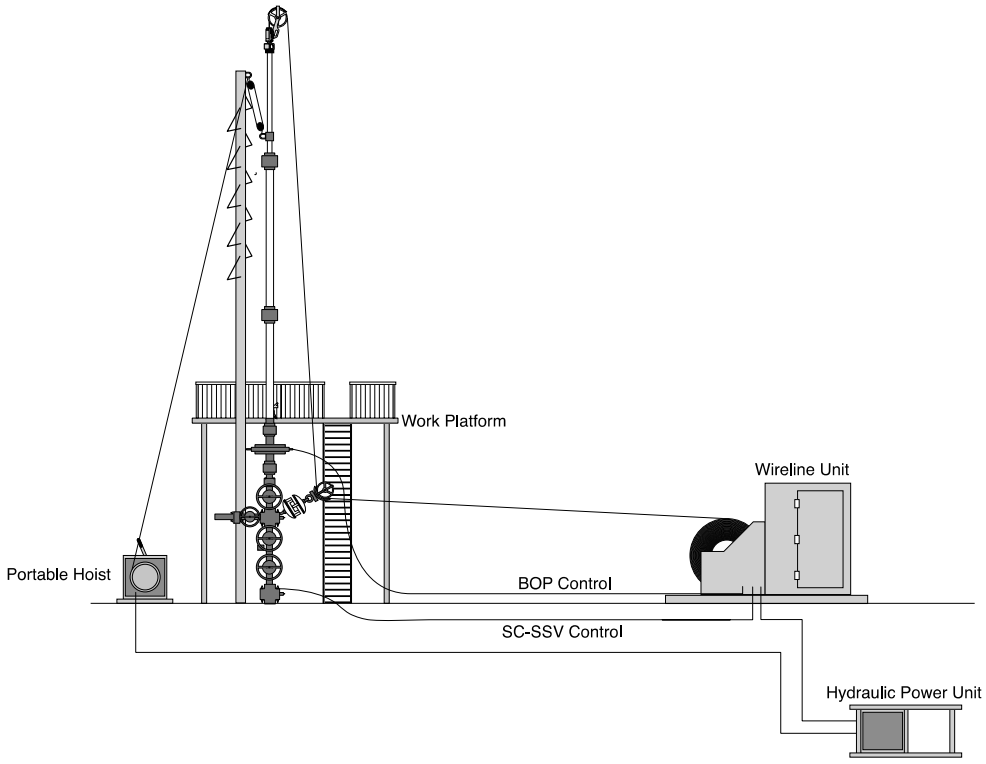

Figure 3: Wireline Surface Equipment

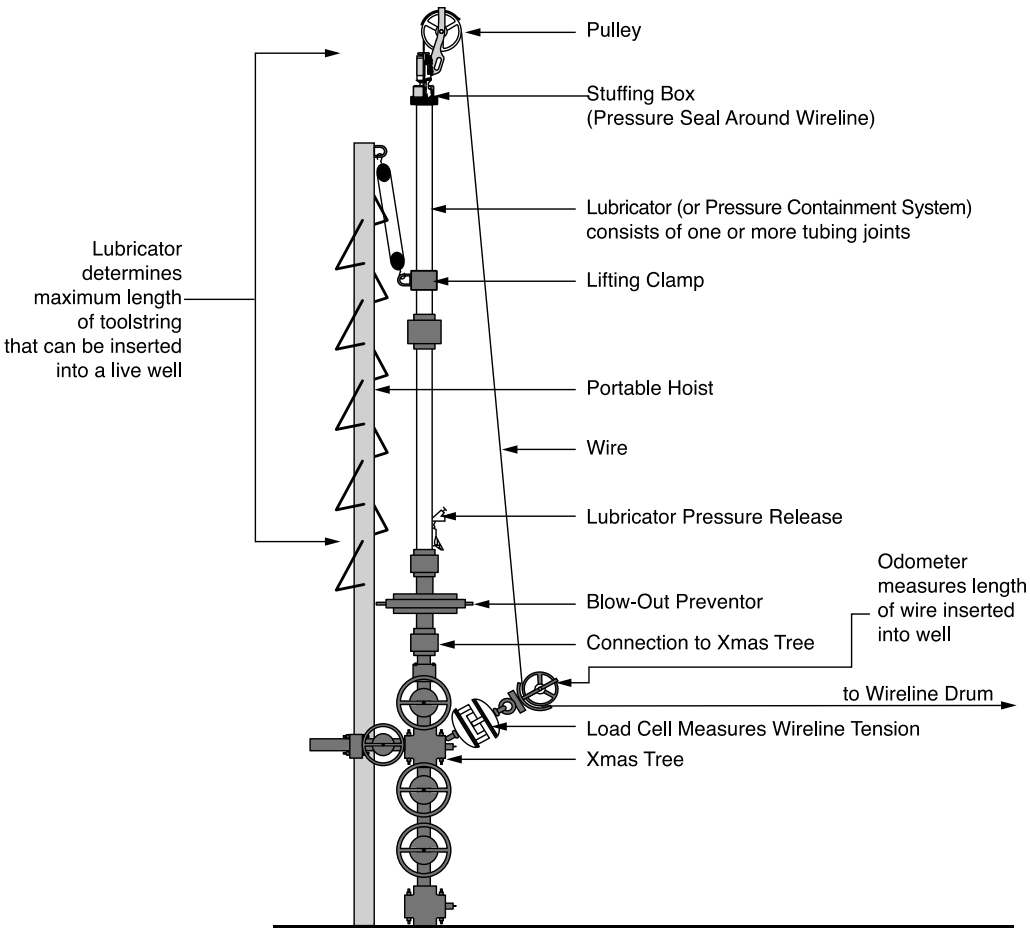

Figure 4: Detailed view of Wireline Surface Equipment mounted on Xmas Tree

The important parameters that the wireline operator must be aware of at all times during well operations are the tool string location (depth in the well) and the tension on the cable (to ensure that the breaking strength of the cable is not exceeded). The length of cable (measured by an odometer) in the well gives an approximate depth for the tool string (approximate because the wire can stretch under load, which is difficult to accurately predict), whereas the tension is measured by a load cell connected to one of the pulleys.

A similar lubricator-assisted well access principles can be also used on subsea wells. In this case the tool string can be guided across the sea water from a ship or a platform into the lubricator attached to the seabed Xmas tree, unless the lubricator extends to surface. Remote operation of the equipment at the wellhead can be carried out by e.g. a diver or an ROV (remotely operated vehicle) operated from surface using e.g. electric cables ('umbilicals').
Subsea wells are tied back to the production facility with flowlines, so it is also possible to alternatively perform some operations using Through Flow Line (TFL) techniques, which imply pumping the tools downhole via the tieback lines. However, a rather complex, dual-tubing well completion is required to have been installed in such wells. TFL can also be applied in highly deviated wells.

The maximum well deviation (from vertical) angle for conventional wireline operations is about 65º due to the increasing friction of the wire and tool string against the tubing and production casing or liner, which prevents delivery of the tool downhole. Wireline servicing of such wells requires use of an electrically driven 'tractor' device added to the tool string, that pulls the tool string into the well. Tractors allow servicing of wells with higher deviation angles, but they require substitution of the slick (solid) wire by a (more expensive) electrical cable as well as hire of the tractor itself. *Alternatively, coiled tubing or snubbing unit can be used to access deviated sections of a well, as is explained later.*
As mentioned, an assessment of the forces and loads acting on the tool string is preferred in all types of well intervention. The same applies to the corrosion considerations (wires or tubulars of different steel grades are available for different corrosivity conditions).

3. COILED TUBING INTERVENTIONS

In addition to the wireline operations, it is possible to access and intervene inside the production tubing using concentric tubing techniques like coiled tubing or snubbing. However in this case these would be considered 'heavy' operations involving larger-scale equipment. They have an advantage compared to wireline in that they can be additionally used to circulate fluids, to accurately place ('spot') a cement plug, to put weight on a downhole tool (*this does not apply to small size coiled tubing though*), to run heavier equipment, and to access highly deviated well sections. Same as wireline, they can be used on live wells.

Coiled tubing (CT) operations involve the mechanical insertion of a small bore, steel tube which is unwound continuously from a reel and driven into the well, optionally under pressure. Ideally the coiled tubing bending should stay within its steel's elastic limits, though this is seldom the case so the CTs have to be changed after multiple uses due to the metal fatigue. Coiled tubing is available in lengths up to tens of thousand feet of continuous reel, depending upon its outside diameter. It normally has a small diameter of around 0.75 - 1.5 inches, although larger CTs are sometimes used. Sometimes a fibre-optic line for taking measurements is attached to CT. The coiled tubing operations can include:

(a) Mechanical operations such as fishing or where devices within the tubing can be operated (hydraulically or mechanically), retrieved or inserted.

(b) Circulation operations such as the well clean-out, the placement of acids or other chemicals, or cement (or polymer gel) to squeeze out at selected perforated intervals *(e.g. to stop production of water or gas from them)*. In addition, CT can be used to kick-off (e.g. by gas lifting or pumping) or kill the well; or as a velocity string to extend the life of a production well where its flow is adversely affected by phase slippage (*in a smaller, 'velocity' string the liquid and gas flow across a smaller tubing they mix more efficiently and lose less pressure. Read more about slippage and flow patterns in Chapter 3*).

(c) Drilling or milling operations.

(d) Perforating.

The general configuration of a coiled tubing unit is shown in Figure 5. It consists of:

(1) A reel of continuous tubing
(2) A tubing straightener or gooseneck
(3) An injector head which will drive the tubing into/out of the well, as well as support the tubing
(4) A stripper (or pack-off) which is a dynamic seal, and below it:
(5) A BOP.

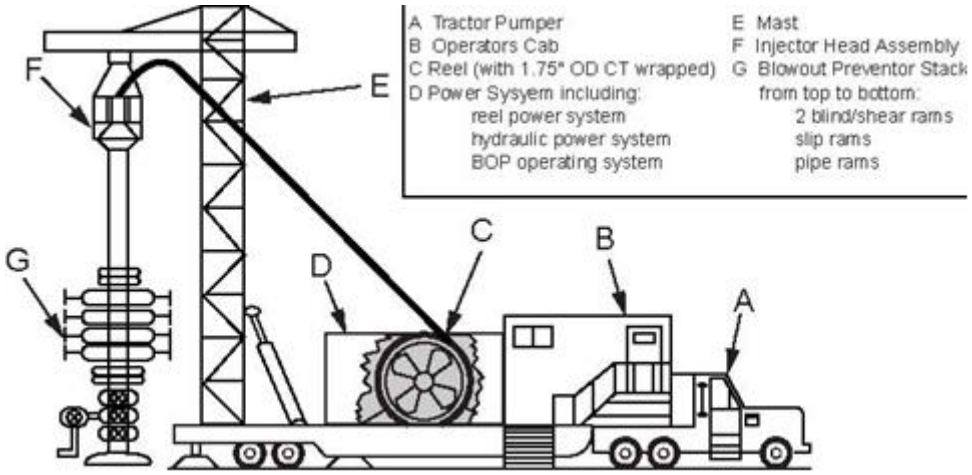

Figure 5: Schematic of Coiled Tubing Facility

The work tools can be added to the lower end of the CT (a.k.a. the CT BHA – bottomhole assembly), e.g. nozzles for spotting acid, hydraulic motors for drilling, an overshot for fishing, etc.

As mentioned, CT can be run under pressure (in live wells). Often one or more check valves are also installed at its lower end as a fluid barrier.

For offshore applications the system can be supplied as a series of vessel mounted modules.

All in all, CT is a popular technique in well servicing (especially of horizontal wells) representing an economic way of conducting a whole range of workover operations.

4. SNUBBING

Snubbing is similar to the coiled tubing in operation and objectives, except it uses tubing-type joints instead of continuous tubing. Thus, the pipe is not bent or reeled and so a larger diameter pipe can be used (though still limited by the size of the completion tubing into which it is run), offering a better load, rotation and flow capacity. However, subbing is a more complex and slow an operation, and is less safe.

Snubbing requires specialist equipment, including:

- A pipe handling system (similar to or the same as the Hydraulic WOrkover HWO unit shown in Figure 6) which normally consists of double acting jacks: one standing (with stationery slips) and one travelling (with travelling sips) in strokes 10-40 ft long, pushing the snubbing pipe downhole once every next joint is made up (or vice versa, pulling it out at the return trip).
- A wellhead safety system consisting of a BOP and a stripper.

- A hydraulic power unit to drive the jack(s) and auxiliary pumps.

One or more check valves must be added to the lower end (or close to it) of the snubbing pipe to prevent fluid inflow from a live well.

Snubbing of a small size tubing (1 in. or less – a 'macaroni' pipe) is a lightweight workover that can use a lightweight, 'macaroni' rig.

As mentioned, the above-described types of intervention (wireline, CT or snubbing) can be performed on live wells. However, there are many operations that require the well to be killed. These include the case when the completion tubing needs to be retrieved:

5. TUBING RETRIEVAL TECHNIQUES

As far as the tubing retrieval is concerned, there are a large number of problems which may occur on the well which necessitate the retrieval. These would include:

(1) Mechanical failure of the tubing string, for example a leak or collapse of the tubing

(2) Inability to conduct tubing wireline equipment replacement through the internal bore of the string due to ID limitations - small tubing size.

(3) The necessary replacement of the completion string by an alternative design, for example to allow the installation of artificial lift.

(4) The replacement of the tubing string to optimise reservoir performance, for example to change the tubing string to a smaller size to better accommodate declining reservoir productivity.

5.1 Tubing Retrieval Equipment

In general terms, the requirement for pulling tubing may be either full retrieval of the tubing or alternatively partial retrieval of the tubing string to the depth whereby components can be accessed at the surface, e.g.: the partial retrieval of tubing only to allow access and replacement of a tubing retrievable sub-surface safety valve.

Equipment available to conduct such operations could be either:

a. A full drilling rig or equivalent (a workover rig).

b. A concentric unit which can be installed over the producing well. This can be either a lightweight unit ('servicing' or 'pulling' unit) suitable for relatively shallow wells with moderate loads or for rod pump service, or a heavyweight one (also called a workover rig).

Either of these will have the necessary safety equipment (e.g. a BOP) and the capacity to pull tubing.

Selection of the rig type depends on their availability, the nature of the operation, well access constraints, and economics.

An example of a hydraulic workover mast is shown in Figure 6. Its operation principle is similar to the snubbing unit's described above: it consists of a double slip system which will engage on a length of tubing,

one set of slips will be travelling and used to reciprocate on a cyclic basis and withdraw tubing, the other set of slips will be static and will be used to clamp and pull tubing into position whilst the travelling slips are re-positioned on the tubing.

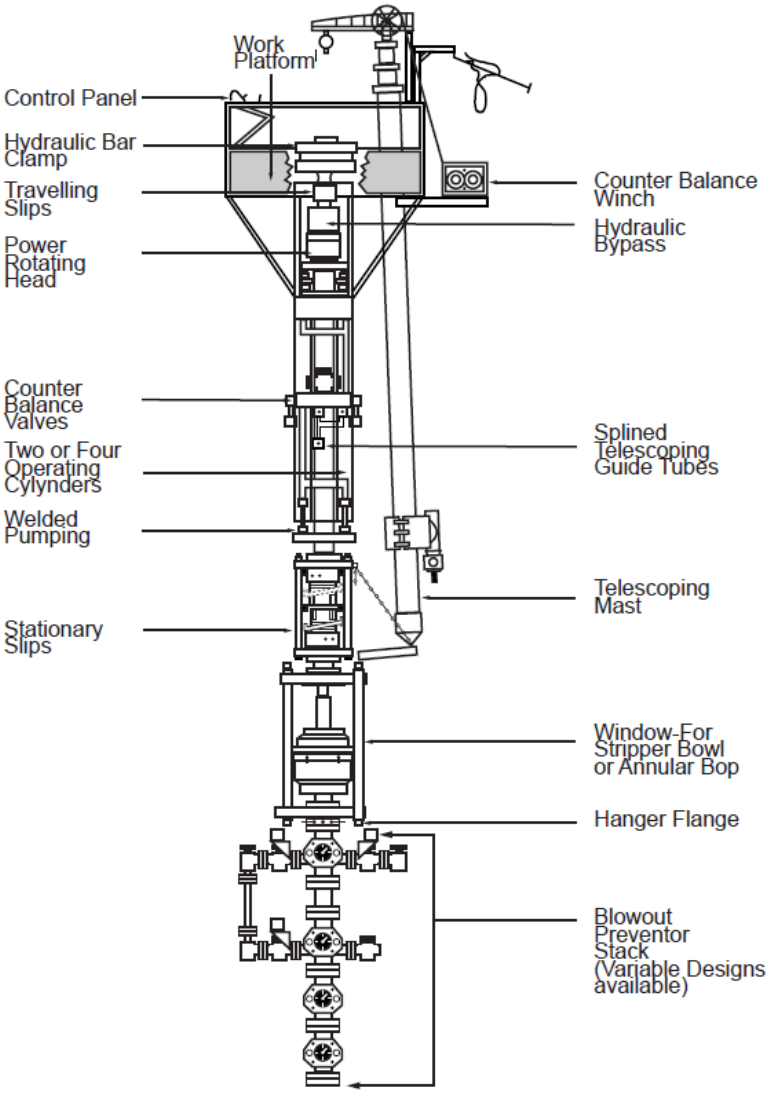

Figure 6: Hydraulic Workover Mast

- *Feel free to attempt Tutorial 1 c) and d).*

6. PRODUCTION LOGGING

6.1 Data Acquisition Methods

Data is essential to the diagnostics of well and reservoir problems, as well as for the collation and evaluation of solution options both technically and economically. Apart from production logging (described in detail later), a range of well data acquisition techniques exist. Measurements can be taken:

- **At the wellhead:**
  - Pressure and/or temperature are often continuously measured in the tubing and annulus using Xmas tree and wellhead gauges. These 'tubing' pressure (a.k.a. THP – tubing head pressure or wellhead pressure WHP) and temperature (THT or WHT); and 'casing' pressure (CHP) and temperature (CHT) can provide valuable insight into the well processes (e.g. a THT decline may mean the decline in the well rate) or alarm (e.g. if there is a dangerous Annular Pressure Buildup APB approaching the maximum allowable annular surface pressure (MAASP) that may result in casing burst or tubing collapse), but in many cases one needs further information to support unambiguous interpretation of the event's cause.

  - The well's flowrate can either be periodically measured using a test separator, or, less commonly, continuously measured using a Multi-phase Flow Meter (MPFM) at surface. Normally, several wells are connected to the manifold which is connected to a primary separator and optionally a smaller, test separator or an MPFM. Periodically, each well flow can be individually diverted to the test separator to measure the well's gas, oil, and water rates, and optionally to collect fluid and sediment samples. In several modern developments each well has been equipped with an MPFM that can measure its flowrate in real time.
    (Further, comparing and plotting the phase rates for each well in a field e.g. as a bubble map helps identifying the wells requiring attention).

  - Some specialist measurements can also be taken where appropriate, e.g. dynamograms in rod-lifted wells (this is explained later in this course), or erosion-related measurement in sand-production wells, etc.

- **In the tubing:**
  - This mostly includes the measurements taken by wireline tools, e.g. by a caliper measuring the tubing walls diameter (e.g. to detect the problem of corrosion or scale build up) or electromagnetic and/or ultrasonic log to check the wall thickness (e.g. to detect the problem of corroded tubing) to inform the subsequent servicing operation.

  - There are types of in-well MPFMs (e.g. venturi flow meters or fibre-optic non-intrusive ones) that are sometimes installed in wells either permanently or temporarily.

  - In some types of artificial lift, e.g. when an electric submersible pump is installed at the bottom of the tubing string, a sensor package can be added to the pump measuring pressure, temperature, vibrations, and possibly even flow velocity.

- **At the bottomhole:**
  - Wireline logging as part of the well maintenance e.g. to detect the sediment top with a gauge cutter before a clean-up job.

  - A pressure (and optionally temperature) gauge, either permanent or temporary, measures bottomhole ('wellbore') pressure (BHP or Pw) and temperature (BHT or Tw) in either flowing well

(FBHP or Pwf and FBHT or Twf) or shut-in well (SIBHP or Pwsi and SIBHT or Twsi) conditions during pressure (and optionally temperature) transient testing and production testing. *In the former case the reservoir pressure response to the well shut-in (pressure build-up test) or opening (pressure drawdown test) can be interpreted to evaluate the reservoir size and flow conductivity. In the latter case the measurement of the stabilised FBHP at several production rates helps finding the reservoir deliverability / inflow performance relationship. Long-term pressure measurements can be used in e.g. extended well tests, reservoir model history matching, material balance or decline curve analysis methods.*

- Drill-stem tests (DSTs) are normally run once the well is drilled (and optionally completed) to test various production intervals by isolating them between packer(s) and producing from them.

- Specialist sensors can be sometimes run e.g. for seismic or electromagnetic (EM) surveys to investigate the reservoir structure or locate the water propagation front respectively.

- **Behind tubing or casing:**
  - It is now possible to permanently install fibre-optic lines in the annulus or behind casing to continuously measure distributed or discrete pressure, temperature, strain, or acoustic signal in wells either in the upper completion or across the whole well length.

> *Suggest a well problem and discuss what data could help detecting and recognising it.*

Useful information can also be obtained from fluid samples that can be collected in various locations in the well depending on the sampling objectives.

6.2 Wireline Logging Types

Wireline logging is needed at different stages of the well life, including:

- It is carried out in an openhole wellbore once the well has been drilled to evaluate the formation properties and saturation. *(Alternatively, some wells are drilled with Logging-while-drilling).* Such logs *(or tools, sensors, gauges, probes)* can measure wellbore diameter (with a caliper), acoustic signal, radioactivity (either its passive level e.g. Gamma Ray log GR, or induced e.g. Neutron log), magnetic resonance, electric and magnetic conductivity, spontaneous (electric) potential (SP), etc. In addition, Formation Testers (e.g Wireline WFT or Repeat RFT) are used to sample reservoir pressure, permeability, and optionally fluid composition at particular points. (*Cased-hole RFTs are also available for use during production.)*

  Needless to say, these logs can also be used during production/injection provided the bottomhole completion is openhole. If it is cased, many of these methods will not work, e.g. because the metallic casing shields electric signals etc. The radioactive logs: GR and Neutron logs, will still work. In addition, bespoke tools exist that are designed to work specifically in cased holes, e.g. the 'cased hole formation resistivity' tools are sufficiently sensitive to quantify the behind-casing formation resistivity by measuring the electric current leaked from the casing.

- Once the well has been cased and cemented the logging tools can be run to evaluate the top of cement and quality of the Cement Bond (e.g. using the CBL log). *(The CBL or equivalent is often*

also included for the cement bond check during production, when flow behind casing is suspected). Casing collar locator (CCL log which measures change in the magnetic field against thicker-wall metal casing collars) is also run along with the GR and/or Neutron log to identify the position of the casing collars w.r.t. the formation logs. The CCL is later used as a positioning log e.g. run along with perforating guns to make sure they are placed exactly at the netpay or target production interval depth.

- During well production or injection life it is routine to run production logging tools (PLT) to check the well completion status and identify the well and reservoir problems, detect tubing leaks, locate the low/high production or injection intervals, detect (cross-)flow inside the wellbore or behind casing where the cement bond has failed, locate sand or water or gas production intervals or fluid contacts, assess the well stimulation results such as the hydraulic fracture height, etc.

Such logging tools are normally run in combinations (suits) on e-line, optionally together with a fibre-optic sensor line as well. Alternatively, some logging tools with memory cards and batteries can be run on slick wireline. (A tubing string, drill string or a CT can also be used in deviated and horizontal wells for tool conveyance). The PLT suits are selected depending on the logging objective. Some companies market their bespoke PLT combination assemblies.
Production logging (PL) methods will be the focus of the remainder of this chapter.

6.3 Production Logging Basics

There are numerous types of PLTs and their interpretation methods. For a brief overview of the traditional ones it is convenient to first discuss the principal PL objectives, followed by the list of measurements normally taken during PL and the list of traditional PLTs used for this. It is also important to understand how the measurements relate to the various phenomena happening in and around wellbores.

6.3.1 PRINCIPAL PL OBJECTIVES

Commonly, PL investigates:

a) **Status of well completion.** There may be leaks, completion components malfunctioning (e.g. an unseated packer, an eroded sandscreen, an enlarged or 'cut-out' valve, etc.), corrosion/erosion damage, sand fills and scale buildups, cement bond damage, etc. (In other words, these are generally the types of problems related to well integrity and/or flow restriction.) Many of these problems can be detected from the surface measurements while the problems' sources further confirmed and located with PL.

b) **Anomalous fluid flow between zones.** This may be flow either behind casing (when the cement isolation quality is inadequate), or inside casing between differentially depleted layers *(i.e. a fraction of the fluid from a layer with higher pressure may be flowing into the layer with much lower pressure instead of flowing to surface)*. In multi-zone completion and intelligent wells this may also be annulus cross-flow between zones due to a failed packer.

c) **Performance of the production or injection interval.** It is important to find out, at least in order

to inform subsequent workover decisions, which zones have lower pressure or production/injection rates; which ones have higher formation damage; which produce much water or gas; which ones produce high volumes of sand.

d) **Success of stimulation treatment.** What intervals were stimulated, and how different is their performance after stimulation?

e) **Reservoir performance.** How has the pressure and/or saturation distribution changed? Has the fluid contact moved? This may inform the well recompletion decisions (e.g. perforation of a new interval) as well as the reservoir management ones (e.g. a new allocation of injected water rates between the injectors to change the water front movement).

➢ *Feel free to attempt Tutorial 2.*

6.3.2 TYPES OF PL MEASUREMENTS

The measurements taken during PL normally include: fluid velocity, pressure, temperature, acoustic (noise), radioactivity, and electromagnetic properties. Each can be measured differently and subsequently related to multiple well and reservoir phenomena.

i) **Fluid velocity measurements**. Fluid velocity profile in the well completion shows if (and, when there is sufficient resolution, how much of) the fluid is flowing in or out of it, which can be related to the presence of productive or non-productive intervals and leaks. The former is common because the reservoir layers may have different permeabilities, formation damage, quality of completion (e.g. some perforations may be plugged), pressure (due to differential depletion), etc. as illustrated in Figure 7.

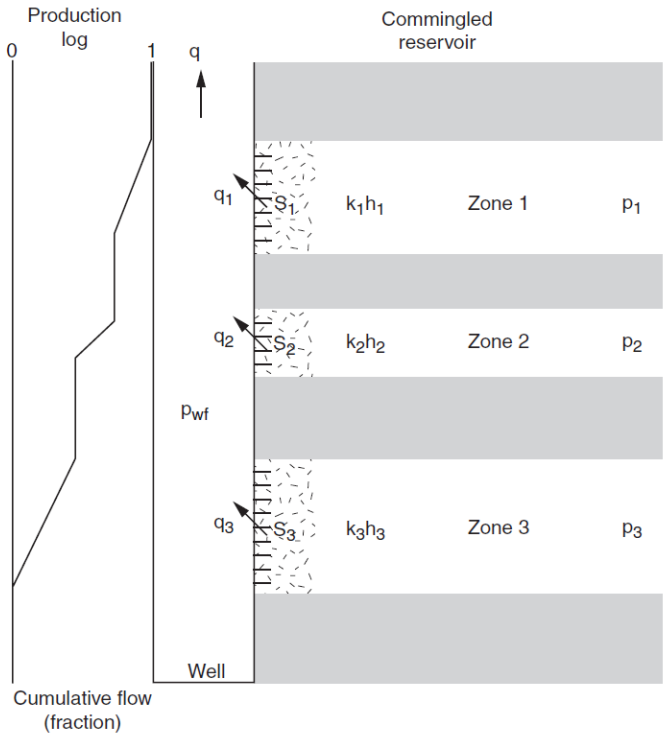

Figure 7: Flow profile in a heterogeneous reservoir

- *Feel free to attempt Tutorial 3.*

ii) **Wellbore pressure.** Distribution of the pressure gradient depends on the wellbore fluid's density which is a function of the phases present in the fluid: oil, water, and gas.

iii) **Electric properties (e.g. electric capacitance) of the wellbore fluid.** These vary for hydrocarbons and water and so can be used to discriminate them.

iv) **Wellbore temperature.** It is a function of the properties of the wellbore fluid, as well as of its flow rate and the ambient (geothermal) temperature. It thus can be used to estimate these quantities.

v) **Fluid and formation radioactivity and related properties.** These depend on the fluid and formation composition and so can be used to distinguish fluid phases and rocks.

vi) **Noise.** Flowing fluid generates 'noise' (i.e. acoustic signal with a broad spectrum). It is a function of the conduit's size, the flowing fluid's velocity, flow rate, flow pattern, and composition. E.G. water flowing in the micro-annulus of the damaged cement sheath generates a different acoustic pattern compared to the noise from gas bubbles entering the wellbore from a perforation.

It's worth noting the uncertainty of the wellbore measurements mentioned above, because:

Fluid velocity and distribution of various properties in the wellbore are complex since they are not uniformly distributed in the wellbore, e.g. in a vertical well the velocity is faster in centre than close to the walls. The situation is more complex in the multiphase flow situations (which almost always happen in wells) when e.g. in a deviated well the water, being heavier, tends to flow on the lower side of the wellbore, whereas gas tends to flow much faster in the upper one. Flow patterns may show other complex configurations, e.g. the gas may start forming slugs (i.e. very large 'bubbles') periodically travelling across the wellbore. Water may stagnate in the lower parts of a horizontal well, etc. So, depending on where radially in the wellbore the tool is located (which is in many cases uncertain), its measurement can vary resulting in the uncertainty of the subsequent estimation of the flow rate and fluid composition.

In addition to the problem mentioned above, not only the tool position affects the measurement, but the tool itself does. For instance, a flowmeter tool travelling along the wellbore partly blocks it causing the pressure and flow to change and making the wellbore fluid flow differently from how it did in the absence of the tool. This, often small an effect, sometimes has to be accounted for.

Also note that many of the above measurements are 'soft' or indirect in the sense that they are not measured directly and have to be instead estimated by interpreting the underlying parameters, which adds uncertainty and implies a (regular) tool calibration. For instance, the spinner flowmeter actually measures frequency of revolutions of its blades (impellers), which can be interpreted to relate to the fluid flow velocity and viscosity; or the temperature sensor actually measures electric resistivity of the temperature-sensitive element, etc.

(In extreme cases, when a parameter is estimated using measurements not originally designed for this, e.g. wellbore flowrate estimated from the side, temperature and pressure measurements using some models relating them, such estimates are usually called 'virtual', e.g. 'virtual flow metering' or 'soft flow metering' / 'soft-sensing'. Many such specialist methods exist and are applicable in certain conditions, but are by far not universal, applied on a case-by-case basis and thus are beyond the scope of this course.)

6.3.3 TYPICAL PRODUCTION LOGGING TOOLS AND THEIR APPLICATIONS

i) Flowmeter

- Spinner flowmeters are basic PLTs and contain one or more spinners: small impellers mounted on a shaft. The flowing fluid causes their rotation, subject to the tool's movement velocity and direction (up or down), the fluid viscosity and phase segregation (e.g. slower water at the lower part but faster gas at the upper part of a deviated wellbore), and the spinner's inertia (e.g. resulting in small fluid velocities being poorly detectable).
  The tool's movement is normally corrected for (i.e. calibrated) by the two-pass (or multi-pass) technique when both the up and down passes of the tool, at different velocities, are used in interpretation.
  To overcome the problem of the non-uniform radial velocity distribution, multi-phase flow, or small flowrates, a diverter-type flowmeter can be used instead of a continuous one as follows:
  - One solution is to position the tool at a certain depth and ensure that all the wellbore fluid is diverted to it e.g. by actuating an inflatable packer (Figure 8).
  - Alternatively a fullbore flowmeter can be used with the spinner blades large enough to cover most of the wellbore diameter.
  - Flowmeters with multiple small spinners at various radial locations are also available.

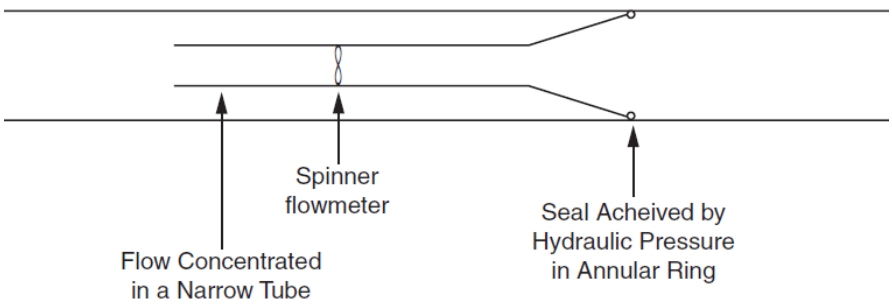

Figure 8: Conceptual design of a diverter type flowmeter

- Downhole flowmeters installed permanently or temporarily are also worth mentioning, though they are seldom used and not normally part of a usual PL service. The classical type is the venturi flowmeter that has a nozzle-type restriction (installed in a landing nipple or mandrel) in the well with pressure and temperature measurements taken across it. Using the model relating the flow velocity to the pressure drop across a nozzle the velocity can be inferred. The velocity estimate's accuracy depends on the fluid composition, flow regime and pattern, tool calibration, and the velocity itself. Thus, such flowmeters are designed to be used only at certain 'application envelopes' of flow conditions, and need recalibration or change when the conditions change e.g. flowrate decreases or watercut increases outside of the envelope.

The nozzle-type restriction in such flowmeters may be a problem due to restricting the fluid flowrate and tool access. Non-intrusive flowmeters are now available e.g. the reverse ones (similar principle but instead of a restriction there is an enlargement) or fibre-optic ones (described below).

ii) Pressure sensors.

- Absolute pressure is measured by the manometer for various reasons. E.g. for pressure transient testing when the sensor (station) is positioned close to the tested interval, or for measuring wellbore pressure profile (a.k.a. 'pressure traverse') e.g. to find an appropriate wellbore flow model to match it. Generally, the absolute pressure and temperature measurements are also used to find at what thermodynamic conditions the fluid is so as to account for this in various PL interpretation methods.

- Pressure gradient measuring is common in PL where it is measured by the gradiomanometer (or 'gradiometer') that essentially consists of two pressure sensors located a few feet apart vertically. Differential pressure between them is recorded with high resolution. It is a function of the average fluid density. Thus, the pressure gradient provides clues about the wellbore fluid phases present at the point of measurement, and can be used e.g. to locate the production intervals or leaks introducing water or gas into or out of the wellbore.

iii) Electromagnetic logging includes **Fluid capacitance logging** that measures capacitance (or dielectric constant) between closely located electrodes of a probe (an electric capacitor) in the wellbore fluid. Water, oil and gas show different capacitance values and can be discriminated. *(This discrimination can be further improved by adding a fibre-optic-aided light emitter-detector sensor, measuring the refractive index of the medium).* Fluid's **resistivity** logging can be done for the same.

Another use of electromagnetic field measurements (apart from CCL mentioned earlier) in the tubing or casing pipes can be related to these pipes' wall thickness, and thus indicate if there is a decrease of this thickness due to corrosion or erosion. *(Alternatively or complementarily, ultrasonic imaging and a multi-finger caliper can be used for the same.)*

iv) Temperature sensors.

High resolution thermometers are traditionally used to measure either the flowing or shut-in wellbore fluid temperature profile. Qualitative and quantitative conclusions from thermometry can be made when observing various phenomena, e.g.:

- Joule-Thomson (or throttling) effect is a thermodynamic effect where the flowing fluid warms up (for liquids) or cools down (for gasses that are not over-pressurised) with the decrease in pressure. This may be used to locate (cooler) gas inflow or gas leak, though this effect may be small.
- Heat flow because of either heat conduction (in non-moving media); or convection (heat transfer by a moving fluid). For instance, in a flowing well the hot reservoir fluid enters and fills the wellbore increasing its temperature (due to heat convection), but then partly cools down (by heat conduction) as it flows upward and loses some heat to the cooler surroundings. Increase in the flowrate reduces the fluid pass time, resulting in it staying hotter (Figure 9. Note how, as a result, the well flowrate increase can be detected from the

THT measurements).

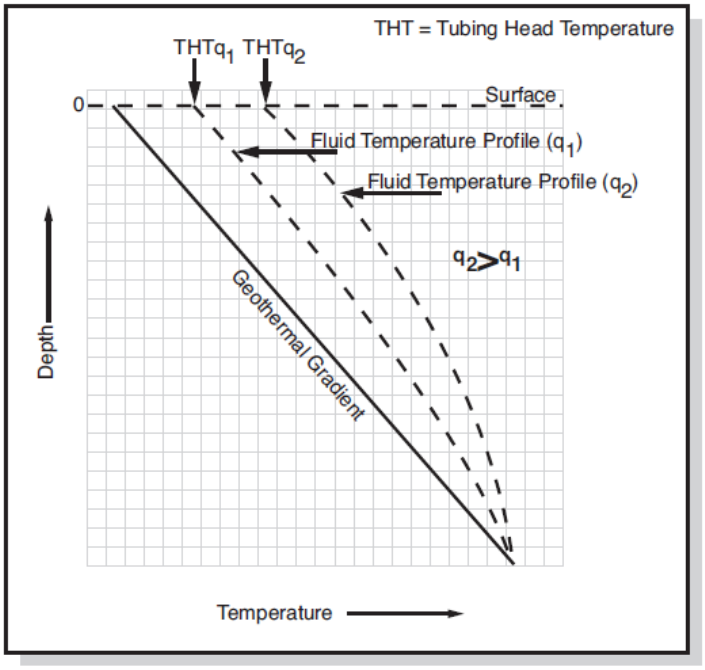

Figure 9: An example wellbore, flowing temperature profile.

Similarly, when the well is shut-in, the stagnant wellbore fluid exchanges heat with the surroundings approaching with time the ambient, 'geothermal' temperature gradient (Figure 9) of the formation. Deviations in this wellbore shut-in temperature profile from the geothermal gradient may indicate e.g. a layer cooled down by cold water injection, or a cross-flow between layers inside or behind casing, etc.

Finally, as far as the flow behind casing is concerned, it is also possible to run a temperature sensor such as a Radial-differential temperature (RDT) log with multiple fingers radially extending to the casing walls. The difference in their temperature values may indicate a cooler or hotter fluid flow in a channel in the non-isolating cement behind casing.

- Disturbance in the expected temperature profiles can also be indicative. E.g. they can be used for locating the cooler region shortly after hydraulic fracturing or acidizing to show where to the (cooler) acid or fracturing fluid went.
- Thermal (tracer) slugging or induced heating methods can be used when a Distributed Temperature Sensor (DTS) is in place. A small volume of hotter or cooler fluid is either injected into the well, or heated up inside it, and then its speed is traced with the DTS to measure the fluid flow velocity.
- Cement hardening is an exothermic reaction releasing heat and increasing the cement's temperature, which can be detected. So a temperature log is often run with a CBL log shortly after cementing is complete to locate the cemented intervals.
- Temperature transient testing can be sometimes used, though it is a relatively novel method. The temperature response of a production or injection interval w.r.t. time after a flow rate change can be interpreted to infer the reservoir properties, subject to the interpretation model available.

v) Radioactivity-related Sensors.

There are many types of sensors employing various fluid or rock atomic properties related to the fluids' and rocks' ability to emit, absorb, or affect the change of state of quantum particles: neutrons, gamma rays, etc. Many of such sensors are used in PL for probing both inside casing and behind it.

- The conventional Gamma Ray (GR) log measures the natural radioactivity level of the formation, which is defined by its composition and saturation. In PL it is quite often used with radioactive tracers: volumes of fluid enriched with radioactive markers (e.g. radioiodine in water solutions) injected into the well. Detection of the intervals to which the tracer went helps identifying the producing/injecting intervals or, if they appear to be behind casing – the flow behind casing. Such tracers can be used in other conditions, e.g. added to the hydraulic fracture propping agents (i.e. the particles used to fill the fracture to prop it open) to find out the fracture position; or added to the cement to show its location; etc.
  As mentioned, GR is also often used to match the open-hole logs and cased-hole log depths.
  In a flowing well, typically a water injector, an ejector-type tool can be used for flow profiling that contains a volume of radioactive material and one or more GR detectors apart. Ejecting a small volume of the material and measuring how fast it flows past the GR detectors helps estimating the fluid flow velocity (provided it is not too small).

- Focused GR (density) logs are designed to detect gamma rays from a radioactive emitter in a small cage inside the wellbore. This way the absorption of the gamma rays by the wellbore fluid is measured. This absorption is related to the fluid density.

- Spectral Gamma Ray logs are able to detect the signal amplitude at various wavelength bands and thus can infer more information about the formation composition e.g. its prevailing clay type.

- Thermal neutron decay rate logging tools generate bursts of neutrons. Their absorption level by the formation largely depends on the amount of chlorine in it, which is often mostly present in the formation water. So these tools can estimate the behind casing formation water saturation (subject to the mud filtrate invasion zone depth), provided the porosity and formation water salinity are reasonably high.

- Generally, pulsed neutron lifetime (PNL) logs bombard their surroundings with neutrons in order to 'activate' (i.e. excite) the elements like oxygen, chlorine, silicon, etc. Due to the fact that the emission is pulsed the log can detect both natural and induced GR spectra and thus distinguish the change. The activated elements have a short lifetime. Gamma rays emitted during their decay are then detected. E.G. in oxygen-activation logging (like Water-Flow Logging WFL) in a shut-in well the GR detectors are located at a distance from the neutron source. If they detect the peak of gamma rays at a distance from the source this means there is flow of water behind casing that transports the activated oxygen toward the detectors.
  Silicon activation can be used to investigate the quality of the gravel pack. Spectral PNL tools provide an opportunity to detect an even wider range of elements.

vi) Noise and other Acoustic/Sonic Logging.

These logs can be either passive (i.e. measuring the natural noise level and spectrum) or active (i.e. generating sound by a transmitter and measuring it by a receiver at a distance.) In the latter case, the sound transmission property of the medium may at certain conditions indicates for instance how good the casing-cement bond is; or the speed of sound in the fluid (which is a function of the fluid composition) and its Doppler effect (which depends on the fluid flow rate). The tools include:

- The passive, Noise log measures acoustic signal within several bandwidths, recorded as several tracks. The noise level and spectrum may be used to infer if there is flow and the type of it, though it normally works when fluid is flowing across a restriction: e.g. a valve, a leak point, a micro-annulus channel, a perforation. The spectral pattern also depends on the type of the fluid, e.g. gas tends to make a higher frequency noise than liquid. Multi-phase flow noise tends to be some combination of the single-phases' noise spectra. The sound of sand particles carried in the fluid and hitting the completion pipe tends to have its signature as well. However, such patterns are difficult to predict and are often analysed in comparison with lab experiments, meaning the typical Noise log interpretation is largely qualitative.

- Modern Ultrasonic logs and generally Spectral Noise Logs (SNL) offer high-precision spectral distribution measurement and can detect quite low-rate leaks and other subtle events. They can also highlight the casing wall thickness loss and the problems with cement bonding.

This concludes the list of traditionally used PLTs. Finally, it is worth giving a bit more detail on the fibre-optic sensing technology that is fast advancing and is becoming popular.

- *Propose an example, well performance problem and list the PLTs suitable to detect or even quantify it.*

Fibre-optic sensors.

Part of the light travelling in one direction along an optic fibre is reflected back. The spectral signal of this back-scattered light, compared to the original, source one, depends on the state of the fibre at the location from which it was reflected. For instance, this spectrum change is sensitive to the fibre bending or generally its strain, or whether the fibre is exposed to high pressure or temperature, etc. Thus, fibre-optic sensors consist of a fibre with an interferometer on one end – at surface. The source light is generated by a laser, followed by the reflected light being received and analysed. The delay between the source pulse and the received, back-scattered light indicates the distance from where the light was reflected from.

Such sensors can be either distributed (i.e. using the light backscattered from every point in the fibre) measuring a quantity continuously along the fibre length; or discrete: measuring the light reflected from periodical structures (Bragg gratings) artificially imprinted at several locations in the fibre. The latter sensors have higher resolution, but measure only in these several points in the fibre.

The beauty of such sensors compared to traditional PLTs is that they are not intrusive (the fibres or bundles of fibres are very thin), do not need any in-well electronics, can be installed permanently or temporary in the well, and simultaneously offer continuous (in time) and distributed or discrete (in space) measurements. As a drawback, the fibre has to be spliced and connected via 'dry' (i.e. connected at surface)

or 'wet' (connected in the wellbore and/or subsea) connectors when passing through e.g. a wellhead or a packer (the same happens to other lines too, e.g. electric cables or hydraulic lines). Every such connection (especially the difficult, wet ones) causes significant attenuation of the light signal, deteriorating the sensor's quality. *(Some well completion installations allow first installing a control line, and then pumping the fibre down (e.g. in a gel) without the need for splicing it.)* Other problems with the fibre include ageing (e.g. due to darkening when hydrogen migrates into the fibre through cladding) which again affects its accuracy, resolution, repeatability, and drift (which is the measurement bias increasing with time).

The widely used sensors include Distributed Strain Sensors (DSS), Distributed Temperature Sensors (DTS), Distributed Acoustic Sensors (DAS). Also, Fibre-Bragg Grating (FBG) sensors that provide high-resolution pressure, temperature, and strain measurements at several locations in the fibre.

The use of these measurements (i.e. their interpretation models) is often similar to the use of conventional PLTs. Some notable exceptions include the ability to continuously measure the speed of sound (SoS), propagation of slugs, and seismic signal by certain types of DAS at certain conditions. DSS behind casing embedded in the cement can measure the stresses acting on the casing. DSS wrapped around a tubing joint can detect the tubing's tiny expansions and contractions due to the propagation of eddy currents in the flowing fluid and thus measure their velocity, acting as a non-intrusive flow meter. The additionally measured SoS in this case is a function of the water and gas cuts and thus also helps estimating them.

Prototype sensors able to measure pressure and chemical composition are currently investigated.

7. WELL ABANDONMENT

The ultimate operation in a well is its plugging and abandonment (P & A). This is required by law to ensure there is no fluid spill to surface nor contamination of fresh water reservoirs by saltwater. First, the top hole, uncemented casing may be optionally cut (e.g. using a drill string mill or a wireline chemical cutter) and retrieved for salvage. All production/injection and liner hanger (if any) intervals are then cemented. Cement plugs at least 500' long with the top of cement at least 100' above each interval are placed and tested. Bridge plugs (i.e. mechanical plugs installed permanently e.g. on a wireline) are installed at the bottom of every next cement plug. The wellbore intervals across the near-surface freshwater reservoirs are also cemented. Finally, all the surface equipment is removed and the casings are cut a few meters below surface (or seabed) and retrieved. (Optionally, no casing retrieval from offshore wells may be required, as long as nothing is protruding above seabed).

8. RECOMMENDED READING

1. "Well Completion and Servicing" by D. Perrin, Editions Technip, Paris, 1999
2. "Well Control for Completions and Interventions" by H. Crumpton, 2018
3. "Well Completion Design" by Bellarby, J., Elsevier, 2009
4. "Petroleum Production Engineering", 2nd Edition, by Guo, B., Liu, X., and Tan, X. Gulf Professional Publishing, 2017
5. "Production Operations", Volume 1, 4th Edition, by Allen, T., and Roberts, A., OGCI, 1997
6. "Production Logging – Theoretical and Interpretive Elements", by Hill, A.D., SPE 1990
7. "Non-technical guide to petroleum geology, exploration, drilling and production", 3rd Edition, by Hyne, N.J., PennWell 2012

CHAPTER 3: RESERVOIR AND TUBING PERFORMANCE

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LEARNING OUTCOMES

(All examinable)

Having worked through this chapter the Student will be able to:

- Describe well inflow and tubing vertical lift performance. Explain what it affects and what it depends on. Be able to predict the performance curves at various flow conditions, as wells as calculate the well performance problems similar to the ones explained here and illustrated in the tutorial section.

- Describe the effects that take place during single- or multi-phase flow in wells, pipelines, reservoirs. Explain how they affect the pressure and temperature profiles.

- Describe how the well completion can change the well performance. Consider examples, e.g. a surface choke or a perforation design.

1. INTRODUCTION

A simple production system is illustrated in Figure 1.

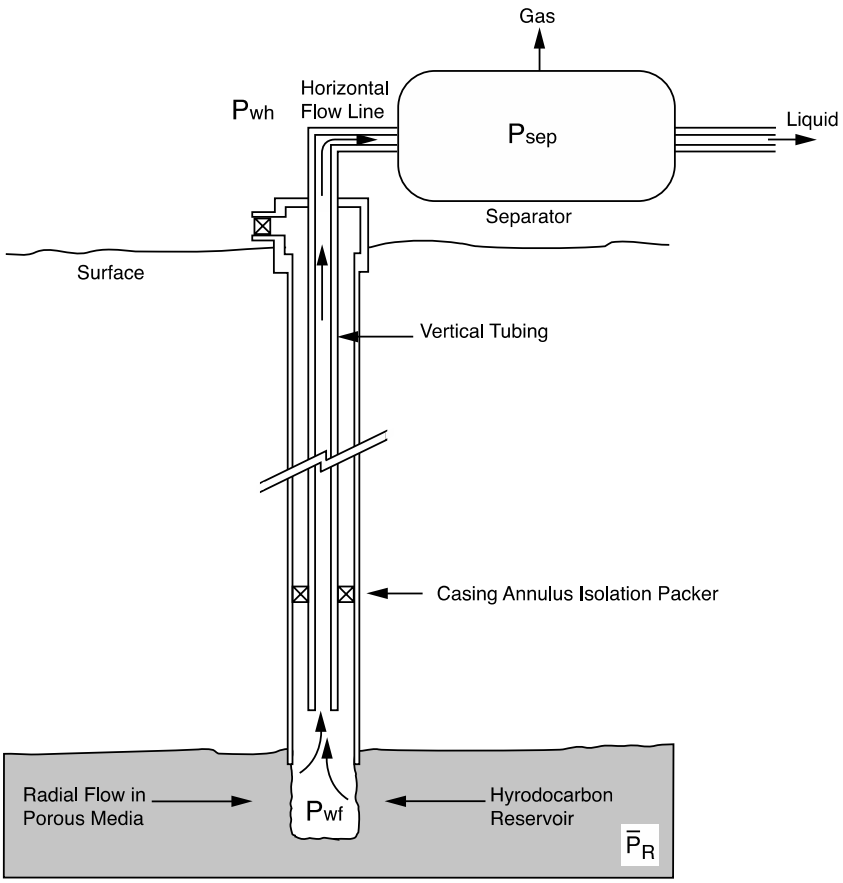

Figure 1 Simplified hydrocarbon production system.

The hydrocarbon fluid flows from the reservoir into the well, up the tubing, along the horizontal flow line and into the separator.

During this process the fluid's pressure is reduced from the reservoir pressure to the separator pressure in a series of pressure loss processes (Figure 2).

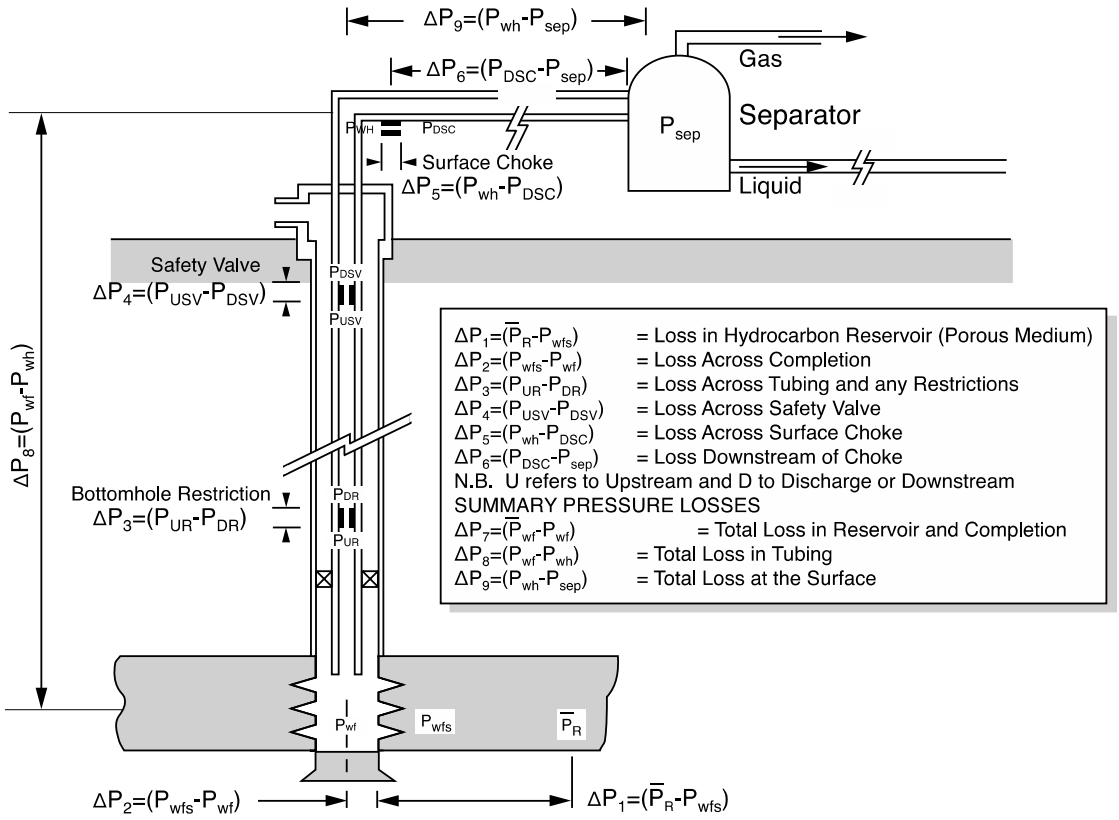

Figure 2 Pressure losses during production.

The nomenclature key to Figure 2 is:

P_r	Reservoir Pressure
P_{wfs}	Flowing sand face Pressure (i.e. the pressure at the 'sandface', before the completion pressure losses apply)
P_{wf}	Flowing Bottom Hole Pressure
P_{UR}	Upstream Restriction Pressure
P_{DR}	Downstream Restriction Pressure
P_{USV}	Upstream Safety Valve Pressure
P_{DSV}	Downstream Safety Valve Pressure
P_{WH}	Well Head Pressure
P_{DSC}	Downstream surface Choke Pressure
P_{sep}	Separator Pressure

The pressure losses include:

- ΔP_1 Across the reservoir
- ΔP_2 Across the completion (perforation/gravel pack etc.)
- ΔP_3 Across the tubing and any restrictions
- ΔP_4 Across the sub surface safety valve
- ΔP_5 Across the surface choke
- ΔP_6 Across the flowline

These pressure losses are conventionally grouped into three main, distinct components:

- ΔP_7 Summarises the total pressure losses in the reservoir and completion: i.e. 'pressure drawdown'
- ΔP_8 Summarises the total pressure losses in the tubing
- ΔP_9 Summarises the total pressure losses at the surface

Note that the separator usually acts as the end point of the flowing system model because its pressure is externally defined and fixed (so it becomes the model's boundary condition). This is because the separator is operated under specified gas pressure control and liquid (oil and water) level control (as is explained later in this course).

The magnitude of these individual pressure losses depends on the reservoir properties and pressures; fluid being produced and the well design and condition. Production Technologists / Engineers need to understand the interplay of these various factors so as to design completions which maximise profitability from the oil or gas production. There are no standard "rules of thumb" which can be used.

Figure 3 schematically represents the example pressure distribution across the production system shown in Figure 2. It identifies the most significant components: the flowline, tubing, reservoir, and completion where pressure losses occur.

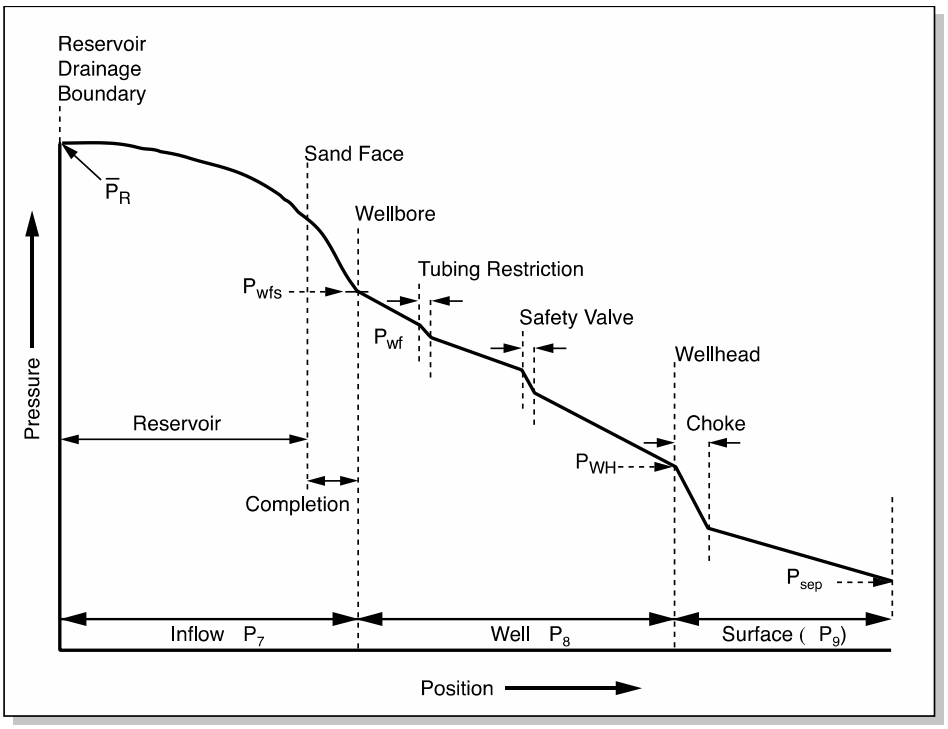

Figure 3 Pressure across production system.

➢ *Feel free to discuss the nature and magnitude of different pressure losses*

Table 1 quantifies possible pressure losses in an example, conventional oil well. Notice how the well's production rate does not increase linearly with increasing reservoir deliverability (expressed by the productivity index). This is due to an increasing pressure drop across the tubing that controls well deliverability: at higher rates this tubing is a 'bottleneck' that can let through only so much oil rate. The solution in this particular case is to install a larger tubing.

Well Productivity Index (bopd/psi)	Production Rate (bopd)	Pressure Loss Distribution (%)		
		Across Reservoir and Completion (P_7)	Across Tubing (P_8)	Across Flowline (P_9)
2.5	2700	36	57	7
5.0	3700	25	68	7
10.0	4500	15	78	7
15.0	4800	11	82	7

Table 1 Pressure Loss Distribution as a Function of Well Productivity Index *(after Duns and Ros)*

- *Feel free to discuss how these observations may change if it was e.g. a horizontal well*

This chapter will describe the major pressure losses and how to calculate them, how to model well production, and how to diagnose well deliverability problems. This knowledge is key in well engineering.

2. NODAL ANALYSIS OF THE PRODUCTION SYSTEM

The use of Systems (a.k.a. Nodal) Analysis to design a hydrocarbon production system is common. Systems analysis, which has been applied to many types of systems of interacting components, consists of selecting a point or node within the producing system (well and surface facilities). Equations for the relationship between the flow rate and the pressure drop are then developed for the well components both upstream of the node [i.e. describing the inflow from the reservoir to the node] and downstream of the node [i.e. describing the outflow from the node to the separator]. Further, considering that at a given time the pressures at the end points of the system: i.e. at the separator (P_{sep}) and reservoir (P_R) are fixed, the node's pressure P_{node} for an arbitrary (stable) flow rate Q can be calculated either way:

$$P_R - (\text{Pressure loss in upstream components for a given Q}) = P_{node} \quad (1)$$

$$P_{sep} + (\text{Pressure loss in downstream components for a given Q}) = P_{node} \quad (2)$$

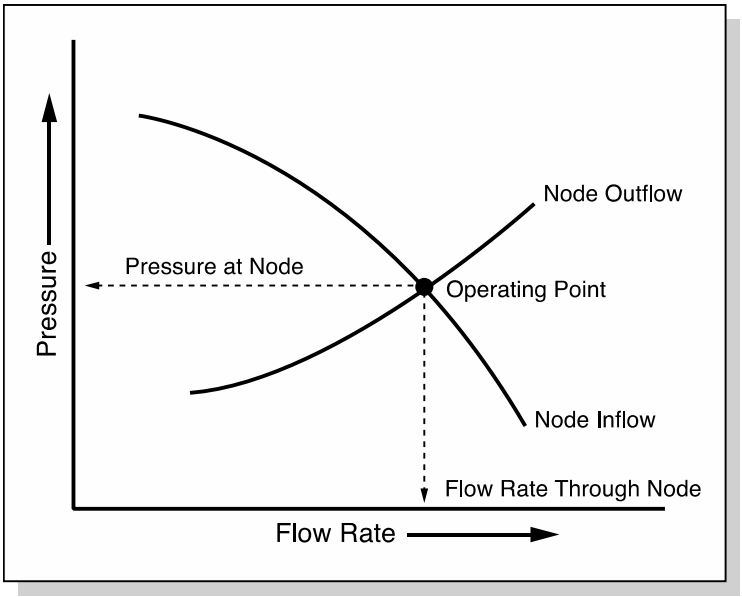

Figure 4 Node flow rate and pressure.

Typical result of such analysis is shown in Figure 4 where the rate-pressure relationship (a.k.a. 'performance relationship') has been plotted for both the inflow (Inflow Performance Relationship IPR described by Equation 1) and outflow (Outflow Performance Relationship OPR described by Equation 2) at the node. The intersection of these two lines is called 'the operating point' corresponding to the operating pressure and rate: it is the only simultaneous solution to both equations 1 and 2, i.e. this is the only condition when the 'fluid supply' (inflow) meets the wellbore flow capacity 'demand' (outflow). This defines the solution pressure and rate at the node. This approach forms the basis of all hand and computerised wellbore flow calculation procedures.

The analysis node can be selected anywhere in the production system depending on what is analysed. When modelling well performance it is conveniently selected at the bottomhole, thus separating two very different flow physics: the reservoir (flow in porous medium, and across the bottomhole completion) and the wellbore (flow in casing and tubing pipes and across restrictions). (*The OPR in this case has many names meaning the same: Tubing Performance Relationship TPR, Vertical Lift Performance VLP, Vertical Flow Performance VFP, Tubing Intake Pressure TIP, Tubing Performance Curve TPC, etc).* The IPR is often associated with the 'reservoir deliverability', i.e. its ability to supply production rate for a given bottomhole pressure. The 'well deliverability' is more complex: it takes into account both the reservoir deliverability and the well's ability to lift the fluid to surface.

(Note that the analysis node can be selected at a different location in some specific cases. E.g. when sizing a downhole pump the node can be moved to the pump intake depth to describe the Pump Performance Relationship PPR; or to a choke valve depth when this Choke's PR (CPR) is modelled, etc.)

- *Feel free to propose and discuss other cases.*

Having established the concept of nodal analysis, the following sections will discuss how the hydrocarbon phase behaviour affects the reservoir fluid Inflow Performance into the well. The outflow, or tubing performance is reviewed next followed by the interaction between the in- and out-flow, and by a number of well performance studies.

3. HYDROCARBON PHASE BEHAVIOUR

Hydrocarbon reservoir fluids are a complex mixture of hydrocarbon molecules, the composition of which is dependent on the source rock, degree of maturation etc. Phase changes occur when this complex hydrocarbon fluid flows from the (high temperature and pressure) reservoir environment to the (cooler, lower pressure) separator conditions. Such changes are sketched for an undersaturated oil in Figure 5 (assuming the flowing fluid is in phase equilibrium).

'Undersaturated oil' is the oil that at a given pressure and temperature conditions is not completely saturated with gas i.e. it can accept and dissolve gas if it is added. At some lower pressure (called 'bubble point' pressure – the one at which bubbles appear) and/or temperature this oil becomes 'saturated': any further decrease in P and/or T will result in the decrease in gas solubility with some fraction of ('evicted') gas evolving (evaporating) from the oil as a separate, gas phase. The oil reservoirs can initially have either undersaturated oil or saturated one (e.g. the oil reservoirs with gas caps are saturated, otherwise the cap gas would have dissolved in the oil).

In Figure 5 it can be seen that the fluid:

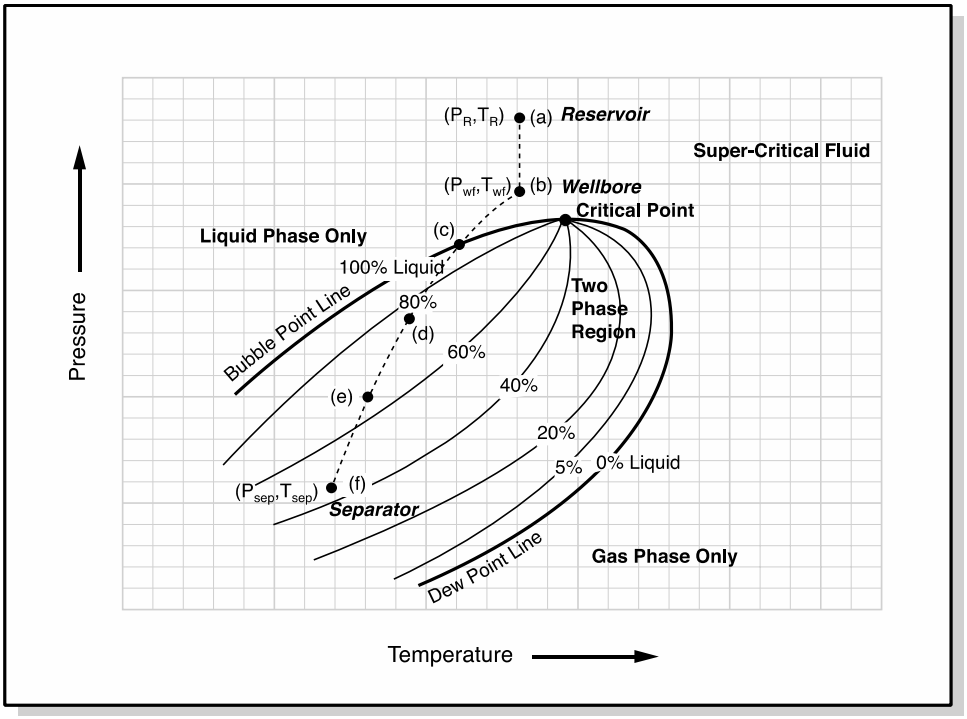

Figure 5 Schematic phase diagram for an undersaturated oil.

- Is present as a single-phase liquid in the reservoir {point (a)}
- Remains a single-phase liquid when it reaches the wellbore (note a significant reduction in pressure and a small change in temperature during flow in reservoir) as long as the wellbore pressure is kept above the bubble point {point b}
- Starts to evolve gas {point (c)} as temperature and pressure are reduced during the flow up the tubing
- Evolves increasing amounts of gas {points (d) and (e)} until the separator {point (f)} is reached.

Some (or all) of the flow regimes illustrated in Figure 6 will be present in the tubing. These multi-phase flow effects in the tubing will be discussed later in the context of TPR calculations.

Note that if the reservoir oil was saturated or the bottomhole pressure was below the bubble point, the gas would have started appearing as a separate phase already in the reservoir, in the near-wellbore zone. This multi-phase flow in porous medium will affect the IPR. Single-phase and multi-phase IPR models are discussed next.

Needless to say that the oil and gas properties: solubility, density, formation volume factors (defining how much the fluid 'swells' or 'shrinks' at the reservoir conditions compared to the standard surface conditions), etc. strongly depend on the pressure and temperature. E.G. gas expands at lower pressures while oil shrinks (due to losing the dissolved gas), viscosities increase significantly at lower temperatures, etc. (Also, oil viscosity and density increase when there is less gas dissolved in it, and vice versa. Note that if this oil and gas keep flowing up the tubing together, the overall density of this mixture decreases due to gas expansion.)

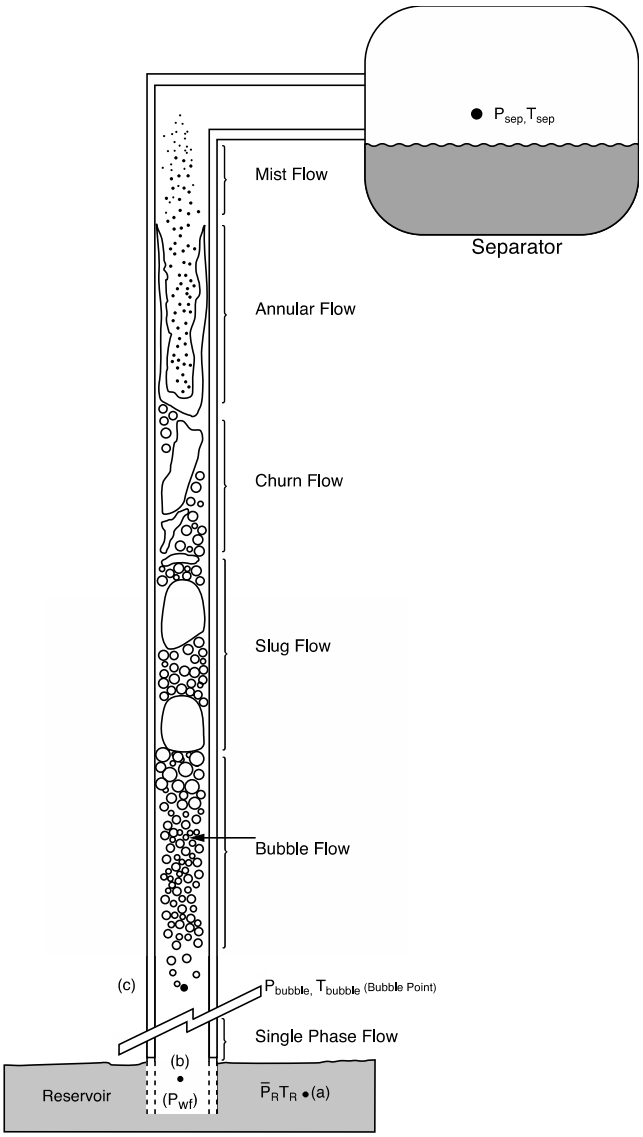

Figure 6 Schematic view of all possible phase changes in tubing.

- *Feel free to revise how the fluid properties change and discuss how this may influence the fluid flow performance.*

4. RESERVOIR INFLOW PERFORMANCE

The Inflow Performance Relationship is routinely measured in multi-rate tests using bottomhole pressure gauges as part of the field monitoring programme. In such tests the wellhead choke position is changed in steps so that the well produces at different rates. After each change the bottomhole pressure takes some time to stabilize. This is repeated several times. This IPR, i.e. the relationship between flow rate (q) and (stabilised) wellbore pressure (P_{wf}) is one of the major building blocks for a nodal-type analysis of well performance. Several of the common models used to describe IPR and/or predict it are presented below.

4.1. LIQUID-ONLY INFLOW

Field measurements have shown that wells producing undersaturated oil (i.e. with no gas flow in the reservoir) or water have a straight line Inflow Performance Relationship (IPR) (Figure 7)

$$q = PI\,(P_R - P_{wf}) \qquad (3)$$

where q is the flow rate, P_{wf} is the Flowing Bottom Hole Pressure (FBHP), $\bar{P}_R$ the Reservoir Pressure, and PI is the Productivity Index defined by Eq. 3 i.e. it is the well inflow rate per unit of well drawdown. PI is inversely proportional to the slope of the straight line in Figure 7.

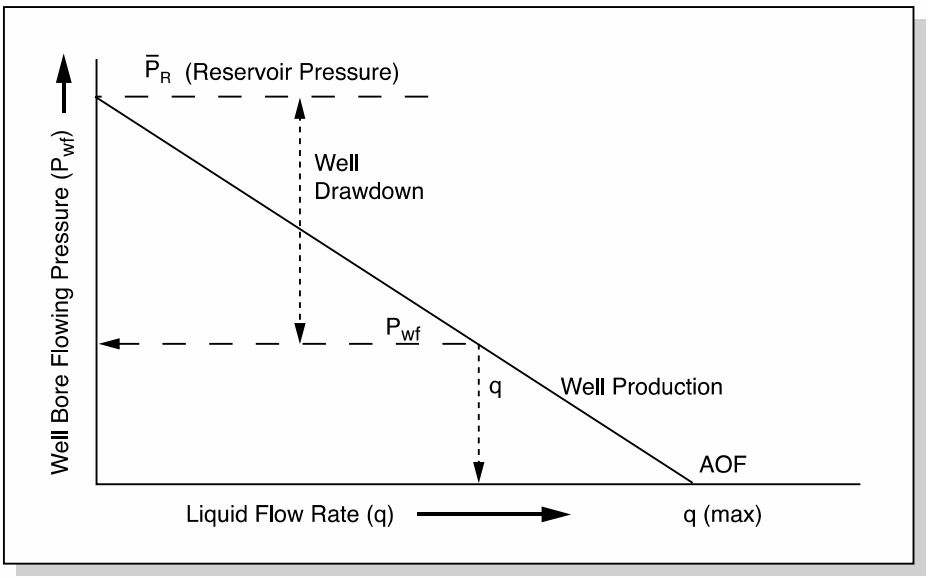

Figure 7 Straight-line IPR (for liquid-only flow in the reservoir).

N.B. The values of P_R and P_{wf} are both dependent on the depth at which they are measured. One frequently used convention is to measure, or correct, the pressure value to the mid-point of the production interval.

PI is a useful tool for describing wells since it combines all the relevant rock, fluid and geometrical properties into a single value to describe the inflow performance.

The theoretical basis for this straight line IPR is convenient to explain using the simplified, ideal radial homogenous reservoir with a vertical well in the centre as pictured in Figure 8.

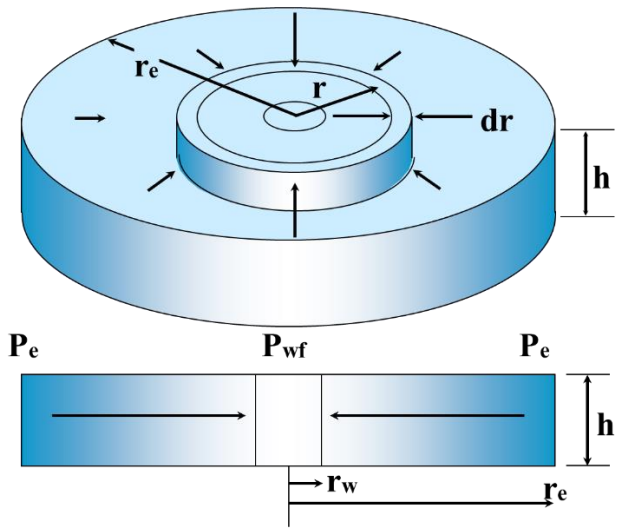

Figure 8 Schematic view of radial inflow toward the wellbore

Darcy's Law is an empirical observation describing laminar flow of fluid in the porous medium:

$$\vec{v} = \frac{k}{\mu}\vec{\nabla}p$$

where v is the fluid's velocity, k – reservoir permeability tensor, μ - fluid viscosity, and p – pressure. The ratio k/ μ is called 'mobility'.

If there are several fluid phases flowing in the medium, e.g. oil and gas and/or water, then each phase will have its own 'relative' permeability. In multi-phase conditions the various pore phase interplay effects result in the relative permeability for each phase being less than that for single-phase conditions.

Also note how the fluid viscosity in the denominator severely restricts the flow of viscous fluids, e.g. of viscous oils, especially when compared to their 'competitors': water and gas.

In the ideal radial case a radial integration of Darcy's Law for stabilised flow of relatively incompressible fluid (e.g. water or oil) through a porous medium yields the following general equation in SI units between the fluid pressure (P) and the radius (r) measured from the centre of the reservoir/wellbore.

$$q = \frac{2\pi kh(P - P_{wf})}{\mu \ln \frac{r}{r_w}}$$

Where r_w is the wellbore radius, and h – reservoir thickness. Note that the well rate q in the above equation is measured at the reservoir conditions. *If it was measured at surface conditions, e.g. in stock tank barrels (STB), its formation volume factor B_o should have been added to the denominator for conversion.*

Pressure difference between the wellbore and the reservoir is required for fluid to flow into the well. Lowering the pressure in the wellbore initiates well production and this pressure change then propagates radially outwards. During this period the well is producing as though the reservoir was of infinite size and the well is described as producing at transient flow regime within with an 'infinitely acting' reservoir. This is illustrated in Figure 9 prior to 400 days, the time at which the pressure transient reaches the reservoir boundary in this example.

N.B. Such long time periods for transient flow times are typical in reservoirs with low permiability rock and/or high viscosity and/or large well spacing or drainage areas. In conventional reservoirs it's usually a matter of days.

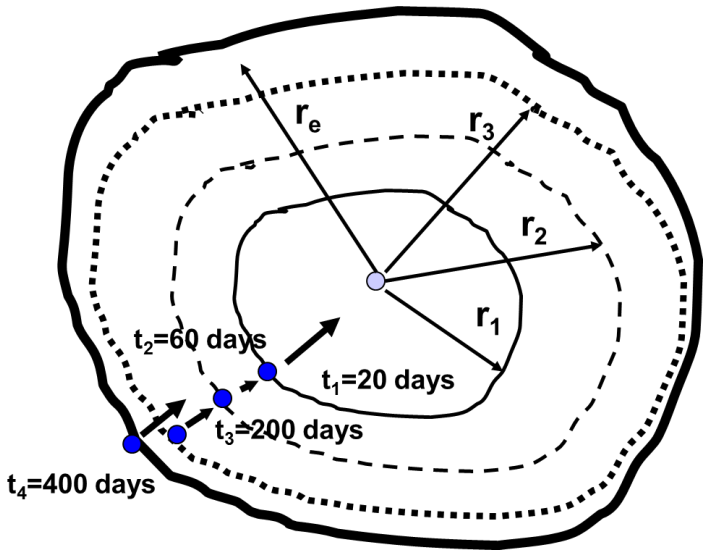

Figure 9 Schematic diagram of the infinite or transient in-flow regime for a radial system that occurs for 400 days after the start of production. Locations of the pressure change front, and expansion of the drainage area, at different times are shown.

After the time (400 days in this example) that the pressure change reaches the (circular) reservoir boundary, the flow will continue as one or a combination of the two following, different extreme scenarios:

(1) The total inflow rate (from the outside of the drainage area) across the reservoir boundary is equal to the well's production rate, allowing the *constant pressure* and *constant fluid-influx* boundary condition (Figure 10) in the radial inflow equation above. *This is achieved when e.g. there is a strong aquifer, or injection wells surrounding the production well that supply exactly as much fluid as is being produced.*

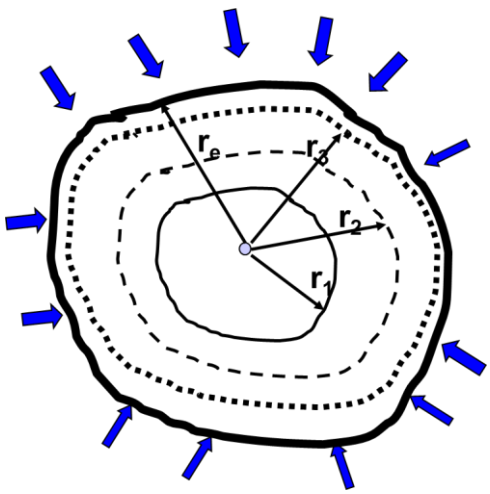

Figure 10 Schematic illustration of the Steady State flow regime for a radial system

This regime, called Steady State flow, results in a constant pressure profile between the reservoir boundary and the well (Figure 11) that does not change with further increases in the production time.

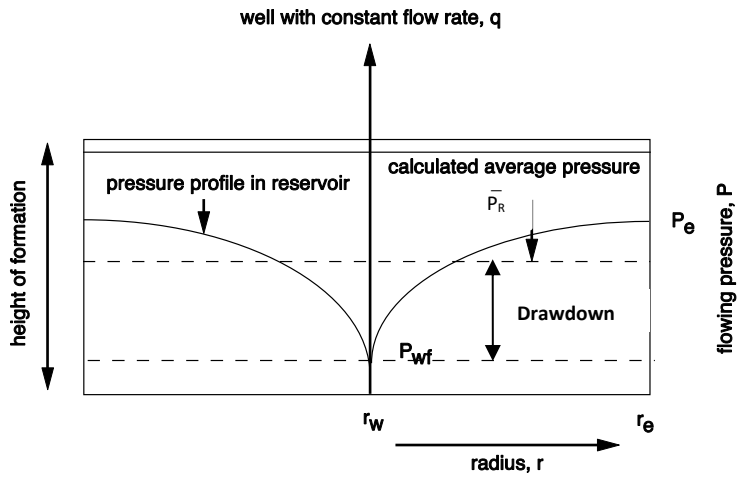

Figure 11 The constant pressure profile between the reservoir boundary (r_e) for a well producing under Steady State flow conditions

Note that $\bar{P}_R$ in Figure 11 is the "Volumetric Average Reservoir Pressure". It can be measured as the (static) bottomhole pressure when the well is shut-in and the pressure in the reservoir is fully stabilised. Also note how the pressure change increases towards the wellbore, with most of it actually happening within a few feet around it. This is because the fluid flow converges towards the wellbore and has to cross a progressively decreasing cross-section on approach. Thus, it has to flow at a faster velocity, which according to the Darcy's law increases the pressure drop. This explains why the state of the near-wellbore formation, where most of the drawdown happens, is very important for well productivity. *Selection of the right drilling mud to reduce its leak-off into this zone and the resulting damage; stimulation of this zone by acids or solvents; bypassing it with a hydraulic fracture; and many more technologies focus on this.*

Applying the Steady State flow regime's constant pressure boundary condition to the general, radial Darcy's Law equation results in the following equation (in Field Units):

$$\bar{P}_R - P_{wf} = \frac{141.2\ qB\mu}{kh}\{\ln\frac{r_e}{r_w} - \frac{1}{2}\}$$

(2) The opposite extreme scenario, a "no-flow" reservoir boundary condition (corresponding e.g. to confined reservoirs under depletion drive), represented by the solid red line in Figure 12, results in the average reservoir pressure continuously decreasing with time whenever the well is produced. This Semi-Steady State or Pseudo-Steady State flow regime is described by the following equation (in Field Units):

$$\bar{P}_R - P_{wf} = \frac{141.2\ qB\mu}{kh}\{\ln\frac{r_e}{r_w} - \frac{3}{4}\}$$

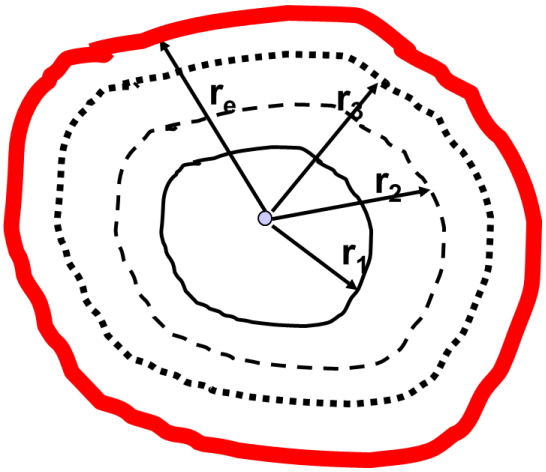

Figure 12 Schematic diagram of Pseudo-Steady State flow regime for a radial system

All the above equations show that the flow rate (q) is linearly proportional to the drawdown (P_R - P_{wf}), explaining the linear IPR in Figure 7.

The transient flow models describing temporal evolution of the production rate or pressure can be used to forecast production during both transient flow and (semi-)steady state periods. In the simple radial cases like above the analytical solutions are available (refer to the well test/pressure transient analysis literature), whereas for more complex cases the models based on material balance or numerical reservoir simulation are used. In some cases, where the above-mentioned approaches are inapplicable or there are no resources available for this, some simplified production rate decline assumptions are made for approximate forecast (decline curve analysis), e.g. it may be assumed that at any time the flowrate decline rate is proportional to the value of the flowrate in the exponential, hyperbolic, or harmonic progression.

The radial flow cases above are idealised models. In reality the reservoir geometry, geology, pressure support, etc. are more complex. For instance, corrections for the reservoir geometry (rectangular, triangular, etc.) or the well location being off-centre are tabulated in handbooks and can be applied as a 'shape factor' in the logarithm term in the above equations.

Further, the wells may not be ideally vertical and may contain features like near-wellbore formation damage, partial perforation (completion) of the reservoir thickness, laterals, various bottomhole completion options (e.g. gravel pack), etc. This is traditionally accounted for by adding a dimensionless 'skin factor' (or simply skin) S to the equations. Note that if S is positive the flow rate is less than 'ideal' (i.e. the one with no skin), whereas when it is negative the flow rate is higher than ideal for a given drawdown. *The negative skins are achieved by IOR methods or well stimulation (e.g. a hydraulic fracture).*

As mentioned, Darcy's law applies to the laminar porous flow. In many instances where there is high flow velocity, e.g. in high-rate gas wells, the turbulent (or inertial) effects may become notable. This adds further pressure losses proportional to the rate q, which is often accounted for by an additional, rate-dependent, 'non-Darcy flow' skin Dq defined by non-Darcy flow parameter D multiplied by the rate q.

For instance, after applying the skin corrections, the pseudo-steady state solution becomes:

$$\overline{P}_R - P_{wf} = \frac{141.2\ qB\mu}{kh}\{\ln\frac{r_e}{r_w} - \frac{3}{4} + S + Dq\}$$

Or, rearranged for q:

$$q = \frac{kh}{141.2B\mu\,\{\ln\frac{r_e}{r_w} - \frac{3}{4} + S + Dq\}}(\overline{P}_R - P_{wf})$$

- *Feel free to derive the formula for the PI from the above equation.*

- *Feel free to discuss the Petroleum Engineering technologies used to improve production by affecting any of the parameters in the above equation. For instance, what are the ways to keep the reservoir pressure high, to reduce S, to reduce viscosity, etc.?*

Note that in many typical developments the value of $\ln\frac{r_e}{r_w}$ *varies between 7 and 8, so some engineers may use a number in this range for snapshot estimation of the production rate. Moreover, in many cases the reservoir boundary conditions defining the additive in the denominator (-3/4 or – ½) are unclear, so this additive is ignored being small compared to the logarithm value.*

Note that an alternative way to write $(\ln\frac{r_e}{r_w} + S)$ *is* $(\ln\frac{r_e}{r'_w})$ *where* $r'_w = r_w e^{-S}$ *is called 'effective wellbore radius'.*

The Absolute Open Flow (AOF or q_{max}) in Figure 7, is the flowrate at zero (bottomhole), wellbore flowing pressure. AOF, although representing an unrealistic condition (it is hardly possible to achieve zero bottomhole pressure), is a useful parameter when comparing wells within a field since it combines both the PI and the reservoir pressure in one number representative of well inflow potential. For instance, a well with a very high productivity index, but whose drainage area's pressure has been depleted, can be production-wise inferior to a well less productive but still enjoying a higher reservoir pressure support.

All the above conclusions made for production wells also apply to injection wells, e.g. when the bottomhole pressure is higher than the reservoir pressure the flowrate turns negative, i.e. being injected. The PI in injection wells is called 'Injectivity Index' II.

- *Feel free to attempt Tutorials 1-5*

4.2. SKIN EFFECT

As mentioned, well skin reflects the fact that the actual fluid flow into the wellbore is different from the ideal case scenario of non-altered reservoir properties and/or non-disturbed inflow pattern.

The typical situations deteriorating productivity include:

- Formation damage (Figure 13). *(The various mechanisms of formation damage are described later in this course).*
- Limited entry or limited completion interval (when for instance only part of the reservoir thickness is efficiently perforated) so the reservoir fluid flow has to converge to access this interval, losing some pressure (Figure 14).

- Perforation effects (i.e. the fact that the flow has to converge to a perforation tunnel and then flow along it, Figure 15). *(Not all such effects are negative: properly designed, constructed and cleaned perforations can result in comparable or higher-than-ideal productivity).*
- High-velocity, non-Darcy flow. *(Such flow may be described by modifications of Darcy's law introducing non-linear pressure losses, e.g. by Forchheimer's equation or similar).*
- Saturation changes around the wellbore (e.g. the water-based mud filtrate saturation around the wellbore reduces the relative permeability to oil)
- Bottomhole completion effects. For instance, completion pressure loss across a gravel pack, or a sandscreen, etc.

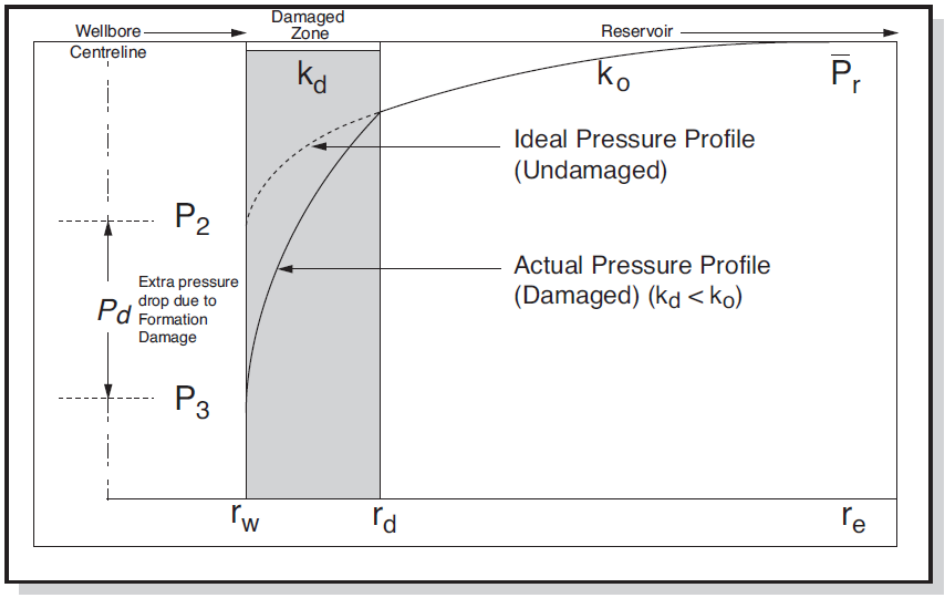

Figure 13: Pressure altered due to formation damage

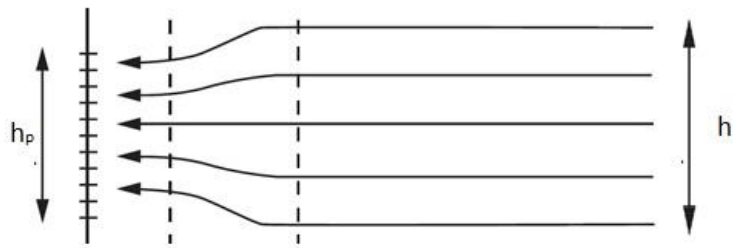

Figure 14: Flow convergence to a limited entry completion interval

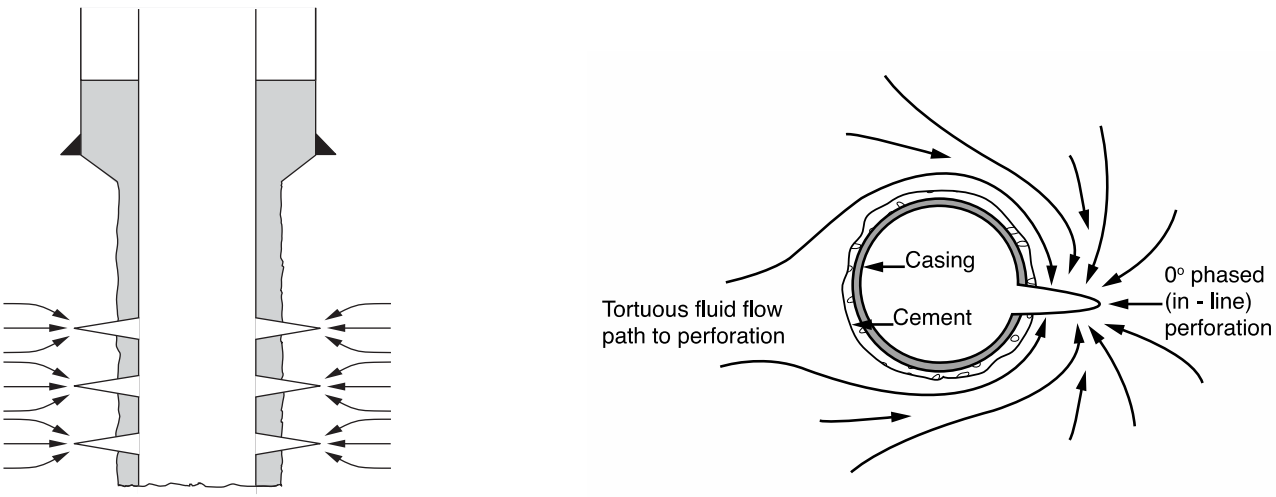

Figure 15: a) Flow convergence into perforations; b) flow around the wellbore to reach the perforations aligned in a single direction (to the right)

Many models exist to quantify skin in such situations. A few examples include:

- Hawkins formula describing the pressure loss due to the presence of a damage zone of radius r_d and permeability k_d around the wellbore:

  $$S_d = \left(\frac{k}{k_d} - 1\right)\ln\left(\frac{r_d}{r_w}\right)$$

- Brons and Martin correlation for the limited entry skin:

  $$S_{entry} = \left(\frac{1}{b} - 1\right)\left[\ln(h_D) - G(b)\right]$$

  where $b = h_p/h$, h_D is the dimensionless pay thickness $\frac{h}{r_w}\sqrt{k_h/k_v}$, k_v – vertical permeability, k_h – horizontal permeability, thicknesses are as per Figure 14, G(b) is defined as

  $$G(b) = 2.948 - 7.363b + 11.45b^2 - 4.675b^3$$

Other limited entry skin models (e.g. by Odeh or Yildiz) are also commonly used.

- Horizontal and deviated wells can either be modelled using their own inflow models and productivity indexes, or represented as a virtual vertical well with a negative skin. One of the commonly used formulae (for either modelling option) is by Joshi that uses the horizontal well's and reservoir's dimensions and the horizontal to vertical permeability ratio (because the reservoir fluid partly has to flow vertically to reach the horizontal wellbore. This may be a problem in e.g. poor k_v and/or laminated reservoirs, see example in Figure 16).
  Multilateral well performance can also be estimated analytically in simple cases. For this the appropriate horizontal or deviated well models suitable for each lateral's PI are used, and then combined as a complex series with the weights defined by the laterals' drainage areas overlap level.

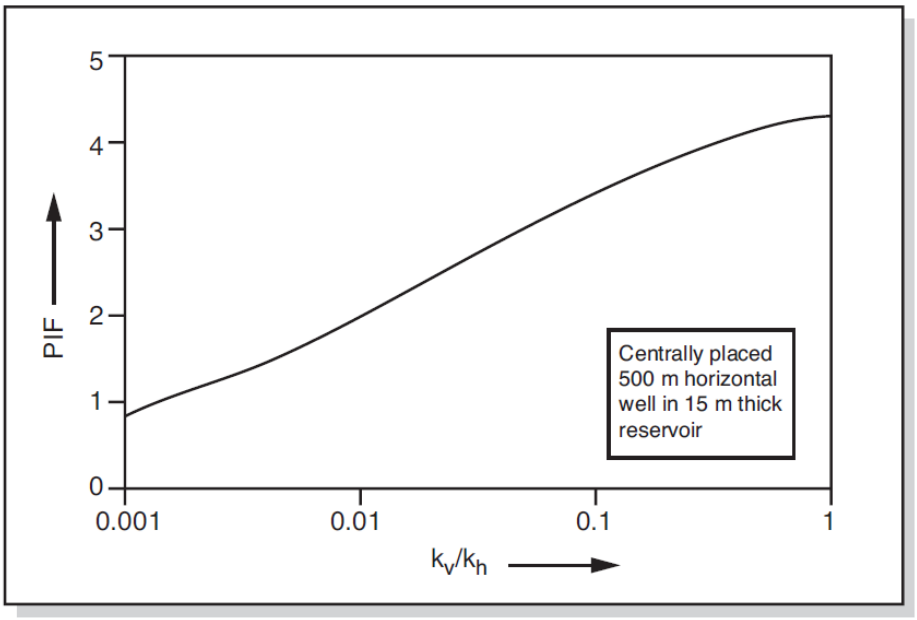

Figure 16 The Production Improvement Factor (PIF = ratio of PI of the horizontal well over PI of the vertical well) for a horizontal well as a function of the vertical and horizontal permeability ratio (k_v/k_h).

Some other skin or inflow models, e.g. related to fractured wells, will be discussed later in this course.

The total well skin is a combination of the partial ones. This can be either a simple summation for vertical wells, or a more complicated combination of the skins and anisotropy-related (i.e. k_v/k_h) effects for deviated and horizontal wells.

Sometimes a 'pseudo-skin' term is also introduced: this is related to that pressure loss component that has nothing to do with the formation damage, but is rather due to the geometry, completion and production skin. This can even be tubing-related e.g. partially blocked or collapsed tubing in which case the resulting pressure loss can be accidentally or deliberately attributed to the well inflow model.

When analysing the actual well performance and trying to estimate various skins it is very important to correctly define their source and magnitude. The subsequent well workover and/or stimulation needs to be carefully designed to target the correct skin sources. (For instance, there is no point in fracturing a well the major skin of which was actually due to the partially blocked tubing.)

- *Feel free to discuss how different skins can be identified by production logging or other methods.*

4.3. GAS INFLOW

The compressible nature of gas results in the IPR no longer being a straight line and declining faster at higher rates. This is because in addition to the above-mentioned flow convergence effect, gas also expands at lower pressures as it approaches the wellbore, so its volume increases and it has to flow even faster losing more pressure as stated by Darcy's law. The extension of this steady state relationship derived for compressible gas using Darcy's Law, assuming an average value for the properties of the gas between the reservoir and wellbore, leads to:

$q = C (P_R^2 - P_{wf}^2)$ (4)

where C is a constant.

Strictly speaking, in the cases where the use of average gas properties is inappropriate, it is possible to operate with the gas 'pseudo-pressure' $m(p) = \int_{p_{gas\ appearance}}^{p} \frac{2p}{\mu z} dp$ *where z that is the gas compressibility factor. In this case the equations presented above for liquid-production wells can be used for gas wells as long as the pressures in them are replaced with pseudo-pressures.*

The relationship in equation (4) is valid at low flow rates, but becomes invalid at higher flow rates since non-Darcy flow effects begin to be observed, and so the pressure losses increase. This can be accounted for by use of the "Bureau of Mines" or 'backpressure' equation that was developed from field observations:

$q = C (P_R^2 - P_{wf}^2)^n$ (5)

where exponent n is within the range 0.5 <n <1.0, and the backpressure constant C is derived from well test data as follows:

A log-log plot of q versus $(P_R^2 - P_{wf}^2)$ measured in a well yields a straight line of slope l/n and the horizontal axis intercept C. The standard practice for testing gas wells is to measure the FBHP at four production rates. Figure 17 shows that the slope has a value of 1 (Darcy flow, equation [4]) for the 2 points measured at low flow rates. This changes to an increased slope due to non-Darcy flow effects (equation [5], n < 1) being observed at the two higher rates. These inertial, non-Darcy flow effects result in a (very significant) 33% reduction in the AOF (from 1.5 to 1.0) in the example shown.

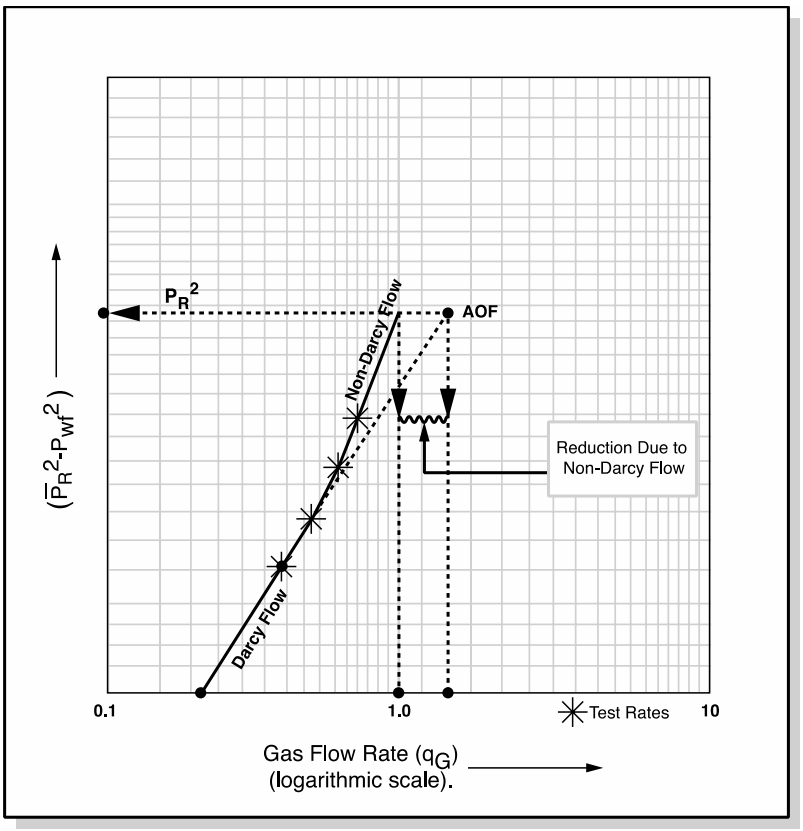

Figure 17 Gas well's reservoir deliverability reduced by non-Darcy flow pressure losses.

4.4. TWO-PHASE (GAS-LIQUID) INFLOW

A straight line IPR is also not applicable when two-phase inflow is taking place, e.g. when saturated oil is being produced. The higher pressure loss in this case is mainly due relative permeability and gas compressibility effects. Many empirical IPR models exist in this case. One of the widely-used ones was proposed by Vogel based on a large number of well performance simulations:

$$\frac{q}{q_{max}} = 1 - 0.2(P_{wf} / \bar{P}_R) - 0.8(P_{wf} / \bar{P}_R)^2 \qquad (6)$$

where q_{max} is the AOF, i.e. the rate q when $P_{wf} = 0$. Vogel introduced the concept of normalising the production rate to the AOF value (q_{max}).

Equation by Fetkovitch (analogous to the backpressure gas equation) is also widely used:

$$q/q_{max} = (1 - (P_{wf} / P_R)^2)^n \qquad (7)$$

Figure 18 compares the production rate as a function of drawdown for an undersaturated oil (straight line IPR, line A) and a saturated oil (curve B). The figure also shows the case (curve C) is for an undersaturated oil reservoir (i.e. the reservoir pressure is above the bubble point pressure) when the wellbore pressure is below the bubble point pressure, i.e. when there is (only) liquid flow in the reservoir far from the well, while in the near-wellbore region there is gas-liquid flow.

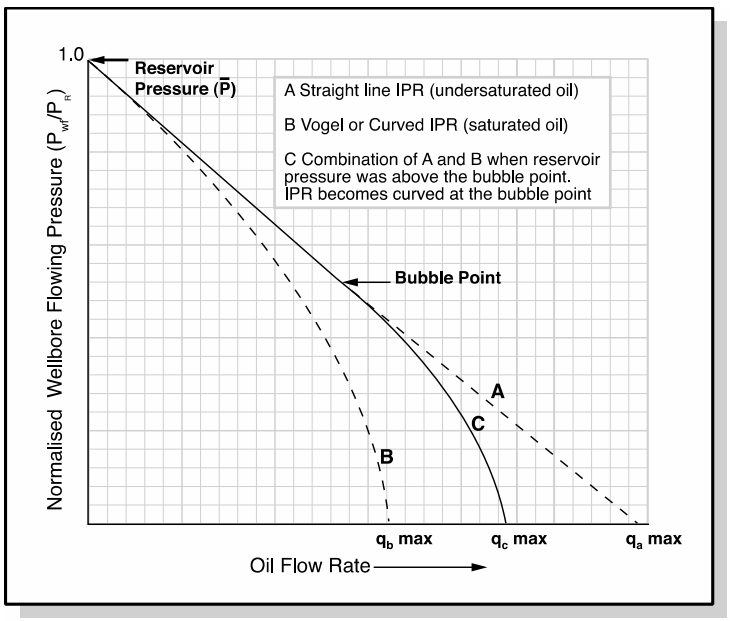

Figure 18 Inflow performance relationships.

To describe the Curve C – type IPR for the cases when the reservoir in undersaturated, but the wellbore pressure drops below the bubble point pressure (from which point the flow in the reservoir around the wellbore becomes multi-phase), the following is done:

1. Describe the IPR for the P_{wf} values above P_b as a straight line

2. Describe the IPR below P_b as a multiphase model of choice, e.g. for the sake of discussion assume it's Vogel's. Since in this case such model is only valid for the wellbore pressures below bubble point pressure, P_b has to be used in it as the 'reservoir pressure'. In order to find the Vogel model's q_{max} ensure that the

linear and Vogel models join smoothly at the junction point, i.e. at $P=P_b$. That is make sure the both models have the same value and first-order derivative at this point.

3. The resulting well rate for a given $P_{wb}<P_b$ will be equal to the linear IPR's rate at the bubble point pressure plus the additive rate predicted by the Vogel's IPR model: $q(P_{wb}<P_b) = q_{linear}(P=P_b) + q_{Vogel}(P_{wb})$.

- *Feel free to attempt Tutorials 6-20*

4.5. COMPOSITE IPRS

All the above refers to a well producing from a homogeneous reservoir. Frequently, wells are also completed on heterogeneous formations where production from several different zones is commingled. Reservoirs with differing permeabilities will be depleted at different rates – the resulting composite IPR being the sum of the separate individual IPRs (Figure 19). It will change as the well depth, fluid type, production rate etc. alter.

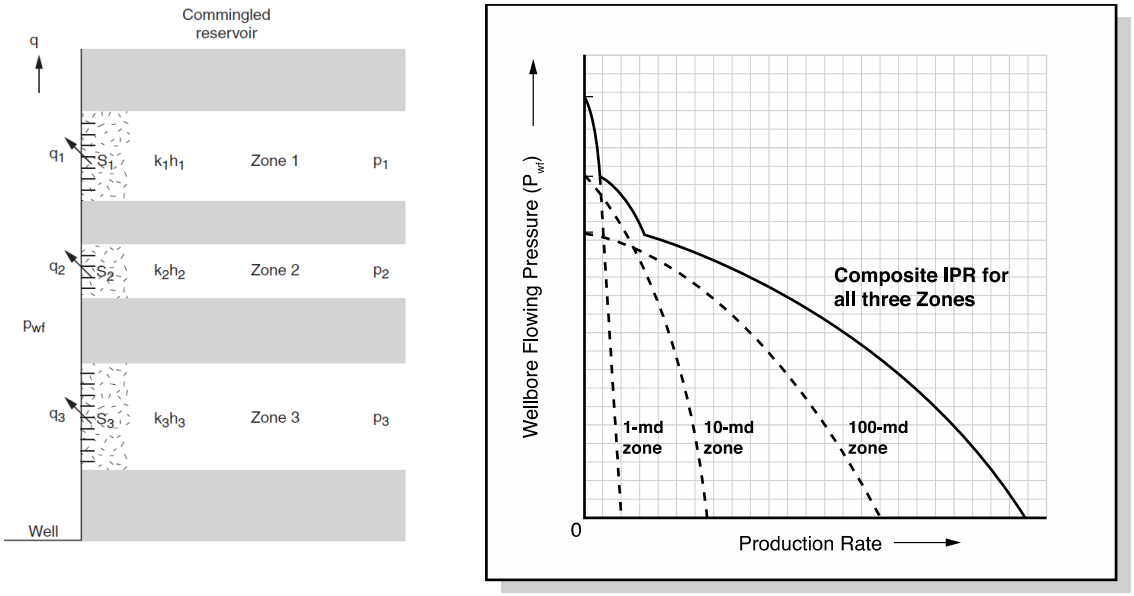

Figure 19 a) Heterogeneous formation; b) Composite IPR for a heterogeneous formation.

The example illustrated in Figure 19 is perfectly reasonable: the zones with higher PI produce more oil and thus their pressure depletes faster (note how the 100-mD zone's reservoir pressure is lower than the others'). The total well rate for a given bottomhole pressure is the sum of the individual rates: this is how the composite IPR is constructed. *Note that if the bottomhole pressure is above the 100-mD zone's reservoir pressure, then the fluids from the 1-mD and 10-mD layers will be partly flowing into the 100-mD zone: this is called 'cross-flow' and is preferred to be avoided so as not to cause production loss and the 100-mD zone's formation damage.*

- *Feel free to attempt Tutorial 21*

5. TUBING (OUTFLOW) PERFORMANCE

The outflow pressure drop required to lift fluids from the perforations to the wellhead and then to the separator is the second factor (IPR being the first one) which determines the well production rate.

Starting from the top of the well, the parameters which contribute to the pressure at the bottom of the well are:

- The (back) pressure at the wellhead.

  ('backpressure' generally is the pressure defined by the system's conditions and such pressure often happens to limit production. E.g. the back pressure at the wellhead has to be kept high enough (despite it, sadly, limiting production) to be able to transport the fluids downstream, to the separator.)

- The hydrostatic head (or 'head loss') between the wellbore and wellhead, which is defined by the fluid column's weight. This is a function of the change in elevation (in TVD) between the wellhead and the wellbore and the average density of the fluid in the tubing, all multiplied by the gravity constant:

  $$\Delta p_{head} = \rho_{average} g h$$

- The pressure loss required to overcome friction losses due to viscous drag. This depends on the fluid's flow rate, flow regime, and the fluid's viscosity as well as the length, diameter and roughness of the tubing.

N.B. – There is another theoretical source of pressure losses: the one due to fluid acceleration, but these losses are normally low in petroleum wells and are neglected.

5.1. THE TUBING FRICTION TERM

A full, fluid-mechanical description of all the situations that are encountered in Production Engineering is beyond the scope of this text. This section is designed to introduce some basic concepts of friction pressure losses for the simplest case – single-phase flow of a Newtonian fluid.

Reynolds Number

The Reynolds Number (R_e) is the ratio of the inertial forces to the viscous forces for fluid (with density ρ, and viscosity μ) flowing in a circular pipe (of a diameter D)

$$R_e = \frac{Dv\rho}{\mu} \quad \left\{ \equiv \frac{\rho v^2}{\mu v / D} \text{ or } \left(\frac{\text{inertial forces}}{\text{viscous forces}} \right) \right\}$$

where v is the average fluid velocity.

Laminar flow happens at relatively low Reynolds Numbers. Turbulent flow first becomes apparent at a Reynolds Number of 2100 with fully turbulent flow being observed at R_e about 3500 and higher. Figure 20 plots the Reynolds Number as a function of fluid viscosity, flow rate and pipe radius. It can be seen that, at the typical flow rates encountered in petroleum wells, fluids with a water-like viscosity (like light and medium oils) are normally in turbulent flow, while viscous oil often is in laminar flow.

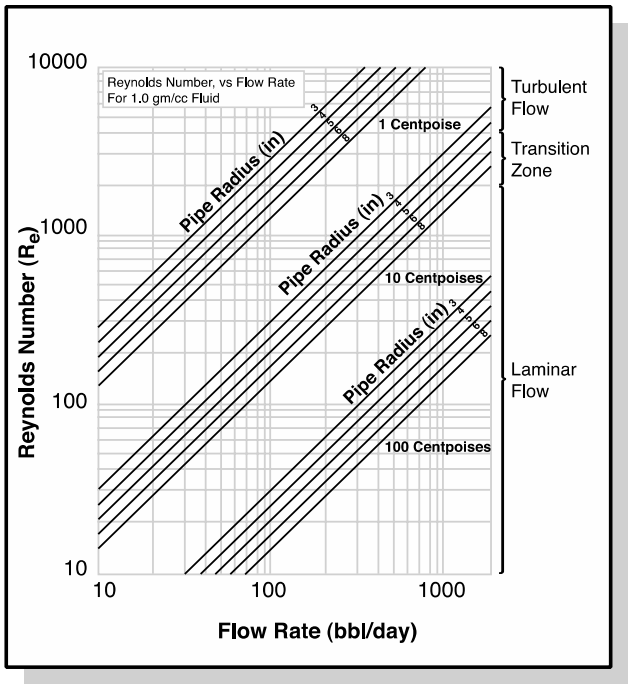

Figure 20 Reynolds number with volumetric flow rate, viscosity, and pipe size.

Laminar and Turbulent Flow

The velocity profile of a Newtonian fluid flowing in the laminar flow regime is shown in Figure 21. Laminar flow is characterised by the individual fluid particles moving only in the flow direction with no fluid movement radially across the pipe, i.e. the fluid can be pictured as flowing in a series of concentric tubes (a.k.a. layers, 'laminae') with the maximum velocity at the pipe centre and the minimum, zero velocity at the pipe wall. This zero velocity layer at the wall forms the fluid film shielding the moving fluid from the tubing wall. So the tubing wall's roughness does not affect the flow in the laminar flow regime.

On the other hand, turbulent flow is characterised by rapidly fluctuating flow velocity components in random directions (but on average in the direction of fluid flow). It also interacts with the pipe walls and is sensitive to the pipe's wall roughness.

Newtonian fluids are defined as having a viscosity that is independent of shear rate. Non-Newtonian fluids, by contrast, have a shear rate dependent viscosity, e.g. the 'shear thinning' type of non-Newtonian fluids has an apparent viscosity which decreases as the shear rate increases. They also have a different velocity profile across the tubing. The third profile in Figure 21 is for a highly shear thinning, non-Newtonian fluid. *This type of fluid is encountered in hydraulic fracturing stimulations and gravel pack operations. Their unusual behaviour allows high concentrations of solid material (gravel pack sand or proppant) to remain in suspension at low shear rates when the fluid is in the fracture or gravel pack; while at the same time when this fluid is being pumped through the tubing (where the shear rate is high) its viscosity is low and therefore it causes lower pressure drops than would be expected if e.g. a Newtonian fluid like water was being used.*

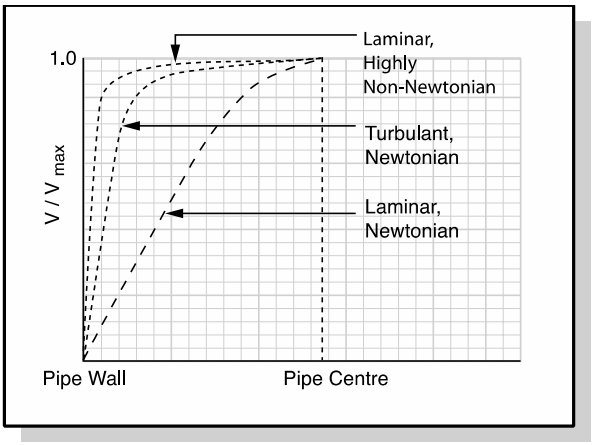

Figure 21 Velocity profiles in laminar and turbulent pipe flow.

Frictional Pressure Drop

Experiments have been made to measure the pressure drop (per unit length of pipe) of a liquid flowing through pipes of known diameter. The measurements were repeated with pipes of differing materials and also with smooth wall pipes which had been deliberately treated to create a surface of known roughness. All the possible combinations of variables have been studied by varying the flow rate and fluid viscosity.

These experiments showed that the frictional pressure drop (ΔP) may be calculated from the Fanning equation:

$$\Delta P = \frac{f_m \rho v^2 L}{2D}$$

where f_m is the Moody friction factor, ρ is the density of the fluid flowing at a velocity v in a pipe of length L and internal diameter D. *(The Moody friction factor is also known as the Darcy-Wiesbach friction factor and is related to the Fanning friction factor as $f_f = f_m/4$).*

Laminar Flow (Re <2100): The frictional pressure drop is independent of tubing roughness and is proportional to the fluid velocity. The Moody friction factor (f_m) is inversely proportional to the Reynolds Number:

$f_m = 64/Re$

Turbulent Flow (Re >3600): The frictional pressure drop is very sensitive to the exact nature of the inner pipe wall as well as to the fluid flow conditions. Experiments showed that the important parameter was the relative pipe roughness ($\varepsilon = e/D$) where e refers to the absolute, average height of roughness features that protrude from the pipe surface into the flow stream and D is the pipe internal diameter.

Chen's equation is one of several widely used correlations for calculating the friction factor:

$$\frac{1}{\sqrt{f_m}} = -2log\left\{\frac{\varepsilon}{3.7065} - \frac{5.0452}{R_e} log\left[\frac{\varepsilon^{1.1098}}{2.8257} + \frac{5.8506}{R_e^{0.8981}}\right]\right\}$$

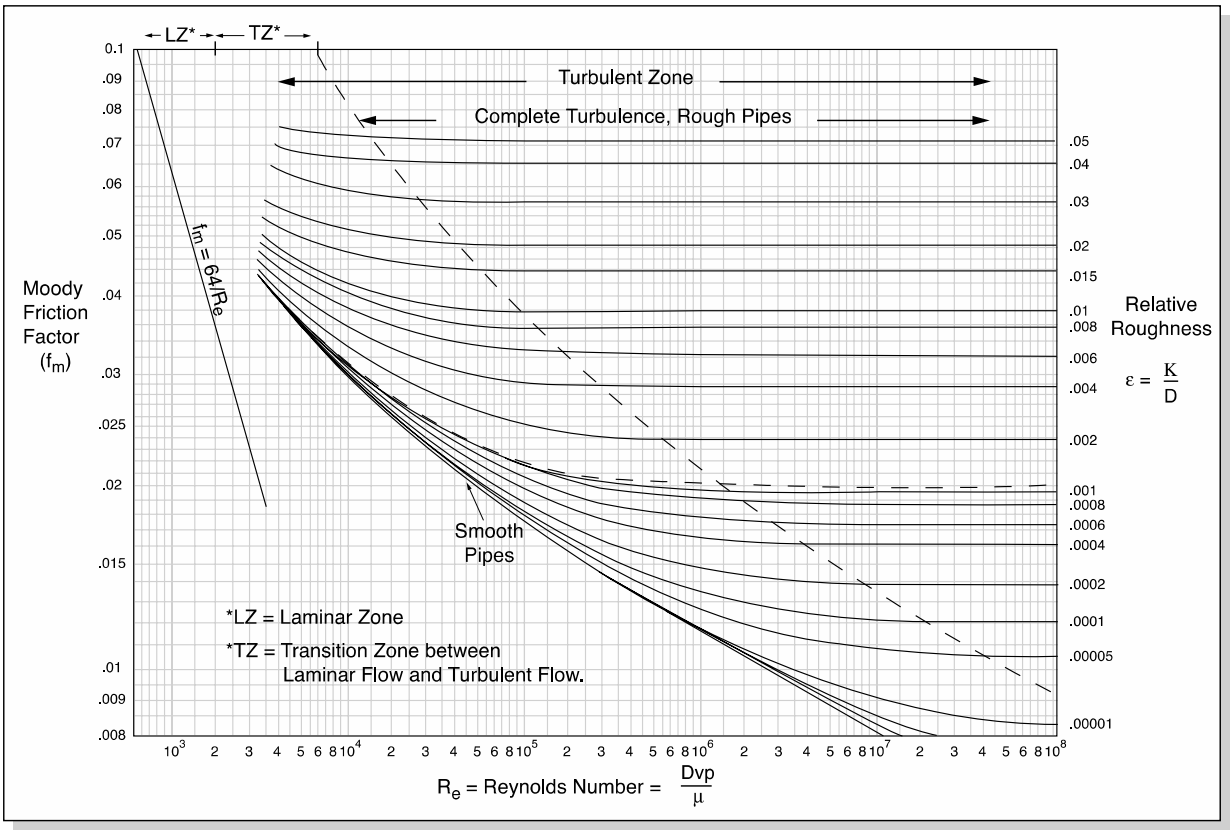

Figure 22 Moody friction factor diagram.

Another normally quoted, though implicit, Colebrook-White equation, has a similar accuracy and was used to generate Figure 22 (a plot of the Moody friction factor as a function of the Reynolds Number and tubing roughness).

➢ *Feel free to attempt the first part of Tutorial 3 ('ESP design') in Chapter 4.*

The pipe roughness depends on many factors; the bulk of which the engineer has little control over. These include:

- Pipe metallurgy and any coating materials applied
- Fluid velocity (erosion at high rates) and fluid corrosivity (pH, the presence of solids, CO_2, H_2S etc.) that affect the tubing wall state
- Deposits (hydrates, paraffins, asphaltenes)
- Years in service

It comes as no surprise to learn that, in turbulent flow where the roughness is an important parameter, this roughness is normally treated as an empirical parameter which is used as a fitting parameter to match calculated results to actual pressure drop measurements. However, the roughness value used must be realistic. Table 2 quotes typical values for use in these calculations. For instance, tubing that has been in service for a number of years is 15 times rougher than when it was first installed, which increases friction pressure losses several fold!

Material	Roughness
Plastic Pipe or Coating	0.0
New Tubing	0.00005
Dirty Well Tubing	0.00075

Table 2 Typical pipe, absolute roughness values (in feet)

Mixing of Two Fluids in a Pipe

On a side note, while the laminar and turbulent flow is being discussed, note that not only will the frictional pressure drop across a length of tubing be different between the laminar and turbulent cases, but their flow velocity profiles will also have significant consequences for several production operations (Figure 23). For example:

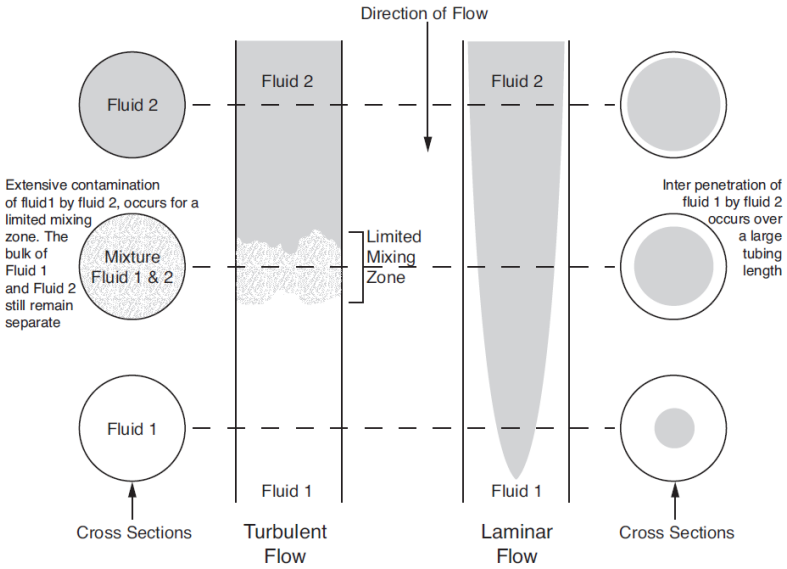

Figure 23 Mixing of fluid in pipe flow as a function of flow regime.

When pumping a series of fluids into a well which should not mix e.g. in a chemical treatment (explained later in the course); the mixing zone between the fluids will be small if both fluids are injected in turbulent flow.

As for the laminar flow: it allows the centre portion of the trailing fluid to penetrate a long way into the leading fluid.

5.2. INTRODUCTION TO MULTIPHASE FLOW IN VERTICAL TUBING

Multiphase flow would be greatly simplified if the two phases behaved as a homogeneous mixture whose properties were an appropriately averaged value of the individual phase properties. However, experiments have shown that this is not the case and that one fundamental phenomenon occurring in multiphase (oil-gas, water-oil, oil-water-gas, etc.) flow is the concept of SLIP (or slippage) and HOLD UP. These phenomena are most important for the gas/liquid case since the density differences are the greatest.

SLIP refers to the ability of the less dense, lighter phase to flow at a greater velocity upwards than the denser, heavier phase due to buoyancy (and vice versa for the downward flow). The difference in their velocities is called slip velocity.

HOLD UP is the volume fraction of the pipe occupied by the denser phase and, because of slip, it appears to be greater than would be expected simply from the denser phase's cut (i.e. from its flowrate fraction) since its flow velocity is slower than that for the light phase. (This is similar to the waiting line effect when a faster counter e.g. in a supermarket can serve as many customers per day as several slow ones. Thus, when the rate of 'fast' and 'slow' customers served per day is, for instance, equal: 50%/50%, the 'faster' customers need less space (a single line and one counter) compared to the 'slower' customers. Similarly, the faster flowing phase may be flowing at a comparable rate to the slower one, but occupies less space in the pipe).

The ability to predict hold-up is very important for both hydrostatic and friction loss calculations since it defines the average fluid density which directly affects both these losses.

These concepts can be best understood with the help of the description in Figure 24. Imagine a volume of fluid in a given pipe's depth is being collected and the gas and liquid in it are separated (Figure 24). The volume fraction occupied by the liquid is the liquid hold up. The faster the average (mixture) fluid flow velocity, the smaller is the effect of slip on the holdup, with the latter getting closer to the liquid cut (or no-slip holdup).

NB. Subscripts G, L, O and W refer to the gas, liquid, oil and water phases respectively, while q is the phase volume flow rate, V the velocity and A_p the cross-sectional area of the pipe.

Superficial phase velocities (V_{SL} and V_{SG}) are given by:

$$V_{SL} = q_L/A_p \text{ and } V_{SG} = q_g/A_p$$

In situ (or actual) **velocities** (V_L and V_G) are given by:

$$V_L = q_L/A_L \text{ and } V_G = q_G/A_G$$

where A_L and A_G are the actual areas of the pipe occupied by that liquid and phases respectively. Hence, $(A_L+A_G) = A_p$

A_L and A_G under NO SLIP conditions can be calculated from the phase flow rates:

$A_L/A_p = q_L/(q_L + q_G)$ and $A_G/A_p = q_G/(q_L + q_G)$

The liquid **Holdup** (H_L) is defined as the fraction of the pipe filled with liquid:

$H_L = V_L/V = A_L/A_p = 1-H_G$ and the gas holdup is $H_G = A_G/A_P = 1 - H_L$

In the case of zero slip the No Slip Holdup is:

$\lambda_L = q_L/(q_L + q_G)$ and $\lambda_G = 1-\lambda_L$ or $q_G/(q_L+q_G)$

where λ_L and λ_G are the inflow and/or outflow liquid and gas volume fractions.

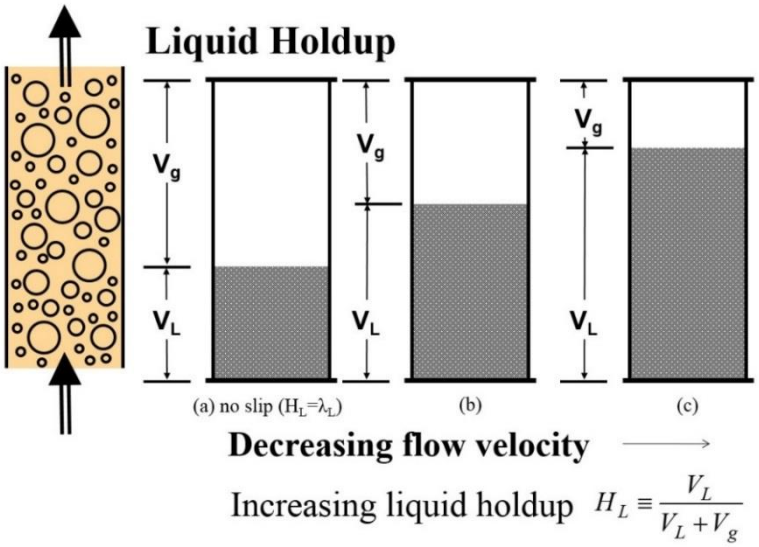

Figure 24 A schematic representation of liquid holdup at various, mixture flow velocity values

➢ *Feel free to attempt Tutorial 22*

5.2.1 Prediction of Multiphase Fluid Properties

The above concepts can be used to predict some of the properties of the multi-phase mixture using a phase averaging mixing rule e.g. the density of a liquid/gas mixture (ρ_m) as:

$$\rho_m = \rho_L f_L + \rho_G(1 - f_L)$$

where f_L is the liquid volume fraction. This density is equal to:

$$\rho_m = \rho_L \lambda_L + \rho_G\{1 - \lambda_L\} \qquad \text{NO SLIP FLOW}$$

or

$$\rho_m = \rho_L H_L + \rho_G\{1 - H_L\} \qquad \text{SLIP FLOW}$$

Other properties, such as viscosity, generally cannot be predicted by this averaging technique and require the use of special correlations.

5.3. LIQUID / LIQUID FLOW

Most properties of the liquid/liquid mixture can be calculated using the phase averaging mixing rule discussed above. One exception is the viscosity. At certain high-shear conditions (e.g. when flowing at high rate through a valve or a pump) an oil-water **emulsion** may form, i.e. a mixture such that oil droplets are dispersed in water (the water being the 'continuous' phase in this case), or vice versa (Figure 25). The emulsions have been observed with viscosities up to 50 times greater than that predicted from the simple averaging rule (Figure 26) though the height of this viscosity maximum is often less than the above value. It is dependent on:

- The extent and type of shear imposed on the oil-water mixture and
- The type of emulsion formed: loose (i.e. easy to separate), medium, or tight (i.e. difficult to separate).

- The presence of small solid particles at the oil/water interface and/or chemical compounds in the crude oil. Both of these can 'stabilise' the emulsion so that it takes a long time to separate.

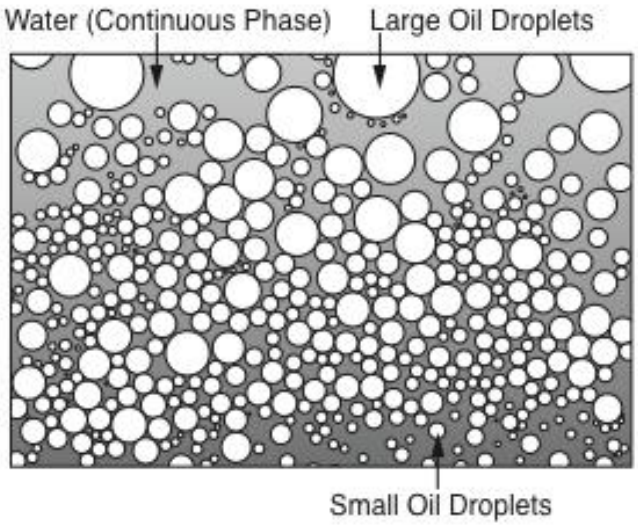

Figure 25 An Oil/Water Emulsion can have high viscosities and/or lead to slow phase separation

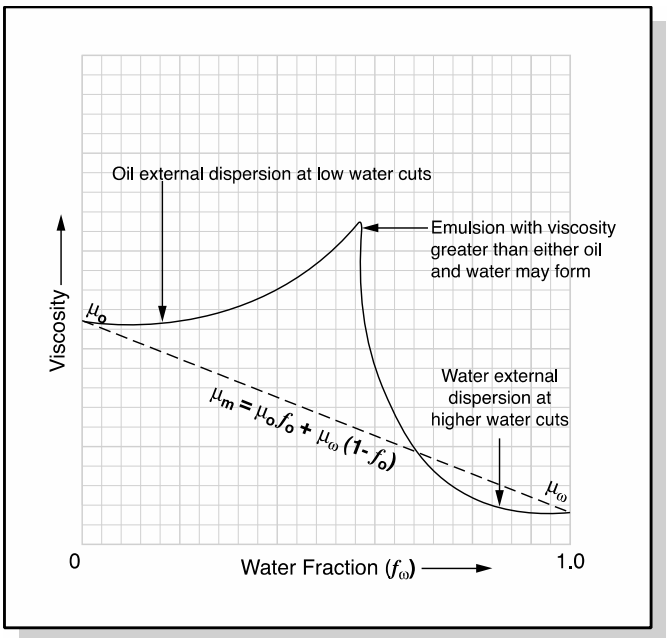

Figure 26 Schematic representation of the viscosity of water / oil mixtures.

The maximum viscosity is observed at the so-called 'inversion' point at which one phase stops being continuous and becomes dispersed (or discontinuous), while the other phase experiences opposite transformation.

The size of the discontinuous phase droplets will depend on the oil's viscosity, the oil/water density contrast, the oil and water's chemical properties as well as the type and amount of shear that the mixture is subjected to.

At low water cuts the mixture is in the form of a dispersion of water droplets in a continuous oil phase; the resulting mixture's viscosity being similar to that of pure oil. Similarly, at high water cuts dispersion of oil droplets in water is formed with a "water-like" viscosity (Figure 26).

5.4. GAS/LIQUID (OIL) FLOW

Earlier sections introduced the concept of phase changes to the hydrocarbon fluid as it travels up the tubing (Figure 6). The following is an elaboration of these ideas and introduces the concept of a flow map to describe multiphase tubing flow which will be combined with the multiphase flow concepts described in the previous section.

Figure 27 illustrates the production case when the wellbore flowing pressure (P_{wf}) is greater than the bubble point i.e. single-phase oil is entering the well. Single-phase flow in the tubing will continue until the pressure (and temperature) decrease so that the bubble point is reached (point c).

The flow patterns in the tubing that will result from this gas bubble formation are a function of:

- Gas and liquid flow rates
- Pipe angle of inclination
- Pipe diameter
- Phase densities

5.4.1. Flow in Vertical Tubing

(Strictly speaking, a 'vertical' well is the well with the trajectory varying within 10-20° from the vertical axis).

- At point c in Figure 27 the first gas bubbles appear and so the fluid mixture's velocity in the tubing increases and the average fluid density decreases.
- The initially formed bubbles will be widely dispersed within the liquid. Continued flow up the tubing results in a further pressure reduction, increasing the number of bubbles – which still remain widely dispersed in a continuous liquid phase. This is called "bubble flow" or "bubbly flow" regime. The low-density gas bubbles flow at a greater velocity than the liquid. Slip is thus occurring affecting the liquid hold up (as described earlier).

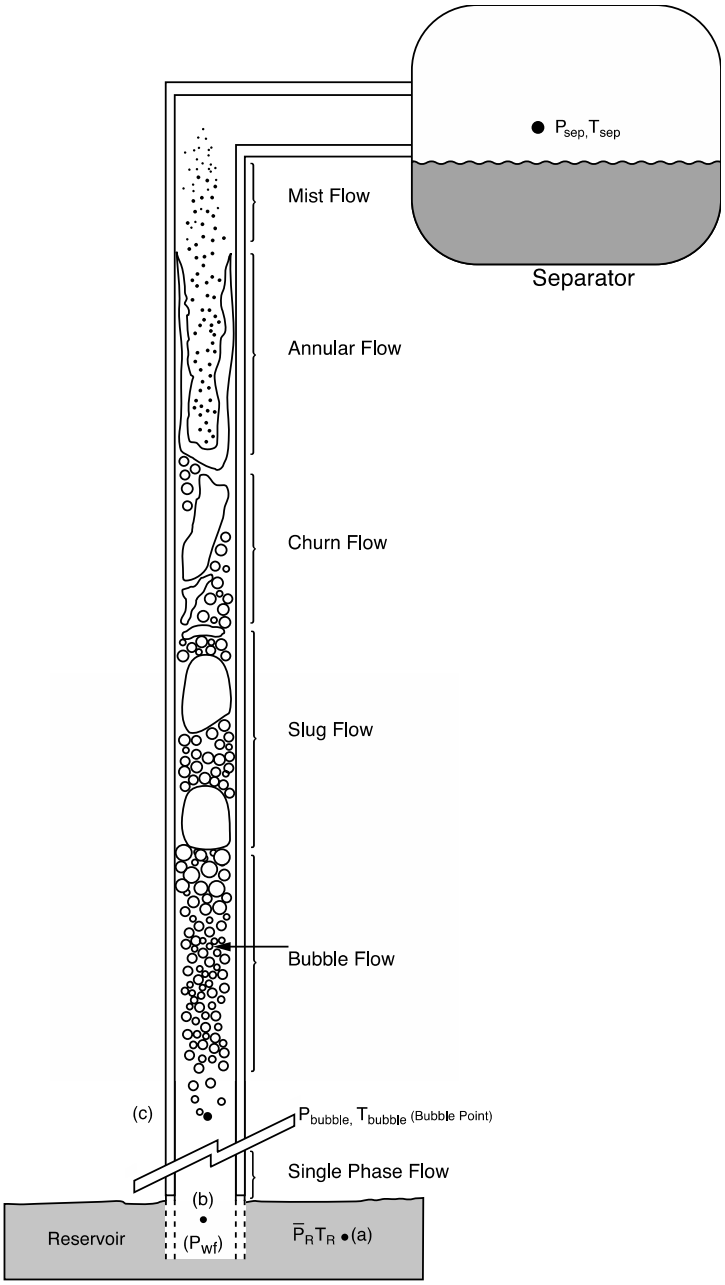

Figure 27 Schematic view of some possible phase changes in tubing.

- Further upward movement of the produced fluid generates an increasing volume (and mass) of gas phase; with a corresponding reduction in the mass (and volume) of the liquid phase. *Intense mixing will ensure the gas and liquid phases remain in equilibrium as the pressure reduces i.e. the composition of the gas phase will change with the evaporation of progressively higher molecular weight, hydrocarbon molecules. Availability of an "equation of state" for describing the reservoir fluids PVT properties allows "flash" calculations to be carried out, i.e. to calculate the composition of the liquid and gas phases at any required temperature and pressure.*

- The increasing tubing volume fraction occupied by the gas allows bubble coalescence to occur to such an extent that they fill the entire pipe cross section and form slugs i.e. a series of very large gas bubbles (gas slugs) of roughly constant size separated from each other by areas of liquid (liquid slugs) containing smaller gas bubbles. This is called the "slug flow regime".

The bubble and slug flow regimes (or patterns) are commonly observed in oil wells. Some wells may develop further flow patterns, subject to the flow conditions, including:

- Velocity increases, associated with continued expansion of the available gas and further volume increase of the gas phase, eventually result in the gas slugs so large that they become unstable and break up into a wider range of gas bubble sizes. This is called "churn flow", a highly turbulent flow pattern associated with oscillating liquid flows. This trend may continue so that the phases become dispersed within one another, i.e. neither is continuous. This is called "froth flow" (not illustrated in Figure 27).

- Further upward the gas liberation and expansion processes continue to such extent that the phases separate into a central, high velocity 'core' flow of gas with a continuous film of liquid flowing on the tubing wall – the "Annular flow" regime.

- Shear at the gas/liquid interface resulting from continually increasing gas velocities will eventually destroy the annular ring of liquid on the tubing wall and disperse it within gas as a "mist" of small droplets – the "Mist flow" regime.

N.B. As can be seen there is more gas in the well flow stream as it approaches the surface, which normally results in the average fluid density being lighter, and so the flowing pressure change (decrease) per foot gets lower. However, in some extreme cases the high velocities experienced near the surface can result in the increase in the frictional pressure gradient exceeding the decrease in the hydrostatic head pressure gradient, so that the rate of pressure loss in the tubing may increase as the depth decreases.

These flow regime transitions have been studied both theoretically and experimentally (by visually observing the flow regime as a function of gas and liquid velocity in a transparent, vertical column). Correlations are generated so that the boundaries between the various flow regimes can be plotted on a Flow Map (Figure 28). (Several flow maps are available obtained by different research groups at different experimental/field conditions.)

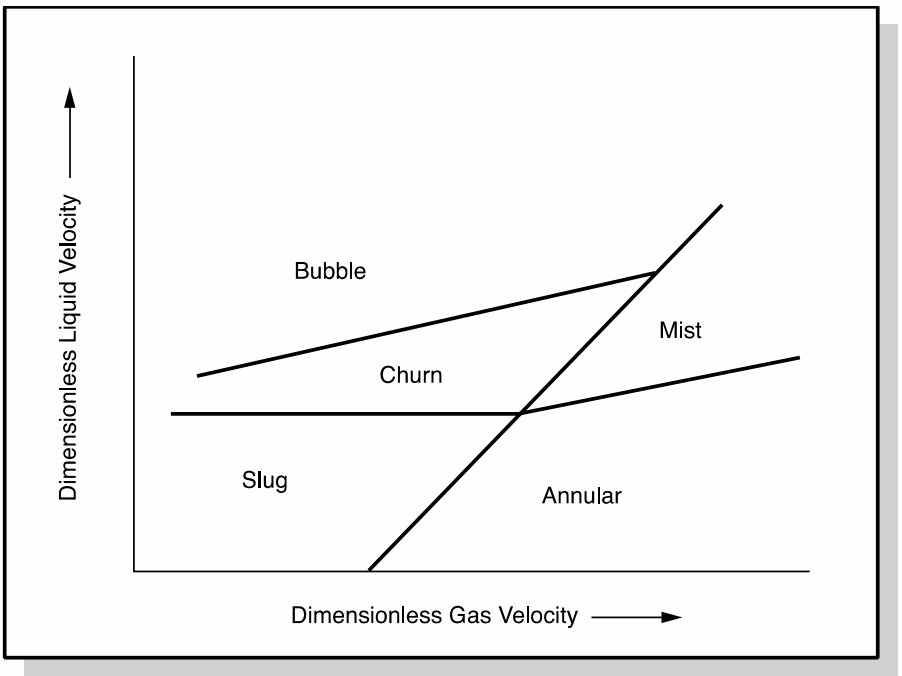

Figure 28 An example of a flow map. Either superficial or dimensionless fluid and gas velocity values are normally used as coordinates.

5.4.2. **Flow in Inclined Pipes**

The inclined or horizontal flow is different from the vertical one – under these conditions it is much easier for the gas to separate from the liquid and flow in the upper section of the pipe, such that the difference between the actual and superficial phase velocities to become much greater than for the corresponding vertical flow conditions, also resulting in a larger holdup value. This naturally alters the flow regime as the pipe's angle of inclination (θ) increases from the vertical. A second effect is that the tubing length (dL) becomes greater than dX (the vertical depth change) as θ increases (dL = dX/cosθ) (see Figure 29), so the relative importance of friction head increases compared to the hydrostatic head. The hydrostatic head per dX is often higher than for vertical flow because the average fluid density will increase due to an increase in the liquid hold up (H_L).

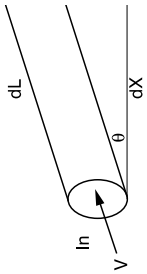

Figure 29: Upward flow in an inclined tubing

5.4.3. **Flow in Horizontal Wells and Flow Lines**

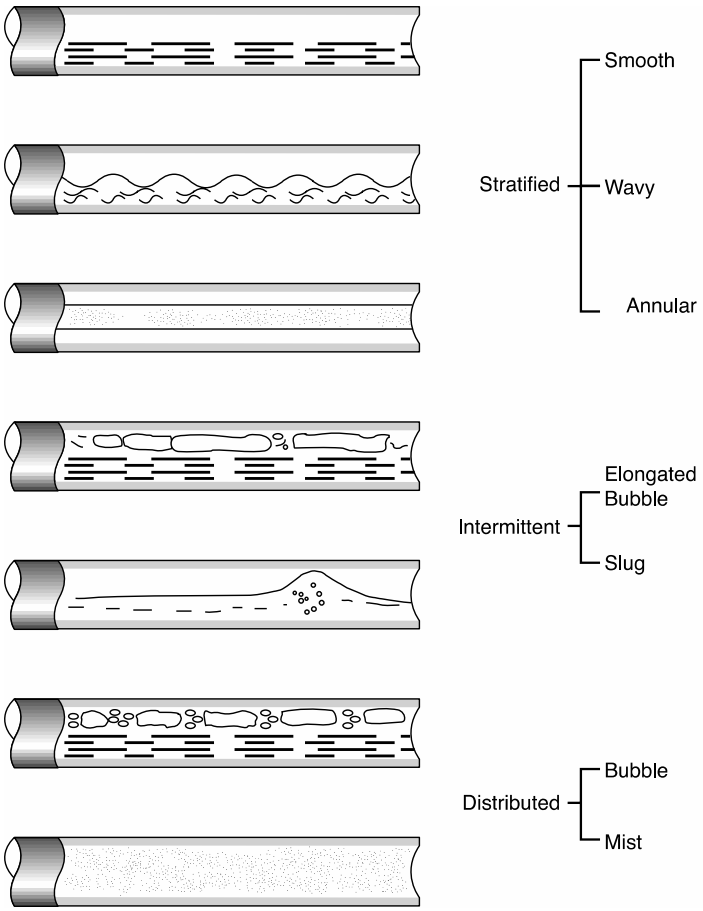

Figure 30 Horizontal pipe liquid / gas flow patterns.

All the above trends (observed in inclined tubings) become progressively more extreme as the angle θ increases to 90° or thereabout meaning a horizontal flow line or horizontal wellbore. Here the hydrostatic head component is of minor importance while the tendency for phase separation due to density difference is at its greatest. Experiments have been carried out in transparent pipes and have identified the following patterns (some illustrated in Figure 30):

Stratified { - smooth, - wavy
Intermittent { - elongated bubble, - slug
Annular { - annular mist, - annular wavy
Dispersed bubble

↓ increasing velocity

↓ increasing liquid fraction

Large changes are observed in the flow pattern when the pipe inclination angle (from the horizontal axis) changes from +1° to -1° under stratified or (relatively) low velocity flow conditions. This can be particularly important when considering the flow regimes in horizontal wells (especially given such wells are never exactly horizontal and have an undulating trajectory, let alone their often-used liner/casing completion has a greater diameter allowing more gas-liquid segregation compared to normal production tubings).

The above, empirical description of multiphase flow has discussed the phenomena identified by experimental studies. The objectives of these studies were:

- To produce a flow map which delineated the boundaries between the different flow regimes and
- To develop a correlation between the pressure drop and the liquid and gas phase properties and velocities, as a function of the tubing diameter, within that flow regime.

The combination of these two factors allows the calculation of the tubing outflow performance.

5.5. TUBING PRESSURE TRAVERSE

The overview of the pressure losses happening in a well is presented in Figure 31.

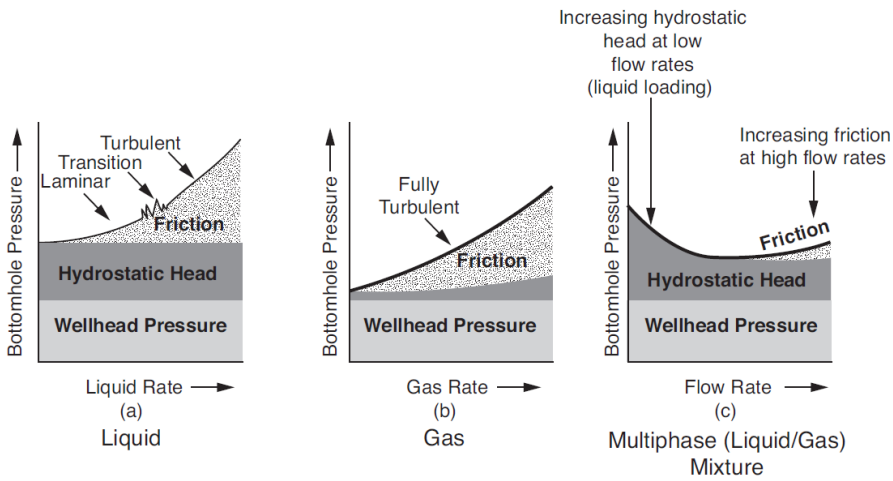

Figure 31 illustrates the relative importance of the pressure losses for a given well depth as a function of flow rate and fluid type.

• Figure 31a is for a single-phase liquid production. This might happen in a water or viscous-oil production well. Being dense, the hydrostatic head component is relatively large and constant (the density of water and the heavier crudes, e.g. 20°API oils, shows only minor variations within the range of pressure and temperature changes typically found in producing wells). Many viscous-oil wells operate in the laminar flow regime with the frictional pressure drop being proportional to flow rate. At high flow rates the friction component increases rapidly once turbulent flow is achieved.

• Figure 31b is for a gas well. The hydrostatic head component is now much smaller, but increases with depth due to higher pressure (gas being compressible since gas density is very pressure dependent). Frictional pressure losses are normally the most important component. Turbulent flow is encountered even at low gas flow rates. The fluid's density (and hydrostatic head) increases as the gas rate increases at the constant wellhead pressure due to the increasing tubing intake pressure which compresses the gas in the well making the gas denser.

• Figure 31c represents the multiphase (gas/liquid) production and shows a complicated variation of friction and hydrostatic pressure losses with increasing production rate. Their relative importance changes depending on the exact conditions. At very small flow rates (normally up to tens of barrels per day) the flow rate is unstable and is in the liquid loading condition: the gas has enough time to flow up and escape from the slowly moving oil, leaving this viscous, 'dead' oil behind whose weight loads the well creating backpressure at the bottomhole. This results in this counterintuitive effect: higher FBHP at lower rates. At relatively higher rates the gas and liquid flow together, and the FBHP behaves as expected: the higher the rate the higher the friction and hence pressure losses.

These differences between the three fluid systems are also apparent when the change in pressure as a function of depth at a constant well production rate is considered (Figure 32). This plot of the tubing pressure profile is known as a "Tubing Pressure Traverse"; and the change in total pressure with depth is known as a "gradient" curve. The behaviour of the individual pressure components which make up the final gradient curve is summarised below.

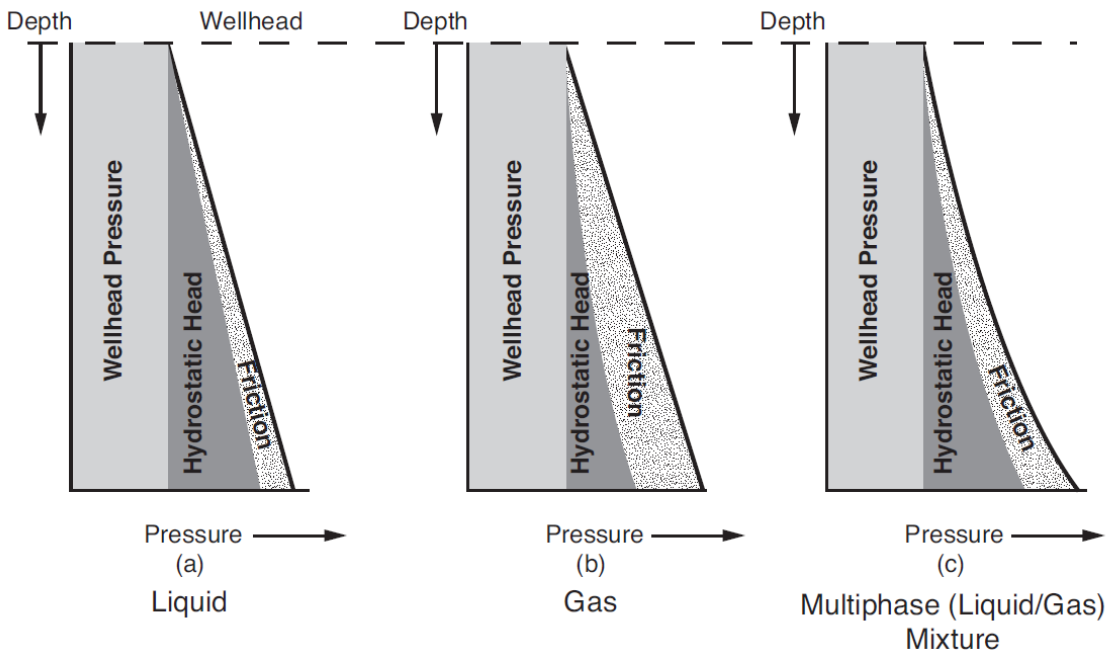

Figure 32 Tubing pressure traverse.

Figure 32a is for a single-phase liquid. The hydrostatic head and friction components are straight lines. This is because the fluid density and the friction loss per unit of tubing length remain constant over the complete tubing length.

Figure 32b is for a gas well. The (relative) contribution of the hydrostatic head component increases with depth since the gas density increases with the total pressure (and well depth). The friction component shows the reverse behaviour: the gas velocity is greatest at shallow depth since the pressure is lowest at this point and the gas expands while the same mass of gas is entering and exiting the tubing. Thus, the ratio: (friction pressure/hydrostatic head) per unit length of tubing increases as the well depth decreases. The opposing behaviour of the friction and hydrostatic head components with depth results in the (total) pressure traverse often close to a straight line.

This conclusion is only true for a constant tubing diameter. Restrictions in gas wells can often lead to unacceptably high pressure losses due to the consequently large increase in gas velocity.

As far as the restrictions are concerned: the pressure drop across some severe ones (e.g. chokes or flow control devices) is described using dedicated models (described later). However, in these pressure calculations, some basic restrictions e.g. SSSVs, nipples, etc. can also be accounted for by an 'equivalent' length of pipe, e.g. pressure loss across a certain valve in the tubing can be equivalent to the loss across the tubing section of the length of N tubing dimeters. Such equivalent (or effective) lengths are tabulated for different restrictions and provided in specialised handbooks. The same approach is used to estimate pressure losses across pipe fittings e.g. bends, elbows, T-junctions (tees), etc.

The multiphase flow (Figure 32c) case is complex combining the above effects as well as phase changes.

In all the above cases the only parameter that is under the operational control of the production engineer is the wellhead pressure or system "back pressure". The remainder of the completion can only be influenced by the engineer at the design stage. This is thus the time when a wide range of sensitivity analyses should be performed in order to ensure that the installed well will be "fit for purpose" during its lifetime. Use of a standardised well design in a field can bring significant cost savings. However, these have to be balanced against the costs of e.g. foregone production, extra workovers to change tubing size, etc. that a non-optimum well completion will bring. Reduction in total, lifetime unit costs of constructing and operating the well is the aim of the production engineer, optimising the profitability of field development.

6. "GRADIENT" OR PRESSURE TRAVERSE CURVES

Gradient curves (originally proposed by Gilbert) correlate pressure drop as a function of tubing length (Figure 33). Field experience lead Gilbert to identify that the main factors in controlling vertical multiphase flow were tubing diameter, oil rate and gas/liquid ratio. His original curves were developed using field data. However, later curves published by other investigators are based on laboratory experimental data and flow maps.

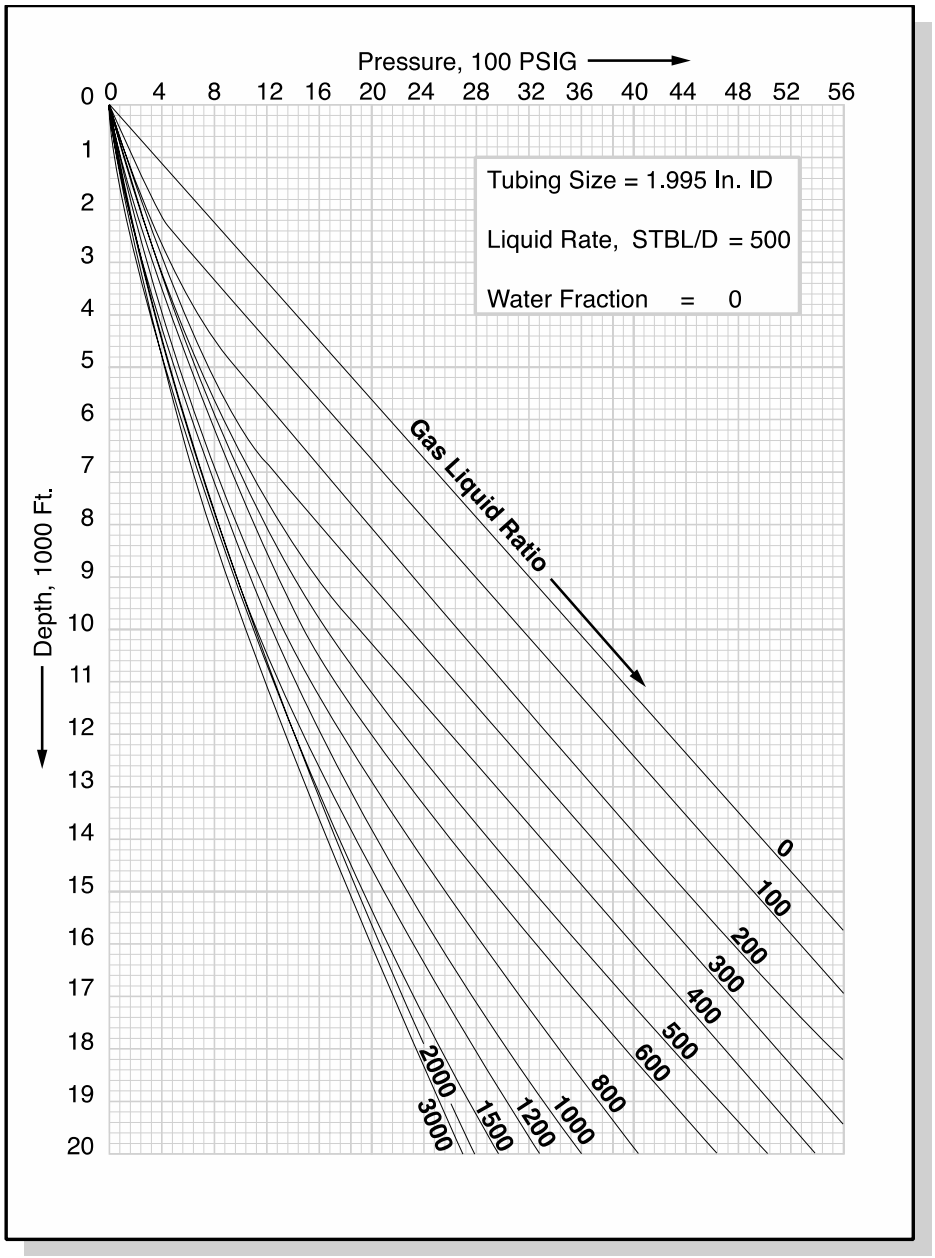

Figure 33 Pressure Traverse Example with several "Gradient" Curves

Figure 33 shows that a different gradient curve is required for each tubing size, liquid rate and water fraction. Each graph consists of a series of lines referring to different gas/liquid ratios.

- *Feel free to discuss the shape of the curves and explain the phenomena behind it.*

7. FLOW MAPS AND CORRELATIONS

Different investigators have published flow maps (which are associated with their names) and experimental correlations which, unfortunately, can be contradictory i.e. under certain flow conditions they predict different flow regimes/patterns (and pressure drops). These pressure drop calculations are quite mathematically complex and were initially implemented using hand calculation procedures. Nowadays, several (commercial) computer programs are available to rapidly and easily complete these complicated

calculations. Prior to the widespread availability of computers or electronic calculators, use was made of "gradient" curves charts (like Figure 33) which greatly simplified the calculation process.

Many authors have studied the phenomena of 2- and 3-phase flow in vertical, inclined and horizontal pipes. They have proposed a large number of flow maps and correlations based on the large (field and laboratory generated) databases generated during their studies e.g. the Duns and Ros study contained 4000 separate laboratory data sets. The database analysis procedure normally consisted of:

- Expressing the data (e.g. gas and liquid velocities, pipe diameter and liquid viscosity) in a dimensionless or dimensional form.
- Using the dimensionless numbers or apparent velocities to draw a flow map indicating the boundaries between the various flow regimes (however some studies concentrated on only one flow regime). Equations were developed to describe these boundary lines.
- Development of correlations, either empirical or theoretical (mechanistic) for each flow regime that allow the calculation of slippage, hold up and friction factor and hence pressure drop in the pipe.

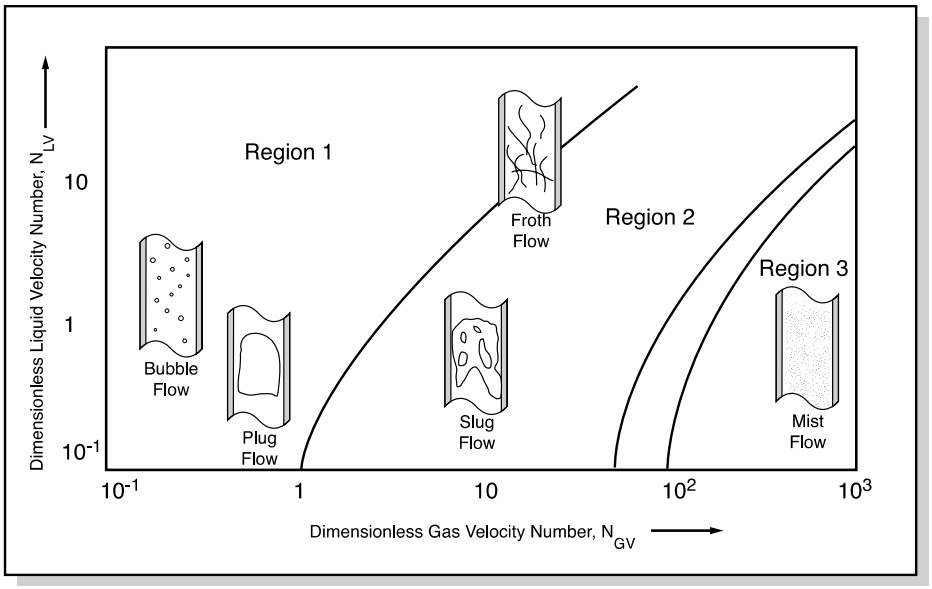

Figure 34 Duns and Ros vertical flow pattern map.

Typical examples of two types of flow maps – one for vertical flow based on experiments (Duns and Ros, 1963) and the other from a theoretical analysis of horizontal flow regimes (Taitel and Dukler, 1976) are presented as Figure 34 and Figure 35.

Many of the correlations were subsequently modified to extend their range of application, e.g. the Duns and Ros correlation was modified by the Beggs and Brill correction factor to account for well deviation.

There are a number of correlations, and yet this process is still ongoing with the correlations suitable to more complex flow cases becoming available. They are developed by research groups, companies (e.g. proprietary PetEx correlations or Statoil ones), University labs (e.g. Tulsa correlations), etc.

We discussed earlier that many different studies have been published and that none of them are universally applicable – some being more limited than others. Application to oil and gas production requires that they should include:

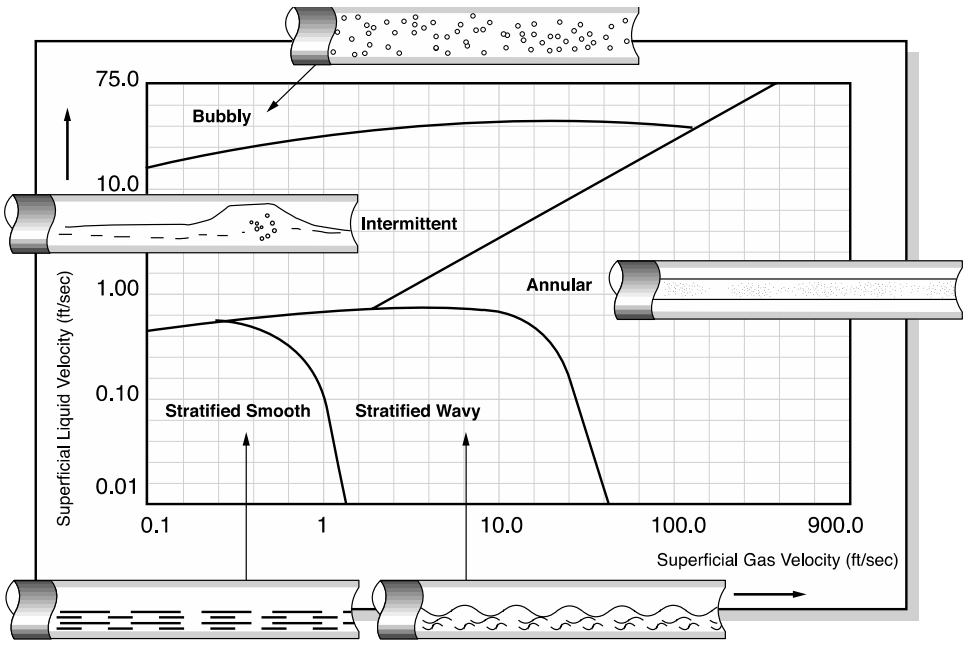

Figure 35 Taitel-Dukler horizontal flow pattern map.

- Phase Slippage and Flow Regime
- Correlations for Frictional Pressure Loss
- Vertical / Horizontal and Inclined flow condition

A few of the correlations that are included in commercial software and will be encountered by the Production Engineer are listed in Table 3:

Reference	Data Source	Fluids	Comments
Gilbert	Field data	G, O, W	Introduced vertical, multiphase gradient curves
Duns and Ros	Field and Lab. data (air, oil & water flow in 1¼ - 3⅛ in. pipes)	G, O, W	Vertical flow over wide flow rate range
Griffith and Wallis[1]	Laboratory data (air & water flow in narrow pipes)	G, W	Good slug flow correlation used by later investigators
Hagedoorn and Brown[2]	Field experiment (gas, oil & water flow in 1 - 4in. pipes)	G, O, W	Forms basis for widely used correlation
Aziz and Govier[3]	Field & Lab. data (air, oil & water flow in a wide range of pipes)	G, W	Correlations developed by mechanistic fluid mechanical study tested against field data
Beggs and Brill[4]	Laboratory data (air & water flow in 1-1½ in. pipes)	G, W	Correlations useable at all inclination angles

Table 3 Some of the many available Flow Correlations.

The practicing petroleum engineer will most often obtain access to these techniques in two manners:

- Use of gradient curves (e.g. Figure 33 was calculated using the Hagedorn and Brown correlation).
- Direct application of the correlations calculation procedure in one of the many computerised well performance prediction packages.

8. TUBING PERFORMANCE CALCULATIONS USING PRESSURE GRADIENTS

Now that the background of the wellbore flow phenomena has been explained, this makes it possible to apply this knowledge in order to predict the Tubing Performance Relationship (TPR).

Figure 36 explains how the gradient curve can be applied to calculate the flowing bottom hole (P_{wf}) or, more precisely, the flowing tubing intake pressure for a fixed wellhead pressure. This is then repeated for a series of production rates to derive the TPR.

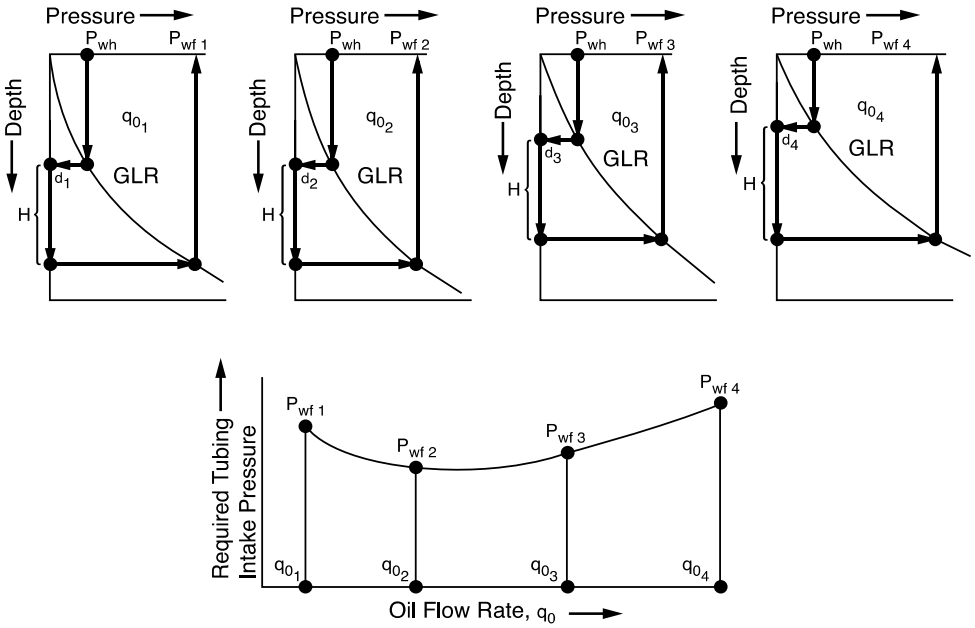

Figure 36 Construction of the Tubing Performance Relation (TPR) using gradient curves.

The gradient curve is used as follows:

i. Select the gradient curve appropriate for the specified oil rate (q_o1), tubing size, gas/liquid ratio and water fraction.

ii. Find the point on the x axis at which the pressure equals the wellhead pressure.

iii. Move vertically downwards to find the depth (d_1) on the appropriate gas/liquid ratio line that corresponds to this wellhead pressure. *Essentially, this distance d_1 is the pipe length equivalent to the pressure difference between the wellhead pressure and zero.*

iv. Move further downwards by a distance (H), equal to the tubing length.

v. Moving horizontally and then vertically, to identify the pressure on the same gas/ liquid ratio line as was used in step iii above, corresponding to this new depth (d_1 + H). This is the required tubing intake pressure (P_{wf1}).

The process may now be repeated at other oil rates (q_{o2}, q_{o3} and q_{o4}). Each rate requires use of a different gradient curve applicable to this rate (while the tubing size, water fraction and gas/liquid ratio are constant). The tubing intake pressures (P_{wf1}, P_{wf2}, P_{wf3}, and P_{wf4}) may now be plotted as a function of oil rate (q_{o1}, q_{o2}, q_{o3} and q_{o4}) as shown in Figure 36 bottom, and the TPR (or outflow OPR) curve interpolated between the points.

This outflow curve is specific to the set of conditions that were used to generate it (the wellhead pressure, tubing size, liquid rate). It should now be combined with the Inflow Performance Relationship as explained earlier and shown in Figure 4 to estimate the well production rate.

- *Feel free to attempt Tutorials 23-39, 43*

9. TEMPERATURE MODELLING

The wellbore temperature change will affect the average fluid properties, particularly viscocity – which in turn will alter the pressure drop calculation. So it is important to understand how the wellbore tempertature is modelled.

Large scale heat loss from the (hot) produced fluid produced from the (hot) reservoir will occur as it flows upwards to the (cool) surface. Figure 37 and Figure 38 illustrate the calculation procedure and compares the formation (geothermal) temperature with the fluid temperature during production. In general, the higher the production rate, the hotter the fluid will be at any given depth since the increase in the (rate of) supply of energy (heat) is proportional to the production increase while the heat losses from the wellbore by thermal conductivity etc. are only a function of the temperature difference between the well and the surroundings i.e. almost independent of the production rate.

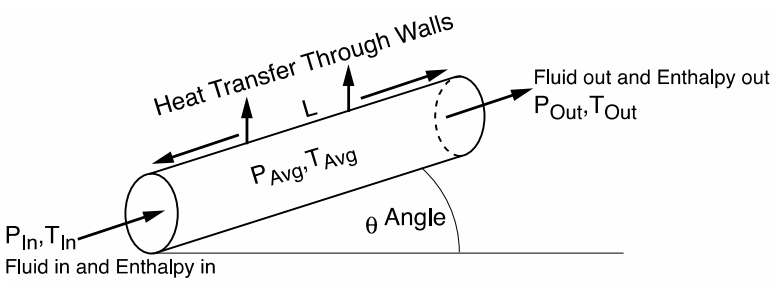

Figure 37 Coupled temperature and pressure calculation across a tubing segment.

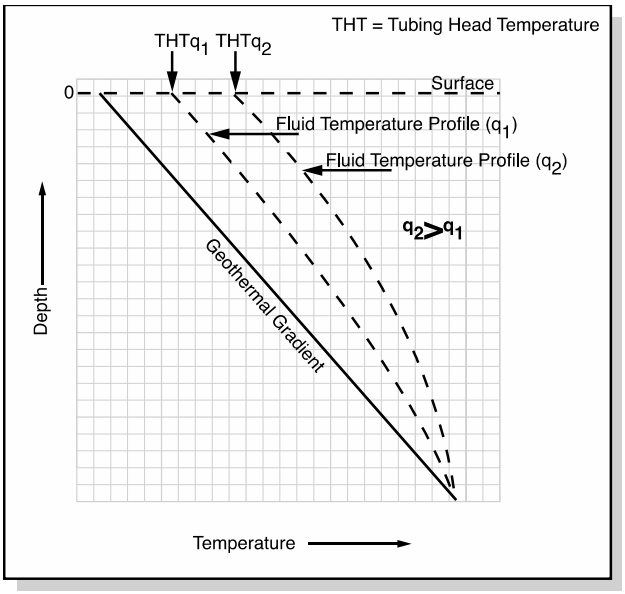

Figure 38 The average tubing temperature increases as the production rate increases.

As mentioned, this temperature change will affect the pressure drop, which will affect the flow rate, and therefore the temperature change again. Hence, full simulation of flow in a well requires coupling of the fluid temperature prediction model with the pressure calculation. This temperature model may range from a simple analytical equation to a rigorous numerical description of heat flows. The coupling of temperature and pressure requires an iterative procedure for their calculation.

- *Feel free discuss how the wellbore temperature profile may look like when e.g. there is a leak, or a gas influx, or a vacuum-insulated-tubing is used, etc.*
  - *Feel free to attempt Tutorial 44*

10. SURFACE PRESSURE LOSSES

10.1. SURFACE COMPONENTS

The principal surface system pressure loss is often across the surface choke installed at or shortly downstream of the Xmas tree, or at the manifold. This is an "optional" pressure loss in the sense that it is designed into the well completion in order to control the well flow rate and the pressures. The choke can be eliminated completely when the reservoir pressure has been depleted to such an extent that economic flow rates can only be achieved by lowering the wellhead pressure to its minimum value.

The second major source of pressure losses in the surface system is the flow line and its fittings.

Excessive flow line pressure losses can be reduced by installing a parallel, or looped, flow line in order to reduce the fluid's flowing velocity. Modelling of looped pipelines is relatively simple for single-phase flow since the flow will divide itself between the two branches so that there is an equal pressure drop along the two pipelines. This is more complex for multi-phase flow cases. The situation is more complicated when there are multiple branches and lines in a complex pipeline network.

The pipe flow pressure loss principles and correlations described earlier similarly apply to the flowlines. E.g. the Beggs and Brill correlation is traditionally used to describe flow in horizontal wellbores and also in flowlines. The nodal analysis to size a flowline is applied in the same manner as in a well model.

10.2. FLOW THROUGH CHOKES

Flow from a well often has to be controlled for reasons such as:

- Limitation of the drawdown to prevent water coning, gas cusping or sand production;
- Dissipation of well energy to meet pressure limitations of the downstream surface production equipment etc.;
- Control of well production rates to meet regulatory or reservoir management objectives or production equipment constraints.

Chokes differ from other completion equipment in that they are designed to produce a pressure loss while other components, such as subsurface safety valves, are designed so that their presence has as low as practically possible an effect on the total system pressure losses. Commonly employed chokes (Figure 39) disturb the fluid flow pattern by use of either a fixed bean (positive chokes); or an adjustable rod or rotating disc which (fully or partly) blocks the orifice (adjustable chokes). Chokes achieve the desired pressure loss by restricting the flow diameter and accelerating the flowing fluid.

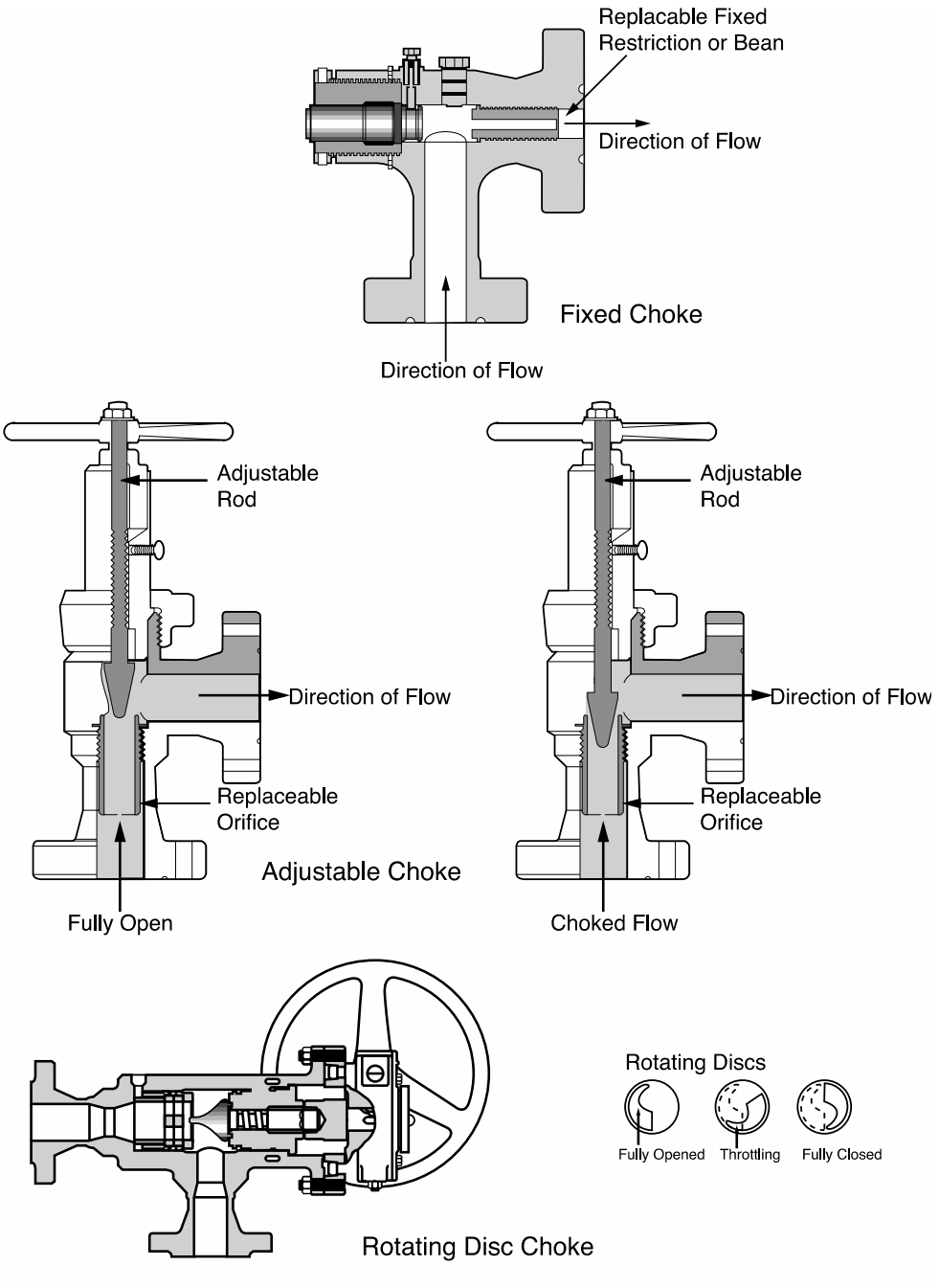

Figure 39 Example of surface choke designs.

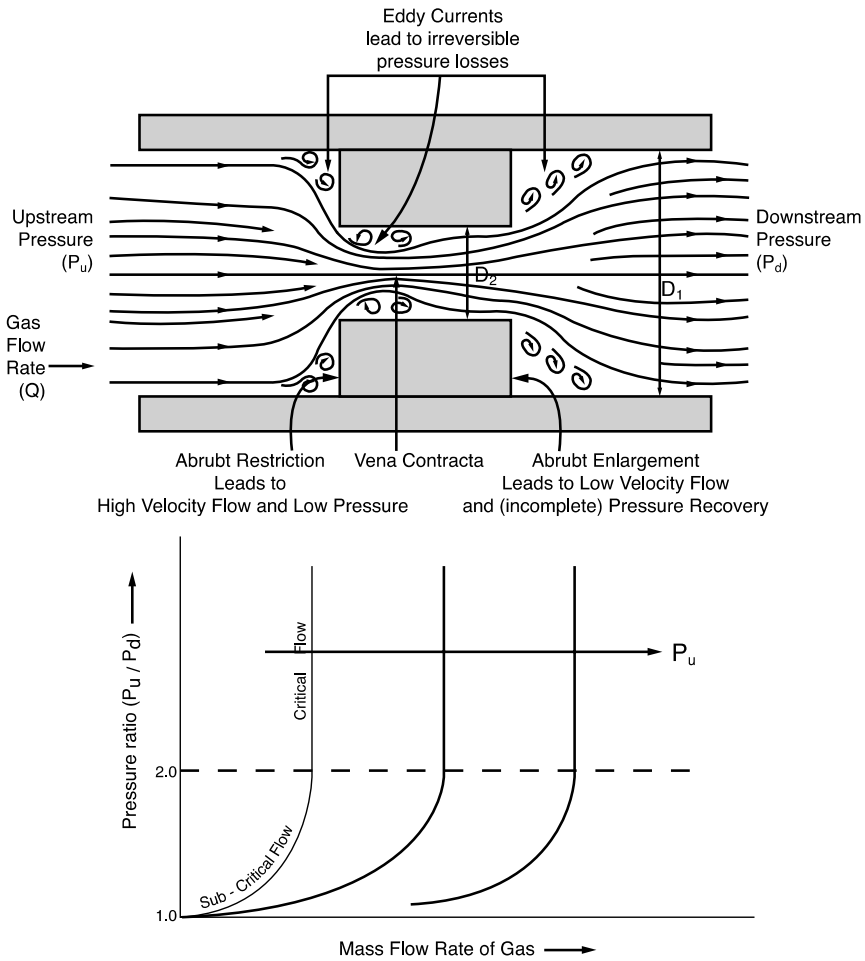

Figure 40 Critical and sub-critical flow through a choke.

Figure 40 sketches the fluid flow pattern through the choke and the resulting flow behaviour. The top part of the figure shows how the choke represents an abrupt restriction in the fluid flow in the pipe. This restriction results in an area of high velocity and decreased pressure in the centre of the choke. This area is known as the "Vena Contracta". As shown, it forces the liquid to flow through an even smaller diameter than that of inner diameter of the choke.

The fluid flow expands again to its original diameter at the (abrupt) end of the choke. The decrease in velocity results in recovery of (some) of the pressure that had been lost during passage through the choke. Full pressure recovery is not normally experienced since there are irreversible pressure losses due to energy dissipation by eddy currents which create disengagement and reattachment of the streamlines to the pipeline wall. Thus, the downstream pressure will be less than the upstream one. *(The energy dissipation results in the choke taking strong erosional impact. The chokes are often constructed from reinforced steel and/or regularly replaced. Having a replaceable 'bean' instead of the whole choke saves costs).*

The phenomenon of critical (or sonic) flow occurs once this acceleration in the throat of the choke is sufficient that the flowing fluid's velocity reaches its sonic velocity. This is frequently experienced in gas and multi-phase flow. The flow regime before critical is called sub-critical (or sub-sonic).

Critical flow is a positive effect that prevents a pressure disturbance downstream of the choke from being propagated upstream, since a pressure wave cannot travel faster than the speed of sound (at which the fluid is already travelling in the opposite direction). The well's performance (upstream of the choke) can

thus be decoupled from events occurring in the downstream flow line and separation system. This has obvious advantages when trying to control the well's performance.

The bottom section of Figure 40 shows how the flow rate through the choke is related to the ratio: {(upstream pressure (P_u)/downstream pressure (P_d)}. For sub-critical flow conditions, the flow rate will increase with decreasing downstream pressure {or increasing (P_u/P_d) ratio} until this ratio is sufficiently large that the critical flow occurs.

The exact ratio (P_u/P_d) when the critical flow starts will depend on the properties of the flowing fluid, as discussed below. Critical flow continues to occur for all higher (P_u/P_d) ratios.

The mass flow rate under critical flow conditions is independent of the upstream pressure for incompressible (liquid) flow. By contrast, it will depend on the upstream pressure when a compressible fluid (gas) is flowing. This is because at higher upstream pressure the gas is more compressed and thus has a higher sonic velocity.

Single-phase (gas) critical flow typically occurs when the (P_u/P_d) ratio is greater than 1.5. Critical flow in multi-phase (gas-liquid) mixtures requires a somewhat greater pressure ratio; the minimum (P_u/P_d) typically having a value of between 2.0 and 3.0.

10.2.1. **Single Phase Subcritical Liquid Flow**

Single phase, liquid flow across a choke is described by:

$$Q = C * C_D * D\sqrt{\frac{P_U - P_D}{\rho}}$$

where:

P_u = Upstream Pressure

P_d = Downstream Pressure

D = Choke Diameter

C_D = The flow discharge coefficient through the choke,

C = A constant depending on the units employed and

ρ = The density

The choke manufacturer normally supplies a choke performance chart or correlation that relates the discharge coefficient (C_d) to the diameter of the choke (D) and the Reynolds Number.

The same equation applies to the flow control devices (e.g. ICDs or ICVs discussed earlier in this course). The appropriate values or charts are supplied by the device manufacturer, or estimated using equations if the device's restriction size is known.

10.2.2. **Single Phase Gas Flow**

It is possible to derive equations describing the isentropic flow of an ideal gas through a choke. These can be found in the standard textbooks on the subject. It can be shown that:

$$\left\{\frac{P_U}{P_D}\right\}_c = \left(\frac{\gamma+1}{2}\right)^{\left(\frac{\gamma}{\gamma-1}\right)}$$

$\{P_u/P_d\}_c$ = the ratio of the upstream to downstream pressures at which critical flow occurs, and

γ = the ratio of the gas heat capacities at constant pressure and constant volume (C_p/C_v).

γ has a value of approximately 1.4 for diatomic gasses such as air, giving a critical pressure ratio of 1.89.

10.2.3. **Multiphase Flow Critical Flow Rate**

Multiphase (gas-liquid) flow is not easily described theoretically. Hence empirical correlations have been developed by a number of investigators. These are normally of the form:

$$P_u = \frac{b * Q_L * R^c}{D^a{}_{64}}$$

where:

P_u = the upstream pressure (psig, except for Ros who uses the unit psia)
Q_L = the liquid critical flow rate (Stb/d)
D_{64} = the choke diameter (in 1/64th of an inch)
R = the gas/liquid ratio (scf/STB) and
a,b, & c = are constants (see Table 4).

Correlation	a	b	c
Ros	2.00	17.40	0.500
Gilbert	1.89	10.00	0.546
Achong	1.88	3.82	0.650
Ausseens	1.97	3.86	0.680
Baxendell	1.93	9.56	0.546

Table 4 Flow through chokes – empirical choke correlations.

The effect of changing the choke size on well production and flow system pressure losses can be studied using the Nodal analysis technique. The upstream side of the choke is normally chosen as the Node. The Wellhead Performance Relationship or Choke Performance Relationship (which depends on the well's both Inflow Performance and Tubing Performance Relationships) is the upstream (or inflow) component to the node; and the choke, flowlines and separator are the downstream (or outflow) component. A typical result from such calculation is shown in Figure 41. This shows an operating point of 460 b/d for a 16/64 in. choke increasing to 1370 b/d for a 40/64 in. choke. *(Traditionally, the choke bean's (inner) diameters are measured in 1/64th of an inch).*

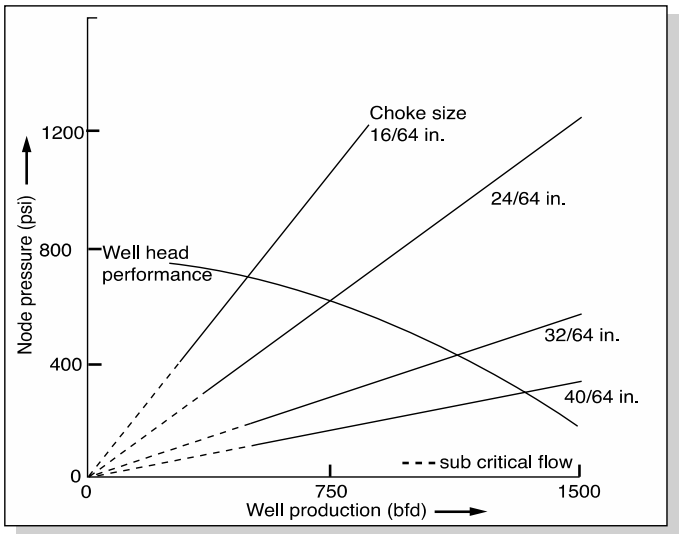

Figure 41 Nodal analysis predicts choke performance.

10.2.4. **Multiphase Flow Subcritical Flow Rate**

Choke flow of multiphase (gas-liquid) mixtures in sub-critical regime can be described by correlations or analytical solutions such as the models by Sachdeva or Perkins.

- *Feel free to attempt Tutorials 40-42*

10.3 GATHERING SYSTEM LAYOUT

The layout of the surface facilities and flow lines is important for land fields where, typically (near) vertical wells are drilled at a relatively small interwell spacing. The wellhead locations thus reflect the subsurface locations – the resulting grid pattern being illustrated in Figure 42 and Figure 43. Connection of each wellhead directly to local gathering stations with primary separation facilities (Figure 42) results in each well being connected by a short length of flowline directly to the primary separator. This allows lower wellhead pressures than the alternative (Figure 43) where the wells are tied into common gathering and trunk flowlines.

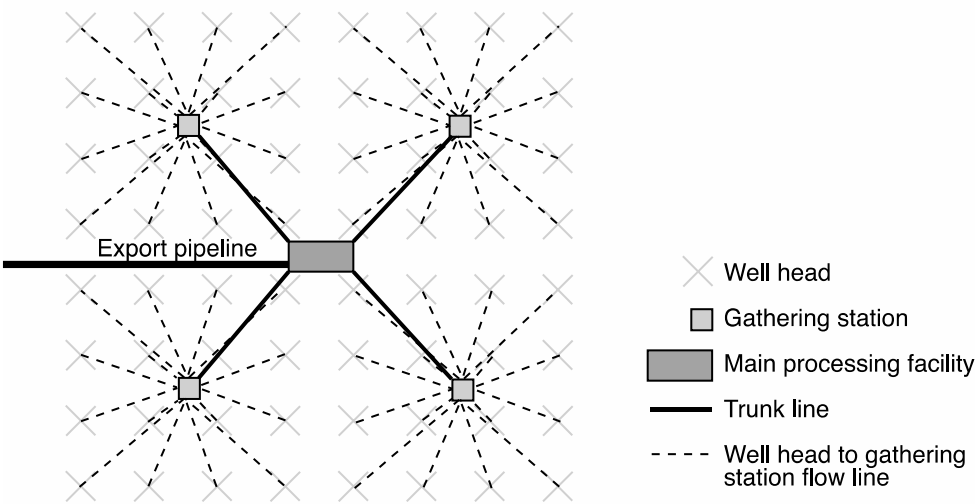

Figure 42 Oil field developed with local gathering stations. Radial layout.

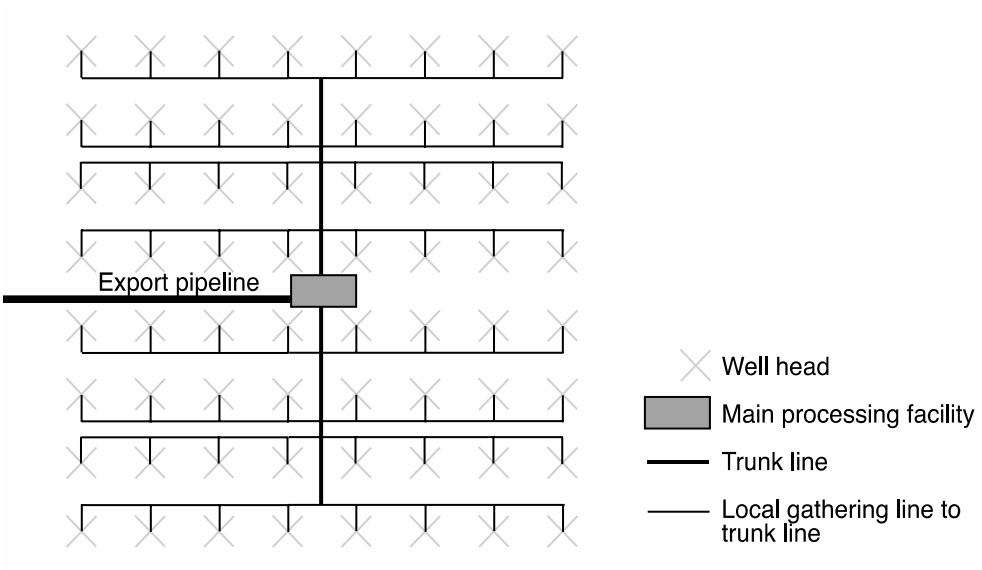

Figure 43 Oil field developed with single processing facility only. Axial layout.

Flowline pressure drops are thus much larger in the Figure 43 case, unless wide diameter pipes are installed e.g. a 50% increase in flow rate can sometimes lead to a 300% increase in the frictional pressure loss across a section of pipe. The increase in flow rate in the gathering system as one gets nearer the separator means that wells with a more direct connection to the separator can be produced at a lower wellhead pressure. The performance of each well has potentially a much greater impact on its neighbours compared to the installation of a local gathering station (Figure 42). This is particularly the case when the field is located in hilly terrain with substantial elevation differences between various parts of the field.

11. COMPUTERISED WELL PERFORMANCE PREDICTION PROGRAMS

The basic concepts required for the calculation of the pressure difference between two points that are connected by a pipe have been discussed in the preceding sections. In complex well trajectory and flow cases the complicated nature of these calculations resulting from a full description of the flow processes requires a computer to carry out the calculations in a reasonable period of time. The wellbore is segmented and this multi-segmented well model is solved iteratively by applying the mass, momentum (or alternatively pressure loss) and energy (or alternatively thermal model) equations between the inlet and outlet of each segment (Figure 44).

Steady-State Flow

(1) Mass flow_{In} = Mass flow_{Out} ,

(2) Momentum_{In} - Momentum_{Out} = Sum of momentum changes and

(3) Energy_{In} + Work Done + Enthalpy (Heat) Changes = Energy_{Out}

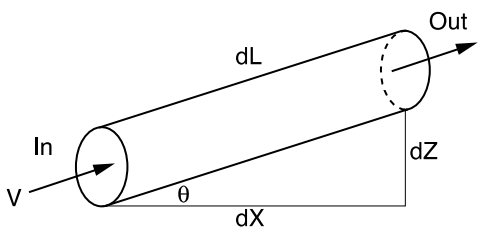

Figure 44: Well Segment Size

Multi-branch segments may be needed when modelling e.g. multilateral wells or smart wells with concurrent flows. The well segments may be coupled with the reservoir gridblocks in an integrated model. Figure 45 illustrates the segmentation process extended to simulate a complete well.

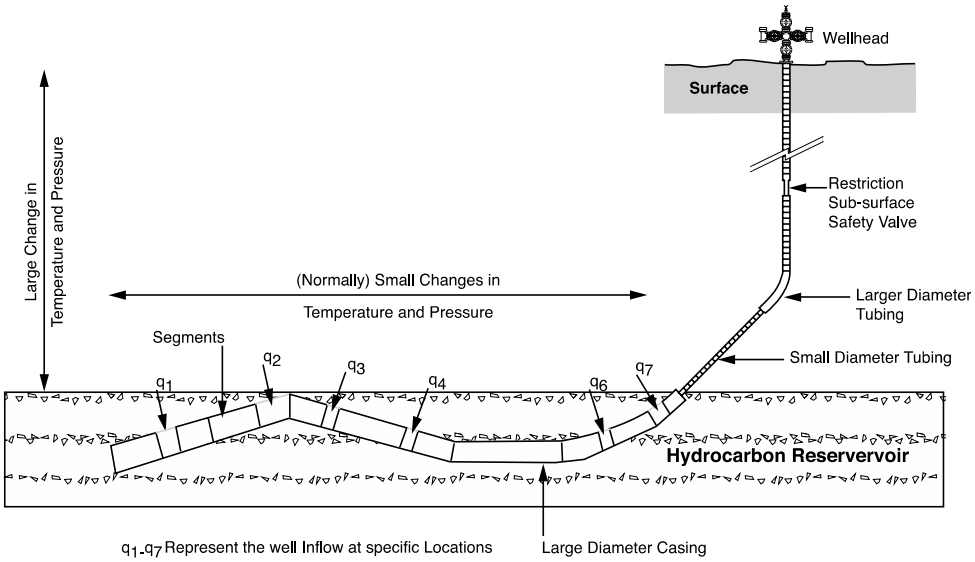

Figure 45 Well segmentation for pressure and temperature calculation in a flowing well.

Unlike the steady-state models and programs described above, transient or dynamic wellbore flow models and programs are more complex as they need to account for fast, time-dependent effects of mass and energy accumulation in a segment, e.g. when the wellbore fluid shrinks or expands during well shut-ins or start-ups (wellbore storage effect). These models may be required when modelling e.g. well clean-up, well start-up, unloading, etc.

12. RECOMMENDED READING

(1) "Production Optimisation using Nodal Analysis" by Beggs H. D., OGCI, 1991.

(2) "Petroleum production Systems" by Economides M., Hill A. & Economides C.; Prentice Hall, 1994.

(3) "Petroleum Well Construction" by Economides M. J., Watters L. and Dunn-Norman S; Wiley, 1998.

(4) "Well Performance" 2nd edition by Golan M. & Whitson C.; NTNU,1996.

(5) "Petroleum Engineering Handbook for the Practicing Engineer", Volume 2 by Mian M. A.; PennWell Books, 1992.

(6) "Fundamentals of Reservoir Engineering", by Dake, L.P.; Elsevier, 1978.

(7) "Petroleum Production Engineering", 2nd Edition, by Guo, B., Liu, X., and Tan, X. Gulf Professional Publishing, 2017

(8) "Well Completion Design" by Bellarby, J., Elsevier, 2009

(9) "Nodal Analysis for Oil and Gas Production Systems", by Jansen JD; SPE, 2017

(10) "The Flow of Complex Mixtures in Pipes", by Govier G. W. and Aziz K.; Van Nostrand Reinhold, 1972.

CHAPTER 4: SELECTION AND DESIGN OF ARTIFICIAL LIFT

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LEARNING OBJECTIVES

(All Examinable)

Having worked through this chapter the student will be able to:

Introduction

- Explain the need for Artificial Lift (AL).
- List the different types of AL.

Rod (Beam) Pump

- Describe the concept and component parts of a Beam Pump.
- Select well conditions suitable for beam pump installation.
- Explain and illustrate the beam pump design methodology

Electric Submersible Pump

- Identify the components of an Electric Submersible Pump.
- Describe the preferred applications and the mode of operation of the Electric Submersible Pump (ESP).
- Select well conditions suitable for ESP installation as the preferred Artificial Lift option.
- Identify the application areas where an ESP is NOT suitable.
- Evaluate the advantages of an instrumented ESP completion.
- Explain and illustrate the ESP design methodology

Hydraulic Pumps

- Describe the HP principles
- Explain the difference between HP types
- Identify application areas/advantages for HPs
- Discuss the limitations of the HPs

Progressive Cavity Pump (PCP)

- Describe the PCP design and operating principles
- Explain their advantages and disadvantages
- Discuss the PCP modifications

Role of Artificial Lift

- Explain the importance of Artificial Lift (AL) for world oil production.

Selection

- Describe the AL selection considerations.
- Select the case-suitable type of AL based on ranking criteria.

1. INTRODUCTION

Artificial lift (AL) is an important production engineering topic that needs to be considered in almost every oil field development project. Over 75% of all wells show no or insufficient production and are equipped with some kind of artificial lift. This chapter will provide a brief description of the common artificial lift techniques that use pumps. (The AL technique that is not pump-assisted: gas lift, is covered separately). This will be followed by discussing the main factors influencing the selection of the most appropriate artificial lift technique.

2. THE NEED FOR ARTIFICIAL LIFT

There is normally sufficient reservoir pressure for hydrocarbons to flow to the surface when the discovery well is completed in a virgin reservoir. Extraction of reservoir fluids once the reservoir is developed will normally reduce the reservoir pressure and/or increase the fraction of water being produced; together with a corresponding decrease in the produced gas-liquid ratio. All these factors reduce, or may even stop, the flow of fluids from the well. The remedy is to include within the well completion some form of artificial lift. Artificial lift adds energy to the reservoir fluid once it has been produced into the well. This, when added to the available energy provided "for free" by the reservoir itself, allows the well to flow (at a hopefully economic production rate).

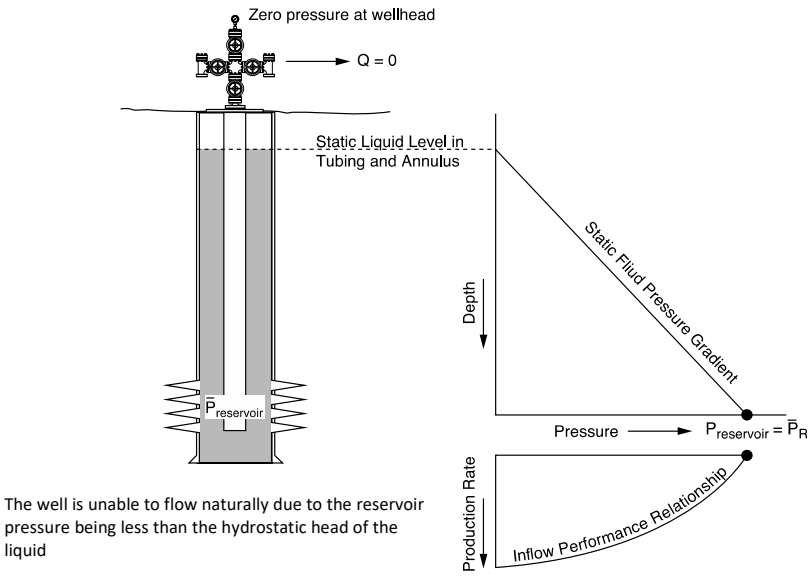

Figure 1 The well is unable to flow naturally and/or to initiate flow

Figure 1 shows a well that is unable to flow since its reservoir pressure has been depleted and is insufficient to lift the fluid to surface. The fluid's static level is below the wellhead. Figure 2 shows how installation of a pump (that adds a pressure boost or 'pump head' ΔP_{1pump} into the system) a small distance below the static fluid level allows a limited drawdown (ΔP_1) to be created. The well now starts to flow at the rate q_1.

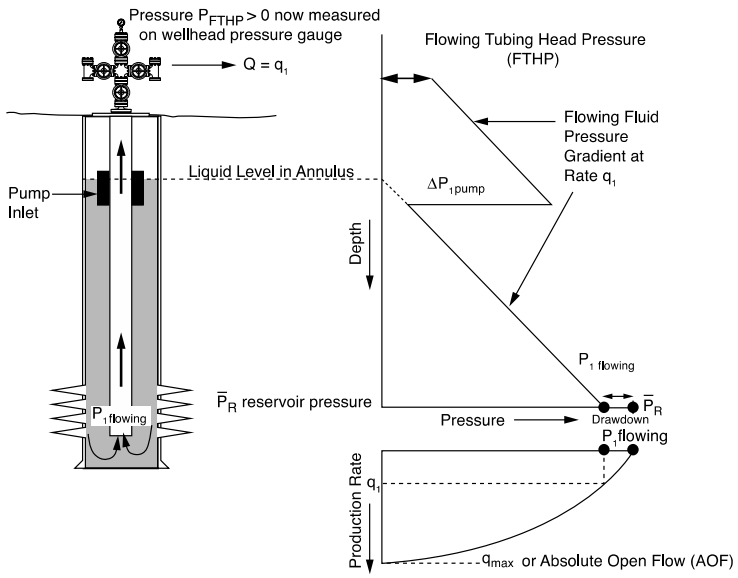

Figure 2 Pump creates a small drawdown and flow rate

It can be readily seen that the same production rate will occur when the pump is relocated to the bottom of the tubing, provided the pressure drop across the pump, and hence the drawdown, remains the same. The advantage of placing the pump near the perforations is that the maximum potential production can now be achieved {Figure 3} by increasing the pump pressure differential ΔP_{2pump} thus imposing a larger drawdown (ΔP_2) on the formation and producing the well at q_2, a flow rate that is only slightly smaller than the AOF. Note that the pump intake pressure is not reduced to zero. The pump requires some reasonable intake pressure (normally at least 150 psi, equivalent to 'submergence' (i.e. height of the dynamic liquid level above the pump) of about 350 ft).

Generally, continuous artificial lift design requires that the capacity of the installed pump is matched to the well's inflow and outflow performance, i.e. the reservoir should be able to supply the rate pumped to avoid well 'pump-off'.

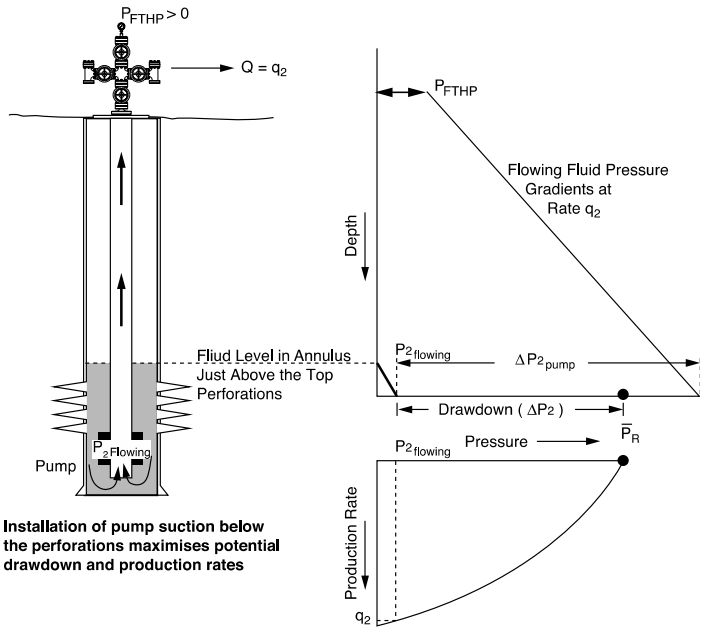

Figure 3 Installation of pump suction below the perforations maximises potential drawdown and production rates

Thus the continuous lift will enable the well to keep producing.

In some situations artificial lift may be needed only temporarily, to kick-off the well (i.e. to initiate production).

Again consider the well in Figure 1. When the well is shut-in any gas in the tubing will separate from the liquid and collect at the top of the tubing. The separated gas at the top of the tubing flows towards the separators by opening the Xmas tree's production valve, leaving dead oil behind that is loading the well. The reservoir pressure is insufficient to lift it.
This well may still be able to flow naturally if the well Productivity Index is sufficiently high and the produced reservoir fluids contain enough gas that the flowing fluid pressure gradient gives a positive wellhead pressure. However, the well must first be "kicked off" by swabbing (Figure 4), injecting gas using coiled tubing (Figure 5) or placing a small temporary coiled tubing pump or other techniques. Once this has been achieved the well will continue to flow on its own.

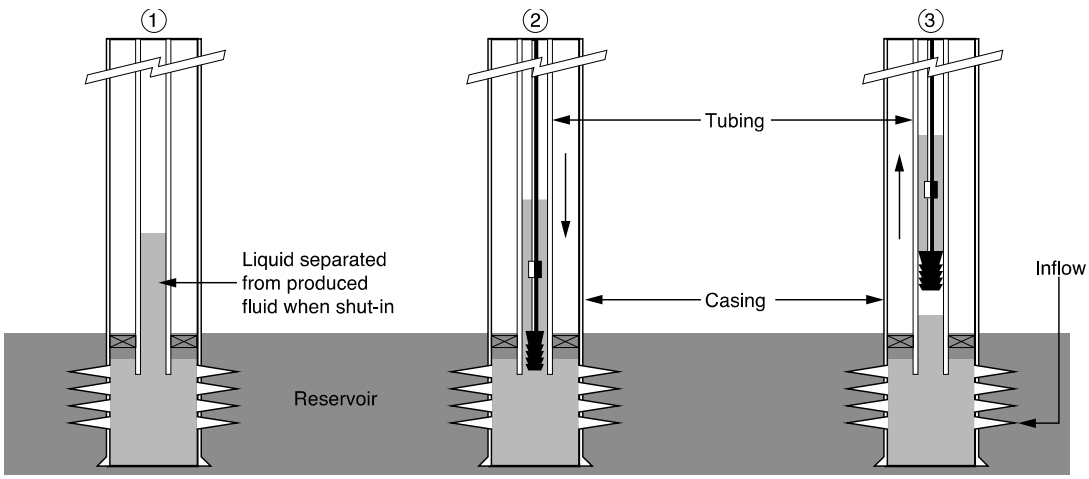

Figure 4 Swabbing removes the fluid accumulated in the tubing.

(Swab cups can be run on a slickline or a coiled tubing and are designed to remove fluid from the wellbore when they are pulled upwards since fluid can only pass in one direction. The process is usually repeated a number of times until a sufficient fraction of "live" oil is produced so that the GLR is high enough to reduce the tubing pressure gradient and restart production.)

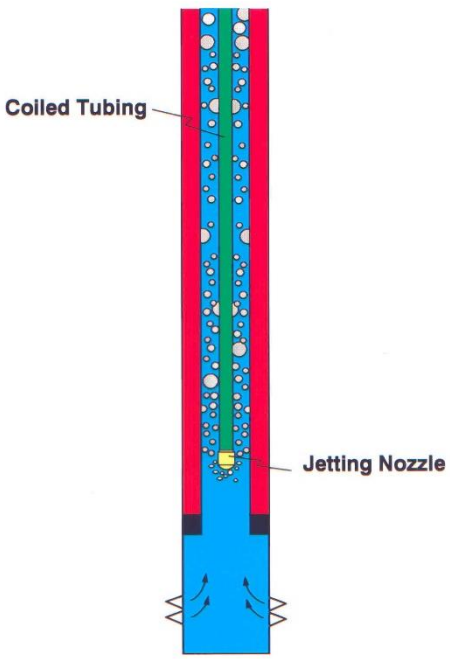

Figure 5 Flow initiated by circulating gas via a coiled tubing to reduce the BHP

- *Feel free to revise the GLR-related tutorials in Chapter 3 to explain how the flowing live oil and/or gas lifted well has smaller pressure gradient than a dead oil well.*

3. REVIEW OF ARTIFICIAL LIFT TECHNIQUES

The most popular forms of artificial lift are illustrated in Figure 6. They are:

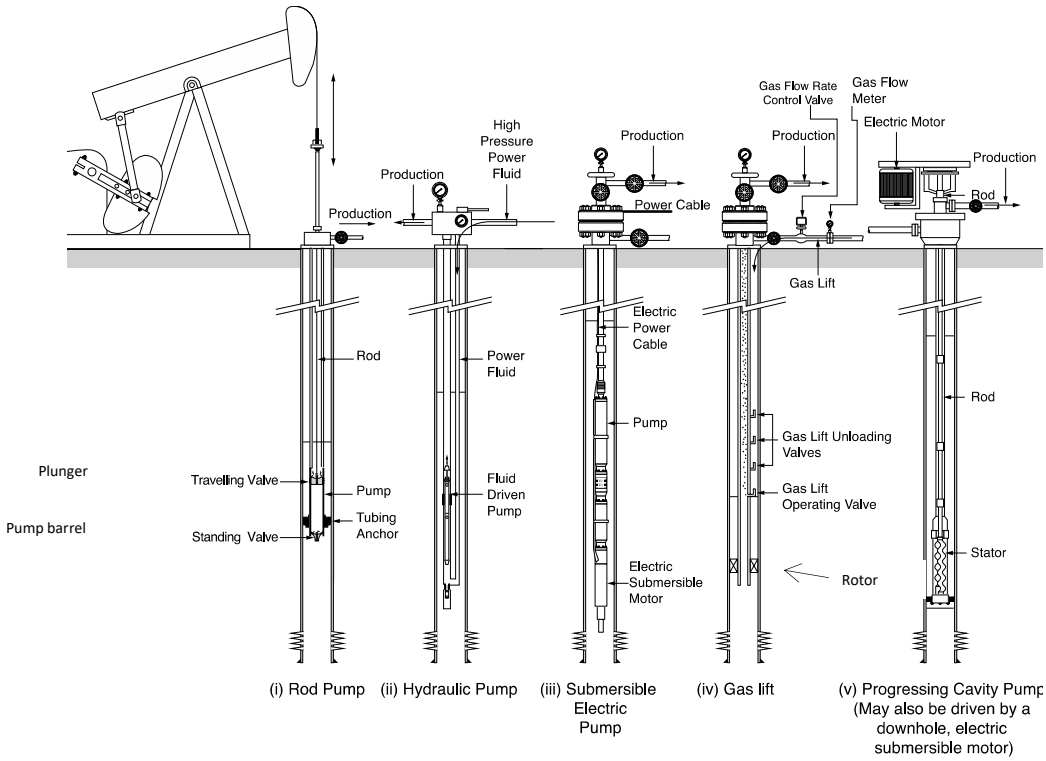

Figure 6 The most popular types of artificial lift

Rod Pumps (RP) – A downhole plunger is moved up and down by a rod connected to an engine at the surface. Upward movement of the plunger creates a drawdown at the perforations which "sucks" reservoir fluids into the pump barrel. Downward plunger movement displaces the produced fluid from the pump barrel into the tubing where it is lifted upwards towards the surface with each subsequent upwards movement of the plunger. *(This is similar to how a bicycle pump works.)*

Hydraulic Pumps (HP) use high-pressure power fluid to either (1) drive a downhole turbine or positive displacement pump; or (2) flow through a venturi (as a jet), creating a low-pressure area which produces an increased drawdown and inflow from the reservoir.

Electric Submersible Pumps (ESP) employ a downhole centrifugal pump with propellers driven by an electric motor supplied with electric power via a cable run from the surface. The cable penetrates the wellhead and is strapped to the outside of the tubing.

Gas Lift (GL) involves injecting high pressure gas into the casing/tubing annulus followed by its injection into the tubing via the Gas Lift Operating Valve. The increased gas content of the produced fluid reduces the average flowing density of the fluids in the tubing, hence increasing the formation drawdown and the well's production rate.

Progressive Cavity Pumps (PCP) employ a helical, metal rotor rotating inside an elastomeric or metallic, stator. The rotating action is supplied by a downhole electric motor or by rotating rods. This low shear pump is mainly used for the production of very viscous crude oils, often with significant concentration of the produced formation sand grains.

All the major classes of pumps are employed in the oil fields for artificial lift (Figure 7).

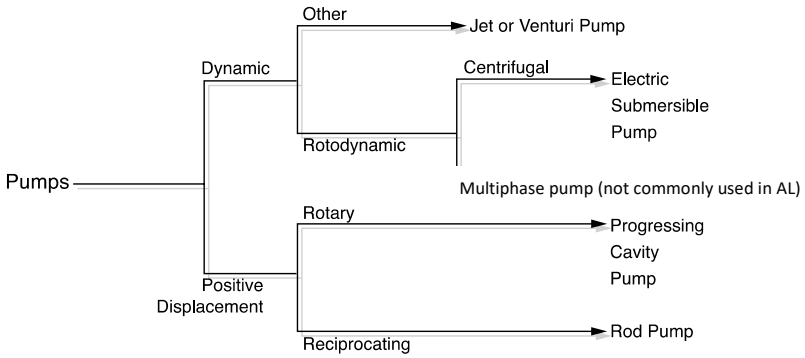

Figure 7 Pump Classification

These major types of Artificial Lift (except GL covered later in this course) are described below.

4. ROD PUMPS

4.1 Introduction

(Sucker) rod or beam pump was the first type of artificial lift to be introduced to the oil field. It is also the most widely used type in terms of the number of installations worldwide: it is energy efficient, relatively inexpensive, easy to maintain, and is suitable for low production (less than 100 bbl/d) wells in depleted reservoirs. It is therefore an ideal candidate for mature, depleted on-land wells which are a plenty. The low cost, mechanical simplicity and the ease with which efficient operation can be achieved makes rod pumps suitable for such low volume operations.

Rod pumps can lift moderate volumes (1,000 bfpd) from shallow depths (7,000 ft) or small volumes (200 bfpd) from greater depths (14,000 ft). They are normally manufactured to standards set by the American Petroleum Institute (API). This means that, unlike other artificial lift methods, the equipment manufactured by the various suppliers is fully interchangeable.

Advantages and Disadvantages of Rod Pumps

Table 2 presents the advantages and disadvantages of Rod Pumps.

Advantages	Disadvantages
• Simple, basic design • Units easily changed • Simple to operate • Can achieve low BHFP • Can lift high temperature, viscous oils • Pump off control (i.e. easy to detect pump off and adjust the pumping to avoid it)	• Friction in crooked wells • Pump wear with solids production (sand, wax, etc.) • Free gas reduces pump efficiency • Obtrusive in urban areas, too large/heavy offshore • Downhole corrosion inhibition difficult

Table 2 Advantages and disadvantages of rod pumps

Rod pump consists of a 1) surface pumping unit, connected by 2) rods to a 3) downhole pump.

4.2 The Pumping Unit

The conventional surface equipment for a rod pump is illustrated in Figure 8. The prime mover, normally an electric motor or gas engine, drives a set of speed reducing gears that reduces the beam speed to some 10-20 strokes per minute – whatever is optimal for this mechanical system in the sense of loads, fatigue, efficiency, etc. The counterweight on the crank balances the load: it adds weight to the crank when the rod string does not (i.e. when it goes down), thus making sure the engine is subjected to a relatively constant load and lasts longer. In some variants the counterweight can be placed on the beam instead (e.g. in shallow wells), or both. Some other pumping unit designs include the ones where the weight and torque are managed by the lever system or by an air-balanced unit.

The beam is connected to the downhole pump via the bridles (or hanger cables) to the polished rod and the sucker rods. The polished rod (made of steel or brass) moves up and down through a stuffing box, backed with seals, mounted on top of the wellhead's T connection. This stuffing box seals against the polished rod and prevents surface leaks of the liquid and gas being produced by the well via the T. The horse head (a.k.a. bridle head) has a specific shape to make sure the polished rod moves strictly vertically when the beam is travelling up (upstroke) and down (downstroke).

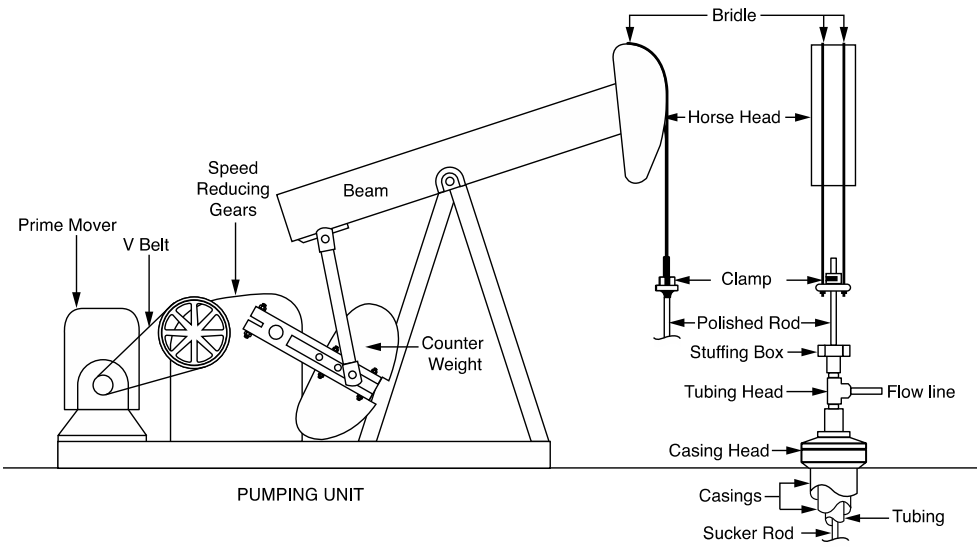

Figure 8 The surface equipment for a rod pump

The API designation of pumping units classifies their type and capacity, for example C-228D-200-74 means:
C = conventional unit; 228 = 228000 lb-in peak torque rating; D=double-reduction gear reducer; 200=20000 lb PRL (maximum Polished Rod Load for the walking beam); 74 = maximum stroke of 74".

4.3 The Sucker Rods

The sucker rods, typically 25 ft long, are circular steel rods with diameters between 0.5 in and 1.125 in. A threaded male connection or pin is machined at each end of the rod. The two rods can be joined together by use of a double box coupling (Figure 9). Square flats are machined near the pins and at the centre of the coupling to provide a grip for a wrench to allow the rods and couplings to be screwed together.

The sucker rods are subjected to continuous fatigue when the pump is operating. Where this is a problem, the weight of the rod string (one component of this fatigue load) can be reduced by using a tapered sucker rod string with wider diameter rods of greater load bearing capacity being used near the surface. Lighter, smaller diameter rods are installed down in the well where the load they have to support (i.e. the weight of rods below and of the fluid in the tubing string) is less than at the top of the well.
Glass fibre rods and continuous solid rods are also in use.

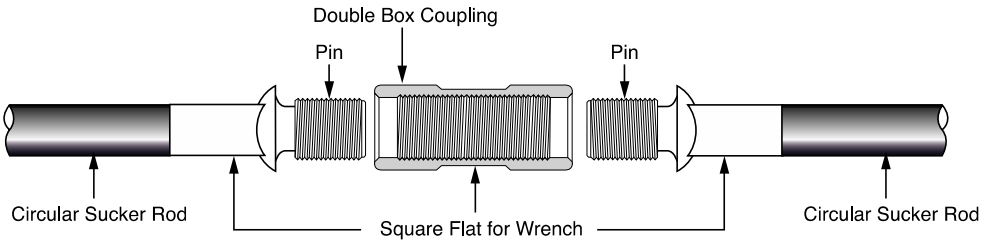

Figure 9 Sucker rods are joined together by a coupling

4.4 The Pump

The pump is located near the perforations at the bottom of the string of sucker rods. Figure 10 shows that it consists of a hollow plunger (optionally with circular sealing rings) mounted on the outside circumference moving inside a pump ('working') barrel which is either inserted into the tubing (R pumps) or is integrated in the tubing string (T pumps). (Casing barrels also exist but are less common). The Standing (or stationary) valve is mounted at the bottom of the pump barrel while the Travelling valve is installed at the top of the plunger. The Standing and Travelling valves contain a cage with a ball which closes the passage in the plunger and the pump inlet when the ball is seated (see Figure 10) i.e. they act as one-way (or no-return) valves.

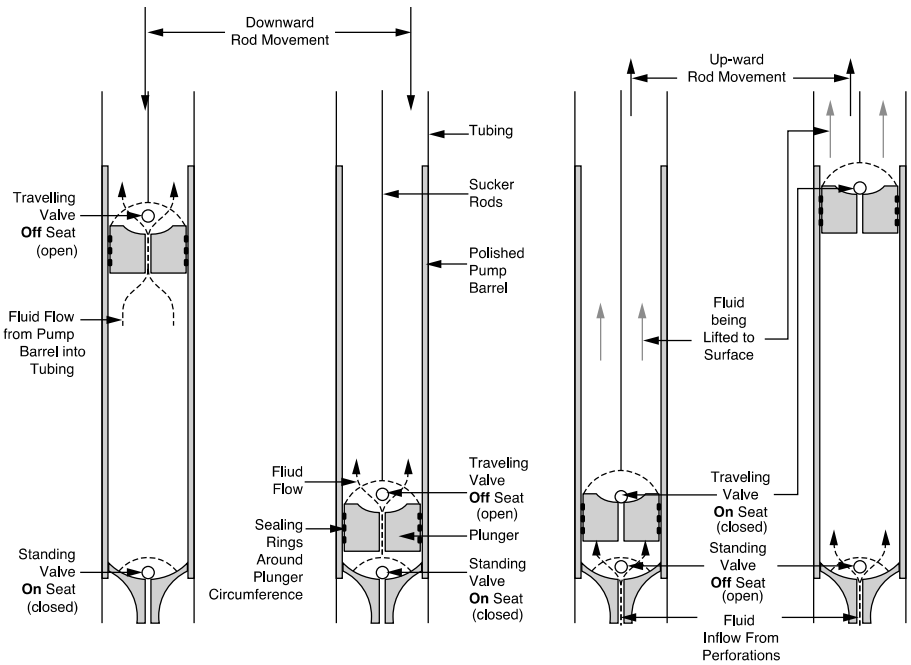

Figure 10 Rod pump operation

The "UP" and "DOWN" movement of the pump plunger allows the fluid pressure in the pump barrel to open and shut the Travelling and Standing valves. The left-hand schematic shows the plunger status at the end of the "DOWN" stroke. The "Upward" rod movement reduces the pressure within the pump barrel and the upward flow of fluid from the perforations below the pump lifts the Standing valve's ball off its seat. The pressure due to the fluid column above the plunger keeps the Travelling valve ball on its seat. The situation is reversed during the "DOWN" stroke - compression of fluid within the pump barrel forces it to flow through the hollow plunger and to lift the Travelling valve off its seat; while ensuring that the Standing valve remains closed.
Alternatively, there are also other R pump types there the plunger is fixed while the cylinder is moving (these are less commonly used, and may be preferred in e.g. the high sand production wells situations).

The gap between the plunger and the barrel is designed small (0.001-0.005 in depending on the fluid viscosity). Nevertheless, there is still fluid slippage reducing the pumping efficiency (which is normally 70-80%), though also lubricating the barrel walls.
As explained, the fluid in the barrel has to be compressed downstroke, before the travelling valve opens letting it through, and this may also reduce the pumping efficiency if the barrel is partly filled with compressible fluid e.g. gas. Besides, the plunger may start hitting the liquid level ('fluid pound' effect) in the barrel, which increases the system's fatigue. In extreme cases, the gas may completely 'lock' the pump so that no liquid is produced at surface.
That's why it is important to keep the pump submerged in liquid (by avoiding well pump off), as well as let the gas flow separately to surface via the open annulus, sometimes assisting its separation from the liquid using downhole gas separation at the pump intake. *This note applies to all pumps except jet pumps.*

Note that the plunger's stroke (i.e. its travelling distance) is different from that of the polished rod at surface because of the rod string's elasticity. This causes the rod stretch and plunger overtravel effects.

4.5. Pump Design

There are various ways to model the pump performance in order to design it. Classical equations can be used, as well as the API Recommended Practice, or more complex, wave models. Some basic elements of the widely used API approach (that offers basic formulae and selection sheets) are discussed here.

4.5.1. PUMP RATE

Every AL design starts from the analysis of the well's IPR and TPR in order to propose an acceptable well rate and the pump's depth and head required to achieve it.

Rod pumps are positive displacement pumps so their pumping rate is relatively independent of the head, as long as the reservoir deliverability (fluid supply) is sufficient. The pump rate (Q) is related to the volume (V) displaced by each pump stroke and the speed rate or the number of strokes per minute (N). Thus:

$$Q = K*V*N*\phi = K*A*S*N*\phi$$

Where, A is the area of the pump barrel, S is the length of the pump stroke, ϕ is the efficiency factor and K is a constant depending on the units employed.

The maximum speed (N_{max}) of the pump unit is determined by the speed at which the sucker rods fall downward in the "DOWN" stroke. Rod failure due to metal fatigue occurs if the rods are placed under compression due to them being forced downwards by the pump unit exceeding this maximum speed. The maximum allowable speed, that avoids fatiguing the rods by placing them in compression, decreases as the length of the pump stroke increases (Table 1).

Maximum Allowable Pump Speed †

Stroke Length (in.)	30	60	90	120	180	240	300
Maximum Pump Speed (SPM*)	34	24	19	17	14.5	11.5	10.5

* Strokes Per Minute

Table 1 Maximum allowable pump speed table example for a conventional pump unit

On the other hand, while the low pump speeds and large diameter pumps lead to the greatest energy efficiency, this also results in the largest equipment loads.
Once the reasonable speed (neither too high nor too low as explained above) is selected it is further checked and corrected to make sure it is not in resonance with the rod string, to reduce further fatigue.

Major factors which reduce the efficiency of the pump include gas influx and rod stretch.

4.5.2. ROD STRETCH AND OVER TRAVEL

During the "UP" stroke the rods support their own weight and that of the fluid in the tubing. The rods will increase in length in response to this load due to elasticity. This decreases the effective travel of the plunger downhole compared to the distance moved at the surface. For example, 0.875 in. sucker rods driving a $2^1/_4$ in. plunger pump set at 6,000 ft will show a stretch of 29 in. when lifting fresh water.

Apart from the rods weight, acceleration and friction, the load imposed on the rod by the fluid is related to the area of the plunger times the hydrostatic head of the fluid column to surface. Rod stretch thus increases when a larger diameter pump is selected. There is a similar tubing stretch effect that results in its 'breathing' (cyclic extension and contraction) and buckling, which causes its fatigue and reduces the effective stroke length unless the tubing is anchored.

Plunger Overtravel, by contrast, increases the effective stroke length. This effect is caused by elongation of the rods due to dynamic forces generated by the weight of the rods reversing direction during the pumping cycle. At this point, following the above example, the weight of a 6,000 ft string of 0.875 in. rods (weight 2.25 lb/ft or 13,500 lb total weight) will be brought to a halt and reverse direction over a time period of less than one second. The rod string velocity will be approximately 6 ft/s when the plunger nears the bottom of its stroke if the pump unit is operating with a 64 in. stroke length at a pump speed of 15 strokes per minute. The resulting (approximately 14") increase in the length of the rods generated by halting and reversing the momentum generated by the weight of fluid in the tubing is called "Plunger Overtravel". Plunger overtravel is less than the rod stretch, so all in all the rod string's elasticity reduces the plunger effective stroke length:
E.g. in the example here, the effective stroke length = surface stroke length - rod stretch + plunger overtravel (and assuming there is no tubing stretch as it is anchored) gives:

$$\approx 64" - 29" + 14" \approx 49"$$

(It is also important to make sure the plunger has enough travel space in the barrel and is not hitting its bearings).

- *Feel free to attempt Tutorial 1*

4.5.3. PUMPING LIMIT LOAD CALCULATIONS

As mentioned, API recommended practice and other techniques can be used to calculate the maximum and minimum polished rod loads, the peak torque and the theoretical horsepower required once the pump speed, stroke length, plunger diameter and rod sizes have been chosen. Typically, a motor power of twice this theoretical value is installed to allow for surface and downhole energy losses.
The rods are continuously subjected to fatigue with the "Maximum Allowable Stress" being a function of the grade of the material used for the sucker rods and the minimum polished rod load/cross sectional area of the top rod. This "Maximum Allowable Stress" is often decreased by a service factor related to the operating conditions e.g. the presence of corrosive salt water or, more importantly, hydrogen sulphide. More expensive, speciality grade, sucker rods can be purchased if higher levels of "Maximum Allowable Stress" are required.

4.6 Rod Pump Operation

4.6.1 PUMP-OFF CONTROL

The speed of the pump motor must be reduced or the pump motor stopped at regular intervals if the dynamic fluid level is reduced to a specified, minimum safety level above the pump. This liquid level in the annulus is often monitored with an "Echometer" (Figure 11) (or its modifications like Sonolog™) attached to the wellhead. The tool consists of a firing mechanism, a microphone and an amplifier/recorder. Figure 12 shows a rod pump equipped with pump-off control unit and powered by solar energy in remote locations.

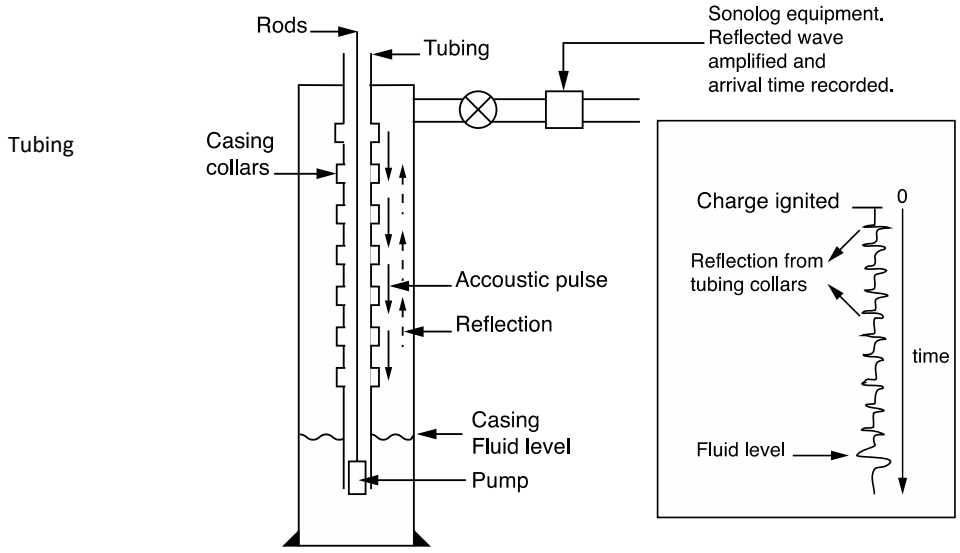

Figure 11 "Echometer" or "Sonolog" annular fluid level survey

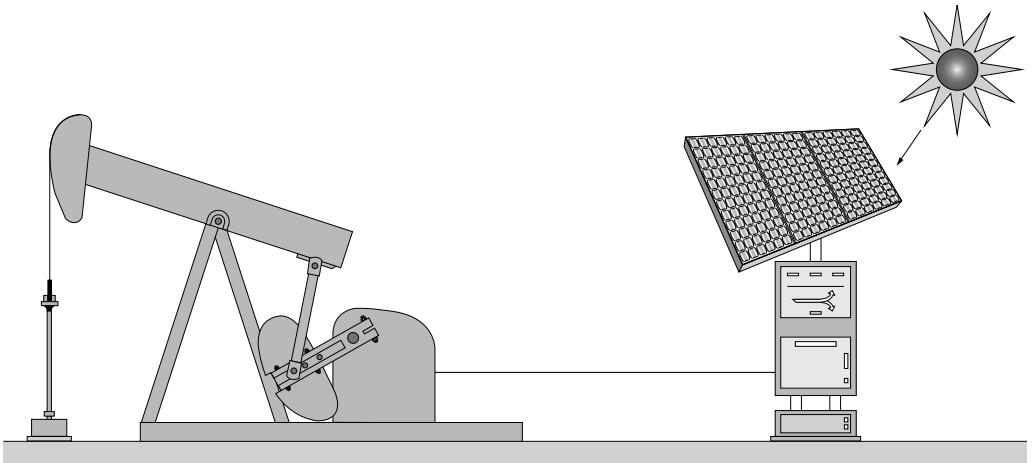

Figure 12 rod pump equipped with pump-off control unit powered by solar energy

Typically, a gas actuated device generates an acoustic pulse at the wellhead. This is reflected back by subsurface items such as tubing collars, but the main reflection is from the fluid level at the bottom of the casing/tubing annulus. The depth of the fluid level can now be found by multiplying this time by half the velocity of sound in the casing/tubing annulus, or by counting the tubing collars and matching this to the completion tally (smaller, pup joints pre-installed in the tubing string can help if the collar count is lost).

Further, the performance of the pump itself can be checked by measuring the dynamometer card at regular time intervals as explained later.

4.6.2 GAS INFLUX

As mentioned, (free) gas sucked into the pump will reduce the pump efficiency.
Placing the pump deeper (where the gas is more compressed and also partly still dissolved in the oil), sometimes even below the perforations (provided there is a sand/debris-free rat hole), can help. (This also increases the maximum possible drawdown as explained earlier).
This is not always possible in practice. In this case, many types of static gas separators (a.k.a. "gas anchors") can be used in order to overcome the resulting difficulties. They all aim to separate some of the free gas from the liquid prior to the liquid entering the pump. As for the separated gas: it flows into the tubing/casing annulus where it is vented off the wellhead or gathered at as low pressure as possible.

Generally, there are two types of gas anchors: the ones not needing a packer e.g. the shroud, skirt, cap anchors; and the ones needing a packer and a bypass tube. Figure 13 shows an example of them. The shroud or the bypass tube directs the multiphase flow downward above the pump, ensuring that mostly liquid is sucked into the pump barrel, while most of the gas keeps flowing upward due to buoyancy force (provided the downward flow velocity is not too high).

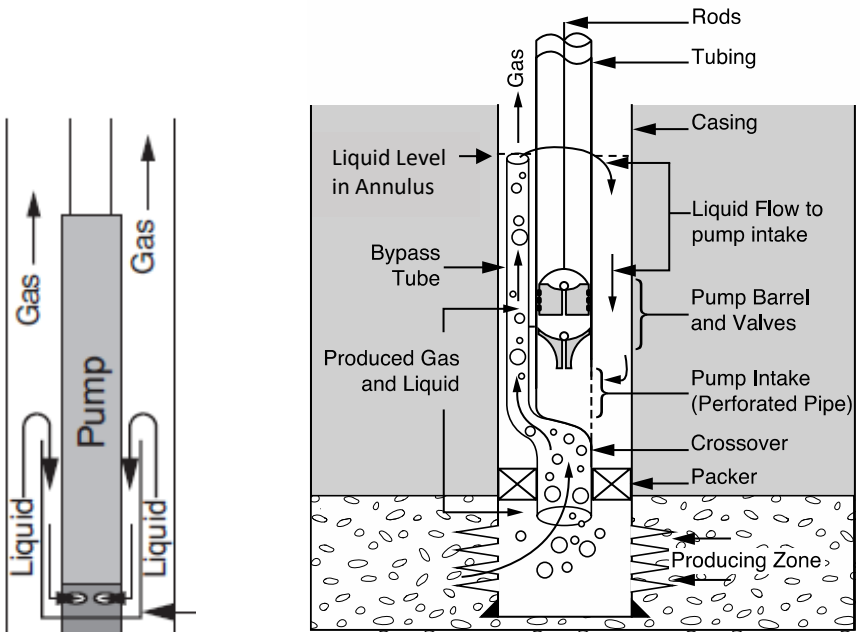

Figure 13 Packerless (a) and packer type (b) gas anchors

4.6.3 CENTRALISERS

The sucker rods may require centralisers or protectors in deviated wells to reduce the friction wear on the tubing and rods (Figure 14). This requirement becomes more extreme in crooked or highly deviated wells; sometimes to the extent that rod pumps cannot be used. *The centralisers may be designed to additionally scrap and clean the tubing wall off e.g. wax deposits in some cases.*

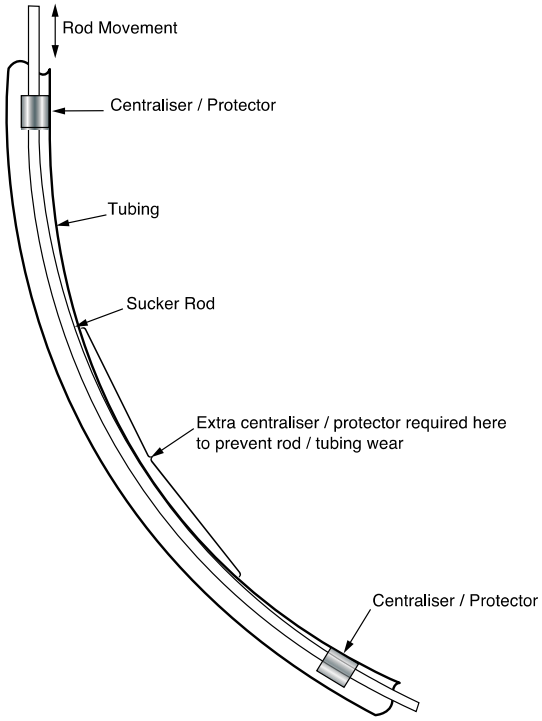

Figure 14 Centralising rod reduces (but does not eliminate) friction and wear in a deviated well

4.6.4 SOLIDS

Rod pumps also have a very limited ability to lift sand due to the sand settling in the low fluid velocity in the production tubing, on top of the plunger and the barrel, plus increasing the wear on the pump valves, seats and plunger. The latter can be (partially) overcome by suitable pump design and choice of construction materials.

Wax and inorganic scale deposition from the produced oil and water can also interfere with efficient rod pump operation. Removal of wax by hot oil/solvent circulation, or injection of a scale dissolver, are possible. Further, recovery and repair/replacement of the pump and rods is often a relatively low cost, simple operation.

4.6.5 PUMP DIAGNOSTICS

The condition of the pump can be evaluated by measuring the load at the top of the polished rod as a function of its position i.e. as it moves up and down within the stroke length. This is recorded in the form of a dynamometer card. Examples of theoretical dynamometer cards are shown in Figure 15.

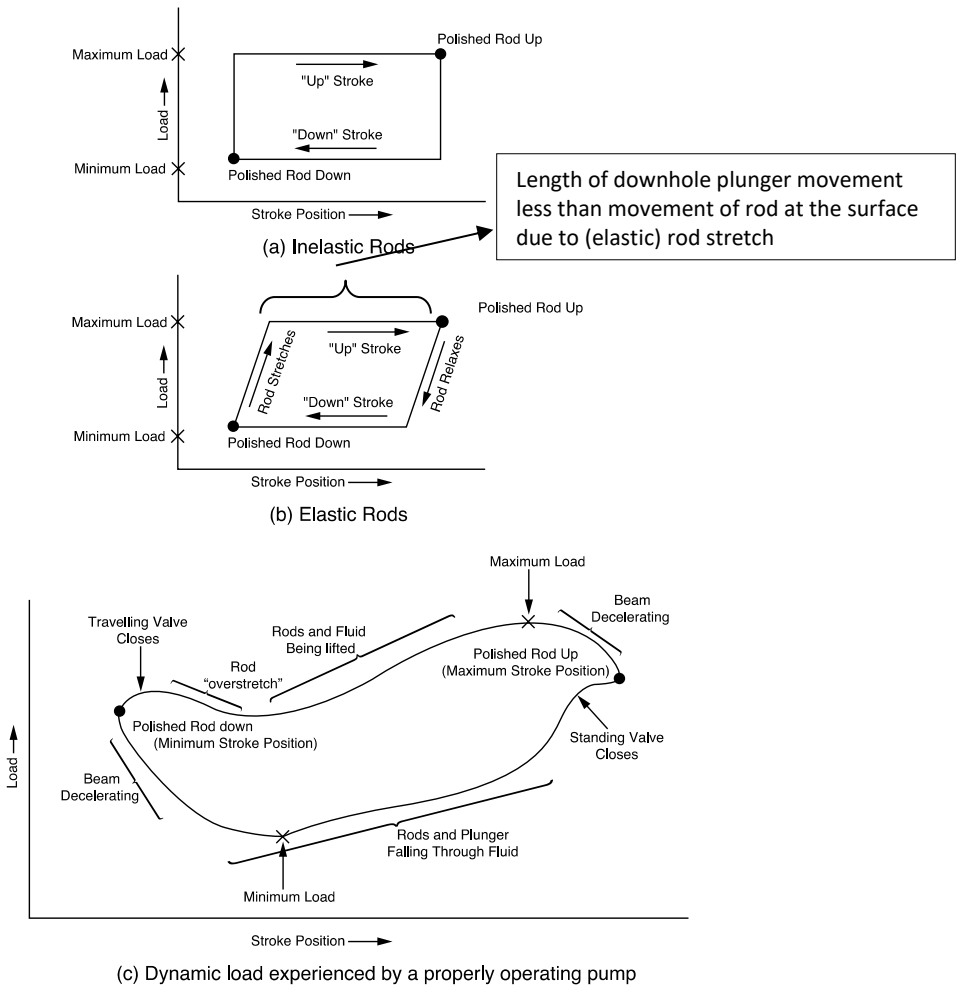

Figure 15 (Theoretical) Dynamometer cards for: (a) idealistic, inelastic rods only (b) elastic rods only and (c) complete model with elastic rods with dynamic load of rods, fluid and surface pump unit

- Figure 15(a) records the variation in load for inelastic rods. The load is either high or low depending on whether the polished rod is moving up or down.
- Figure 15 (b) adds the elasticity of the rods. The change in load is no longer instantaneous when the polished rod starts moving in a particular direction and starts stretching or contracting.
- Figure 15(c) further adds a more realistic fluid and surface pump unit dynamics. The times at which the various processes become controlling during the pump cycle are indicated.

These cards can be interpreted using readily available principles and charts (derived both theoretically and experimentally e.g. using experimental downhole plunger loads dynagraphs). Practical problems that can show and be interpreted include: excessive rod or pump friction, restriction in the flow-path, vibrations, sticking plunger, leaking Travelling or Standing valves, presence of gas in the pump barrel, viscous emulsion formation etc. All the above effects alter the shape of the dynamometer trace in a distinctive manner allowing the source of the problem to be (hopefully unambiguously) diagnosed and then rectified.

➢ *Discuss the features in Figure 15(c)*

5. ELECTRIC SUBMERSIBLE PUMPS (ESPS)

5.1. Introduction

Electric Submersible Pumps (ESP's) are a versatile form of artificial lift with pumps typically ranging from 150 to 60,000 bfpd in operation. They are energy efficient, do not require much surface equipment, can be adjusted to match the inflow. They are however relatively expensive, have limited lifetime (a few years), and require heavy workover (i.e. tubing retrieval) to be replaced or repaired. These pumps are common in medium-to-high production wells both offshore and on land.
A typical low pressure well that is being artificially lifted using an ESP system is shown in Figure 16 which illustrates:

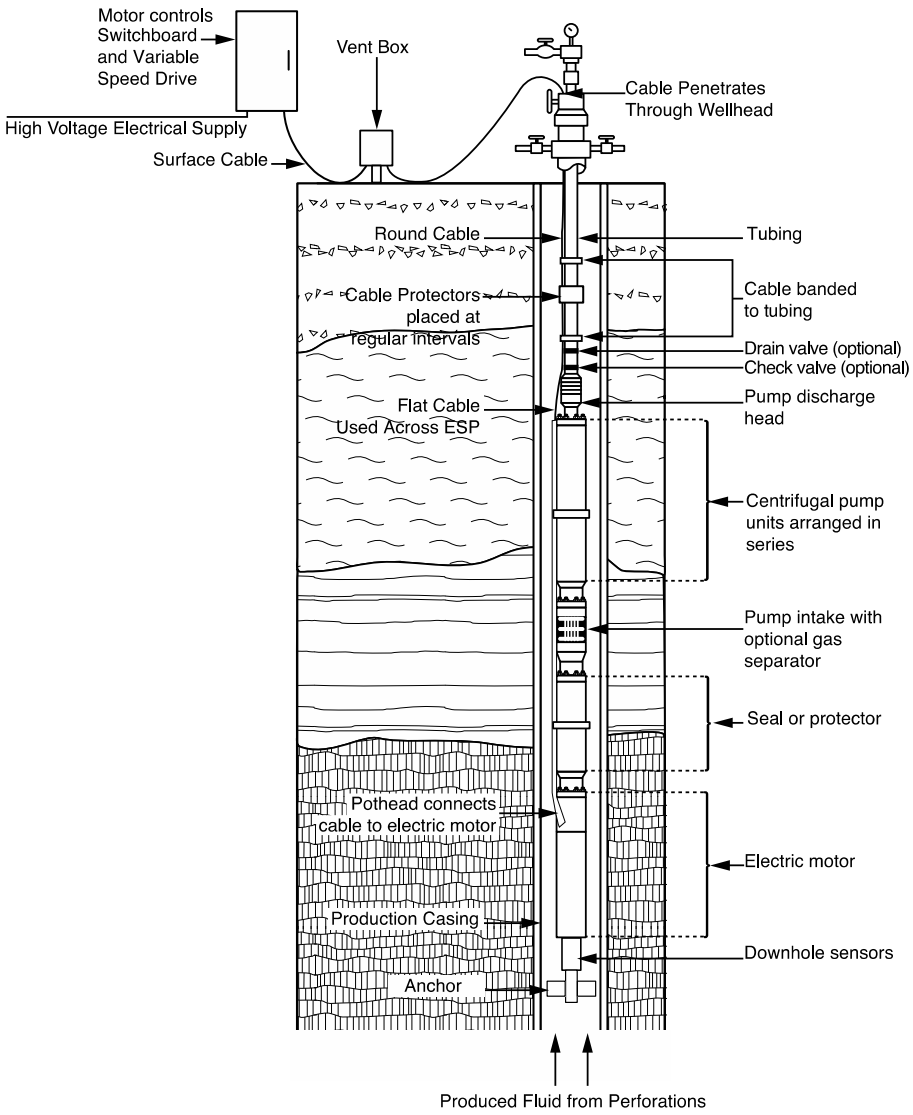

Figure 16 A well completed with an electric submersible centrifugal pump

- **A high voltage, three phase electricity supply** being transformed to the "nameplate" voltage of the ESP and is monitored and switched "on" and "off" in the switchboard. The supply frequency may also be changed using a Variable Frequency Drive (VFD) (also known as Variable Speed Drive VSD). A VFD allows the speed of the electric motor to be altered because e.g. starting the pump using the "nameplate" design frequency of 50 Hz (Europe) or 60 Hz (North America) results in high

instantaneous electric motor currents since the power developed by the pump is proportional to the frequency. These can be reduced during well startup by supplying the electric power at lower frequencies and gradually increased to the required pump operating voltage. A VFD also allows the pump flow rate and pressure increases to be adjusted to the well inflow conditions (e.g. changes in reservoir pressure and skin) as these change during the life of the well. This avoids the necessity for a well workover to change the ESP unit to the one of appropriate capacity. For instance, practical experience shows that an operation motor designed for 60 Hz can be operated between 35 Hz and 80 Hz. As a drawback, a VFD installation increases the surface energy losses from some 3% to 5-15% of the total power supplied.

- **The vent box** separates the surface cable from the downhole cable. This ensures that any gas, which gets dissolved in the cable insulation downhole and then diffuses up this cable to surface, does not reach the electrical switchgear and cause an explosion due to a spark generated when switching the pump on or off.

- **The downhole cable** with several conductor strands penetrates the wellhead. It is banded to the tubing at regular intervals. Additional protection is supplied by cable protectors which are installed at critical points to prevent damage while the completion is being run into the hole. A "flat" cable shape is employed across the larger diameter completion components to minimise total width. The cable enters the electric motor housing at the Pothead. It not only carries the electrical power supply for the motor, but also carries the measurement signal from the (optionally installed) downhole sensor package underneath the motor to the surface read-out.

- **The pump unit** consists of a stacked series of rotating centrifugal impellers running on a central drive shaft inside a stack of stationary diffusers, i.e. it is essentially a series of small turbines. Rotation of each impeller accelerates the liquid to be pumped which is then discharged into its neighbour diffuser where this kinetic energy is transformed into potential energy i.e. into a pressure increase. The total pressure increase is proportional to the fluid density and the number of stages (i.e. impeller/diffuser pairs) while the pump capacity (throughput volume) increases as the diameter and speed of the impellers increases. The impeller/diffuser pairs are arranged in series with the discharge of one unit being the inlet of the next one. The number of pump stages may range between a few to more than 100; depending on the pressure increase required. Abrasion resistance to produced solids is very dependent on the detailed design of the pump parts and the pump material selection.

However, as discussed at the beginning of this chapter, ESPs with their rapidly rotating internals are not compatible with large quantities of produced sand even when hardened, wear resistant materials are used. The option of using other forms of artificial lift – e.g. gas lift or PCPs - should be considered.

- **Standard pump impellers** are very sensitive to gas fractions (a.k.a. Gas Void Fraction GVF) greater than 20% vol. in the produced fluid at the pump intake. Changes in the pump design, such as altering the design of the impeller from pure radial flow to mixed (i.e. a combination of both radial and axial) flow, can double the allowable gas/fluid ratio to 40% vol. or even higher with modern designs.

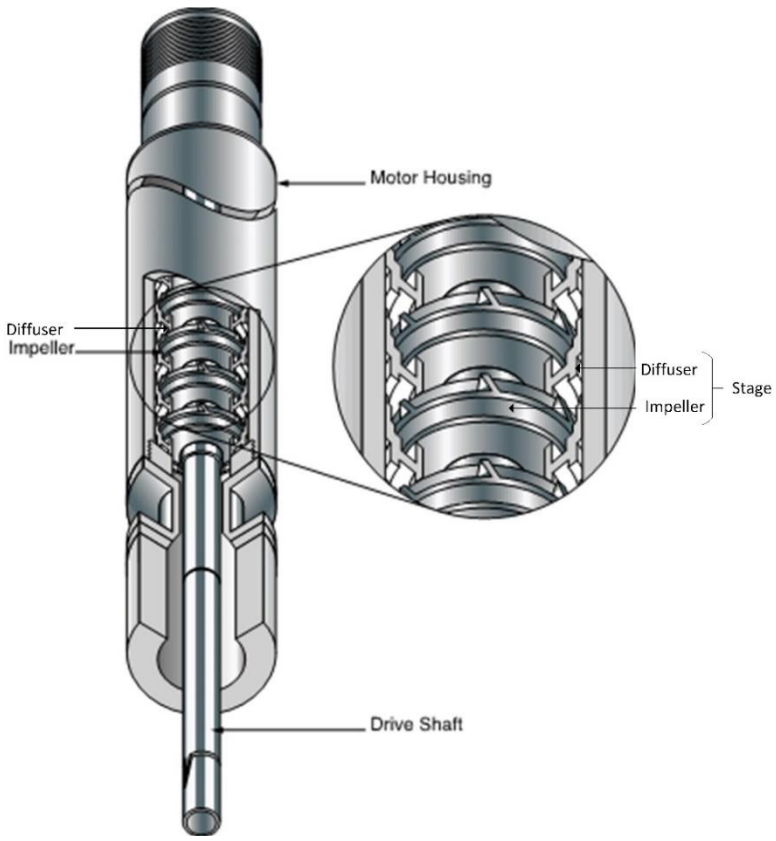

Figure 17 Cutaway schematic drawing of the pump unit in an Electric Submersible Pump

A tapered pump design using (*larger and more expensive*) mixed flow impellers in the lower pressure stages (where higher gas volume fractions are encountered) and (*conventional*) radial flow impellers in the upper stages (where the pressure is high and the gas is more compressed) is also in use.

- A gas separator (or several) can be included at the pump intake. These can be static (i.e. gas anchors), although the fact that there is a rotating shaft in the ESP makes it possible to add a more efficient, **rotary gas separator**. This is sort of a centrifugal device with rotating paddles which separates some of the lower density gaseous phase from the denser liquid phase *(the force similar to the one that moves clothes to the drum walls during a washing machine's drying cycle)*. The latter is then directed into the pump suction while the lighter, gas phase is expelled into the casing/tubing annulus. This separated gas then rises to the wellhead where it is vented or collected in a low pressure, gas gathering system.

Venting or gathering this casing gas is necessary to reduce the casing/tubing annulus pressure and increase the maximum achievable drawdown at the formation face. A single rotary gas separator can increase the ESP's gas handling capabilities up to 80% vol. Two separators, arranged in tandem, are even more efficient, increasing the pumpable gas fraction to > 90% vol. Gas handlers can also be added that break and distribute the gas bubbles in the liquid at the pump intake, reducing the risk of the pump gas lock. The addition of extra equipment has to be carefully considered as it consumes extra power as well as may eventually cause additional operational problems e.g. produced formation solids can damage the rotary separator, or scale formation can unbalance rapidly rotating equipment.

- *Feel free to revisit the Chapter 1 tutorials' ESP completion design example and discuss its features.*

- As mentioned, **alternative completion strategies** include placing the pump below the perforations or installation of a gas anchor. Figure 18(a) illustrates the use of a shroud to make use of the casing's ability to (partially) separate produced (free) gas from the liquid. Note that, if it is decided to mount the pump below the perforations {Figure 18(b)}, then a shroud is also required to initially direct the production flow below the electric motor too, where this flow provides the necessary motor cooling. The normal completion design of mounting the motor at the bottom of the ESP system {Figure 18(a)} provides this cooling by default when the pump is placed above the perforation.

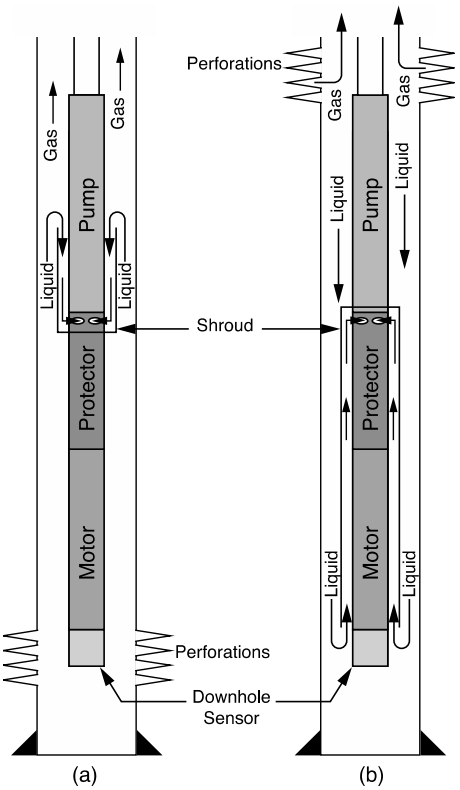

Figure 18 ESP completion designs with gas anchors to aid gas separation in the casing

It should be noted that:

- Liquid/gas separation in the casing will only work when the upward velocity of the gas bubbles is greater than the downward fluid velocity, i.e. it will work better for lower rate wells with larger annular clearances and where a good proportion of the gas is produced as large bubbles. Even then such gas separation efficiency has to be evaluated and confirmed first.

- The fitting of a shroud decreases the maximum ESP diameter (requiring either a large casing for installation of the same motor/pump combination, or a smaller diameter pump/motor). Practical experience has shown that, for a given power requirement, smaller diameter equipment is often less reliable. Further, high power equipment is not available in the smaller sizes.

- **The Protector or Seal** unit connects the drive shaft of the electric motor to the pump or gas separator shaft. It also acts as an:

    - Isolation barrier between the clean motor oil and the well fluids;

- Expansion buffer for the motor oil which heats up when the ESP is initially run into the well and when the motor reaches operating temperature when the pump is operating.
- Equaliser for internal motor pressure and well annular pressure. This is normally achieved by flexibly changing the volume of the seal or by a labyrinth-type communication.
- Absorber for part of the up- and down-thrust generated by the pump.

• **The electric motor** is the "high tech" component of the ESP completion. It is powered by three-phase alternating current supplied from the surface by the cable connected to the motor at the pothead. Motors are normally available in sizes between 15 and 900 HP. Two or even three motors may be placed in series if higher pump power requirements exist.

The motor is filled with lubricating oil which insulates the electrical winding. Ingress of reservoir fluids (especially water) is a common cause of motor failure.

Motor cooling is an essential requirement. The completion design should direct the fluid flow along the motor to provide sufficient cooling as discussed above. (The term 'cooling' here is relative: the production fluid is hot, but the motor can get much hotter and burn if not 'cooled'!). The pump should not be operated when the well is shut-in (e.g. X-mas tree valves are closed) or there is no flow for other reasons (e.g. pump-off or plugged completion) as the long-term operation in this condition will result in the motor overheating. High temperatures will degrade the motor winding, causing early motor failure.

When the motor is switched off the hydrostatic head of fluid present in the tubing will reverse the flow direction through the pump as it flows back into the reservoir. This will cause the motor to spin backwards. Trying to restart the motor while it is rotating backwards will lead to the motor burning out very quickly. This can be avoided by:

- Installing a check valve in the tubing to prevent fluid backflow (Figure 16). (However, this results in a "wet string" and spills when the tubing/ESP is recovered unless a drain valve is also installed. In his case, before tubing retrieval a sinker bar can be dropped downhole to open the drain valve first).
- Preventing motor restart for a specified time after it has been shut down or
- Using a sensor to detect backspin and prevent motor restart.

• **A downhole sensor package** may be mounted underneath the motor. Measurements can include:

- Pump suction and discharge pressures and temperatures.
- Electric motor temperature. (Excessive temperatures are indicative of lack of cooling.)
- Motor and Pump Vibration i.e. mechanical condition of the motor and pump bearings.
- Electrical Current leakage to earth i.e. condition of the electrical insulation.
- A downhole flow meter and/or phase cut meter can be added to the above.

All the above data is transmitted to surface via the power cable. It is combined with measurement of the power supply frequency and surface current/voltage as well as wellhead temperature, pressure and surface flow rate. A complete picture of well performance can be generated from this combination of data. The data can be:

- Used later for online or offline analysis of the pump performance (but also of the well and reservoir performance in some cases).

- Used to trigger on-site alarms which shut the ESP unit down, e.g. if the pump suction pressure falls below a pre-set value indicating that the fluid level in the well has dropped and the well is being "pumped off".

At the beginning of this section we stated that Figure 16 was for a low-pressure well since a packer had not been installed in the well, i.e. the well will probably not flow without artificial lift. Inclusion of a packer in the completion design, as is often required by the regulatory authorities in live and many offshore wells, precludes venting the gas to the surface via the casing/tubing annulus unless a dual packer arrangement is employed with an annular safety valve installed on the gas vent line as well. One example of this possible completion design is illustrated in Figure 19.

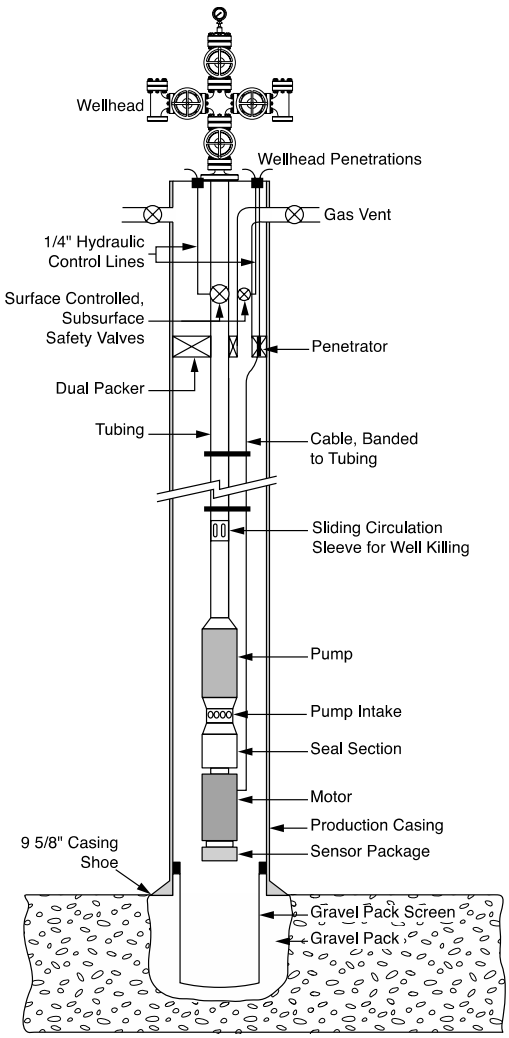

Figure 19 ESP completion incorporating packer and two surface controlled sub surface safety valves

5.2 Well Completion Employing Electric Submersible Pumps (ESPs)

5.2.1 TYPICAL ESP APPLICATIONS

The ESP application illustrated in Figure 16 and Figure 19 is the standard application where the ESP is used to lift production from a single zone through a single tubing. Many other application configurations are possible, including:

Figure 20 (a) shows aquifer water being lifted from supply zone and pumped directly to an injection well.

Figure 20 (b) illustrates a 'dump flood' well powered by an ESP where the water supply well and injection well are combined into one. Note that the ESP is inverted with the pump at the bottom. The ESP is being used here to replace the conventional surface-mounted transfer pump. Measurement of the injection flow rate and pressure can be made by inclusion of a sensor package (not shown) in the well completion design.

Figure 20 (c) shows an ESP placed in a shallow well being used to boost pressure in a surface flow line (note the shroud installed to ensure adequate motor cooling).

Figure 20 (d) is a horizontally mounted ESP as a surface pump in a flowline.

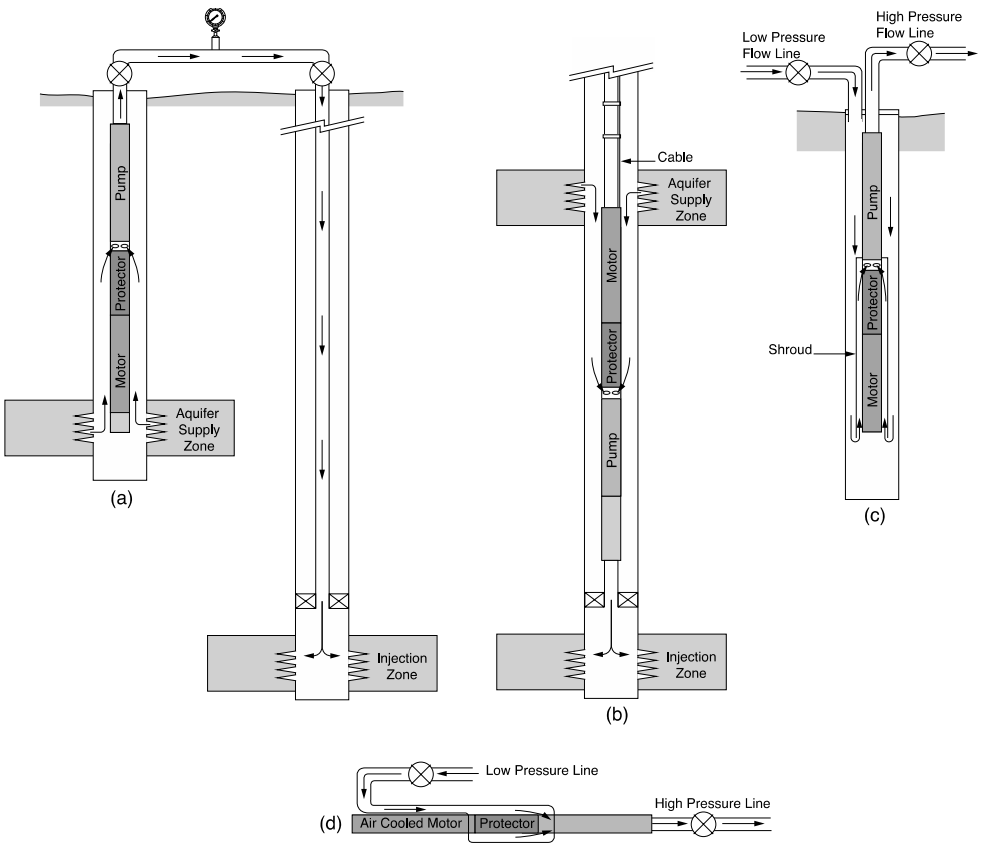

Figure 20 ESP applications (a) Direct water injection (b) Powered dumpflood with ESP
(c) Pressure boosting surface pipelines with a shallow, subsurface mounted ESP
(d) Horizontally mounted ESP surface pump

Some other ESP applications include the deployment with coiled tubing, in-well water separation and dumping, dual pump installations (including dual tubing completions), etc.

- *Feel free to review some other ESP applications in Tutorial 9.*

5.2.2 HORIZONTAL WELLS

The ability of ESP to pump large volumes of produced fluid coupled with the flexibility of pump design and operation makes them very suitable for the large volume production associated with horizontal wells. Experience has shown that a high-quality pump can be placed anywhere within the well at angles up to 80° providing the dogleg severity is not too great (< 6°/100 ft). More severe dog legs result in bending of the ESP as it is pushed through this section of casing. The resulting (even minor) damage often leads to a reduction in the pumps run-life.

5.2.3 "Y" TOOL

The problem with ESPs is that they block the tubing for tool access below the pump, e.g. for logging or perforating. The "Y" tool is a device to allow wireline or coiled tubing access below the ESP (Figure 21). However, it can reduce the maximum diameter of the ESP that can be installed.

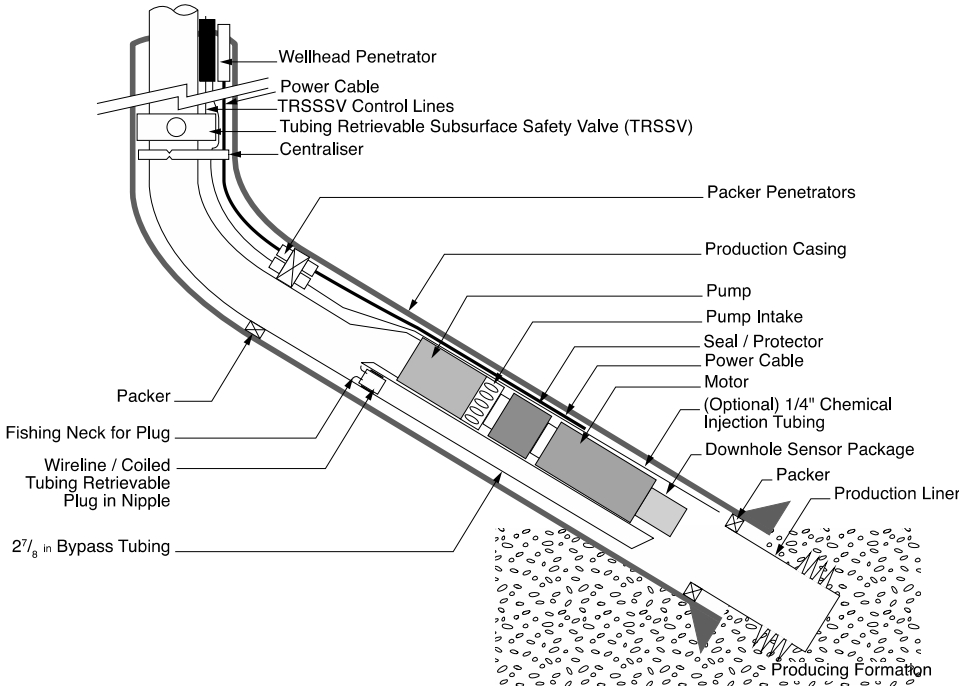

Figure 21 The "Y"tool"

The bypass tube of the Y tool must be closed during pumping (otherwise the high-pressure fluid from the pump discharge will flow back to the low-pressure pump suction). This can be done by either setting a wireline plug, or using a modified 'auto' Y tool that has e.g. a flapper door that automatically closes or opens when the pump is on or off respectively.

5.3 Basic Pump Selection

Unlike the positive displacement type, rod pumps, the ESP is a dynamic rotary pump which means its flow capacity and pump head are related.

The pressure increase that the pump is required to deliver, also called the "Total Dynamic Head (TDH)" or difference between the pump discharge and suction pressure, is the sum of three components (Figure 22).

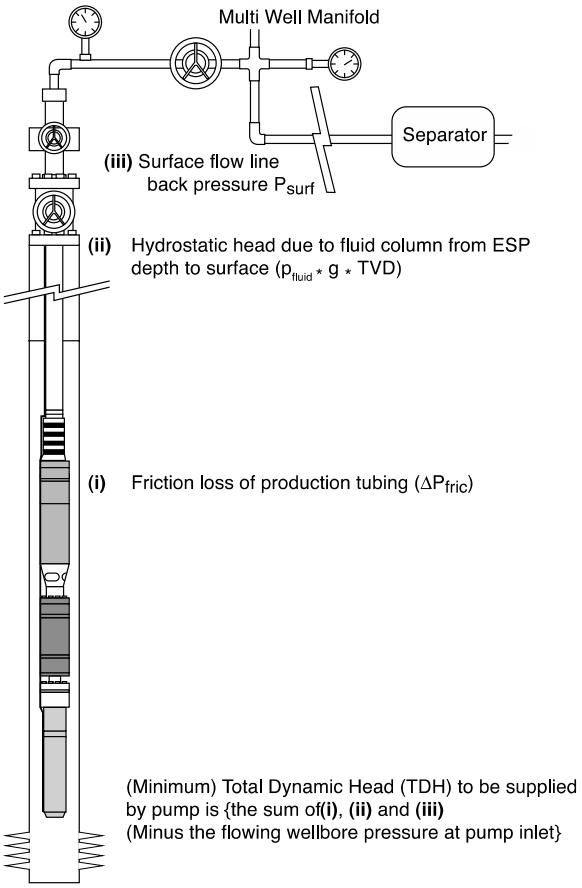

Figure 22 Pump outlet pressure requirements

- The **hydrostatic head** from the ESP pump to the surface. This is equal to the (average) density of the produced fluid in the tubing (ρ_{fluid}) multiplied by the True Vertical Depth (TVD) at which the ESP is installed (h) and the acceleration due to gravity (g).

- The **Friction pressure loss** in the tubing (ΔP_{fric}) at the required production rate.

- The **Surface backpressure (P_{surf})** required to overcome flowline back pressure and flow the produced fluid to the separator at the required production rate. This can have a high value if the completion is a satellite well situated some distance (can be up to 50 miles) from the host platform.

Thus: $TDH = \rho_{fluid} * g * TVD + \Delta P_{fric} + P_{surf} - P_{pump\ intake}$

As mentioned, the pump intake pressure should not be brought to zero otherwise the pump submergence will be compromised. This pressure is normally selected to ensure sufficient submergence level and further analysed with respect of what GVF (gas volume fraction) is expected at such pressure and whether this GVF is suitable for the pump in question (or else a separator or a different pump is needed).

The data describing the performance of an ESP is provided by the manufacturer for the case of water flow, and can be translated to oil flow (provided the oil is not very viscous. The manufacturer should also supply a correction factor for the fluid viscosity if the oil viscosity is high. Further correction is required if significant volumes of free gas are being pumped).

Formation of viscous emulsion in ESPs is sometimes a problem and ideally should be avoided.

Once the pump has been chosen, optimum motor and seal section can then be identified, along with the electric cable, variable speed drive, etc. The corrections to the power supply for temperature and cable resistance are made. The power supplied is further corrected by the power factor relating the real and apparent power in the system. It also needs to be checked that the chosen ESP design will operate efficiently for a variety of well conditions (higher/lower well PI, greater water cut, lower reservoir pressure, etc.) so as to delay the ESP replacement/resizing workover.

The choice of the correct ESP design, along with the actual, operational installation of ESPs, is thus a complex task. This results in the average run lifetime, or "mean time before failure (MTBF)" often being low when ESPs are first introduced into a field. The MTBF then increases as the "learning curve" is climbed. The typical average MTBFs are within 1.5-4years. (This is a statistical estimate: there are pumps that operate for over 10 years without fail, and the pumps that fail shortly after installation e.g. due to a system or mission failure).

It needs to be mentioned here that average statistics need to be treated with caution - the actual run times will be very dependent on the aggressiveness of the producing conditions e.g. temperature, concentration of sand produced, corrosivity of the produced fluid (due to e.g. presence of H_2S, CO_2, etc. in the fluid), skill of the rig crew, manufacturing quality control etc.

5.4 Advantages and Disadvantages of Electric Submersible Pumps

Table 2 presents Advantages and Disadvantages of ESPs. The points discussed in this table should be self-explanatory when read in conjunction with the previous sections.

Advantages	Disadvantages
• Can achieve extremely high volume lift using up to 1,000 kW motors • Unobtrusive surface location • Downhole telemetry available • Tolerant high well deviation / doglegs • Corrosion / scale treatments possible	• Full workover required to change pump • Cable susceptible to damage during installation • Cable and motor deteriorate at high temperatures • Gas and solids intolerant • Increased production casing size often required

Table 2 Advantages and disadvantages of electric submersible pumps

5.5 Monitoring the Performance of Electric Submersible Pumps

Prior to the implementation of automated SCADA (Supervisory Control and Data Acquisition systems that measure a range of surface and in-well parameters in real time) systems, the monitoring of ESP performance was limited to surface measurement of the current supplied to the pump along with an infrequent (e.g. monthly) well test. However, considerable information can still be derived on well performance from such measurements – Figure 23 is a schematic example of a 24-hour chart recording of electrical current consumed by an electric submersible pump during normal operation. The current taken is constant.

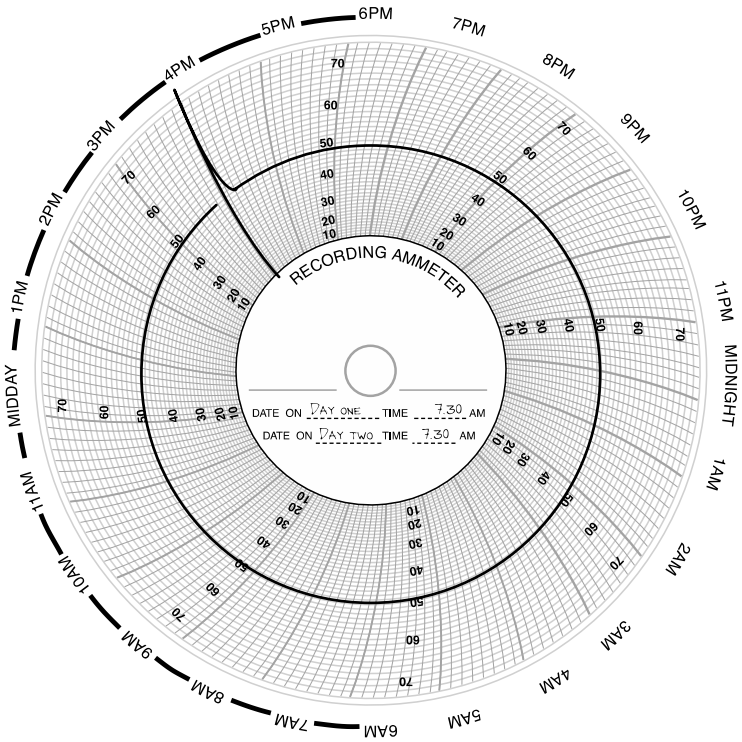

Figure 23 Ammeter chart monitors electric submersible pump performance. Normal operation

By contrast, the current taken when the well is being pumped off shows a much more erratic behaviour (Figure 24).

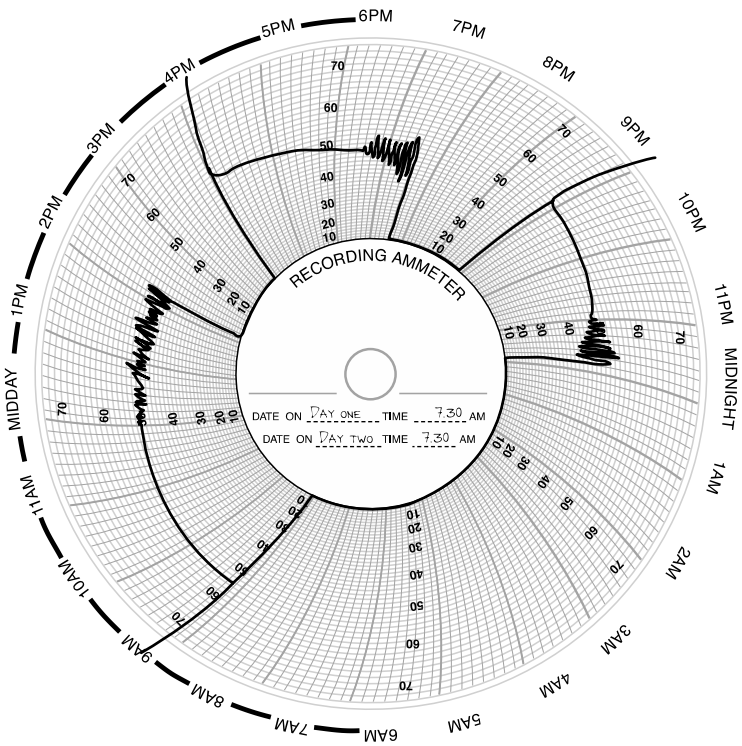

Figure 24 Ammeter chart monitors electric submersible pump performance. Well pumped off

The pump started at 09.15 am – note the large, initial surge in current while the motor is getting "up to speed". A steady current is then drawn for the next 3 hours – decreasing slightly as the fluid head above the pump decreases. At 12.10 the current begins to oscillate rapidly – the size of these oscillations increases until 2.15 pm when the pump was shut down. It was suspected that the problem was due to gas being formed when the flowing bottom hole pressure was reduced to below the bubble point, leading to gas locking and the pump ceasing to pump. This was confirmed by leaving the fluid level in the well to build up for 100 minutes and restarting the pump at 4.05 pm. The same cycle repeats itself, however this time the problems appear after some 2.5 hours of steady production. The pump was shut down a second time at 7.15 pm. A third cycle was started at 8.50 pm after a second 100 minute shut in – current oscillation starting again after 2 hours production. The well was shut in just after 11.30 pm.
Continual stopping and restarting the ESP motor is not recommended due to damage to the motor winding by the initial high current surge as the motor begins to rotate. This leads to early motor burnout. The options are to:

- Install a lower capacity (smaller) pump section.
- Operate the pump at a lower speed using a VFD.
- Stimulate the well to improve the inflow performance.

Modern SCADA systems allow a much more complete picture to be built up. Installation of a downhole monitoring package (providing data similar to what is shown in Figure 25) allows the motor/pump conditions to be monitored closely. Figure 25 is an example of a normal start up. It can be analysed as follows:

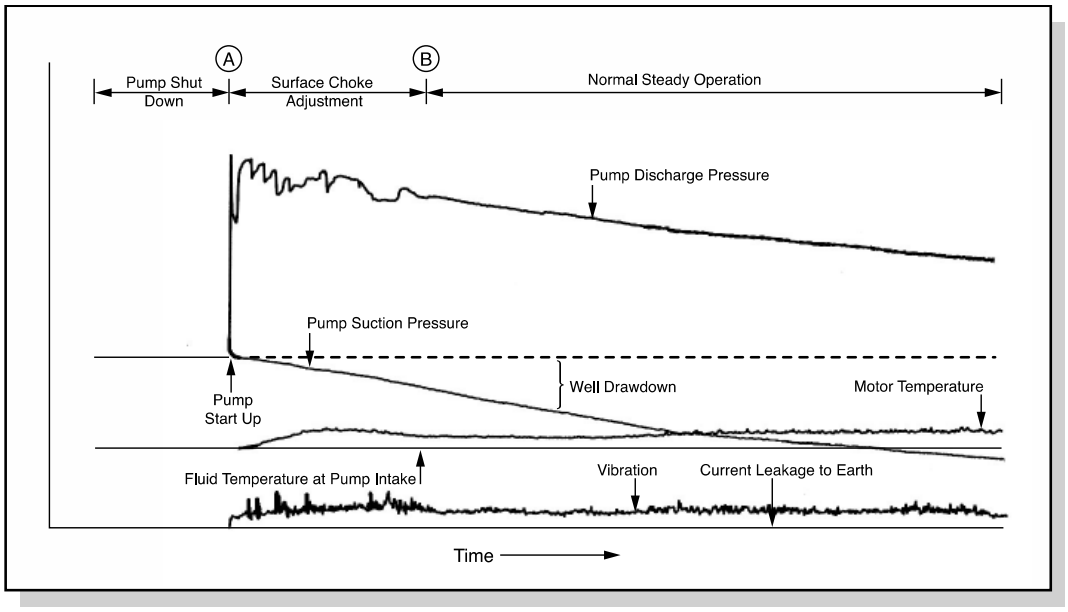

Figure 25 Electric submersible pump and motor condition monitoring

Initially, prior to energising the pump, the pump intake and discharge pressures have the same value; as does the motor and pump temperatures. The pump starts up at point A, as shown by:

- The pump discharge pressure increasing
- The motor temperature becoming warmer than the fluid entering the pump
- A limited amount of vibration during surface choke adjustment

Then follows a period of surface choke adjustment, as shown by fluctuations in the pump discharge pressure and increased vibration. However, after point B, steady operating conditions are achieved and a slow decline in pump suction and discharge pressure are observed as the well's flowing bottom hole pressure is reduced.

Protection of the ESP can now be achieved by monitoring the pump's condition and shutting it down when problems develop before physical damage to the pump results. For instance, a "pump off" control can be implemented by stopping the pump when the intake pressure drops below a pre-set value. The pump is then restarted once the well pressure builds up to a second, higher predetermined value. This type of monitoring is very diagnostic when problems develop, but can have much more "added value" when combined with surface flow measurements (gross flow rates and water cut). However, as explained, continually restarting pump motors reduces their operational life. Installing a correctly sized pump unit is the preferred solution.

Moreover, the effective use of the pump performance monitoring and timely adjustments that increase the pump's life consequently notably cut the development costs.

5.6 Electric Submersible Pump Performance and Design

As mentioned, the centrifugal pump unit employed in ESPs is a dynamic, centrifugal pump in which the pump rate depends on the pressure head generated – the pump rate is low when the pressure head is high and vice versa.

The relationship between the pump rate and the pressure generated for dynamic pumps is called the pump characteristic curve (see Figure 26). It is measured by the pump manufacturer in laboratory tests using a standard fluid (fresh water) with the pump running at 3500 rpm (60 Hz electrical supply) or 2915 rpm (50 Hz supply).

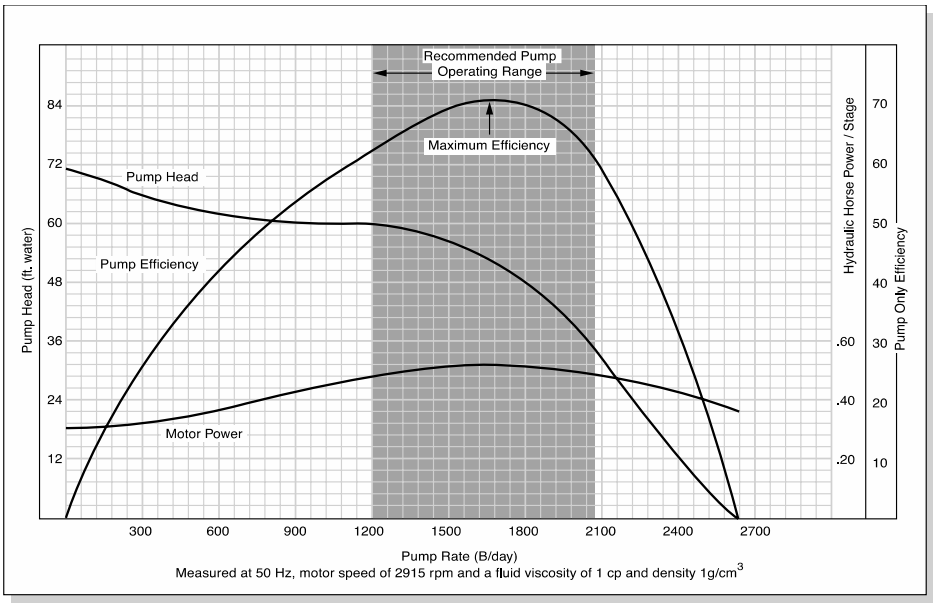

Figure 26 A typical pump characteristic curve for a centrifugal pump

The "pump head" per stage, i.e. the increase in pressure per stage (ΔP), is often expressed not in psi but in terms of the pressure generated by an equivalent fluid column H that the pump can lift. E.g. for water pumping the pressure increment (in psi) as a function of equivalent column height H (in feet) is:

$\Delta P = \rho_w * g * H = 0.433 * H$

For a production fluid with relative (to water) density γ:
$\Delta P = 0.433 * \gamma * H$

Such head expressed in feet is fairly independent of the fluid type (except heavy oils or other very viscous and/or non-Newtonian fluids). Recall that the pressure increase per stage is proportional to the fluid density, which means the pressure increase will be lower for lighter fluids, and higher for heavier ones, all in all resulting in the lift height being the same for either fluid. That's why the head in feet (or meters) is the preferred pump characteristic.

But the discharge pressure is proportional to the specific gravity (γ) of the liquid pumped, as mentioned above. The pump head (in feet) - pump rate relationship can be used for all liquids, though as mentioned it requires further corrections for high-viscosity ones.

Pump power is the hydraulic work done per unit time. This is proportional to the pump rate multiplied by the pump head, i.e. to the product ($q * \Delta P$).

Power is normally expressed in terms of Kilowatt (KW) or Horse Power (HP); where 1 HP = 0.746 KW. The pump (or hydraulic) power is the (useful) work done by the pump; while the mechanical power is the work done by the electrical motor which is driving the pump. The pump efficiency (E) is:

E = hydraulic power/mechanical power

Pump Efficiency is also recorded in the pump characteristic curve. It is recommended that the pump operating range be within around ±12.5% of the maximum efficiency point (the shaded area in Figure 26). During pumping there are forces acting upwards (fluid drag) on the impellers and downwards (the pressure differential across the stages). If either force prevails the impellers may experience excessive friction against the fixed diffusers or bearings (if the impellers are free on the shaft) or cause high impact on the shaft's thrust bearing (if the impellers are fixed on the shaft). These 'upthrust' and 'downthrust' conditions should be avoided. So the ESP manufacturers design the pumps so that these forces on the impellers are balanced within the range of rates selected around the pump efficiency maximum. That's why it is not recommended to operate the pump outside this recommended flow rate envelope (at least not for long). *(The use of a VFD changes the shaft's RPM and pumping rate, and also affects the operational envelope shifting it to the lower rates for lower frequencies, and vice versa. See* Figure 27*).*

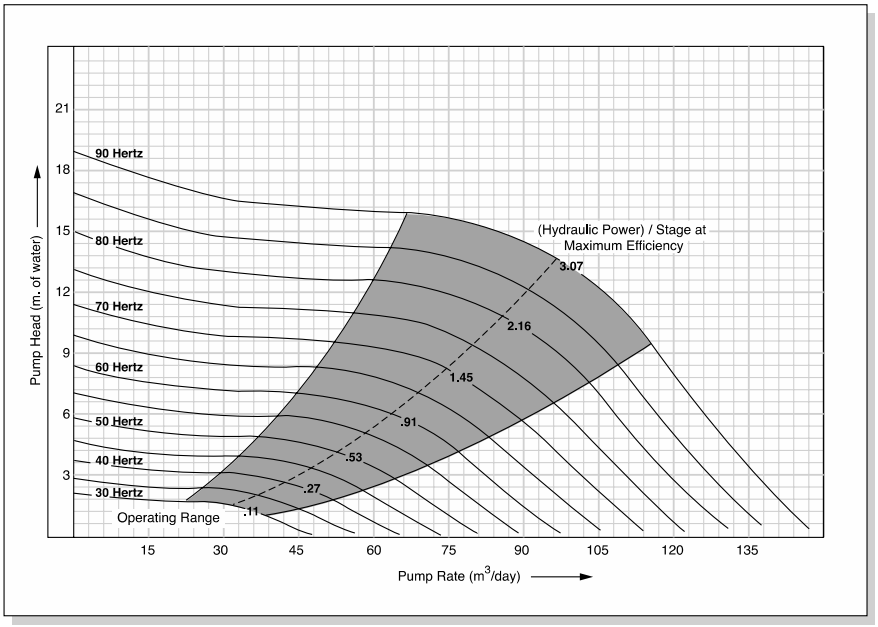

Figure 27: Typical changes in pump/motor characteristic performance as a function of electric supply frequency.

- *Feel free to attempt Tutorials 2, 3*

6. HYDRAULIC PUMPS

Hydraulic pumps use a high-pressure power fluid pumped from the surface (Figure 28) as the source of energy. This power fluid can drive a:

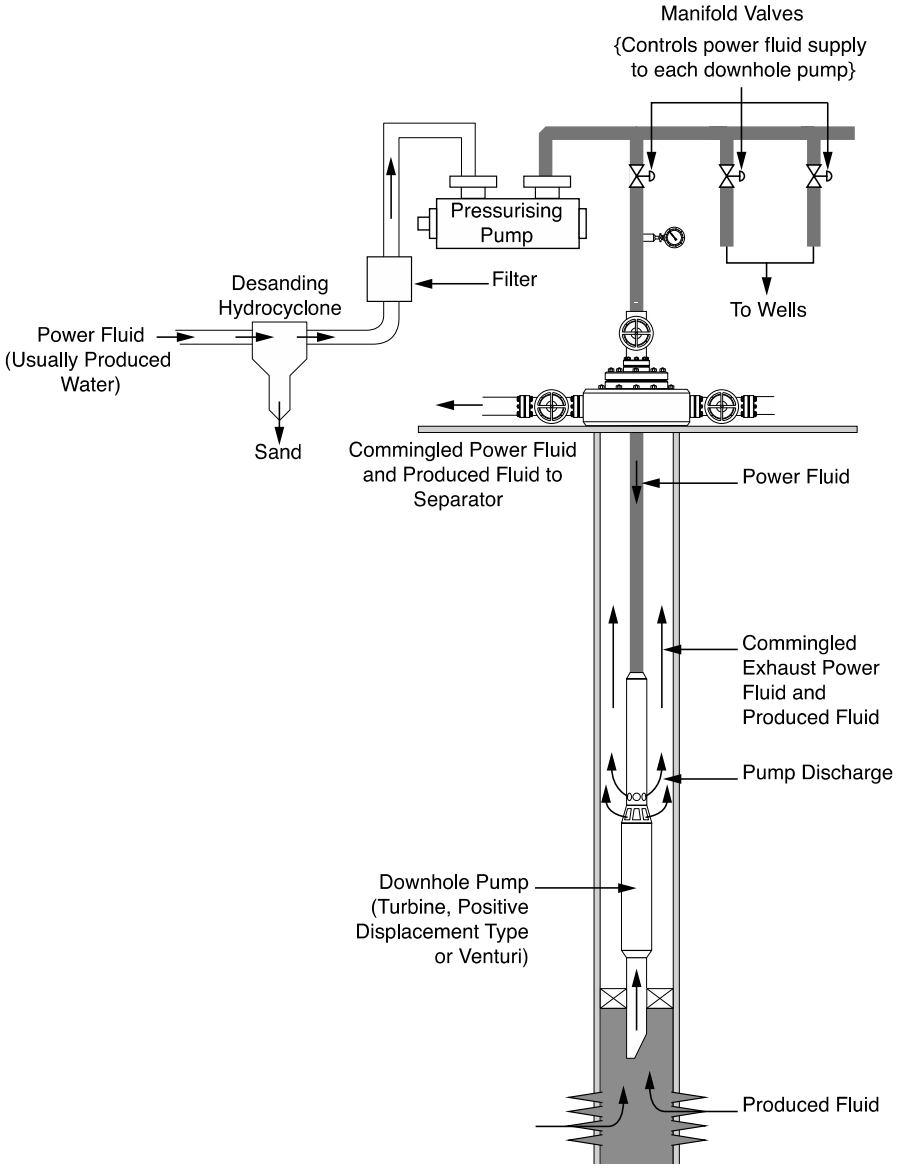

Figure 28 A hydraulic pump.

- **Positive displacement pump**. Figure 29 shows how the flow of power fluid in a Hydraulic Piston Pump (HPP) through the upper engine unit moves the engine and pump piston connected by a shaft which is translated into the outflow of high pressure produced fluid. This is similar to the rod pump unit with plungers and valves except HPP are normally double-acting i.e. the fluid is displaced during both the "UP" and "DOWN" strokes.

The pump rate is proportional to the power fluid injection rate as $Q_{pump} = Q_{power_fluid}*(A_{pump}/ A_{power_fluid})$

where A is the net cross-sectional area of the piston. Changing the ($A_{pump}/ A_{power_fluid}$) ratio to magnify the pump rate comes at a cost of the need for injecting the power fluid at a higher pressure.

➢ *Feel free to attempt Tutorial 4*

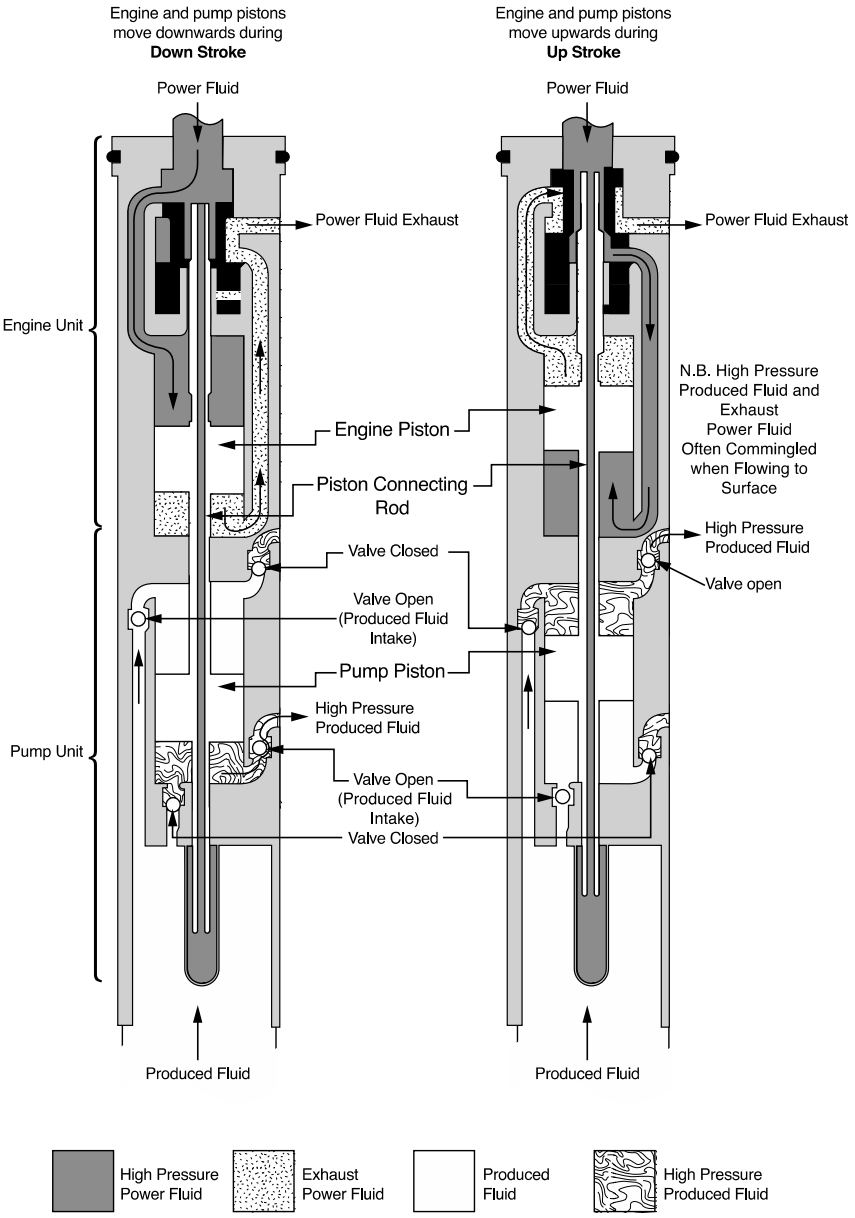

Figure 29 Operation of a positive displacement hydraulic pump

- Alternatively, the engine could be a **turbine or centrifugal pump** (a.k.a. a Hydraulic Submersible Pump HSP or Weir pump after the name of the manufacturer). This is similar to an ESP except instead of the electric motor there is a downhole turbine driven by the power fluid.

- The dynamic displacement, jet or venturi pump creates a reduced pressure by the power fluid passage through a **venturi** or nozzle (Figure 30) where pressure energy is converted into velocity. (Bernoulli's principle states that when flowing across a restriction, the fluid's pressure increases when the velocity decreases, and vice versa). This high-velocity low-pressure area sucks the production flow in the throat of the pump where it then commingles with the power fluid. The mixture is then flowing through a diffuser which reduces the flow velocity, therefore increasing the mixture fluid pressure to the value sufficient to lift the mixture to surface.

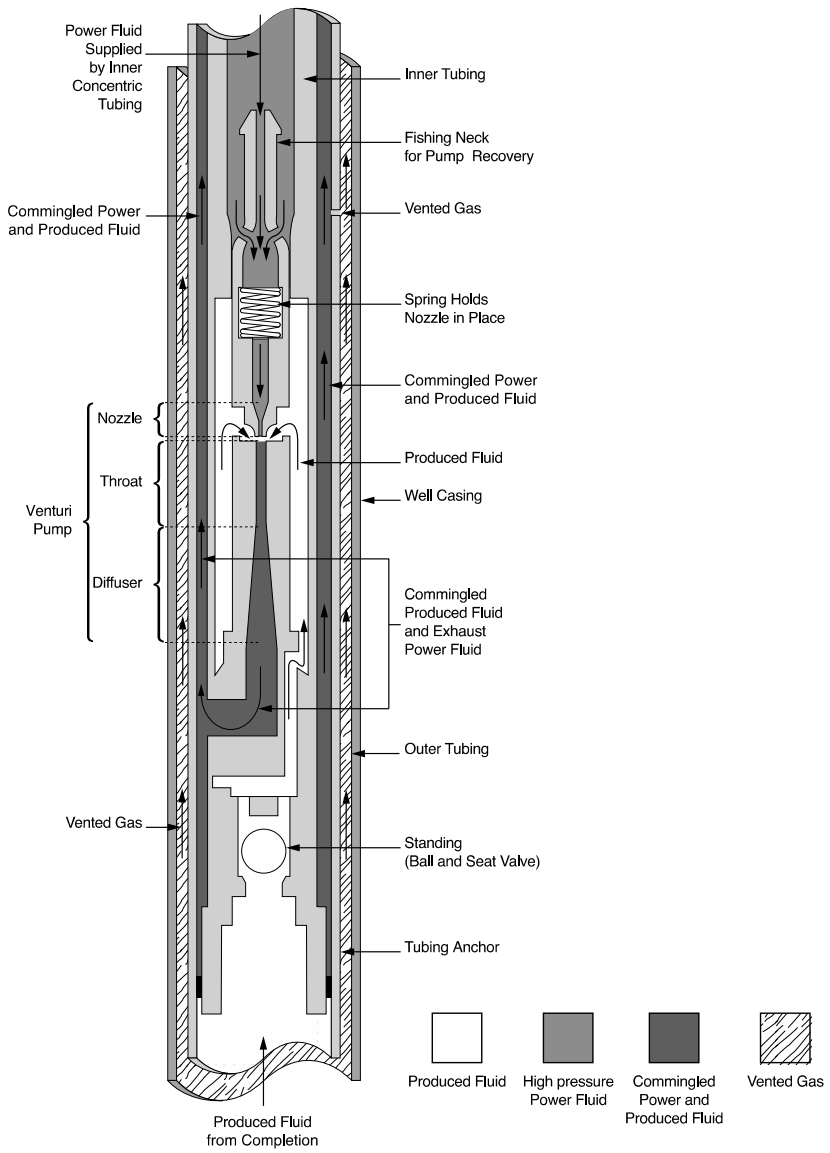

Figure 30 Jet or Venturi pump operation

In hydraulic pumps the production fluid rate is normally comparable to the injection power fluid rate. This makes it easy to control the production rate. The fact that the power is transmitted downhole by fluid without mechanical parts, makes the hydraulic pumps applicable in any geometry well.

The power fluid normally consists of oil or water, but either way must be clean of solids and not harmful to the well equipment. Pump efficiency-wise these two fluid options are normally comparable. Power fluid is supplied to the downhole equipment via a separate injection tubing.

The majority of installations commingle the exhaust fluid with the production fluid {an "Open" system Figure 31(a)}. If difficulties or high costs are encountered in preparing power fluid of the required quality from the production fluid, then a "Closed" system may be installed in which the power fluid (often water) returns to the surface via a (third or second) separate tubing installed in parallel {Figure 31(b)} or concentrically. This option is not available with a venturi pump: in it the fluids must mix at the nozzle throat.

The completion design may also allow gas to be vented to surface via the casing/tubing annulus.

The mixture may also flow via the tubing-casing annulus, in which case a single-tubing completion is applicable. In some less common cases it is possible to dump the exhaust power fluid into an aquifer immediately in the well, without the need to return it to surface.

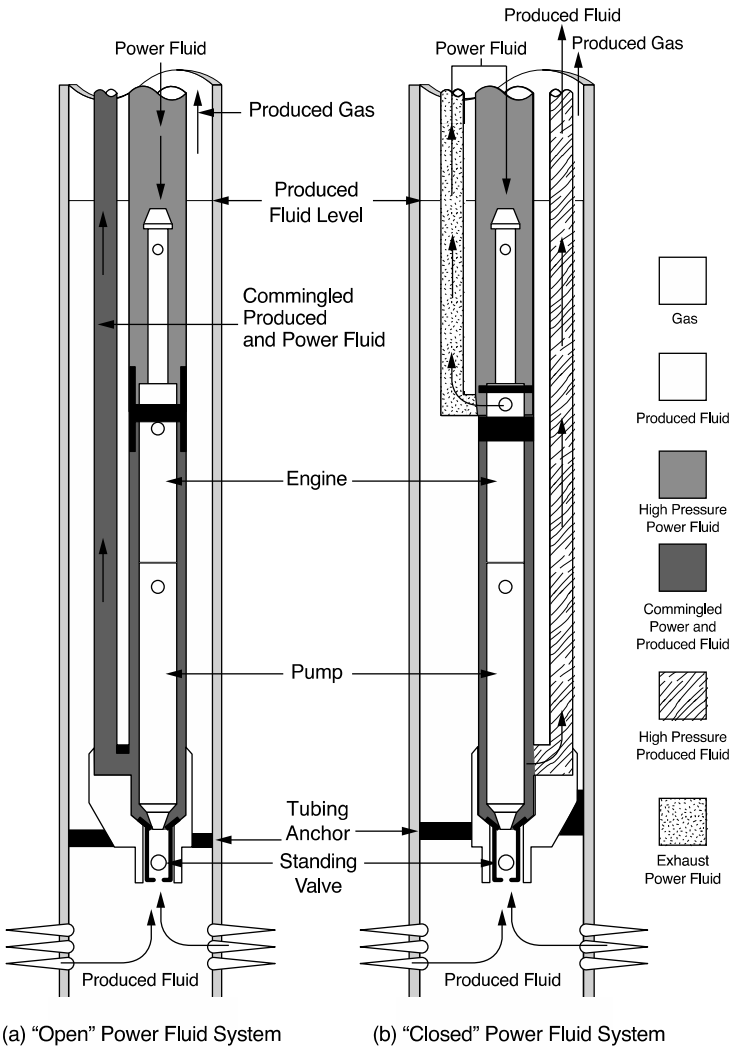

Figure 31 Types of hydraulic pump installation

A typical power fluid supply pressure of between 1,500 and 4,000 psi. is provided by a pressurising pump at surface (Figure 28). This may be a reciprocating plunger (triplex) pump or a multi-stage, centrifugal pump. This pressure determines the pressure increase achievable by the downhole pump unit. The pump rate (and the rate at which power fluid has to be supplied) is determined by the diameter and speed of the downhole pump.

"Clean" power fluid is required to avoid erosion of the downhole pump components. The power fluid is often drawn from a settling tank where the larger solid particles are removed. It is then pumped via a desanding hydrocyclone and a guard filter before having its pressure raised to the operating pressure by the charge pump. The power fluid from the pressurising pump may supply one or more wells (Figure 28). The choice of power fluid: oil or water, depends on the resources and capacity available. High-pressure oil line at surface is a hazard, while the use of water complicates further separation of water from the produced oil in an open system.

6.1 Advantages of Hydraulic Pumps

Hydraulic pumps have the following advantages:

- Suitable for crooked and deviated wells.
- Reciprocating and turbine pumps can work at great depths (up to 17,000 ft).
- Very flexible speed control by the (surface) supply of power fluid. Turndown to < 20% of design maximum speed can be achieved.
- Jet pumps have no moving parts and can handle solids and high gas ratios.
- Turbine pumps can be manufactured from erosion resistant materials which gives an increased lifetime with "reasonable" solids production. They have proven to be very reliable for operation in remote locations where access to the wellhead is limited. The operating costs were 50% lower than for ESPs while the pump reliability and the yearly oil production were greater than for ESP's. It was also found possible to use the same water source (and many common flow lines) as used for reservoir pressure maintenance.
- The power source is remote from the wellhead giving a low wellhead profile, attractive for offshore and urban locations.
- The power fluid can carry corrosion or other inhibitors downhole, thus providing continuous inhibition when the well is producing. It can also be heated e.g. to reduce the viscosity of viscous production fluid. Alternatively, the continuous supply of cool power fluid increases the maximum allowable bottom hole formation temperature at which the pump can be installed.
- The pump unit can be designed as a "free" pump; the pump unit having the capability of being pumped through the power fluid tubing from the surface to its downhole location (Figure 32). It can then be recovered by reversing the flow direction. The ability to recover the pump without the need to move a rig/workover hoist to the wellsite is attractive for offshore platforms as well as remote and urban locations.

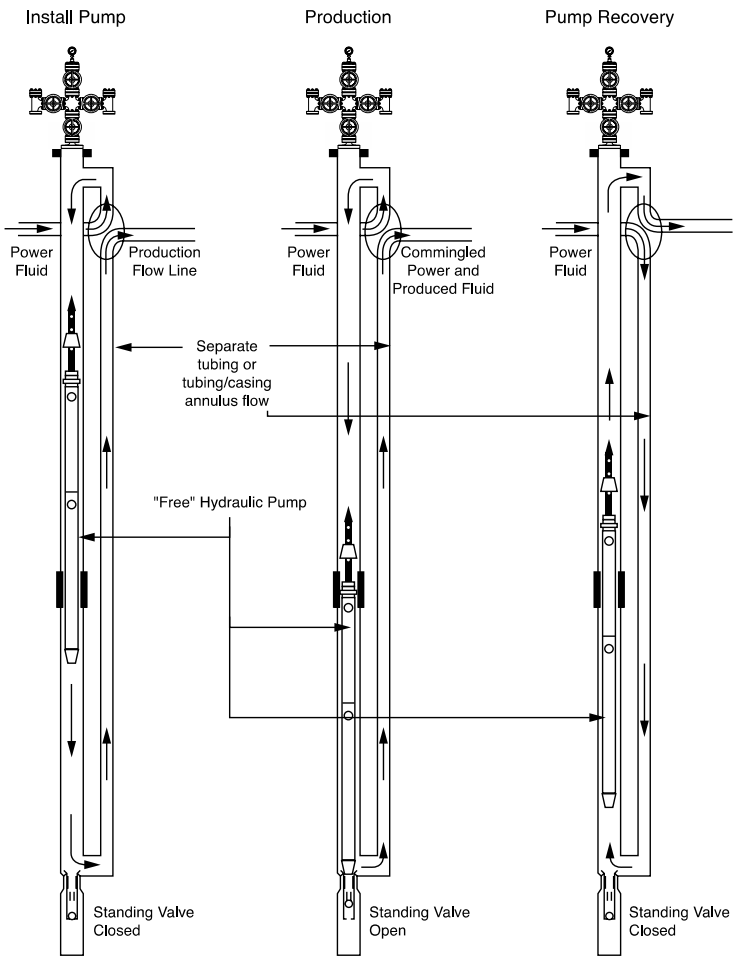

Figure 32 Installation and recovery of a "free" hydraulic pump

6.2 Disadvantages of Hydraulic Pumps

- Pumps with moving parts have a short run life when supplied with poor quality (solids containing) power fluid. Jet pumps can have a long run life under similar conditions.

- Positive displacement and centrifugal pumps can achieve very low flowing bottom hole pressures in the absence of a gas effect. The lowest pressure achievable by jet pumps are much higher, being comparable to gas lift.

- A similar volume of power fluid and produced fluid is required, increasing the size of the production separators.

All in all, the hydraulic pumps are a reliable, attractive technology suitable in many applications. They are still less common however than rod pumps, ESPs or gas lift being relatively new and thus more expensive and requiring specialist equipment and assistance.

7. PROGRESSIVE CAVITY PUMPS

Progressive (or Progressing) Cavity Pumps PCPs (also called Moyno pumps after the inventor: Rene Moineau) are becoming increasingly accepted in the production of viscous crude oils, as well as in some other niche areas e.g. liquid pumping from liquid-loaded gas, gas-condensate, coal bed methane, etc. wells. A typical completion is illustrated in Figure 33 where a prime mover (in this case an electric motor) is shown rotating a rod string and driving the PCP. The rods used are the same as in the sucker rod pumping.

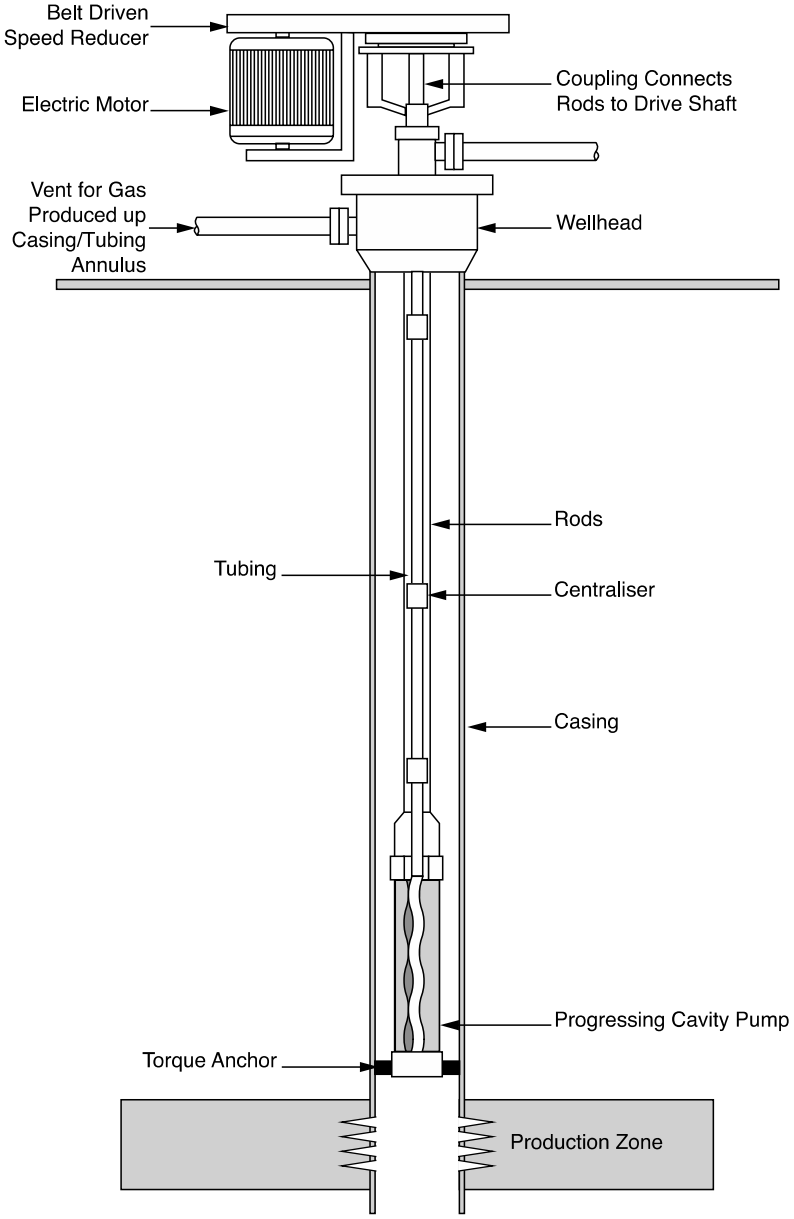

Figure 33 A well completed with artificial lift using a progressing cavity pump

7.1 Progressing Cavity Pump Principle

Figure 34 illustrates the main components of a PCP downhole pump. A steel shaft rotor of diameter d has been formed into a helix {Figure 34(a)}. The rotor is rotated inside an elastomeric or metallic pump body (stator), which has been molded in the form of a double helix with a pitch of the same diameter and exactly twice the length of the pitch given to the rotor {Figure 34(b)}. Figure 34(c) shows that, when assembled, the centre line of the rotor and the stator are slightly offset, creating a series of fluid filled cavities along the length of the pump. Figure 35 is a perspective view of Figure 34(c), which helps explain how the interference fit between the rotor and stator creates two chains of spiral (fluid filled) cavities.

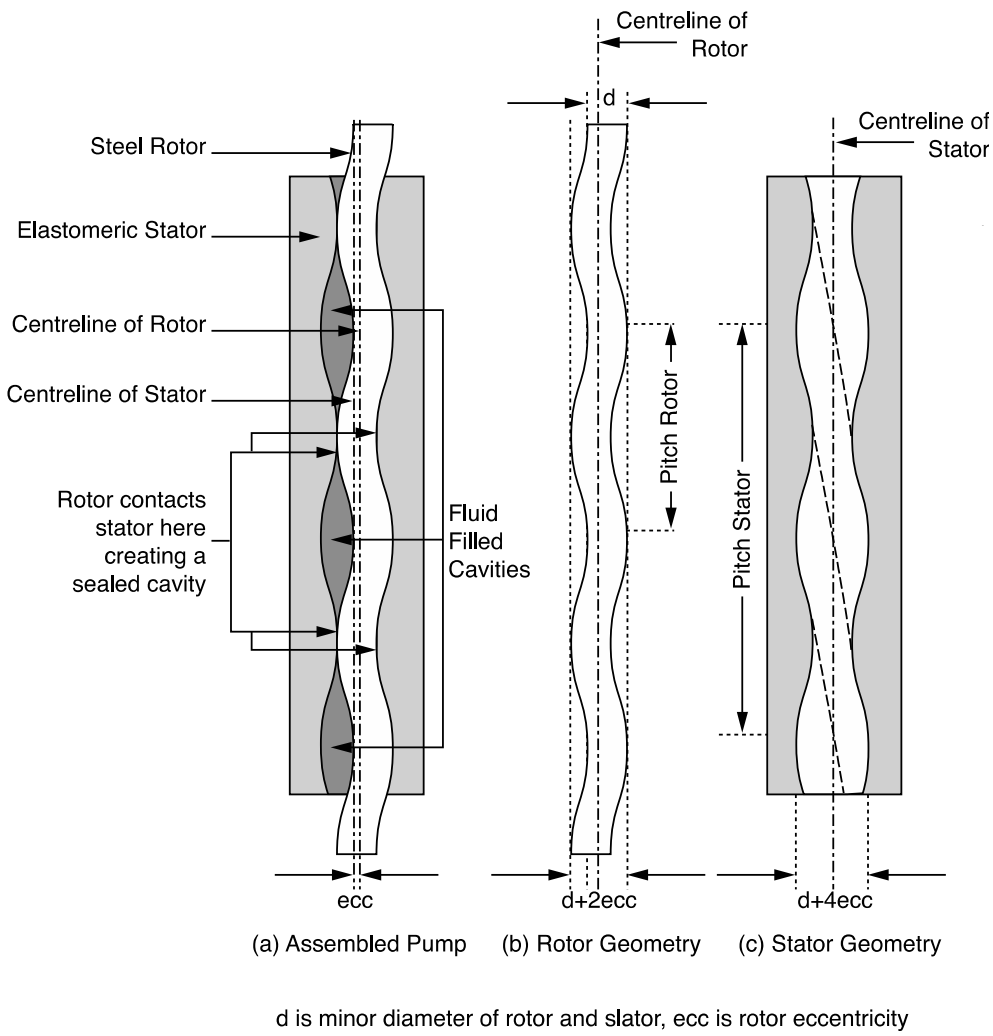

Figure 34 Cross section of a progressing cavity pump and its components

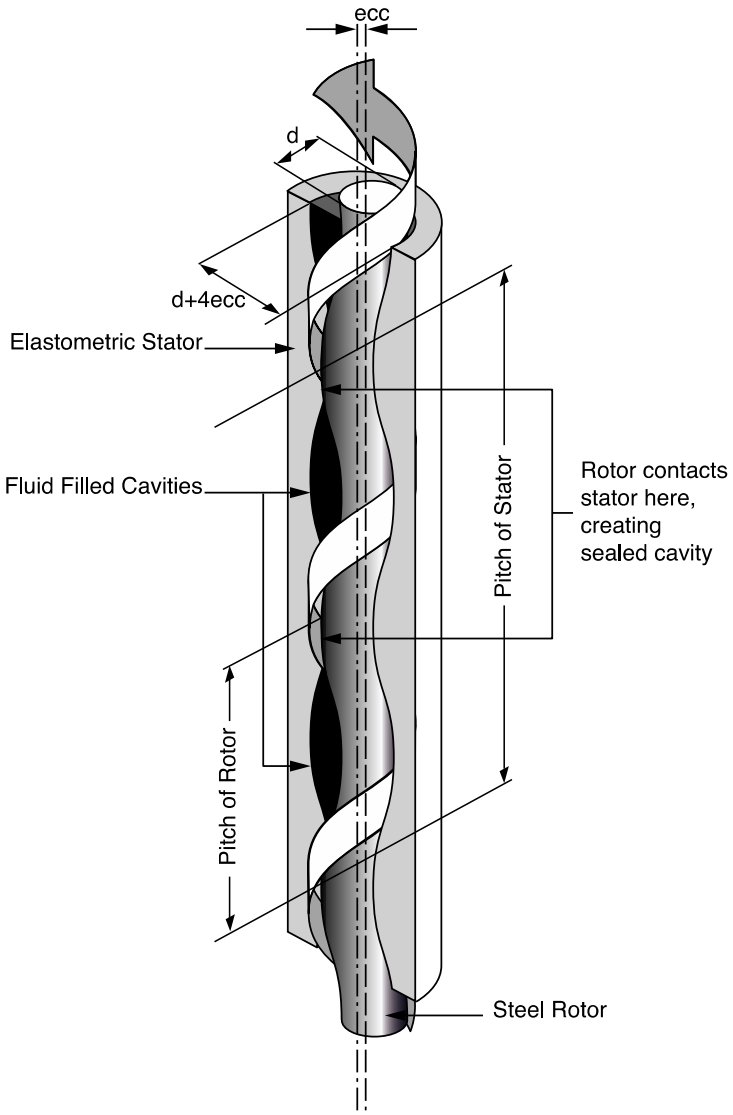

Figure 35 Perspective view of operating Progressing Cavity Pump

The rotor within the stator operates as a pump. This causes the fluid, trapped in the sealed cavities, to progress vertically in the cavities (pockets) along the length of the pump from the suction point to the pump discharge. These cavities change neither size nor shape during this progression. Figure 36 (a-e) shows how, as one cavity diminishes, the next one increases at exactly the same rate; giving a constant, non-pulsating flow. It acts as a positive displacement pump. The pump head for the desired rate is calculated using the IPR and TPR well model (similar to the other pump types' design) and the number of stages is selected so that the pressure difference per stage is not higher than the recommended value, otherwise excessive backward slippage of the fluid may occur. The pressure increase that can be achieved by the pump depends on the number of "seal-lines" formed along the pump body by the rotor and stator. Typically, this is found to be 200 – 300 kPa pressure increase per stage. Wear of either the stator or rotor will decrease this value since the maximum pressure increase depends on this interference fit. However, the construction of the stator body from an elastomer (provided the elastomer is not sensitive to the production fluid and conditions) makes this pump design relatively tolerant to produced solids – let alone such pumps are often used to pump viscous oils which provides a lubrication film to protect the rotor and stator from wear.

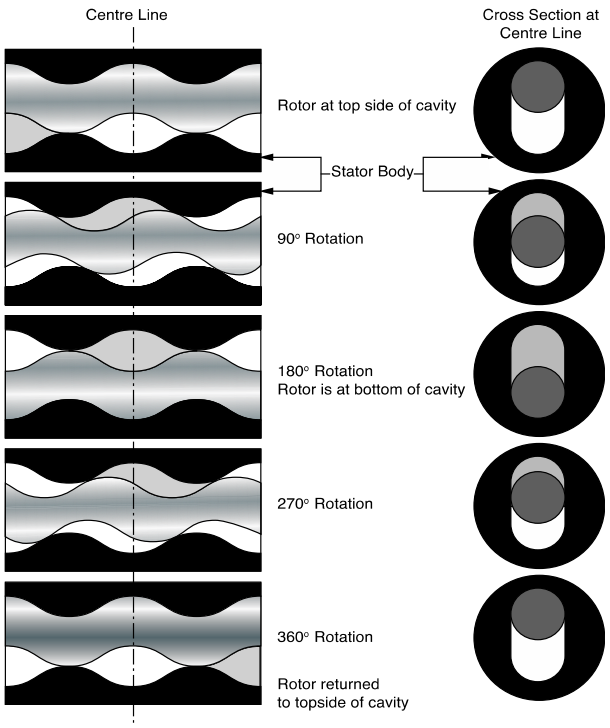

Figure 36 Operating principle of Progressing Cavity Pump

The flow rate achieved by a liquid filled (no gas) PCP pump is directly proportional to the speed of rotation of the rotor (N):

Flow rate = k*Pitch of Stator*4*eccentricity*Stator minor diameter*N

Where k is a constant. The volumetric efficiency is typically 70-80%. The presence of gas will reduce this efficiency, a gas anchor being frequently included in PCP completions.

The advantages and disadvantages of a PCP are summarised in Table 3 and Table 4. It can be seen that the pump's characteristics make it very suitable for artificial lifting wells producing medium to high viscosity crude oil reserves. These crude oils often have a tendency to form highly viscous emulsions when mixed under high shear with the produced water (as occurs in a centrifugal pump). They are often found in (relatively) shallow, soft formations where the inclusion of sand control in the completion design is a necessity with other types of pumps. Elastomer selection problems are minimised because these crude oils tend to have a low GOR, a low aromatic content and, due to their shallow location, a low Bottom Hole Temperature.
As mentioned, many PCP applications are at shallow wells. However, it is also possible to design PCP's with production rates between 5 to 5,000 bfd producing from depths >8,000ft TVD and with a maximum pressure differential across the pump of greater than 5,000 psi.

Advantages of PCP	Comment
Simple design	Rapid repair of pump unit by replacing rotor and stator as a complete unit
High volumetric efficiency	In the absence of gas. Efficient design for gas anchors available
Tolerant of produced solids	At reasonable levels
High energy efficiency	PCP is a Positive Displacement Pump
Emulsions not formed due to low shear pumping action	Centrifugal (e.g. ESP) pumps promote emulsion formation due to high pump speeds
Capable of pumping viscous crude oil	(1) Diluent mixed as required with crude oil if extreme viscosities to be pumped (2) "Water-like" behaviour observed at high water cuts when oil becomes the internal phase

Table 3 Advantages of a Progressive Cavity Pump

Disadvantages of PCP	Comment
High Starting Torque	consider PCESP
Fluid compatibility problems with elastomers in direct contact with aromatic crude oils	Carry out tests prior to producing a new crude oil
Gas dissolves in the elastomers, at high bottom hole pressure	Avoid rapid depressurisation of the pump. Destructive bubbles form in elastomer body when pressure is lowered rapidly

Table 4 Disadvantages of a Progressive Cavity Pump

7.2 Progressing Cavity Pump Operational Issues

Surface driven PCPs are often installed in deviated wells, the pump being landed in well sections with a deviation in excess of 70 degrees in some cases. Note that the dogleg severity should also be controlled, a value of < 5º/100 ft being recommended for normal PCP performance. Rod/tubing frictional contact, even when reduced by centralising the sucker rod string, leads to a high starting torque as well as wasting power when the pump is operating. The use of rod centralizers to reduce the side loading of the rods against the tubing is a necessity in deviated wells. A small diameter, production tubing has a reduced clearance between the rod couplings and tubing's inner wall. An increased number of non-rotating couplings is required to manage the contact forces between the rod string and tubing. An alternative is to reduce this side loading further by running Conrod (a continuous rod without couplings).

The required pressure boost to be generated by the pump needs to be carefully calculated. For example, the pressure drop across the centralizers and the extra friction and hydrostatic head associated with denser crudes, needs to be considered along with the necessary reservoir drawdown to produce at the planned production rate.

Failure of either the pump, the sucker rod string or the tubing requires that all three have to be pulled to the surface and then rerun to return the well to production. This operation can normally be done by a light workover hoist, since the PCP pumped wells are normally shallow and are not capable of natural flow.

7.3 Some other PCP Variants

The resulting high torque and friction losses, as well as the tubing and rod failure discussed above, can be reduced by placing the electric motor downhole – the unit is now known as a Progressing Cavity Electric Submersible Pump (PCESP). A grearbox has to added to the electric motor to keep the pump rotor's RPMs at a reasonable level. The PCESP technology helps to reduce the operating costs and increase the life of the pump.

Low-cost replacement of the PCP unit can be achieved by making it wireline retrievable. A fishing neck is provided for wireline recovery, while a (re)latchable drive shaft connection is made at the bottom of the pump unit so that it can be connected and disconnected.

8. HYBRID SYSTEMS

Many other, much less common artificial lift technologies exist. Quite often, these technologies are hybrid in that they use the combination of two forms of 'conventional' artificial lift types, e.g. the PCESP technology mentioned above is a combination of PCP and ESP.
Most hybrid systems combine gas lift with one of the other types of artificial lift. For example, it has been shown that injection of gas above an ESP or PCP can reduce the hydrostatic head against which the pump (e.g. ESP, PCP etc.) is pumping against by up to 40%. This can lead to a significant increase in pump performance. It may also allow the well to continue to produce even when the pump is experiencing mechanical problems e.g. ESPs are susceptible to high levels of sand production and may show frequent failure. Gas lift is tolerant of sand production and will often be capable of drawing the well down sufficiently that production continues, although at a lower rate compared to when the pump is operational.

Increased volumetric efficiency - higher liquid volumes.
Decreased injection gas requirements compared to gas lift alone.
Increased reservoir drawdawn and production.
Increase pump installation depth - allows greater reservoir drawdown.
Reduction in pump and motor power requirements.
Lower electrical energy consumption compared to pump alone.
Gas lift provides backup in case of pump failure.

Table 5 Benefits of combining gas lift with a positive displacement artificial lift method e.g. ESP, PCP sucker rod etc.

This concludes a brief overview of the artificial lift types involving pumps. The remainder of this chapter will discuss the general considerations of the role and selection principles of Artificial Lift.

9. THE ROLE OF ARTIFICIAL LIFT IN FIELD DEVELOPMENT

Rod pumps are the most frequently used installation type of AL on-land, followed by gas lift and ESPs. Gas lift and ESPs are most popular offshore.
HPs, PCPs, and others share a few remaining percent of the installations.

However, by the volume of fluid pumped gas lift and ESPs lead the overall statistics since the rod pumps are often used in low-production wells.

Artificial lift is being widely applied in field development due to:

Field development state – Most fields are mature with the consequent reduction in the average well's flowing bottom hole pressure (depletion) and increasing water cut.

Pressure maintenance. The development plans for many of the early, giant, high productivity, fields employed early water injection to maintain the reservoir pressure above the hydrocarbon fluid's bubble point, which happened to be well above hydrostatic pressure. This means that the high water cut wells still continue to flow now.
Later fields with lower well productivities and lower reservoir pressures, that may also not have employed any form of pressure maintenance, required early installation of artificial lift.

Satellite or Subsea Wells. These wells are often positioned a considerable distance from the host platform. The extra pressure drop caused by flow through these long, subsea pipelines needs to be overcome by some form of pressure boosting. This could either be an increased pressure boost from e.g. an ESP installed downhole or by a multiphase pump mounted on the sea bed.

Business drivers. Profitable field development requires that the average well production rate exceeds a minimum value, with higher values being more profitable. Well design innovations can increase the well flow rate. These include: (1) drilling long (horizontal) wells that increase the exposure to the producing formation. (2) Installing large diameter tubing to decrease the frictional pressure losses allowing flow rates of over 76,000 bopd with a 9 5/8 in. production tubing. And (3) early installation of artificial lift to increase the flow rate above the natural flow value.

Marginal (possibly subsea) field development requires a minimum number of wells plus little or no need for well intervention to repair or modify the downhole installation. High equipment reliability is thus a "must". The reliability of artificial lift equipment has been increasing through: (1) Improved engineering design, (2) the ability to monitor downhole conditions from the surface. (3) Better materials selection and, most importantly, (4) better training of wellsite personnel who install and operate the equipment.

- *Feel free to discuss examples of the above drivers.*

Developments in the application of downhole electronics and measurement sensors allow downhole monitoring of the performance of the artificial lift equipment. The improved performance after implementation of a real time monitoring and control in artificial lift projects results in instantaneous production increase (lift conditions optimised and immediate alarm given when wells cease producing), reduction in well entries (earlier recognition of developing problems allowed preventive maintenance change in wells operating conditions etc.), reduction in energy consumption (wasteful "over-lifting" operating conditions recognised immediately).

Figure 37 presents the failure frequency of pumps in a field for wells which are using automated systems and non-automated wells. The general declining trend of the failure frequency is due to the technological developments (more reliable pumps) and experience in installation and operation (learning curve). Moreover, implementing automated systems using [Rod Pump Control (RPC) or Pump-off control] and [Variable Speed Drive (VSD) or Variable Frequency Drive (VFD)] increase the reliability and reduce the failure frequency.

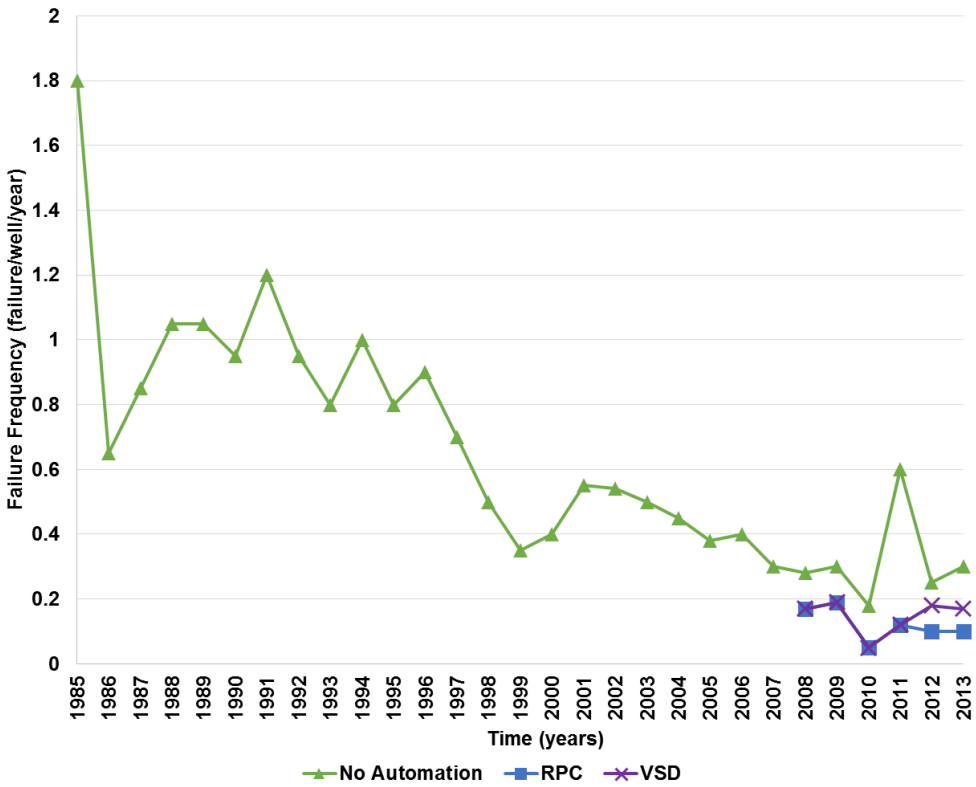

Figure 37 Failure frequency of beam pumps in a field in non-automated wells (No Automation) and wells using automated systems; Rod Pump Control (RPC) and Variable Speed Drive (VSD)

Integration of artificial lift software into field development planning and operation. The software tools to manage oil field operations and the design procedures for artificial lift techniques have improved tremendously. The field/production system models are more and more common. These contain models describing the performance of the reservoir, wells (including artificial lift), manifolds, facilities and pipelines. This integrated system has the ability to:

- Calibrate (or automatically history match) the various model elements against actual measured data.

- Compare the measured field data with the production plan or forecast.

- Optimise the production within any (permanent or temporary) production constraints. This may include control of the AL or well rates as well as identifying and correcting the system's bottlenecks e.g. insufficient capacity pipeline network or fluid processing elements. The optimisation can also be either short-term 'reactive' (e.g. looking after instantaneous increase in production rate) or long-term 'proactive' (e.g. trying to improve the overall field recovery or net present value) if the production forecast models (e.g. reservoir models) are in place.

- Recognise discrepancies between forecast and actual production. The identified wells/production systems are producing at a lower-than-expected rate and are listed for engineering investigation and possible remedial activities.

Building and operation of such a model requires input from geoscientists, production technologists, pipeline and process engineers as well as production operations staff. Obtaining consistent and accurate field production data has historically been a challenge. The advent of the Digital Oil Field (DOF) has resulted in the engineering staff located a large distance from the field having similar data to that available to the production operations staff that are managing the wells at the field location.

The availability of such integrated models allows the "total cost of ownership", or "total lifetime cost" of a particular form of artificial lift, to be evaluated when selecting the preferred artificial lift technique for a particular field development. For example, two or more lift methods may be technically capable of producing a well at the designated production rate. It is relatively easy to obtain figures for the initial, capital costs of installation. However, the (often) comparable long-term costs due to (un)reliability, energy consumption, maintenance, manpower etc. figures have to be obtained from field operational data.

- *Feel free to select an AL type and discuss what can be monitored, controlled and optimised in a field with a number of wells equipped with this AL type.*

10. ARTIFICIAL LIFT SELECTION CRITERIA

There are many factors that influence which is the preferred form of artificial lift in a given well/field. Some of the factors to be considered are:

10.1 Well and Reservoir Characteristics such as:

- Production casing size dictates the maximum size of production tubing and required (gross) production rates.

- (Legal) requirements for annular and tubing safety systems.

- Producing formation depth and deviation (including doglegs, both planned and unplanned).

- Nature of the produced fluids (gas fraction, sand/wax/asphaltene production, corrosivity, etc.).

- Well inflow characteristics. A "straight line" inflow performance relationship associated with a dead oil is more favourable than the curved "Vogel" relationship found when well inflow pressure falls below the fluid's bubble point pressure (Figure 38).

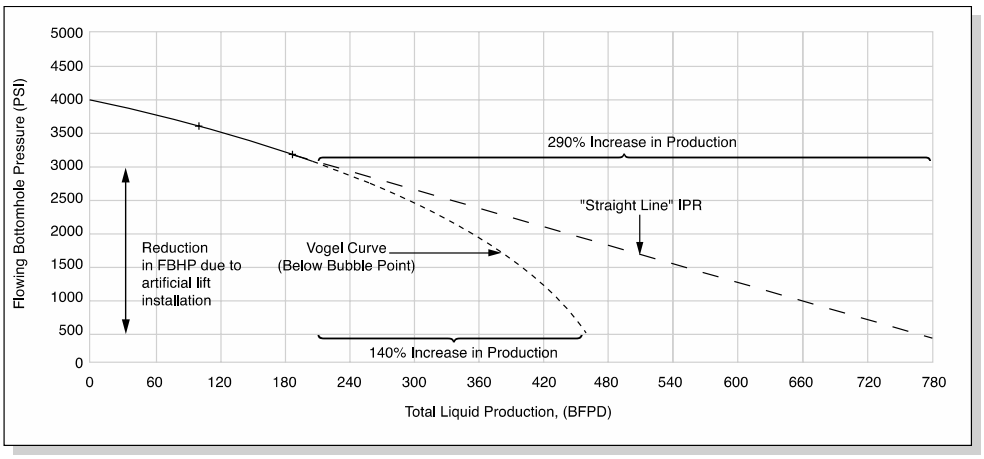

Figure 38 Influence of fluid inflow performance on the production increase achieved when well drawdown is increased. The linear IPR model predicted a 290% production increase for the design pump head, whereas the actual IPR appeared Vogel and resulted in a 140% increase.

10.2 Field Location

Offshore platform design dictates the maximum physical size and weight of artificial lift equipment that can be installed while the on-shore environment can also influence the artificial lift selection made. Different situations can lead to different artificial lift types being selected for wells of similar design and producing characteristics. For example, an urban location requires a minimum of visual and acoustic impact while climatic extremes e.g. arctic operations or a hot desert environment limit the practical choices.

10.3 Economics

A lot of attention is paid to the costs: both the initial capital investment required to install artificial lift as well as the operating costs which are often more important than the capital cost when a full life cycle economic analysis is carried out (Figure 39).

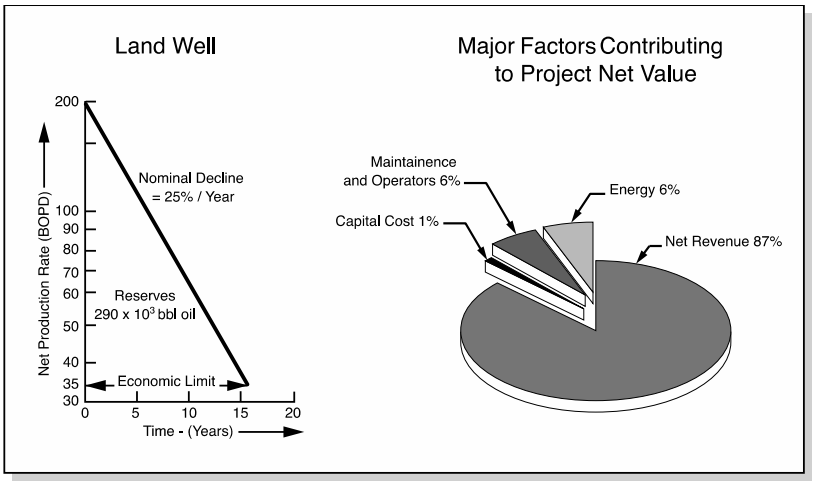

Figure 39 Example full life cycle economics includes maintenance and other operational costs as well as capital costs.

Good operating cost data for the different artificial lift methods in different locations is difficult to find. Reliability (including maintenance and operator costs) is one key issue while the second, Energy Efficiency (and hence energy costs) can be calculated from first principles. There is a wide variation – see Figure 40.

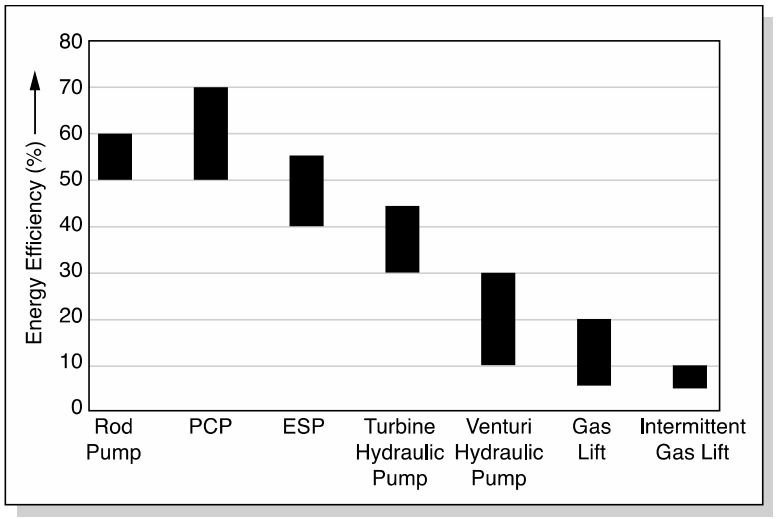

Figure 40 Comparison of the energy efficiency of the major artificial-lift methods

- Maintenance costs will vary between operating locations depending on the local, service company infrastructure. It can be costly in remote locations.
- The number of wells in the field with one particular form of artificial lift (economy of scale) will influence the operating costs.
- Similarly, the desirability and/or need for automation, how many operators are to be employed and the decision on whether to install centralised facilities also influences the operating costs.
- The speed with which the "learning curve" is climbed for the more sophisticated forms of artificial lift will depend on the selection of equipment with the correct specifications as well as the skill base and the training provided to the operations staff. This human experience factor is quite often the major factor defining the choice of AL type.

10.4 Implementation of Artificial lift Selection Techniques

To sum up, the artificial lift engineer is faced with matching facility constraints, artificial lift capabilities and the well productivity so that an efficient lift installation results. Frequently, the type of lift has already been determined and the engineer has the problem of applying that system to the particular well. A more fundamental question is how to determine the optimum type of artificial lift to apply in a given field.
There are certain environmental and geographical considerations that may be overriding. For example, sucker rod pumping may be by far the most widely used artificial lift method in the area. However, sucker rod pumping may not be a suitable form of artificial lift if production is required from the middle of a densely populated city or on an offshore platform with its limited deck area. There are also practical limitations - deep wells producing several thousands of barrels per day cannot be lifted by rod pumps. Likewise, there are many considerations that may need to be taken into account choosing the optimum type of artificial lift.

Some types of artificial lift are able to reduce the bottomhole producing pressure to a very low value, an important factor for depletion type oil fields. The characteristics of the reservoir fluids must also be considered. Wax & formation solids present greater difficulties to some forms of artificial lift than others. The producing gas-liquid ratio is another key parameter to be considered. Gas represents a significant problem to all the pumping methods; while gas lift utilizes the "free" energy contained in the produced gas and supplements it with injected gas.
The "Advantages and Disadvantages of the Major Artificial Lift Methods" are summarised and compared in Table 6 and Table 7.

Rod Pumps	Electric Submersible Pump	Venturi Hydraulic Pump	Gas Lift	Progressing Cavity Pump
Simple, basic design Unit easily changed Simple to operate Can achieve low BHFP Can lift high temperature, viscous oils Pump off control	Extermely high volume lift using up to1,000 kw motors Unobtrusive surface location Downhole telemetry available Tolerant high well deviation / doglegs Corrosion / scale treatments possible	High volumes Can use water as power fluid Remote power source Tolerant high well deviation / doglegs	Solids tolerant Large volumes in high PI wells Simple maintenance Unobtrusive surface location / remote power source Tolerant high well deviation / doglegs Tolerant high GOR reservoir fluids Wirleine maintenance	Solids and viscous crude tolerant Energy efficient Unobtrusive surface location with downhole motor

Table 6 Advantages of artificial lift methods compared.

Rod Pumps	Electric Submersible Pump	Venturi Hydraulic Pump	Gas Lift	Progressing Cavity Pump
Friction in crooked / holes Pump wear with solids production (sand, wax etc.) Free gas reduces pump efficiency Obtrusive in urban areas Downhole corrosion inhibition difficult Heavy equipment for offshore use	Not suitable for shallow, low volume wells Full workover required to change pump Cable susceptible to damage during installation with tubing Cable deteriorates at high temperatures Gas and solids intolerant Increased production casing size often required	High surface pressures Sensitive to change in surface flowline pressure Free gas reduces pump efficency Power oil systems hazardous High minimum FBHP. Abandonment pressure may not be reached	Lift gas may not be available Not suitable for viscous crude oil or emulsions Susceptible to gas freezing / hydrates at low temperatures High minimum FBHP. Abandonment pressure may not be reached Casing must withstand lift gas pressure	Elastomers swell in some crude oils Pump off control difficult Problems with rotating rods (windup and after spin) increase with depth

Table 7 Disadvantages of artificial lift methods compared

➢ *Feel free to review these pros and cons and relate them to the AL types' operating principles.*

10.5 Long Term Reservoir Performance and Facility Constraints

Another factor that needs to be considered is the long-term reservoir performance. Two approaches are frequently used to solve the problem of artificial lift selection and sizing; despite both of them having (different) disadvantages.

- The long-term reservoir performance is predicted and artificial lift equipment installed that is suitable for handling the well's production and producing conditions over its entire life. This frequently leads to the installation of oversized equipment in the anticipation of ultimately producing large quantities of water. As a result, the equipment may have operated at poor efficiency due to under-loading over the early portion of its total life.

- The other extreme is to design for today's well producing conditions and not to account for the future changes. This can lead to many replacements in the type of lift equipment installed during the well's producing life. Low-cost operation may result in the short term, but large sums of money will have to be spent later on to change the artificial lift equipment and/or the completion.

Likewise, in a new field development, the fluid handling requirement from some artificial lift types can significantly increase the size and cost of the facilities required. Only the produced fluid is handled through the facilities with rod pumps and ESPs. However, gas lift requires injection gas compression and distribution facilities; hence the extra circulating (lift) gas increases the size of the production facilities required.

The selection of the artificial lift for a particular well must meet the physical constraints of the well. Consideration should be given to the size of the well bore required to obtain the desired production rate once a particular type of lift is selected for use. The desired production may not be possible because the production casing was designed to minimize drilling cost, resulting in a size limitation on the artificial lift equipment that can be installed. Even if production rates can be achieved, smaller casing sizes can lead to higher, long term production costs due to well servicing problems, gas separation problems etc.

Figure 41 is a screening selection tool in which areas where particular artificial lift methods have been frequently applied are compared as a function of depth and well rate. It must be realised that there are many proven applications where a particular form of artificial lift has been installed in a well at greater depths or produced at higher rates than is indicated in this figure.

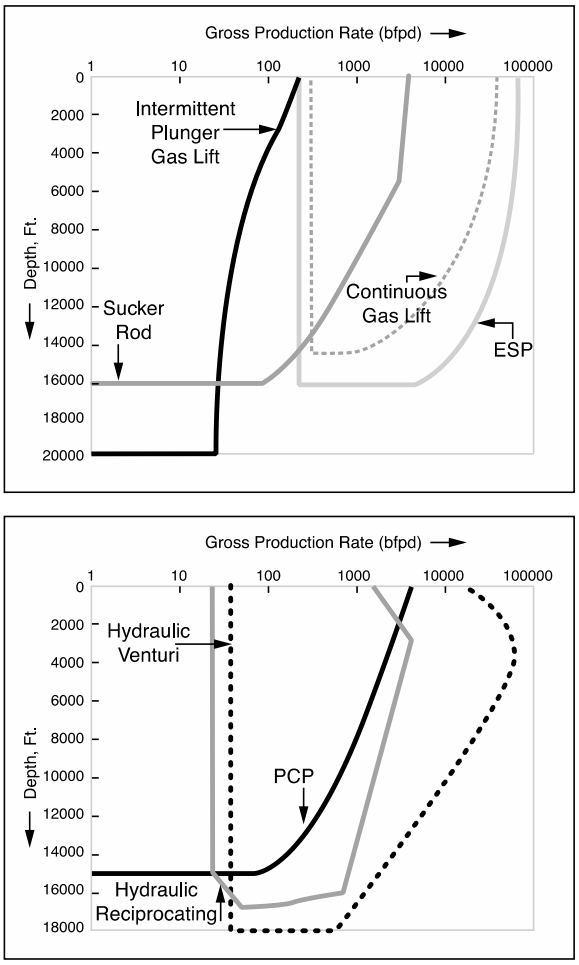

Figure 41 Typical application areas of artificial lift techniques

Remember: the correct way to design a well is to obtain an estimate of the expected production rates at various times in the field's life (from the Reservoir Engineer). The required size of the production tubing is estimated to allow these volumes of fluid to be produced.

- *Feel free to attempt Tutorials 4-8*

11. RECOMMENDED READING

1. "Well Completion and Servicing" by D. Perrin, Editions Technip, Paris, 1999
2. "Well Completion Design" by Bellarby, J., Elsevier, 2009
3. "Petroleum Production Engineering", 2nd Edition, by Guo, B., Liu, X., and Tan, X. Gulf Professional Publishing, 2017
4. "Petroleum Engineering Handbook for the Practicing Engineer", Volume 2 by Mian M. A.; PennWell Books, 1992.
5. "Progressing Cavity Pumps", by Cholet C., Edition Technip, 1997
6. "The Technology of Artificial Lift Methods", Volumes 1-4, by Brown, K.E., PenWell, 1980
7. "Well Performance" 2nd edition by Golan M. & Whitson C.; NTNU,1996.
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CHAPTER 5: GAS LIFT

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LEARNING OBJECTIVES

(All Examinable)

- Describe the gas lift process
- Explain the impact of the key gas lift process variables
- Identify and describe application areas/advantages for gas lift.
- Discuss the limitations of the gas lift process
- Describe the well unloading process
- Identify and explain the action of gas lift hardware components
- Design a gas lift completion
- Identify reasons why efficient gas lift depends on availability of high quality data
- Describe gas lift problems and the ways to monitor and rectify them
- Construct a methodology for revenue optimisation with limited gas availability
- Describe the intermittent gas lift and plunger lift processes

1. INTRODUCTION

Chapter 4 introduced the concept of mechanistic, or pump-assisted artificial lift. The only other major type of lift is gas lift, the subject of this chapter. The objective of installing gas lift in a completion is to increase the drawdown on the producing formation by improving the tubing flow performance. For this, gas is injected via the casing-tubing annulus into the lower part of the tubing string where it mixes with the production fluid (and the mixture further flows up the tubing) consequently a) reducing the flowing gradient in the production string as well as b) adding more lift energy due to gas expansion.

- *Feel free to revisit the GLR calculation tutorials in Chapter 3. Select a tutorial problem and find the required GLR for several rates. Plot the GLR vs. oil rate and notice there is an optimal GLR. Discuss this result.*

We will first introduce the basics of gas lift and discuss its advantages and disadvantages. The design, operation and maintenance of the gas lift valves, which control the gas injection from the annulus into the tubing, will then be described. Typical gas lift operational problems and their solutions will then be discussed, and the need for optimisation of gas lift reviewed.

2. INTRODUCTION TO GAS LIFT

A continuous flow, gas lifted well completion has been sketched in Figure 1.

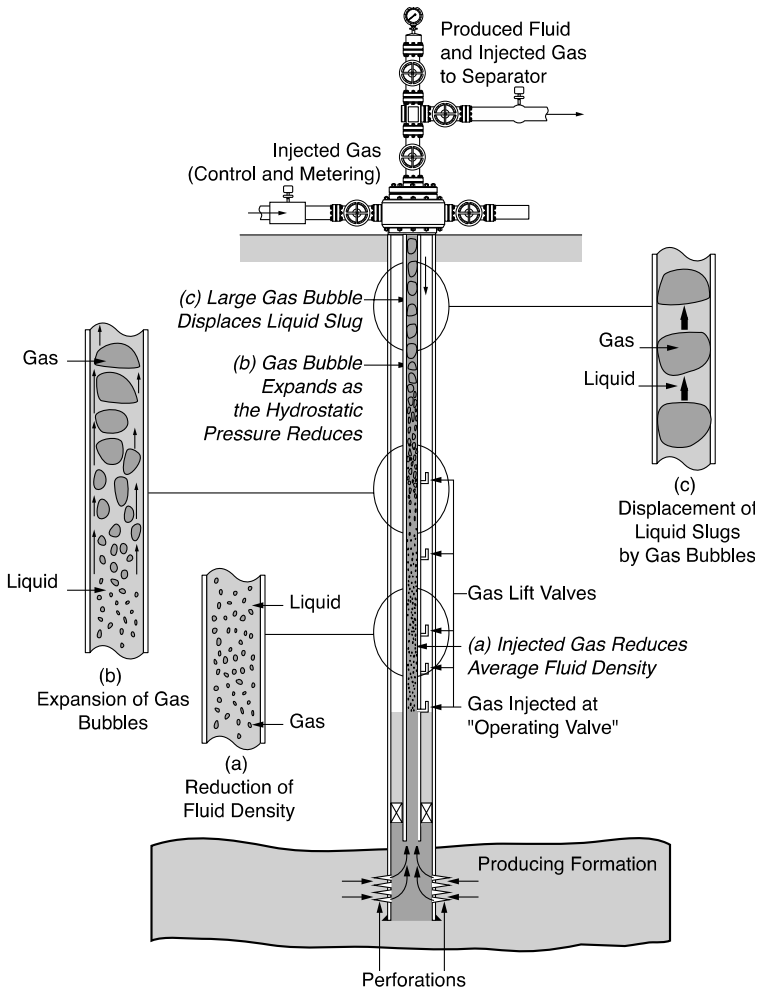


Figure 1 A Gas-lifted Well Completion

The completion differs from the natural flow completions in that:

- Gas, at a controlled volume and pressure, is injected into the tubing/casing annulus.
- The tubing string can be fitted with a number of gas lift valves. These valves are installed at carefully spaced intervals so that any liquid present above them in the casing/tubing annulus (e.g. due to killing of the well) can be removed by injection of gas at the top of the well annulus leading to the liquid U-tubing into the tubing and its subsequent ejection from the well. The gas injection point into the tubing is then transferred to successively deeper gas lift valves. This process, called 'unloading', happens when the well production needs to be kicked-off. Otherwise, the unloading valves are closed, and
- The gas is injected into the tubing through the "operating valve" (a.k.a. the master gas lift valve). This valve normally is an orifice and is always open. The injected gas enables the well to flow by:
  - Reducing the average fluid density above the injection point.
  - Partially dissolving into in the produced fluids, providing they are undersaturated with respect to the gas solubility. The undissolved gas, in the form of bubbles, will expand due to reductions in the hydrostatic pressure as the fluids rise up the tubing.

The coalescence of these gas bubbles into larger bubbles progressively expanding and occupying the full width of the tubing will most often turn into slug flow. *(This also means that the slug flow –suitable correlations like the one by Hagedorn and Brown are often used in gas lift calculations).*

The design of a gas lift completion thus consists of two separate distinct parts:

- During the unloading process: Choice of the installation depth, type and design of the unloading gas lift valves placed above the operating valve so that any liquid in the tubing and casing/tubing annulus can be unloaded via the wellhead.
- During the continuous (steady-state) gas lift operation: Optimisation of the flowing gas lifted well. The well essentially behaves as a conventional flowing well, except that the gas/liquid ratio (GLR) changes at the operating valve depth. In general, the deeper this valve is installed the better, though it will be shown that its deepest location is not that easy to find given there are other constraints. As for GLR – there is an optimum one (neither too big nor too small) for a given setup.

Intermittent gas lift is very different and is discussed separately, later in this chapter.

As far as the continuous gas lift is concerned (where the lift gas is injected into the operating valve continuously) the calculations for a given valve location are relatively straightforward:

The wellbore opposite the perforations (or alternatively the openhole production interval) is treated as the node pressure when the system is analysed using the "nodal analysis" process discussed earlier in this course. The pressure at the node, at any given flow rate, can be calculated from:

Inflow to Node (the perforations):

$$P_{reservoir} - P_{drawdown} = P_{perforations}$$

Outflow from Node (the perforations):

$$P_{separator} + \Delta P_{flowline} + \Delta P_{choke} + \Delta P_{tubing\ above\ operating\ valve} + \Delta P_{tubing\ below\ operating\ valve} = P_{perforations}$$

The pressure drop across the tubing below the gas injection valve is estimated using multiphase flow correlations or pressure traverse curves using the natural gas liquid ratio describing the reservoir fluid. The pressure drop between the gas injection valve and the surface is calculated using the "enhanced" gas liquid ratio calculated from the sum of the {lift + produced} gas rate divided by the liquid production rate.

Figure 2 illustrates a pressure traverse down the well when it has reached steady state operation. The gas is being injected at the wellhead at the pressure of 1100 psi. The pressure of the gas in the annulus increases with depth mainly due to its density. The gas is initially being injected at the valve 4 at 3800 ft. The well is producing with a 500 psi drawdown. The flowing pressure gradient from the producing perforations to the operating gas lift valve is equal to 0.44 psi/ft. There is a 250 psi pressure drop across the gas lift valve and the average fluid gradient above the injection valve has been reduced to 0.27 psi/ft by the injected gas. The situation for deeper gas injection is also sketched in which the gas is being injected through valve 7 at 5000 ft. The gas lift pressure is now just sufficient to allow injection to occur if the pressure drop across the gas lift valve is restricted to 50 psi.

It can be seen that the deeper injection allows the drawdown to increase to 850 psi.

It can also be seen that the pressure drop across the operating valve makes some difference. The conventional operating valves with a square orifice will show pressure drops of around 50-200 psi. Some modifications operate at a lower pressure difference.

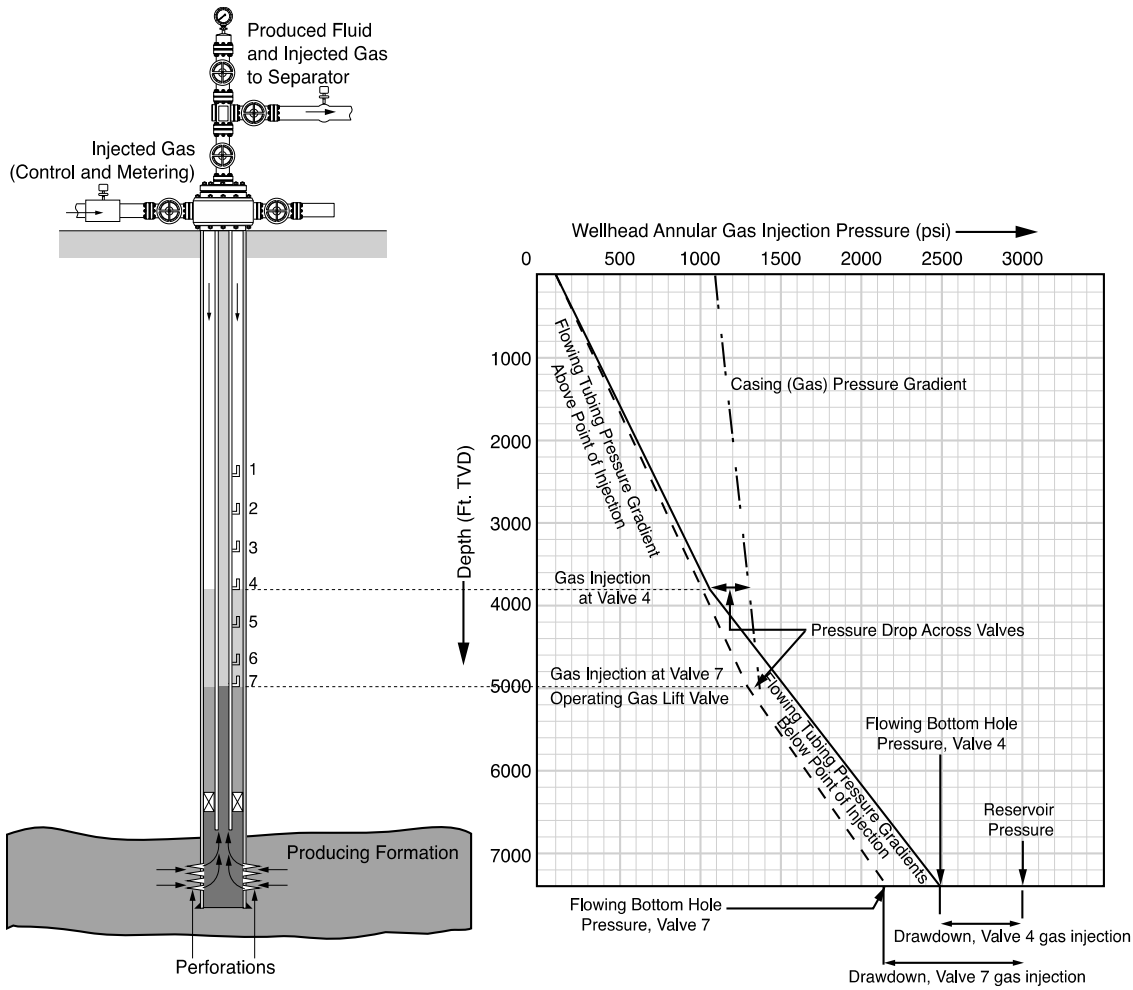


Figure 2 Pressure Traverse of a Gas-Lifted Well

It can be appreciated from this diagram that the gas injection pressure is the main control on the depth of gas injection (the higher the gas injection pressure the deeper the valve this gas can reach) while the gas injection rate also contributes to the extent of the reduction in the flowing pressure gradient (the closer it brings the mixture's GLR to optimal the steeper its gradient is). These parameters can be adjusted as required on a day-to-day basis.

The pressure settings of the unloading gas lift valves (which control the pressure levels at which these valves open and close during unloading) can be adjusted when required using wireline techniques. This is because the gas lift valves are normally set in the preinstalled Side Pocket Mandrels: as explained earlier in this course it is possible to change the valves without the need to retrieve tubing. The depths at which the valves are set however (i.e. the SPMs' setting depths) can only be altered by pulling the tubing and recompleting the well. That's why more than initially needed, 'bracketing envelope' SPMs with dummy valves are normally preinstalled in the tubing string. When a valve needs to change location this can be done by wireline to a vacant SPM.

This reliability and control flexibility explains why gas lift is popular offshore, in particular for subsea wells.

As far as the optimum GLR is concerned: increases in the gas injection rate through a gas lift valve set at a given depth will increase the fluid production rate until a maximum is reached (Figure 3). At this point the "reduction in the average fluid density in the tubing due to a slight increase in the gas injection rate" is being exactly counterbalanced by the "increased frictional pressure losses due to the greater mass of fluid flowing in the tubing". This is the "technical optimum gas injection rate" at which the well liquid production rate is maximised. Further increases in the gas flow rate will result in the friction term increasing relatively faster than the hydrostatic head reduction term.

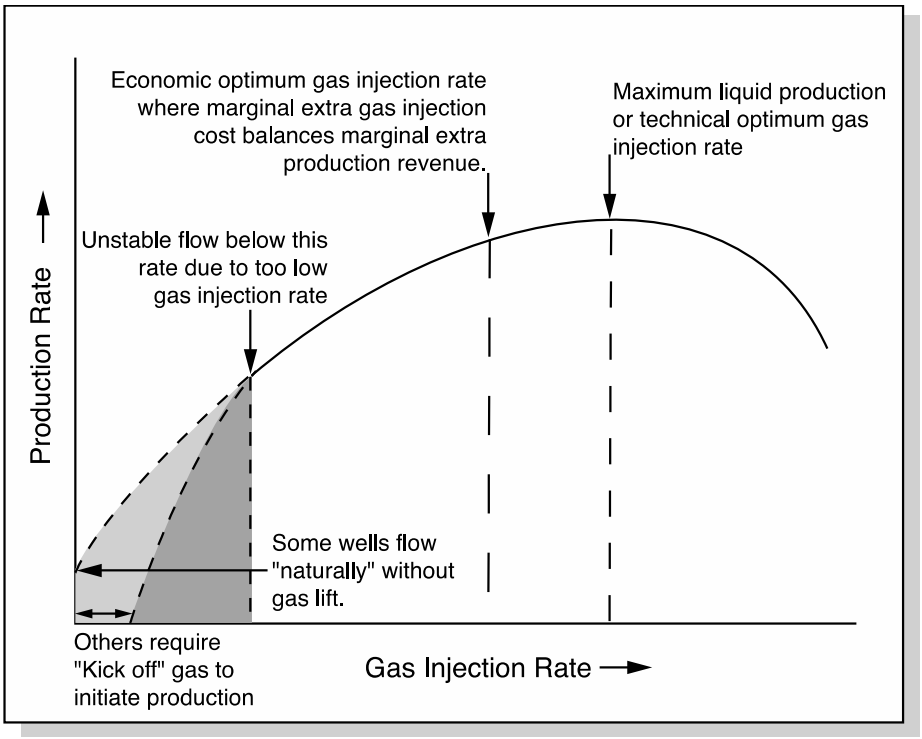


Figure 3 Effect of gas rate on well production rate

"The maximum economic gas injection rate" will be somewhat lower – this is the gas injection rate at which the marginal cost of providing extra injection gas is equal to the marginal revenue from the extra well production.

Figure 3 also illustrates that gas lift may be applied to increase the production from wells which will flow naturally at a low(er) rate. The second case illustrated is for a well which is "dead" and does not produce without some form of artificial lift. Gas then has to be injected at a certain rate ("kick-off" gas) before any well production is possible.

An efficient gas lift system depends on a continuous supply of gas at the specified pressure. A considerable infrastructure is required for gas lift. This is normally only installed when there are a number of wells in the area using gas lift as the preferred form of artificial lift, in which case the lift cost per well is fairly low. (Naturally, it's also important to ensure the gas supply is reliable). And vice versa: in small developments gas lift is often less attractive economically. A typical gas lift system arrangement is shown in Figure 4. This figure shows several wells producing into a production manifold. The gas is then separated, compressed and dried in a dehydration unit (because if wet gas is used this may cause corrosion and/or hydrates forming). Any excess gas may be sold or, when instead there is shortage of gas, some make up gas can be imported, as required by the demands of the gas lift system. The lift gas is supplied to the gas lift manifold, after which the injection gas flow rate and casing head pressure are adjusted using gas injection chokes before injection into individual wells.

Figure 4 is a closed-circuit system where part of the produced gas is re-used for gas lift. In this case the gas lift injection optimisation is a complex process to iterate between various gas injection pressures, rates, and operating valve depths in wells to come up with the economic optimum.

In an open-circuit system, where lift gas is supplied externally (e.g. from a nearby gas field), the gas injection pressure is often defined and the gas supply may be less limited, in which case the optimisation comes down to finding the optimum valve depth and injection rate for each well.

Either way, the optimisation problem of gas lift allocation (i.e. how much gas should each well receive provided the total gas lift rate is limited) to maximise profit in developments with many wells is often a challenge.

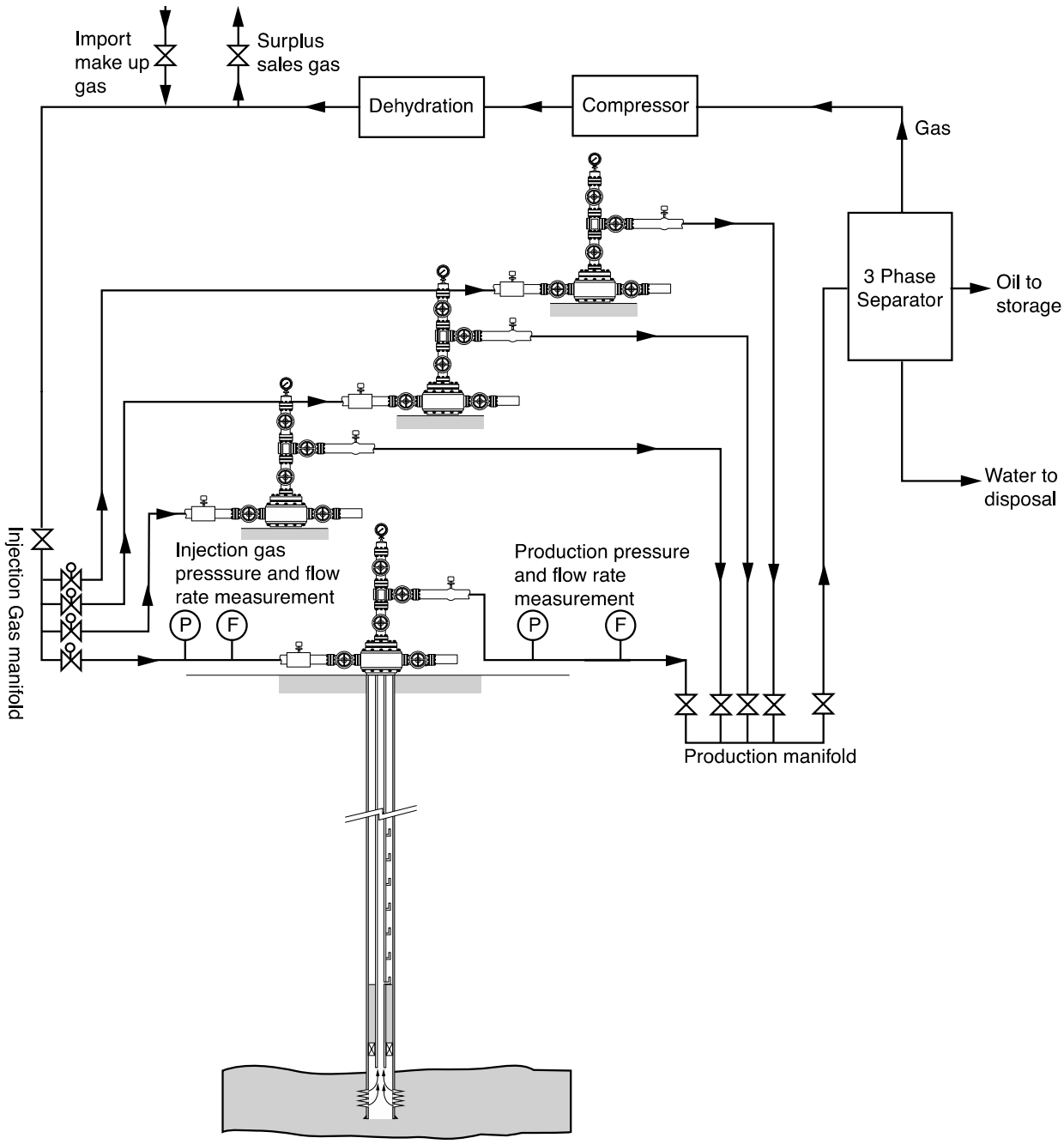


Figure 4 Gas lift system

The injection lines are also often equipped with gas injection meters (often the orifice (plate) gas meters where the gas pressure drop across a sharp-edge orifice cut in a thin plate is used to estimate the gas flowrate).

The metering and control equipment for a gas lifted well that is being individually tested is illustrated in Figure 5. Both manual and automatic lift gas control options are illustrated.

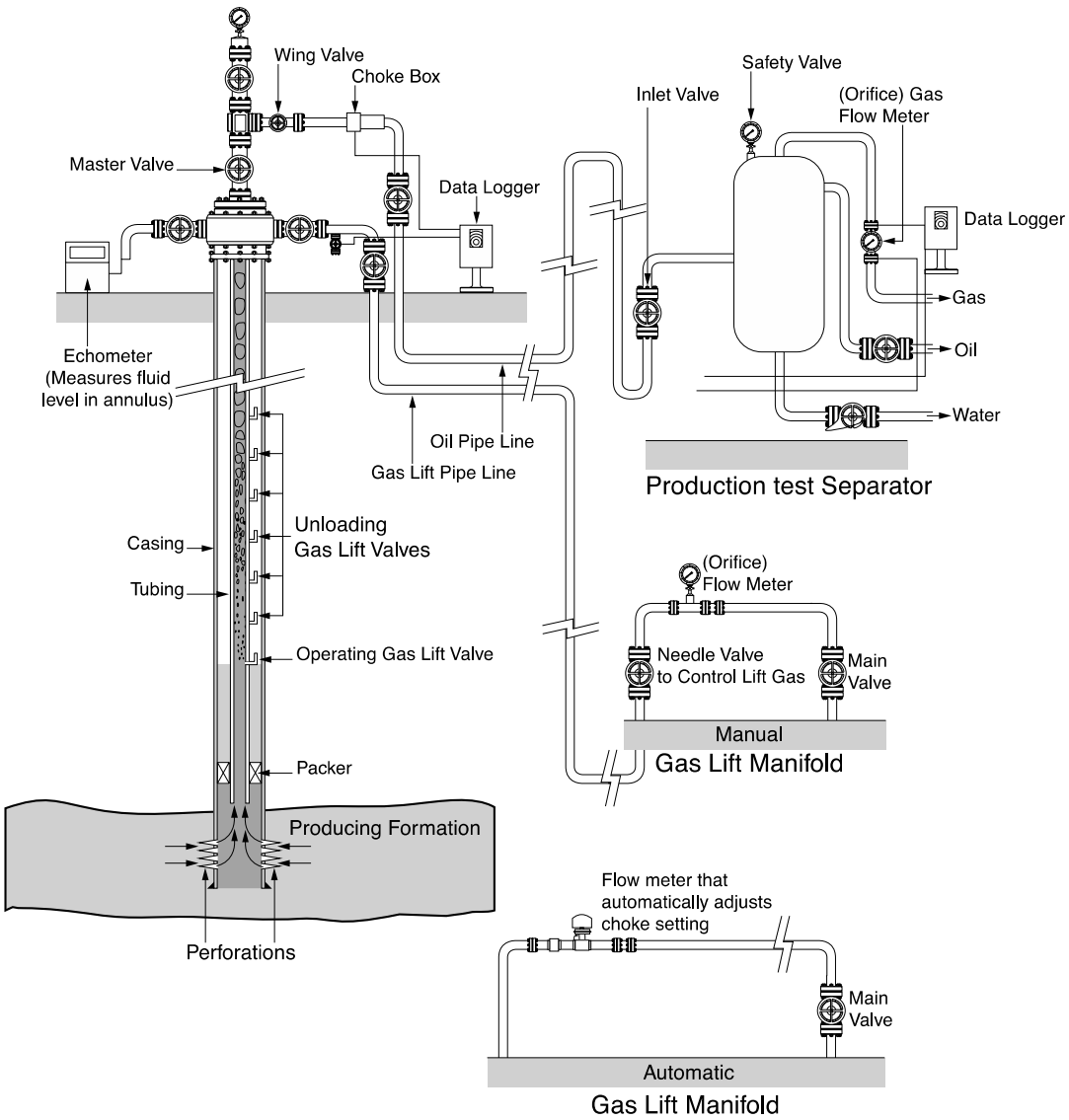


Figure 5 Metering and control of a gas lifted well

➢ *Discuss the tools used for monitoring and control in Figure 5.*

3. GAS LIFT APPLICATIONS

Continuous vs. Intermittent Gas Lift:

The other thing to notice in Figure 2 is that the minimum achievable bottomhole pressure with continuous gas lift is limited. Unlike the pump-assisted lift, gas lift cannot reduce this pressure to a low value.

Thus, continuous flow gas lift is normally applied in high PI (>0.5 b/d/psi), relatively high reservoir pressure wells. The former condition can be explained using Figure 3 - note there is an unstable flow region at low rates, hence high PI is needed. (The latter condition, by the way, often means the GL-assisted developments also employ waterflood for reservoir pressure maintenance.)

If the reservoir pressure is low, "intermittent gas lift" is an option (for both high and low PI wells). It is less efficient than the continuous one, but can be used in low rate production wells and is one of the few methods that can be used in high PI, low P_R wells. This approach involves switching off the injection gas at regular intervals using 'intermitter' at surface so as to allow the fluid level in the well to build up. The gas injection is recommenced when a sufficient depth of produced fluid is present in the well, and the fluid in the tubing is lifted to surface. The cycle is then repeated. Intermittent gas lift is thus used for the cases where the outflow capacity of the gas lifted tubing is greater than the formation's capacity to produce fluid into the well.

Wells originally assisted by continuous gas lift are often converted to intermittent gas lift-assisted ones when/if the reservoir pressure depletes.

The section on multiphase flow in vertical tubing explained earlier in this course how the flowing gas slug will by-pass some of the liquid in the tubing (the slip phenomenon). This liquid will fall back down the wellbore each time the gas lift is switched off. Fall back can be avoided by installing a free plunger at the bottom of the well (Figure 6e). Gas injection now occurs underneath this plunger, which rises upwards, displacing the liquid above it to the surface. The plunger falls to the bottom of the well when the gas is switched off. The downhole completion is designed so that inflowing fluid can collect above the plunger while a check valve ensures that the injected gas cannot be injected into the formation. The cycle can now be repeated at a regular time interval. This interval will depend on the well productivity and the volume of liquid displaced to the surface by the plunger. Both Intermittent Gas Lift IGL and Plunger Assisted Intermittent Lift PAIL are described in greater detail later.

(In some cases plunger lift may not need to use gas lift at all. Opening the well regularly may be enough if the wellbore pressure build up is sufficient to lift the plunger with the liquid on top.)

Implementation Criteria of Continuous GL:

Gas lift has been applied to a wide range of production scenarios – as can be seen from Table 1.

1	Production wells which will not flow naturally.
2	Increase production rate in flowing wells.
3	Unload liquid from wells that will flow naturally once on production.
4	Unload liquid in wet gas wells which would otherwise cease to flow.
5	Back flow injection wells.
6	Lift aquifer (water) wells.

Table 1 Continuous flow gas lift applications

In fact, gas lift is the only artificial lift method that actually works better in a well that is producing at a significant gas/liquid ratio. Gas lift is often the preferred artificial lift method for wells with a:

- High gas-oil ratio produced fluid.
- High reservoir inflow productivity index;
- (Relatively) high bottom hole pressure due to reservoir pressure support being provided by a natural or artificial water drive.

The key point of gas lift is that a reliable, adequate (in terms of pressure and flow rate) gas supply has to be **available at all times.** When the field/wells are operating normally the (lift) gas system will be fully charged with gas. This gas will be recovered and recirculated many times. Extra volumes of "make-up" gas associated with the current oil production will only be required to replace any losses from the system, as well as any gas used for compression or other power requirements. When planning a gas lift installation for a field one should specifically allow for the:

- Decrease in (fresh or make-up) gas supply as the field reserves are depleted and the well water cut increases. This can result in gas being imported during the late project life. This is particularly true for offshore developments when the produced gas is also used to generate the platform's electrical power.
- If none of the wells flow naturally. An external gas source is then required to bring the (first) well(s) onto production after a facility shutdown and depressurisation of the gas lift system. (Vaporised, liquid) Nitrogen can be used for this purpose if there is no provision to import natural gas.
- It will take a long time to return all the wells to production after a shutdown if only a low-rate gas supply is available.
- Choice of lift gas injection pressure has to be made at an early stage in the project lifetime when the gas compressor is specified. There is often little information available about the actual well performance at this time.

3.1 Gas Lift Advantages and Limitations

These are summarised in Table 2 and Table 3. They are self-explanatory if read in conjunction with the above discussion.

Operation of gas lift valves is unaffected by produced solids (sand etc.)
Gas lift operation is unaffected by deviated or crooked holes.
Use of side pocket mandrels allows easy wireline replacements of (inexpensive) gas lift valves when deviation <65°.
Provides full bore tubing access for coiled tubing or other well service work.
High gas oil ratio improves lift performance rather than presenting problems as with other artificial lift methods.
Flexible - can produce from a wide range depths & flow rates - uses the same well equipment from 100-10,000bpd production rates - copes with uncertainties and changes in reservoir performance, reservoir pressure, water cut & production index over the well life.
Low surface profile important for offshore & urban locations.
Tubing & annular subsurface safety valves available when required by safety regulations.
Gas lift tolerates "bad" design - though "good" design is more difficult.
Gas lift has a low initial (downhole) equipment cost.
Gas lift has a low operational and maintenance costs. Major workovers are infrequent when wireline servicing is possible.
Well completions are relatively simple. This can be important in remote areas.
Gas lift operation independent of bottom hole temperature.

Table 2 Gas lift advantages

High tubing intake pressure due to fluid in the tubing restricts production. - e.g. Gas lifting a well with a Productivity Index of 1 bpd/psi from 10,000 ft with a static bottom hole pressure of 1000 psi is difficult.
Flowing bottom hole pressure is greater than with e.g. Electric Submersible Pumps. This leads to a potential loss of reserves in depletion type reservoirs.
Gas lift is inefficient in energy terms (typically 15-20%).
Gas compressors have a high capital cost. They require expensive maintenance & require skilled operations staff. However, they may already be required for gas sales.
Annulus full of high pressure gas represents a safety hazard.
High installation cost can result from top sides modifications to existing platforms e.g. Compressor installation.
Adequate gas supply required throughout project life - Decreasing BHP, increasing water cut etc. - Sufficient gas to start up FIRST well - Slow start up after facility shut down - Increased gas handling requirements in facilities.
Gas lifting of viscous crude (<15°API) is even less efficient.
Wax precipitation problems may increase due to cooling from (cold) gas injection & subsequent expansion.
Hydrate blocking of surface gas injection lines can occur during cold weather if gas is not adequately dried.
Lifting of low fluid volumes is inefficient due to gas slippage.
Good data management and complete production/gas lift network modelling is required for efficient/maximum profitability operation.

Table 3 Gas lift limitations

➢ *Feel free to review the advantages and disadvantages in the tables and explain them.*

3.2 Some Examples of Gas Lift Completion Designs

Figure 6 shows types of completion designs for gas lifted wells.

➢ *Feel free to explain the design solutions in Figure 6a-f*

Each completion is discussed in turn below:

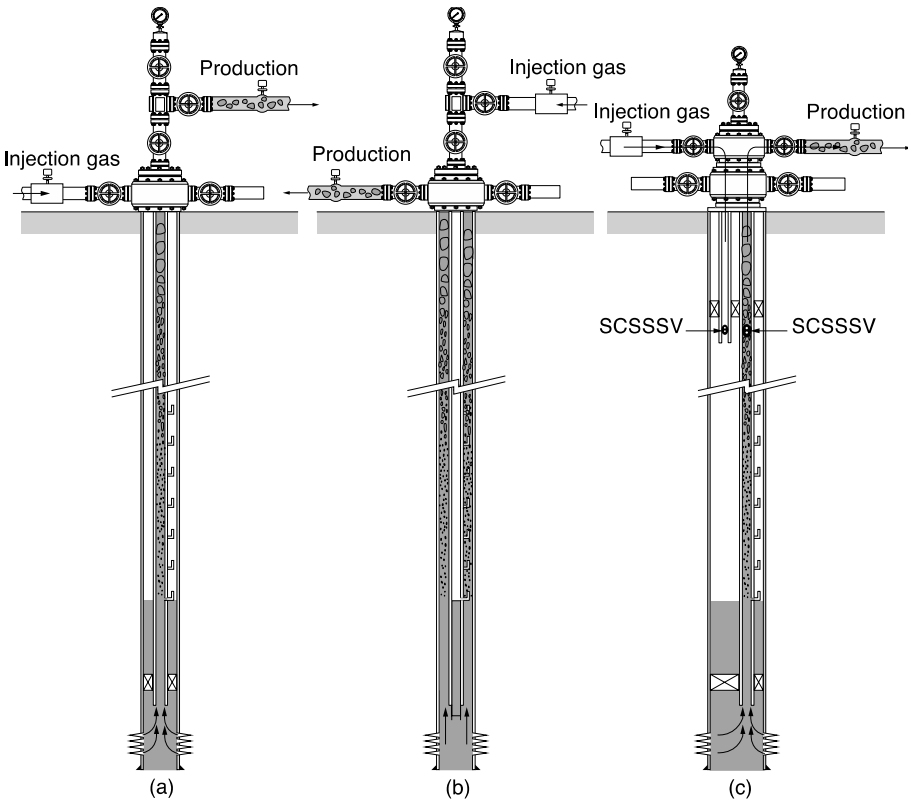


Figure 6 ***(a) to (c)*** Gas lift completions designs

Figure 6 **(a) Single String Continuous Gas Lift Completion**

This is the standard completion design, most commonly used. Gas is injected in the annulus (a.k.a. 'direct GL' as opposed to injection via tubing: 'reverse GL') and the produced fluids are lifted to the surface through the tubing. The well may be completed on a single or on multiple formation zones. In the latter case, the separate zones may be:

- Produced together (commingled) or
- Isolated from one another by packers. The required zone can then be produced selectively by opening and closing the appropriate sliding side doors.

Note that the packer isolates the high-pressure gas -filled annulus from the tubing ('semi-closed' system). In addition, a check (standing) valve can be installed at the lower end of the tubing ('closed' system) allowing only upward flow. This valve may e.g. help when unloading the well so that no kill fluid is squeezed into formation at the beginning of unloading.

Some other, less common installations include:

Figure 6 **(b) Annular Flow Gas Lift Completion**

The gas is injected down the tubing and the production flows up the annulus (reverse GL). There is a check valve at the tubing end.

Higher production rates are achieved compared to the conventional production configuration where the produced fluid flows up the tubing. This is due to the reduced (frictional) pressure drop in the annulus compared to the tubing due to the annulus's larger flow area. The disadvantages are that corrosion of the casing by the produced fluids will lead to a loss in well integrity. Also, a decline in the well production rate will lead to severe slugging earlier than for tubing flow because the annular cross-section is larger and therefore excessive slip occurs at lower rates.

Figure 6 **(c) Continuous Gas Lift without the surface section of the Casing/Tubing Annulus being Live (i.e. filled with high-pressure gas)**

This completion features the gas being injected into a separate injection string with its own Surface Controlled Sub Surface Safety Valve (SCSSSV) installed below a dual packer. The gas is then injected into a single tubing designed for conventional, continuous gas lift. This type of well design offers higher safety minimising the volume of high-pressure gas exposed to the wellhead in the case of system shutdown. It has been installed offshore.

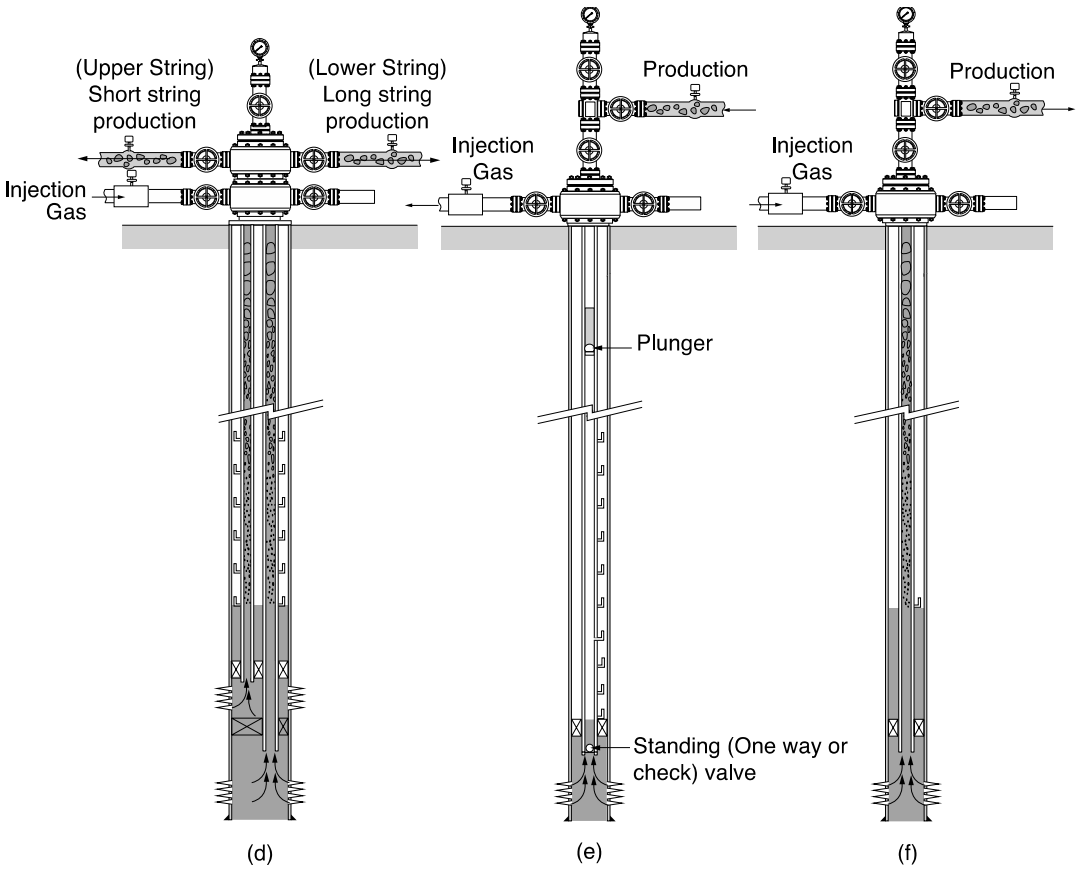


Figure 6 ***(d) to (f)*** Gas lift completions designs

Figure 6 **(d) Dual, Gas Lifted Completion**

This completion allows two zones to be independently produced by gas lift through separate production strings. It may be difficult to achieve optimum lift on both strings since the gas lift valves on the different strings may interfere with each other (e.g. one tubing may start 'stealing' the other's gas from the shared annulus).

Figure 6 **(e) Intermittent, Plunger Lift**

This is installed in low-rate wells where the inflow rate from the formation is smaller than the outflow capacity of the gas-lifted tubing. The plunger partly prevents fallback of the liquid.

Figure 6 **(f) Single Valve (Subsea) Completion**

This completion is used when intervention (change of gas lift valve settings etc.) is difficult and/or expensive. The single (orifice) operating valve minimises operational problems. However:

- The depth of lift gas injection is restricted since unloading valves are not used.
- This injection depth is often maximised by increasing the gas injection pressure above the normal 1,000 - 1,200 psi. A compressor capable of delivering gas at such a higher pressure can only be provided at a substantial extra cost. Temporary, 'kick-off' compressors (often mobile) with pressures over 3,000 psi have been used during the unloading process so that a substantially greater depth of injection can be achieved. Once gas lift has been initiated and the well is flowing steadily, lower (or conventional) lift gas injection pressures can be applied.

Gas lift can also be retrofitted concentrically, either temporarily or permanently, in the tubing using coiled tubing or 'macaroni' or 'capillary' (i.e. small size) pipes. For instance:

3.3 Coiled Tubing Gas Lift Completion Examples

Coiled Tubing based Gas Lift Completions can incorporate gas lift valves and mandrels as an integral part of a coiled tubing string. These can be employed in two manners:

- To replace the conventional production tubing (Figure 7). This particular completion was designed to test an exploration or appraisal well.

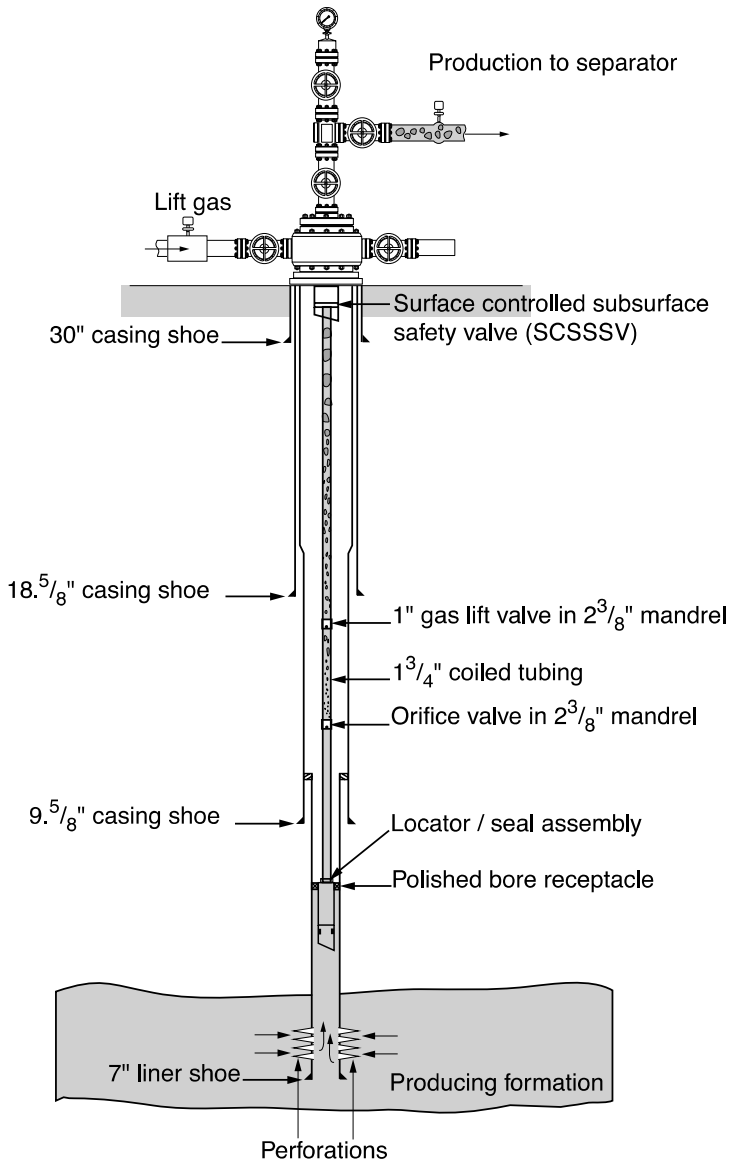


Figure 7 Gas lift completion where coiled tubing has replaced the tubing string.

- As a second production string within an existing tubing (Figure 8). This allows gas lift to be introduced to aid well production without having to mobilise a drilling rig to recomplete the well. This does however require that a polished bore receptacle, into which the coiled tubing seal assembly can be located, is included in the original tubing string. The advantage of this approach is that it is probably the cheapest methods of installing gas lift in a well where the casing integrity has been lost.

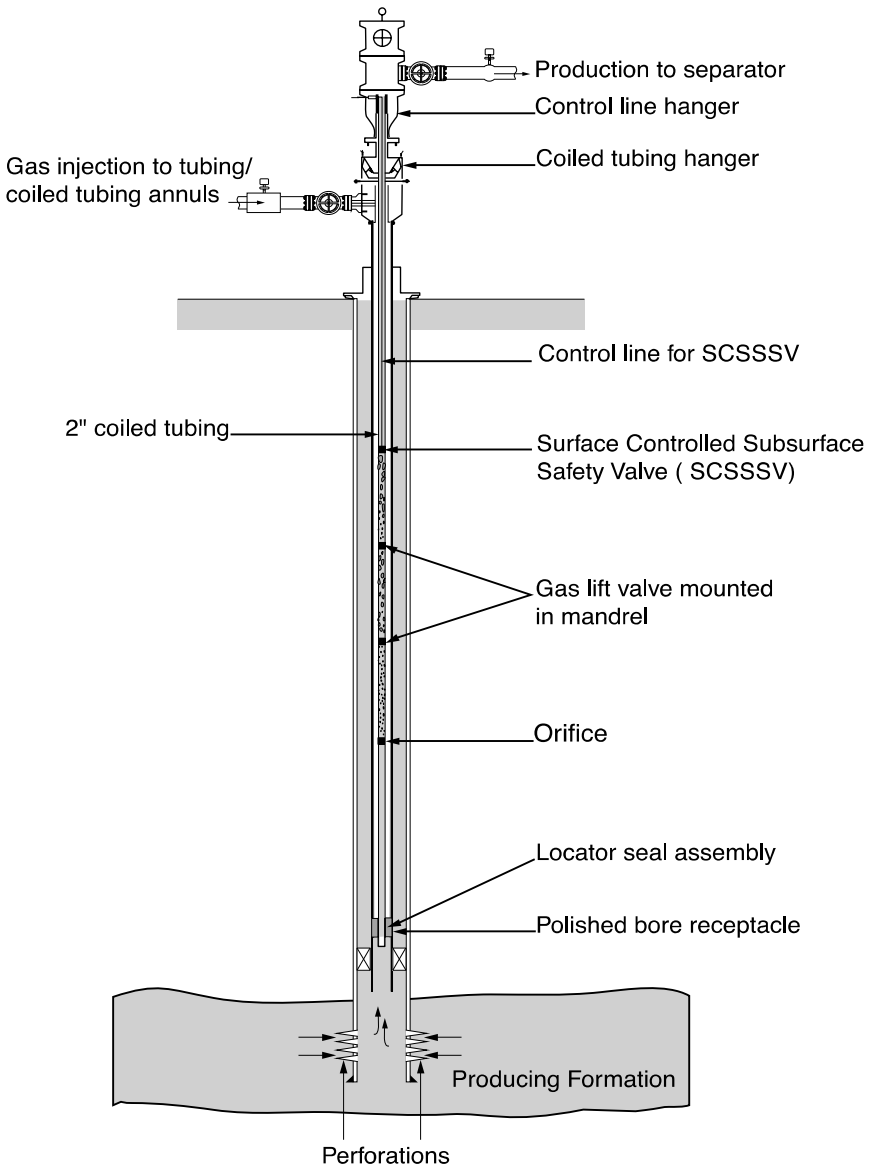


Figure 8 A coiled tubing inner production string.

- Alternatively, the orifice valve can be omitted with the coiled tubing suspended from its hanger – the gas injection taking place via the coiled tubing's open end.

3.4 Auto Gas Lift

In some development there is an option to use gas from a gas layer as lift gas, instead of injecting it from surface. In this 'auto gas lift' case the gas layer is normally completed as a separate zone and the gas from it enters the tubing via an operating valve or a flow control device (in smart wells).

4. GAS LIFT DESIGN CONSIDERATIONS

4.1 Gas Lift Design Objectives

The gas lift system designed for installation in a specific well should meet the following objectives:

Maximise the (net) value of oil produced. This normally implies that the:

- Operating valve, through which the gas will be continuously injected, should be situated as deep as possible and
- Gas injection rate should equal the economic limit at which the marginal value of the extra oil produced equals the marginal cost of providing this extra gas (Figure 3).

As mentioned, further optimisation is required when more than one well is being produced and there is insufficient lift gas available to meet these economic criteria in all wells.

Maximise design flexibility. The gas lift design should be capable of coping with the expected changes in the well producing conditions during its lifetime, as well as the "unplanned" uncertainties in reservoir properties and performance. These changes normally involve a deterioration, from a well productivity point of view, due to a decrease in the Reservoir Pressure or the Well Productivity Index or an increase in the Water Cut. Extra SPMs (Side Pocket Mandrels) providing optional valve depths can help with adjusting the gas lift to such changes.

Minimise well intervention. This is particularly important in subsea or other wells where wireline access is difficult or impossible.

Well completions with a "dry" tree and deviations less than 60° allow the option to replace the gas lift valve by a wireline when required. The operating parameters (or valve performance) of the gas lift valves installed in the side pocket mandrels can thus be easily (and cheaply) adjusted at any time in the well's life i.e. the tubing production conditions can be adapted to take into account changes in the reservoir conditions and the well performance. These operating parameters include the:

- Tubing or casing pressures (depending on the type of side pocket mandrel installed) at which gas flow through the gas lift valve starts and stops and
- Port (or choke) size, which controls the maximum volume of gas that can be injected as well as the associated pressure drop due to the gas flow through the valve.

As mentioned, the flexibility of a particular gas lift design is further increased by installing extra SPMs to potentially host gas lift valves both above and below the operating valve. They should be placed as close together as possible, but sufficiently far apart that they do not interfere with each other's operation (typically 450-500 ft or 150 m vertical depth apart is recommended). This is known as the "bracketing envelope". The inclusion of the bracketing envelope mandrels will allow the operating valve to be moved to a slightly higher or lower depth, as dictated by changes in the well & reservoir performance changes during the well life. This procedure maximises the (liquid) production by allowing the well to be lifted from as deep as possible commensurate with the current producing conditions.

- *Feel free to revisit Figure 2 and explain: to which location would the operating valve be moved if the reservoir pressure has depleted and/or the watercut has increased?*

Stable Well Operation. Well "heading", in which the Tubing Head or Casing Head Pressure Shows regular changes (like cyclic perturbations of pressure and/or rate) should be avoided. Stable operation – with a constant value for the casing and tubing head pressures – should be aimed for. This is because stable well operation will always produce more oil and has a less damaging impact on the system components. A reduced volume of lift gas often stabilises an unstable gas lifted well operation. Also, injection of gas at a constant rate by the means of sonic flow across the gas choke and/or operating valve is practiced. This way the small flow changes in the tubing will not cause large gas flow changes in the annulus.

Casing head (i.e. gas injection) pressure excursions of as little as 5 psi can indicate valve multipointing {the gas injection point changing from one valve to another; or another valve cycling: regularly opening and closing}.

- *Discuss how a leaking mandrel or a cycling valve can be located using production logging*.

4.2 Gas lift design parameters

The gas lift design process has to answer the following questions to meet the above objectives:

- How many unloading valves are required and at what depths should they be placed?
- What are the required settings for the Unloading Valves?
- What is the depth of the operating valve where the gas is continuously injected?
- What is the gas injection (or casing head) pressure?
- How much lift gas should be injected?
- What is the tubing head pressure for the target flow rate?

This is often translated into practice by ensuring that the gas lift valve spacing and pressure setting are such that:

- The operating valve should have adequate flow capacity and be placed as deep as possible,
- The available lift gas pressure must be able to displace the fluid in the casing to the operating valve depth,
- The unloading valves can be opened and closed by the appropriate pressure gradient (and each valve will have its own unique setting).

4.3 The Surface Gas Network

Figure 4 illustrated the complete gas lift system. It will have become apparent from the above and the following sections that the performance of the gas lift system will depend on the pressure and flow capacity of the lift gas available at the well head. The surface piping network should thus be designed to:

- Have minimal pressure loss between the compressor and the most distant wellhead,
- Prevent one well from interfering with a second well by having sufficient pipe volume to dampen pressure surges, and
- Provide individual gas measurement and flow control for each well.

Large diameter piping encourages all the above. Typically, 4 in. (OD) piping is used for the main backbone of the system with individual 2 in. OD flow lines installed to each well. A ring main system is an option for larger systems employing more than one compressor.

The commonly used compressors can be either reciprocating (having pistons and valves) or rotary (e.g. the centrifugal ones with propellers on shafts). The former ones are suitable for a wide range of rates and compression ratios, but are less energy efficient. The latter ones are more energy efficient but have limited compression ratios, and therefore are often fed cooled gas in order to compress it more efficiently (because the cooler gas is denser and is naturally more compressed than the hotter one. Cooling is often achieved using heat exchangers where during circulation the heat from the gas is lost to the sea or fresh water). Such cooling also saves some compression costs. The compression power is one of the major GL operating costs.

5. THE UNLOADING PROCESS DESCRIBED

This section will describe how the dead well is unloaded of the kill fluid (often brine) resulting in the well production kicked-off. This unloading process traditionally involves the use of unloading valves that are designed to close and open at certain conditions (e.g. open above a certain casing pressure value and close below a certain one. Each valve has its individual pressure setting). *(In the cases where such valves are not installed, e.g. the one mentioned above in Figure 6* ***(f)****, a high pressure kick-off compressor may be used instead to force the gas down to reach the operating valve).*

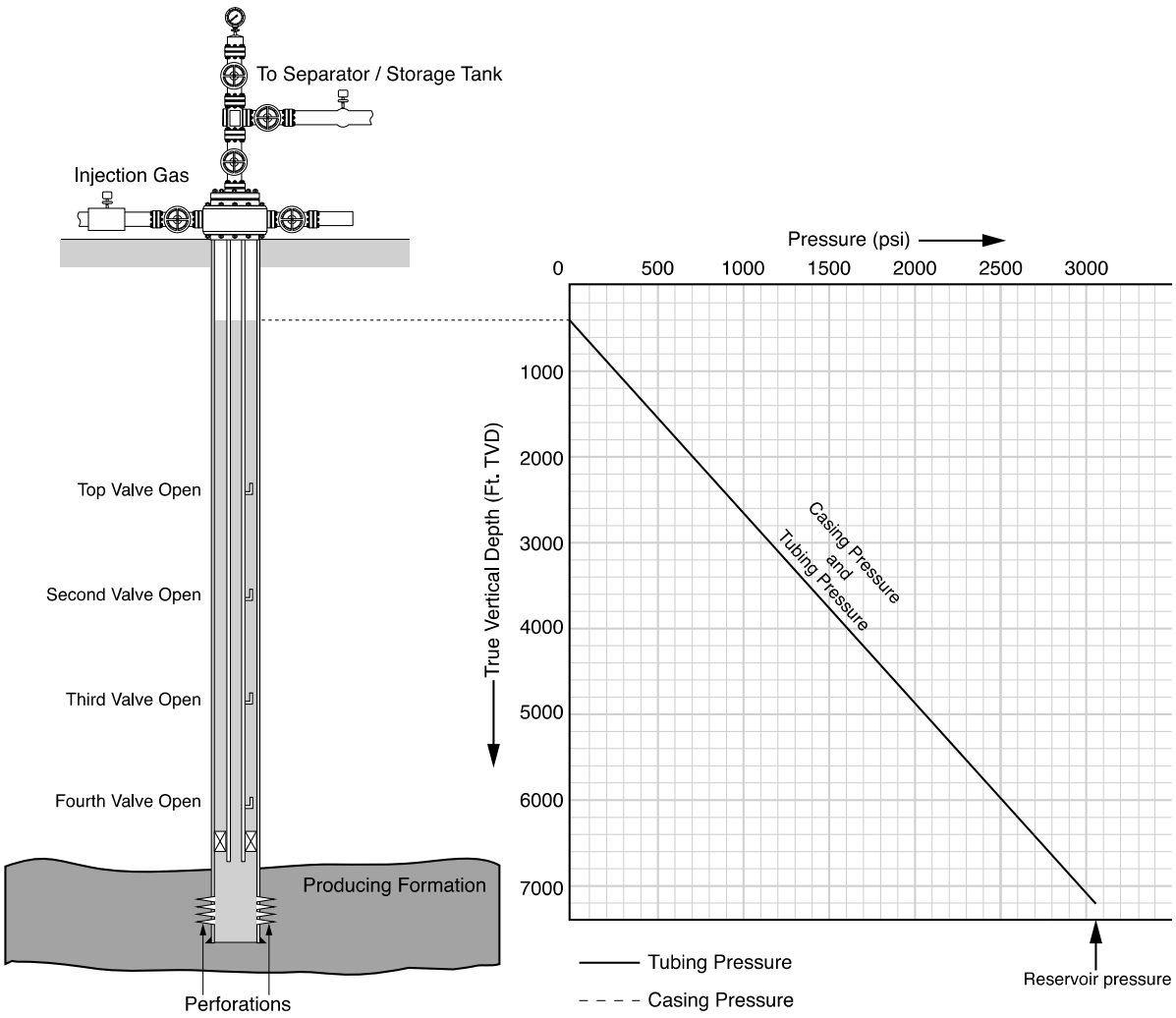


Figure 9 The "dead" well. All valves are open

Figure 9 shows the situation when a well planned for gas lift has just been (re)completed. The fluid level in the casing and the tubing is just below the surface and balances the reservoir pressure. The well is dead – no fluids are being produced. The hydrostatic head of the fluid column will equal the reservoir pressure, the actual fluid height will depend on the liquid density – a column of water will have a lower height than an oil column. No gas is being injected into the casing – both the tubing and casing have been depressurised at surface to atmospheric pressure. All the gas lift valves are open at this high pressure (due to the hydrostatic head of the fluid being high).

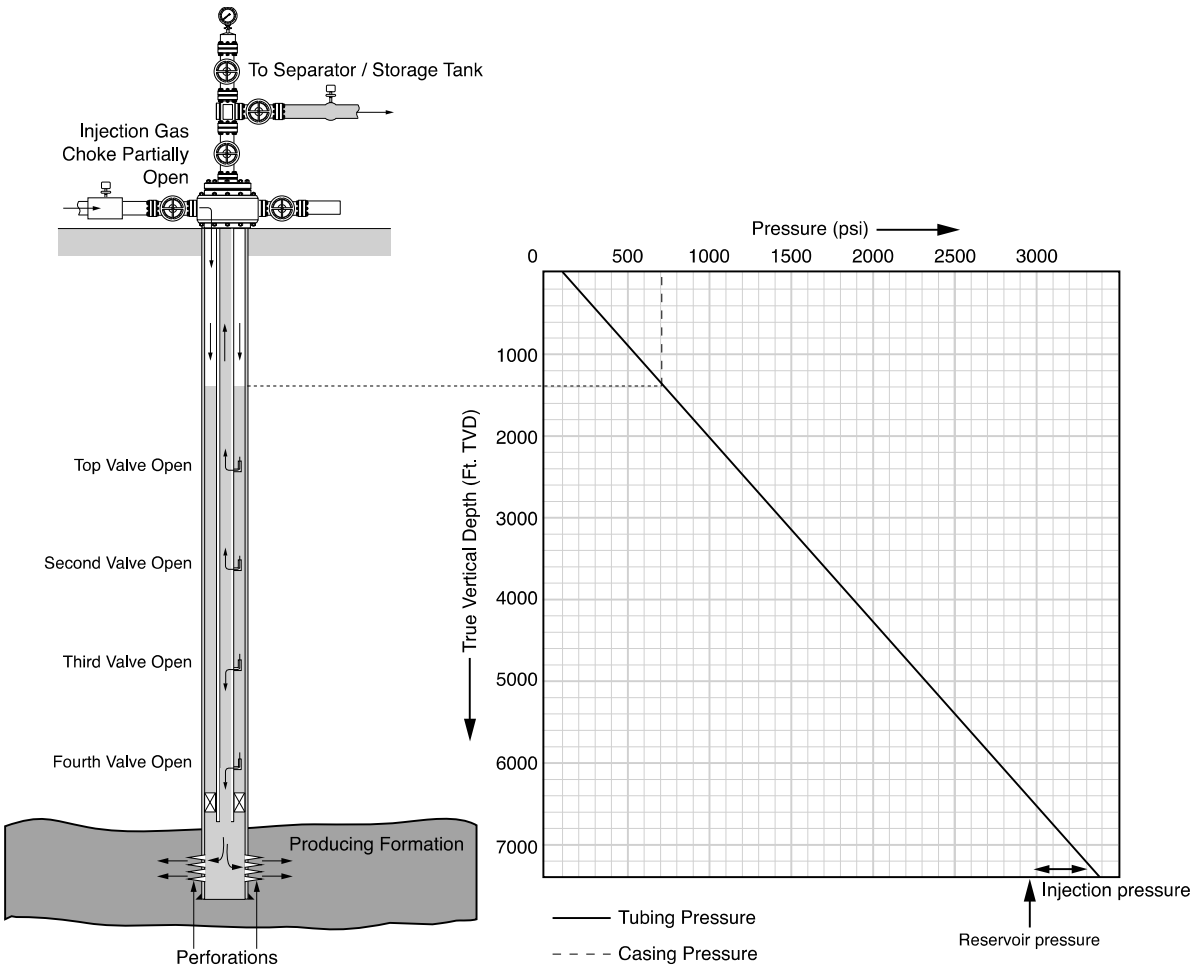


Figure 10 Gas-lifted well unloading, stage 1

Gas injection into the casing/tubing annulus has been started in Figure 10. The fluid is being U-tubed from the casing into the tubing through all the open gas lift valves. The gas lift pressure is sufficient to raise the fluid level in the tubing to the surface so that it flows via the surface flowlines into the separator. The pressure in the wellbore at perforation depth is greater than the reservoir pressure i.e. some of the liquid originally present in the well is being injected into the formation. This injection of contaminated, potentially formation damaging, fluid can be prevented by installing a one-way flow valve (i.e. a check valve) at the bottom of the tubing. It is important that the unloading process should occur at a controlled, not too high a rate – the gas injection rate is carefully controlled through the partially opened injection gas choke. This will prevent erosional damage to the gas lift valves as the fluid flows from the casing into the tubing across them.

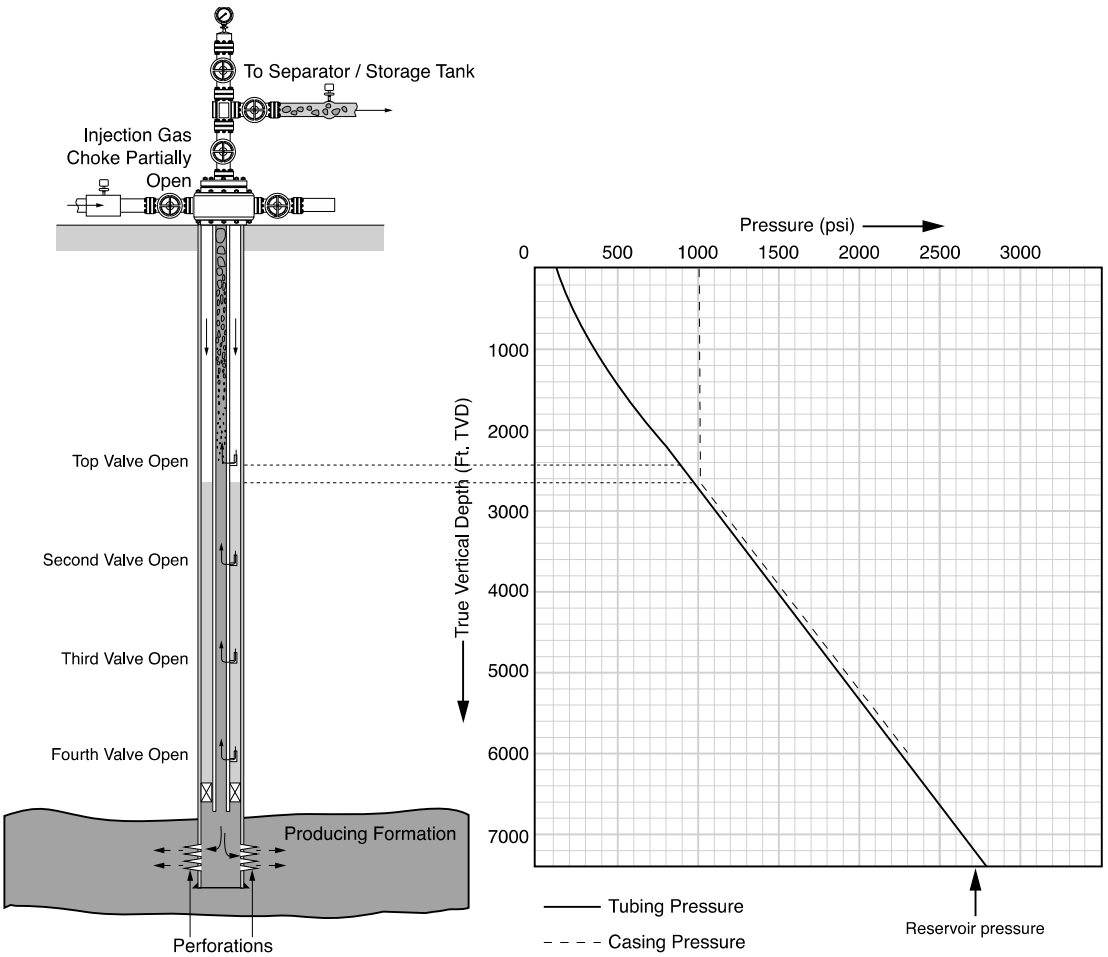


Figure 11 Gas lifted well unloading, stage 2

Figure 11 shows the situation when the unloading process has lowered the fluid level in the casing annulus to the top gas lift valve. Gas injection into the tubing has now commenced. The injected gas partially evacuates the liquid in the tubing above the top gas lift valve into the separator under multi-phase flow conditions. This partial evacuation reduces the fluid density in the tubing above the top gas lift valve and ensures that further casing fluid is to be unloaded through valves No. 2, 3 and 4. The well will also start to produce formation fluid if this reduction in pressure is sufficient to give a drawdown at the perforations.

N.B. Any fluid lost to the formation earlier on in the unloading process will be produced back first. This will be "dead" i.e. not "live" formation fluid. When live oil later follows, its intrinsic gas content would also help reduce the hydrostatic head in the tubing and partly help bring the well into production.

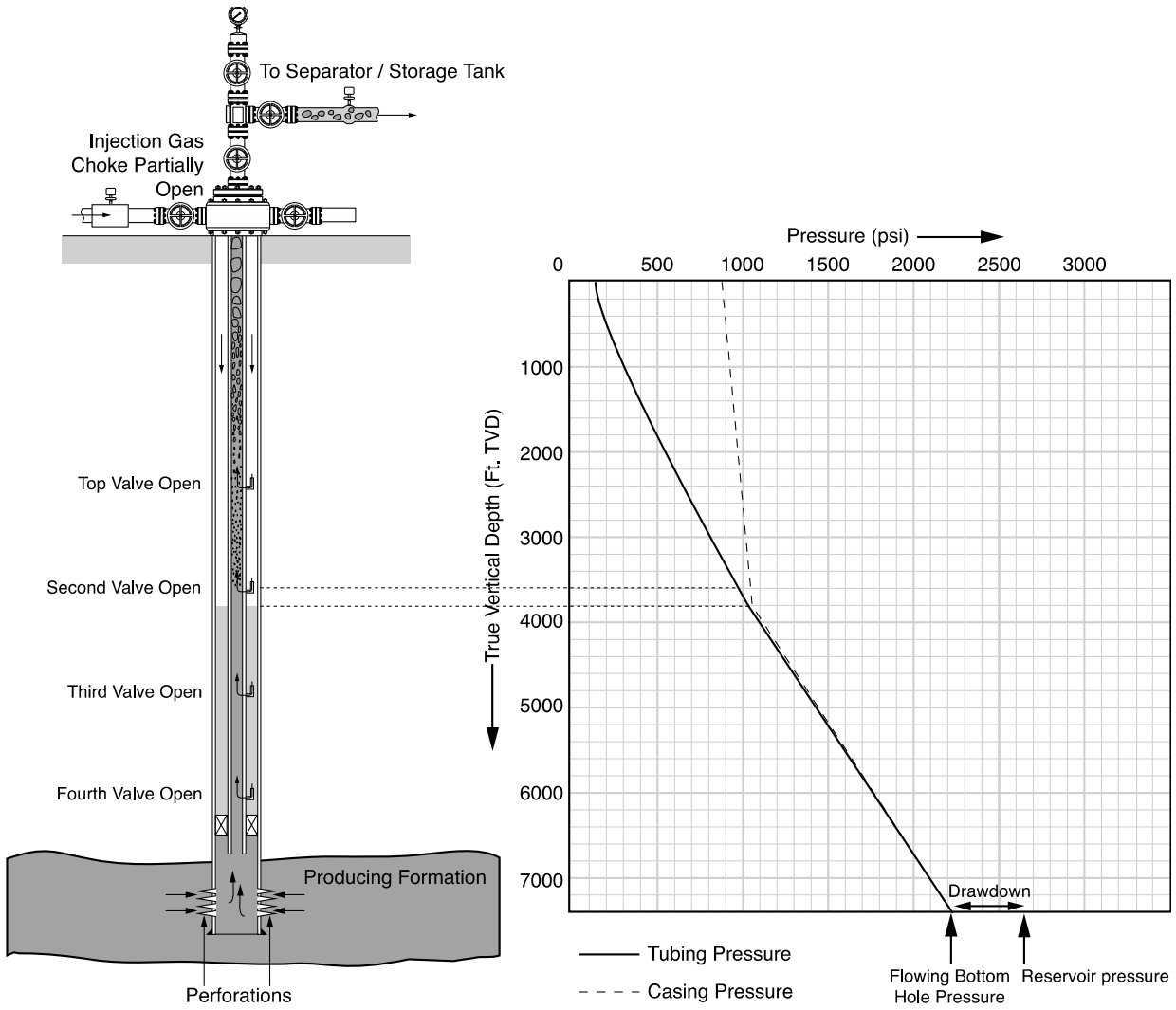


Figure 12 Gas lifted well unloading, stage 3

In Figure 12 the fluid level in the casing has now been lowered sufficiently to expose gas lift valve No. 2. The top two gas lift valves are open, and the gas is being injected through both valves. All valves below also remain open and continue to pass casing fluid into the tubing. The tubing has now been unloaded sufficiently to reduce the bottom hole pressure below that of the reservoir pressure. This pressure difference, or drawdown, induces flow of formation fluid from the reservoir into the wellbore i.e. the well is starting to produce.

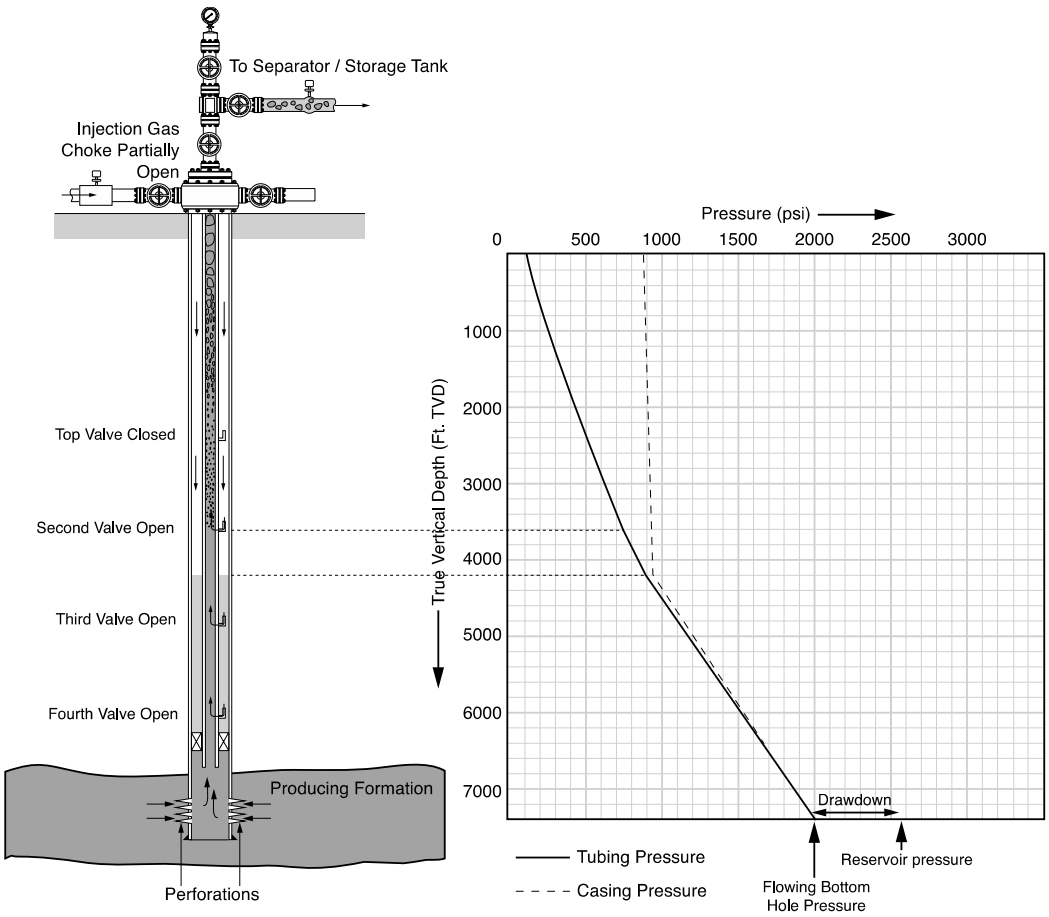


Figure 13 Gas lifted well unloading, stage 4

The process continues in Figure 13. Once the gas-liquid mixture from Valve 2 reaches the top gas lift valve the tubing and casing pressures next to it decrease. Valve 1 was pre-set to close at such conditions. It has now closed due to the reduced pressure. All the gas is being injected through valve No. 2. Unloading the well continues with valves 2, 3 and 4 open and casing liquid flowing into the tubing via valves 3 and 4. *If valve 1 did not close, the gas would not be able to flow deeper and would short-circuit via the top valves.*

There are generally two basic types of gas lift valves – the valves the opening and closing action of which being in response to either mostly/solely the tubing or mostly/solely the casing pressure. In the scenario discussed here the casing pressure-sensitive unloading valves are used (such 'casing pressure operated' valves are most common), so the closure of the top gas lift valve was triggered mainly by the reduction in the casing pressure after gas lift had been established through valve number two. *As for the tubing pressure: it is most important for 'fluid operated' and 'proportional response' valves used e.g. in dual gas lift or reverse gas lift completions.*

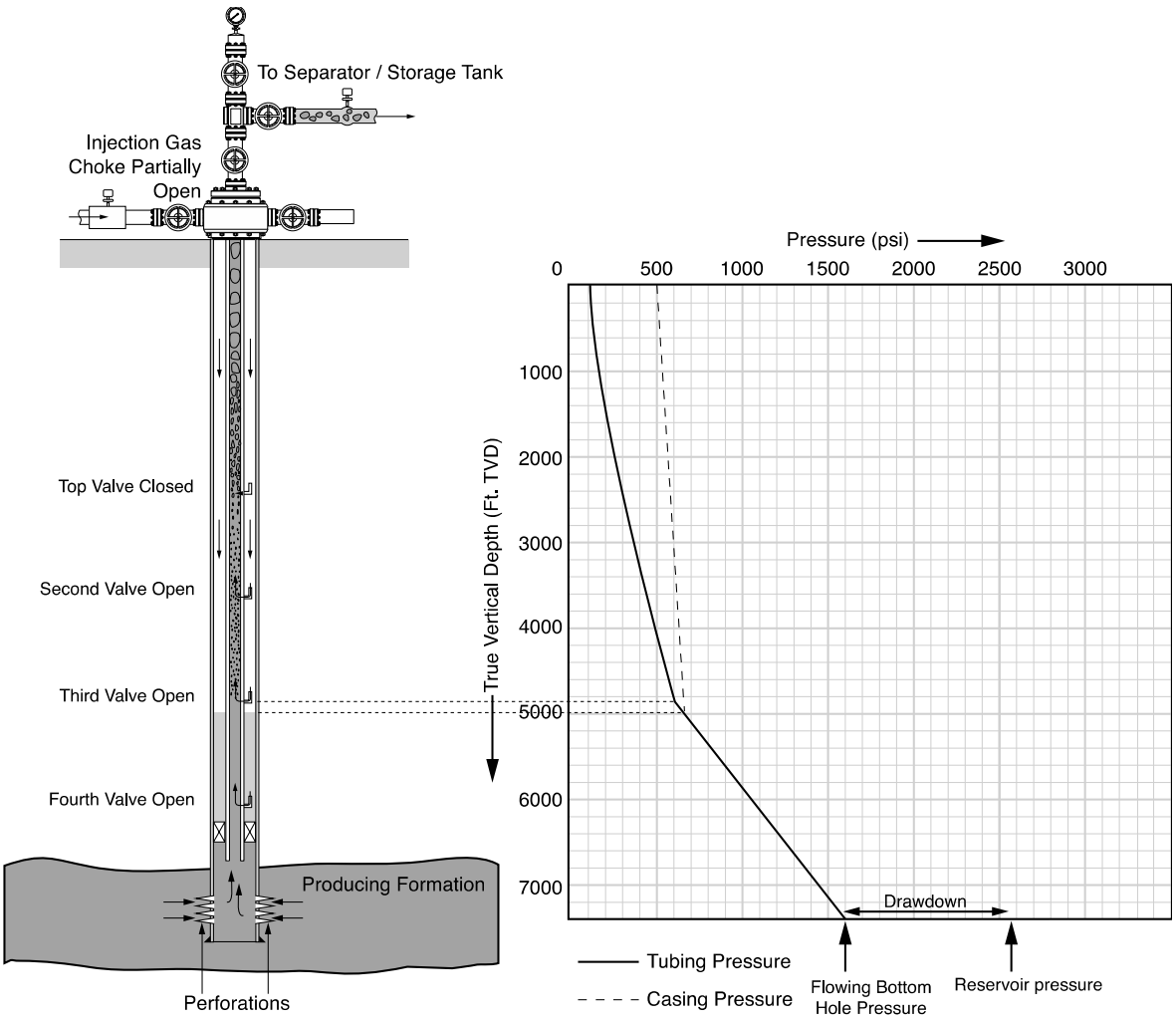


Figure 14 Gas lifted well unloading, stage 5

Figure 14 shows valve No. 3 having just been uncovered so that both the No. 2 and 3 valves are passing gas. The bottom valve below the liquid level is also open and liquid unloading from the casing/tubing annulus into the tubing continues.

NB. A deeper point of injection lowers the Flowing Bottom Hole Pressure; creating a greater drawdown and hence increasing the production rate.

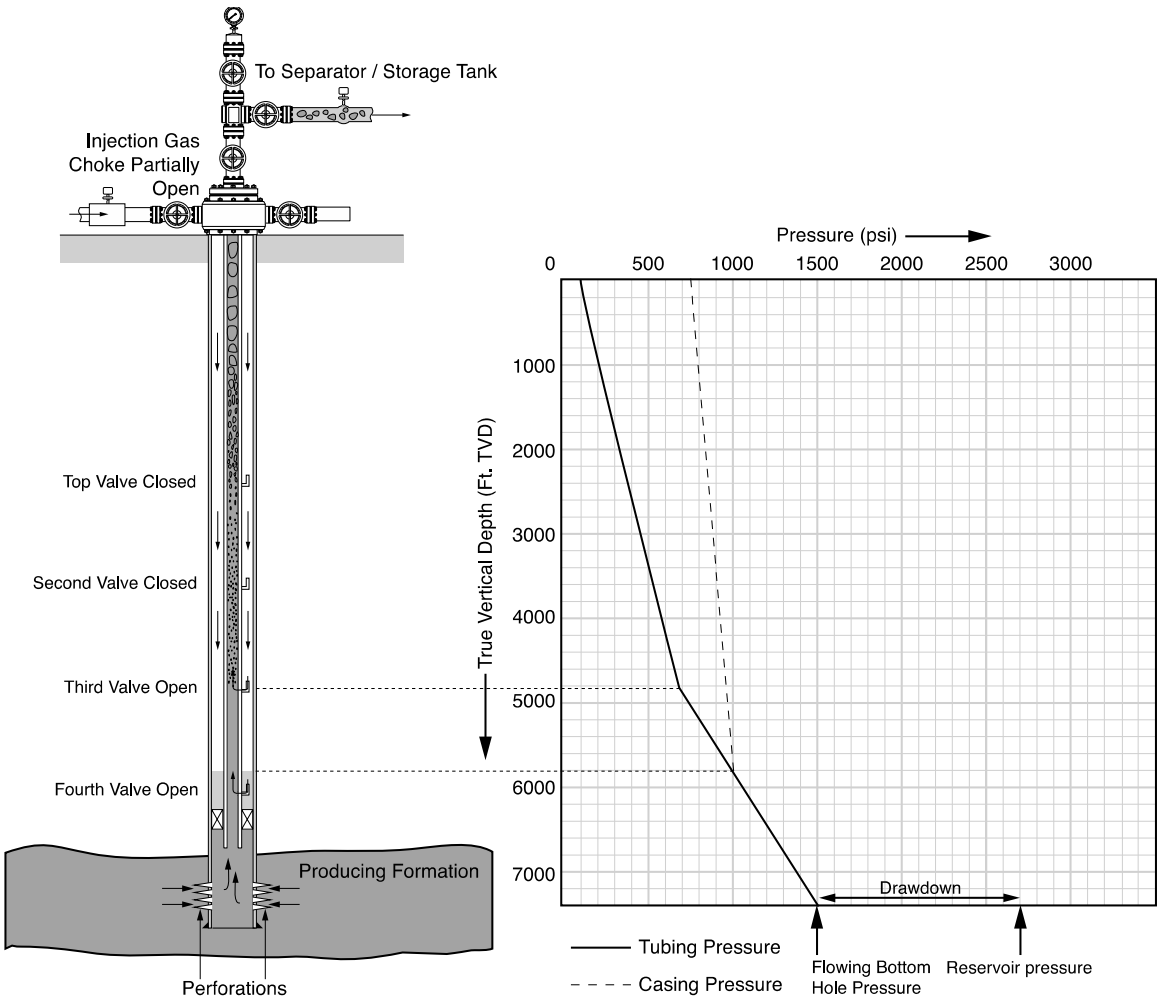


Figure 15 Gas lifted well unloading, stage 6

Figure 15 shows that, similar to the chain of events that lead to the closure of valve No. 1, the reduction in casing or tubing pressure once valve No. 3 starts to flow gas will result in valve No. 2 closing. All the gas is now being injected through valve No. 3.

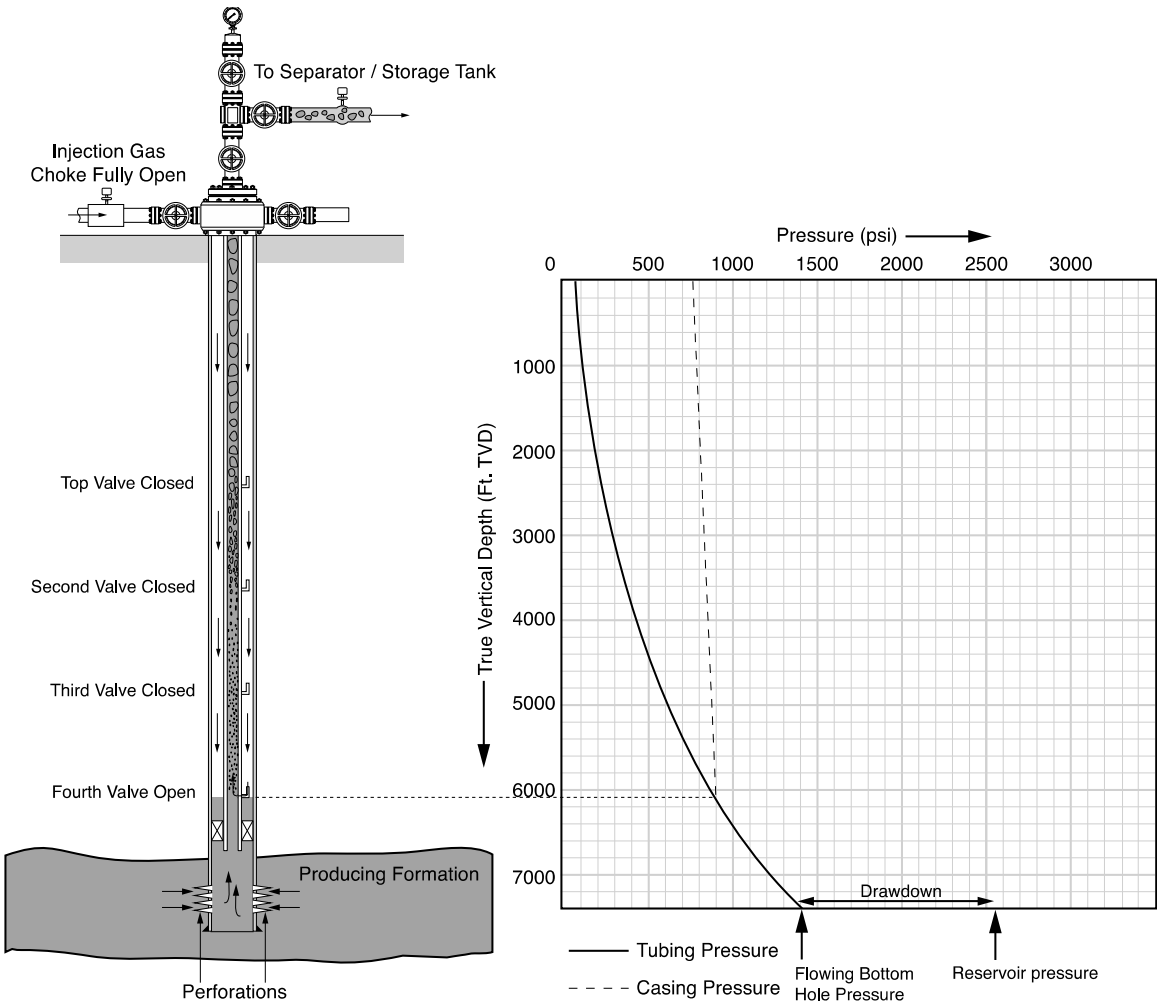


Figure 16 The producing gas lifted well

The process has continued to its logical conclusion in Figure 16. (Operating) Valve No. 4 has been exposed to gas flow and valve No. 3 has shut. All the gas is being injected through valve No. 4 – this is the operating valve. An operating valve can be either a gas lift valve or a simple orifice.

Figure 17 is an illustration of the normal development of the tubing head and casing head (or gas lift) pressure with time during unloading process described in Figure 9 to Figure 16. The sequential reduction in casing head pressure, happening naturally when every next interval of the tubing is unloaded as the lift gas is successively injected through every next gas lift valve, is shown. This is not always so clearly observed in practice. The annulus pressure is not only controlled be the settings of the gas lift valve(s) referred to above, but also by the balance between the casing head (surface) gas injection rate and the (total) gas passage rate through the valves. Further, it can be seen that the erratic behaviour of the tubing head pressure as the well is being unloaded is replaced by a steady value as stable production is achieved when the well is lifted from valve No. 4.

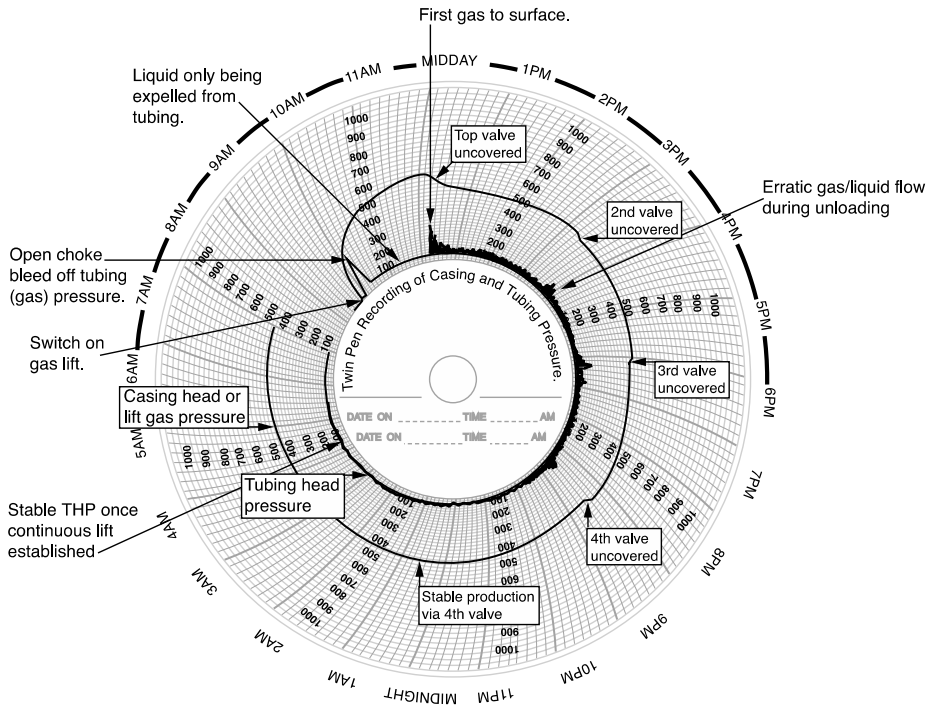


Figure 17 Typical casing and tubing pressure measurements during unloading of a gas lifted well

5.1 Safety Factors

Several safety factors are normally introduced when preparing gas lift designs for real wells. This is to account for:

- Errors in the valve pressure settings,
- Errors and fluctuations in the well data, lift gas injection pressure and the estimate of the valve temperatures under flowing conditions,
- The pressure drop across the valve's choke and that required to obtain sufficient movement of the valve's stem (*read more about the stem movement below*).

5.2 Gaslift Valve Spacing Criteria summarised

The well unloading process was described in the previous section. The chosen installation depths of valves Nos. 1 – 4 will have been based on the following criteria:

- Specify the minimum number of gas lift valves. This will not only reduce the cost but also the number of potential leak paths.
- Gas lift valves to be installed sufficiently far apart that they do not interfere with each other's operation (150 m suggested minimum spacing).
- (Continuous) Gas injection through the operating valve occurs as deep as possible (i.e. the deepest point within the reach of injected lift gas for the given gas injection pressure and rate) based on current producing conditions.

6. SIDE POCKET MANDRELS

Completion equipment is available so that gas lift valves can be permanently installed as part of the tubing in e.g. 'conventional' mandrels. Such wells require a workover if any repairs or changes to the settings of the gas lift system need to be made. However, **nowadays most completions employ side pocket mandrels** (Figure 18) installed at appropriate depths in the tubing string as part of the permanent completion. Side pocket mandrels allow gas lift valves to be installed (and recovered) in a live well using wireline techniques. Side pocket mandrels are oval shaped accessories with an outside diameter greater than that of the tubing {Figure 18 (c)}. This shape allows the gas lift valve to be installed in the pocket placed to one side of the tubing conduit while maintaining fullbore access throughout the complete tubing length. More on SPMs was provided earlier in this course.

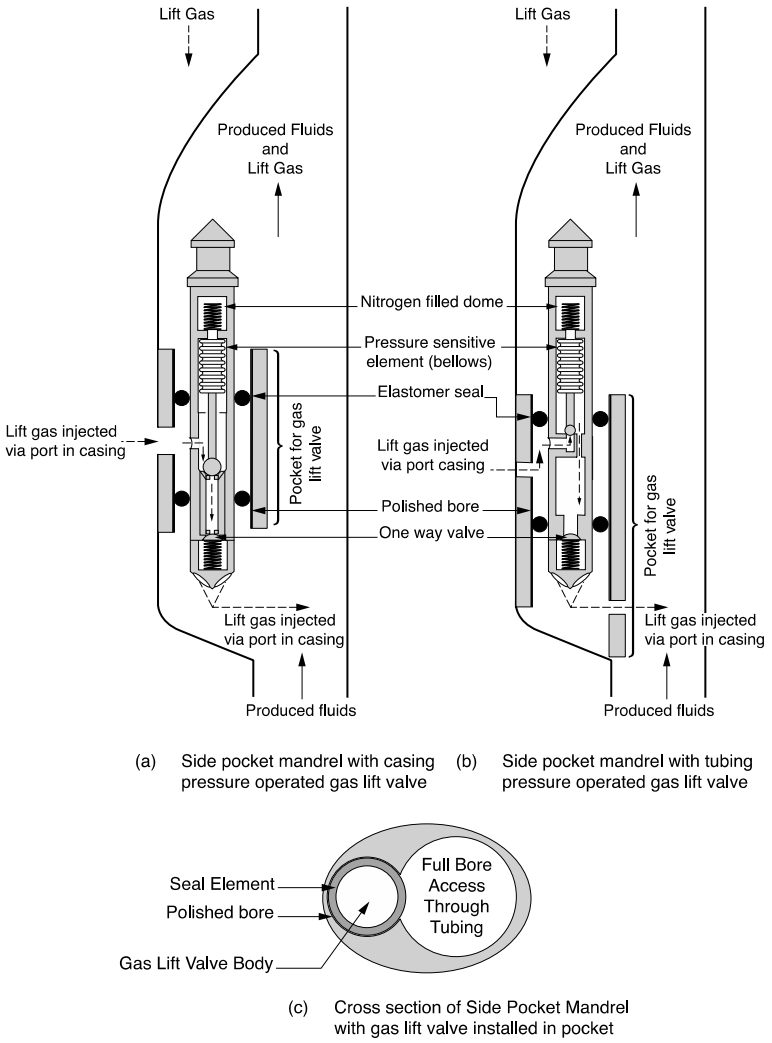


Figure 18: Schematic view of Side Pocket Mandrel showing comparison of Injection and Tubing Pressure operated gas lift valves

Figure 18(a) is a schematic illustration of a side pocket mandrel intended for use with an Injection (a.k.a. Casing) Pressure Operated (IPO or CPO) valve; while Figure 18(b) shows the equivalent mandrel construction details for a Tubing Pressure Operated a.k.a. Production Pressure Operated (TPO or PPO) valve.

7. GAS LIFT VALVE MECHANICS

The unloading gas lift valves have ports sized to pass only the limited volume of gas required for unloading. A larger port is often installed in the operating valve so that gas injection can be increased to the optimum value dictated by the current or future well or reservoir conditions. Dummy valves are installed in the "Bracketing Envelope" SPMs where "live" valves are currently not required.

The following sections discuss the valve's mechanical construction.

7.1 Casing or Injection Pressure Operated (CPO or IPO) Valves

A schematic diagram of a casing pressure operated, bellow valve is shown in Figure 19. The:

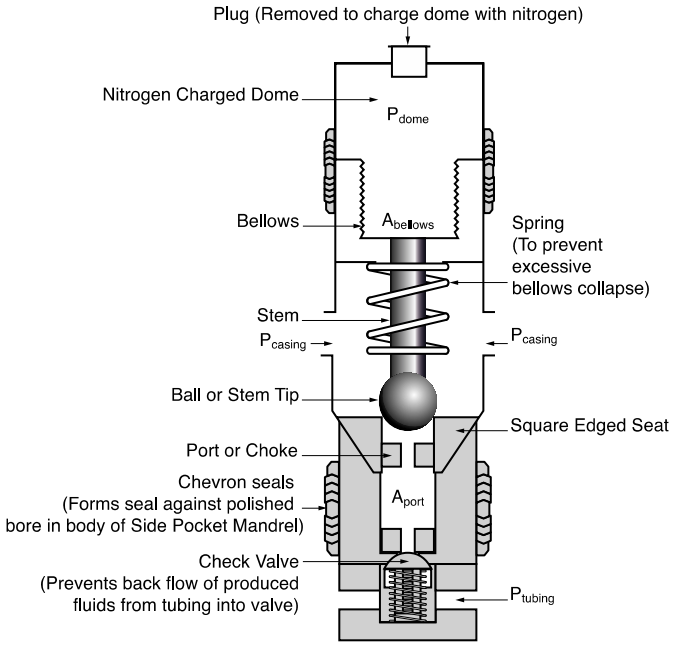


Figure 19: Schematic diagram of a casing pressure operated valve

- **Dome** or top section of the valve is charged, via the plug, with nitrogen to the required pressure (P_{dome}).
- Nitrogen charge acts on the **bellows**; exerting a force pushing the stem with the ball against the choke or port and halting the flow of lift gas into the tubing. This pneumatic control of such bellow valve is quite accurate. *(Some other, spring-type valves rely on the spring force alone. They are subject to the spring's state and sensitivity).*
- (Optional, additional) **Spring** prevents damage to the bellows due to excessive collapse when exposed to forces much greater than those generated by the nitrogen charge. Such excessive collapse would result in the bellows losing their elastic response to pressure changes. If this occurs the gas lift valve needs to be changed.
- **Choke** or **port** prevents excessive (gas) flow rates.

- **Check valve** prevents formation fluids flowing from the tubing into the annulus e.g. when the well is not gas-lifted.

Simple, mechanical considerations allow to derive the following equations (ignoring the additional spring factor):

The Closing Force, F_c, tending to seat the ball is given by:

$$F_C = P_{dome} * A_{bellows}$$

Where A_x refers to the Area of component x and P_y refers to the Pressure at point y. See Figure 19 for further explanation of nomenclature.

The Opening Force (F_O) is made up of two components: F_{O1}, and F_{O2}, where

$$F_{O1} = P_{tubing} * A_{port}$$

$$F_{O2} = P_{casing} * (A_{bellows} - A_{port})$$

and $$F_O = F_{O1} + F_{O2} = P_{tubing} * A_{port} + P_{casing} (A_{bellows} - A_{port})$$

The Opening and Closing forces are equal just before the valve opens.

$$P_{dome} * A_{bellows} = P_{casing} * (A_{bellows} - A_{port}) + P_{tubing} * A_{port}$$

or

$$P_{casing} = \frac{P_{dome} - P_{tubing} (A_{port} / A_{bellows})}{1 - (A_{port} / A_{bellows})}$$

Thus, the key factors controlling the gas lift pressure required to open the valve are the dome and tubing pressures and the ratio of the bellows and port areas. CPO valves normally have the ratio ($A_{port}/A_{bellows}$) set as small as practical.

The equivalent equation for a Tubing Pressure Operated (TPO) valve can be deduced from Figure 19 where P_{casing} and P_{tubing} are changed places.

$$P_{tubing} = \frac{P_{dome} - P_{casing} \left(A_{port} / A_{bellows}\right)}{1 - \left(A_{port} / A_{bellows}\right)}$$

$$\text{or } A_{port} / A_{bellows} P_{casing} = P_{dome} - P_{tubing} \left(1 - \frac{A_{port}}{A_{bellows}}\right)$$

7.2 Dome Pressure Calibration

The dome is charged with nitrogen and the gas lift valve is installed in a Test Rack placed in a temperature controlled enclosure set at 60ºF (see Figure 20). Nitrogen is used for this purpose since it is non-corrosive, inflammable and its behaviour is well known. The simulated P_{tubing} is at atmospheric pressure (or 0 psig). A gradually increasing gas pressure is applied to simulate P_{casing}. The valve opening pressure ($P_{opening}$) is recorded as the pressure when gas begins to flow.

An increase in P casing or P tubing will move the stem tip proportionally further from the seat and allow more gas passage.

(A_{port} /$A_{bellows}$) the ratio of the port area to bellows area is obtained from the manufacturer's specifications.

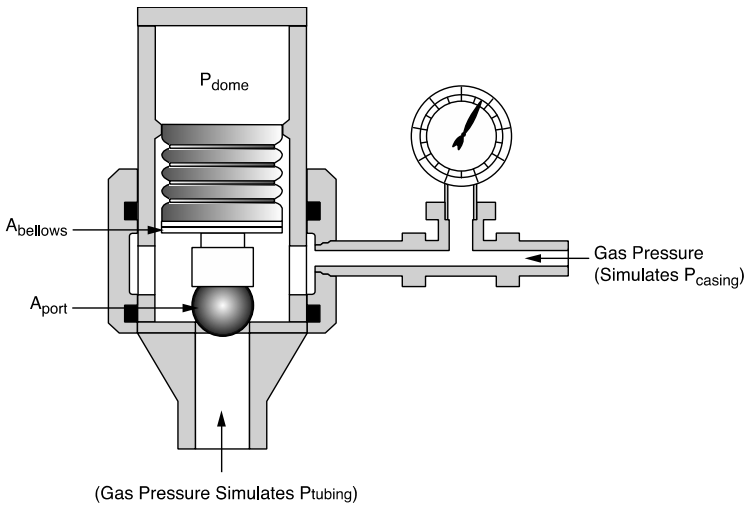


Figure 20 Test rack for gas lift valve

Application of the above force balance equation gives:

$$P_{opening} = P_{dome}/(1 - A_{port}/A_{bellows})$$

This can be used to confirm that the manufacturing of the gas lift valve is to specification and that the dome nitrogen pressure, P_{dome}, has been set correctly.

The valve closing pressure ($P_{closing}$) may be measured by pressurising both the injection and tubing sides so that the valve is fully open. The pressure on the tubing side is reduced and valve closure recognised as the pressure at which P_{casing} no longer decreases in line with P_{tubing}. The design of the valve dictates that $P_{closing}$ will be lower than $P_{opening}$, since starting from the open valve situation means that the injection pressure acts on the complete bellows area.

The **valve spread** is defined as the difference between the valve test rack opening and closing pressures i.e. ($P_{opening}$ - $P_{closing}$). It is a measure of the difference between the effective area of the bellows and the port. Figure 21 illustrates a typical valve spread and its variation with changes in the casing pressure.

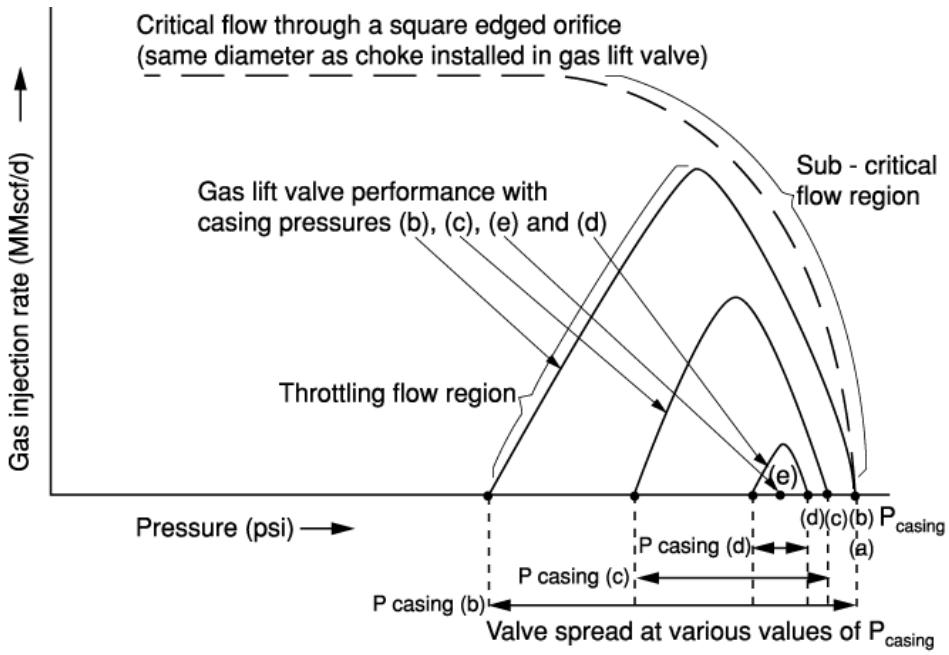


Figure 21 Valve performance

Further, adjustments for nitrogen expansion at hotter well conditions are applied. It may be difficult to exactly predict the valve temperature during unloading, so some approximations are often made.

7.3 Valve Flow Performance

As mentioned, the operating valve at the bottom of the gas lift string, through which gas will be continually passed, is normally equipped with a square edged, orifice choke. The resulting flow performance is shown in Figure 21, curve (a) – the dashed line. The gas flow rate passing through the choke increases with increasing pressure difference between the casing and tubing until a maximum value is reached when the critical flow rate is achieved. At this point the gas flow velocity has become sonic and the volume of gas passed does not increase further with increasing pressure differential. The valve is often referred to as being "choked" at this point. Orifice flow can be described using approximate formulae or more complex numerical models. The orifice size determines the maximum or "choked" volume of gas that can be injected to aid lifting the well fluids to the surface.

Some further observations from Figure 21 prove that the simplified gas lift design procedures, which assume that the unloading valve will shut immediately once the casing (IPO valve) or tubing (TPO valve) pressure drops below the pre-set value, may not be correct:

7.3.1 DYNAMIC VALVE PERFORMANCE

Dynamic testing of the valve, in which the injection gas flow rate is measured for a fixed casing pressure and a range of tubing pressures (Figure 21), is required to properly understand the valve's performance. The dynamic valve performance describes the:

- Valve's ability to start passing gas when the ball first lifts from its seat
- Rate of increase in the gas flow rate as this clearance of the ball from the seat increases (flow capacity)
- Corresponding decrease in gas flow rate as the valve closes and
- Resistance to vibration under flowing conditions.

The valve's **load rate** (measured in units of psi/inch) is the pressure difference required to move the stem a given distance; while the valve **spread** is the difference between the opening and closing pressures. The **shape** of the performance curve represents the valve's sensitivity to pressure. There are standardised testing procedures to measure a particular gas lift valve's dynamic performance. The valve is installed in the test equipment after being set up with a suitable dome pressure using the manufacturer's recommended procedure.

Measurements are made of the:

- Valve opening pressure
- Pressure increase required to move the stem to its value of maximum travel
- Position of the stem for various intermediate pressures.

These gas flow rate measurements can be represented by:

- A Flow Coefficient (C_v). This is a measure of the gas flow rate as a function of pressure differential across the valve
- The distance of the stem from its seat.

There are various approaches to analysing this flow data using C_v values, including simplified, data driven, and mechanistic models.

Further, a performance relationship curve constructed for a given valve in a given well helps quantifying its operating conditions and whether it may show stable or unstable behaviour.

7.4 Proportional Response Valves

The design of a Proportional Response Valve (see Figure 22) involves:

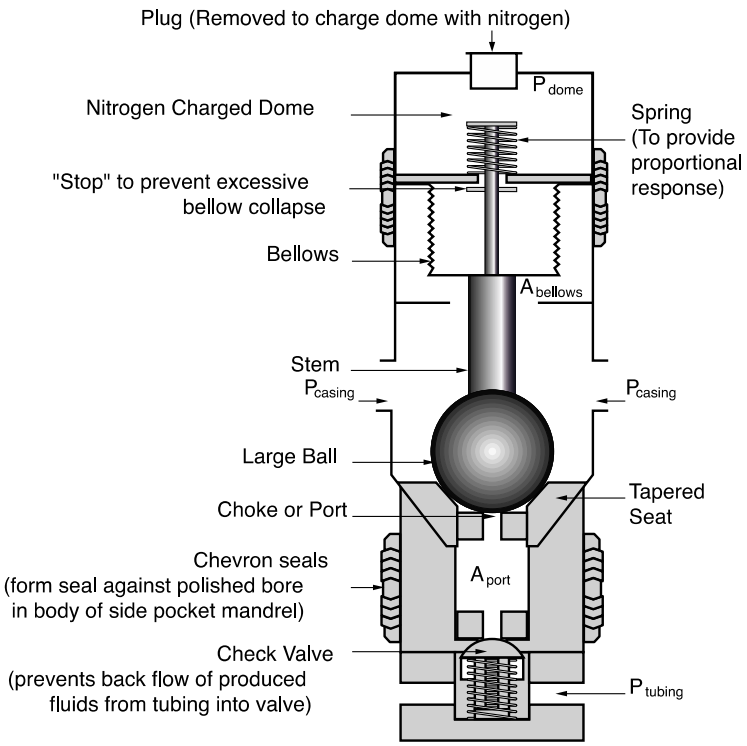


Figure 22 Proportional response gas lift valve

- The addition of a spring to counterbalance the force trying to expand the bellows,
- A "stop" to prevent excessive bellows collapse,
- A larger ball at the tip of the stem and
- A tapered seat instead of a square edged seat.

The proportional response valve has more parts than the "traditional" valve. It is not only more expensive but also more prone to failure i.e. Proportional Response Valves should only be specified when they have definite operational advantages.

Generally, by design the types of gas lift valves include:

- Casing pressure-operated CPO valves (a.k.a. IPO or 'pressure valves').
- Proportional valves (a.k.a. throttling pressure valves or continuous flow valves).
- Fluid-operated valves (a.k.a. fluid valves) – sensitive to tubing pressure TPOs.
- Combination valves (a.k.a. 'fluid-open – pressure-closed' valves).

These valves can be classed as either unbalanced (i.e. their closing or opening mechanisms sensitive to both tubing and casing pressures), balanced (i.e. closing or opening sensitive to only one pressure), and pilot valves (adjustable, and also can have a larger port and larger spread which is beneficial for the operating valves used in intermittent gas lift).

7.5 Controlling the Lift Gas Injection Rate

It will have become apparent from the above that optimising the gas injection rate at the operating valve is a key parameter in the control of a gas lifted well. New developments in this area include:

- A surface-controlled gas lift valve where the required choke settings are transmitted from surface via a cable or wireless transmission system. Two-way information exchange can be implemented. Thus, annulus and tubing pressure and temperature measurements at the gas lift valve depth as well as flow measurements can be incorporated in the same instrumentation package which transmits data to the surface. This allows the optimum choke setting to be specified.

- A redesigned, venturi choke that develops critical flow when the tubing/casing pressure ratio is as high as 90% compared to the normal ratio of 55% (Figure 23). This critical flow condition decouples the pressure behaviour in the annulus from that in the tubing as well as gives a constant gas injection rate for most producing conditions (this also certainly simplifies modelling of the process of gas lift and operation!).

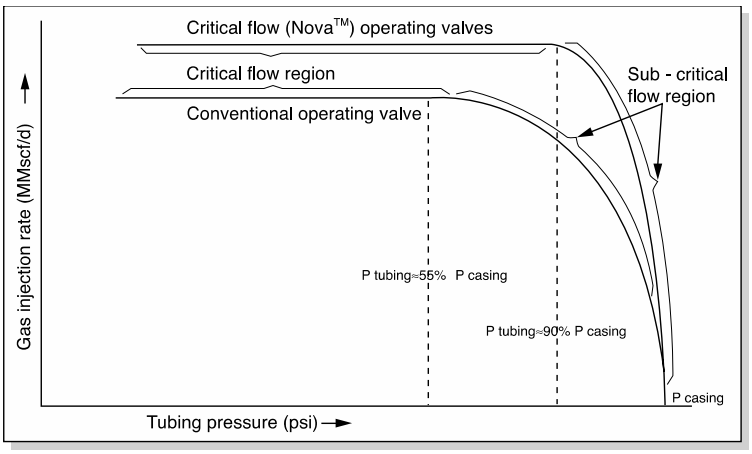


Figure 23 Operating valve performance compared

7.6 Dynamic Valve Response and Gas Lift Completion Modelling

Simple (manual) gas lift completion design methods and common software programs assume that the valves will open fully at (casing or tubing) pressures slightly greater than the set value and will completely close when the pressure drops below this value. They assume that the well "jumps" immediately from steady state operation when lifting through one (fully open) valve to a second, steady state condition when lifting through the next deeper valve. In practice:

i. The volume of gas injected through a given valve will vary with time.

ii. The well will only reach steady state inflow a considerable period of time after the unloading process has finished.

iii. The combination of changes in (i) and (ii) will result in continuous changes in the well's Gas

Liquid Ratio (GLR) during the unloading process. This is especially true when any fluid lost to the formation during the workover or the early stages of well unloading has to be produced first before live formation fluids can enter the well and improve the well outflow.

iv. There is a significant volume of gas in the casing/tubing annulus. Pressure changes will not occur instantaneously due to the limited gas supply rate at the surface or the finite gas flow rate through a particular valve.

v. The valves can open and close a number of times during the unloading of a multi-valve completion string e.g. as the well temperature profile changes during the unloading process (when the well has neither the geothermal nor the steady state flowing temperature gradient).

It can be appreciated that a transient rather than a steady state model is sometimes required to accurately simulate the unloading process. Such models must accurately predict the development of the above parameters as a function of time. The output of the model will include, as a function of time, the:

- Tubing and annulus pressure at valve depths as well as surface casing (annulus) and tubing head pressure,
- Flow rate of liquid and gas through open valves,
- Depth of liquid levels in tubing and annulus,
- Volume of fluids (gas and liquid) produced to the surface and
- Inflow from the reservoir (after making allowance for any liquid lost to the formation, as discussed above).

This may be useful for troubleshooting problematic wells e.g. the prediction of when the following difficulties can be expected during well unloading – erosion of (gas lift) valves, severe slugging, excessive well stabilisation times, etc.

7.7 Well Stability

Dynamic Well Simulation programs can also be used to evaluate potential causes of lift problems once the well has been placed on production. These valve problems manifest themselves by the:

- Well not producing or producing at a lower-than-expected rate,
- Unstable well behaviour (casing and/or tubing head pressures oscillate regularly) and
- Excessive unloading and well stabilisation times.

The quickest method to correct the problem is to identify which valve is the cause of the production difficulty and then replace it with a correctly calibrated valve. The alternative, to replace the gas-lift valves in a random, ad hoc manner is often much more time consuming and may never solve the problem.

Comparison of the actual and the predicted well behaviour allows identification of the type of problem being experienced as well as which gas lift valves is the cause of the improper operation. Typical problems which have to be diagnosed include:

- Valves that have become either (partially) plugged or enlarged (cut out)
- Valves set to an incorrect dome pressure or are operating incorrectly due to mechanical problems and
- Multi-pointing (injection through more than one valve at the same time). This is often due to an upper valve opening and closing.

A quantitative evaluation of the flow rates and the tubing and casing pressure values and their stability are required to differentiate between the above causes, as well as to identify the specific problem valve. Additional or alternative measurements (e.g. production logging) may be needed.

8. GAS LIFT DESIGN PROCEDURES

This section will discuss the procedure used to design a gas lifted well. It will combine the flow performance of operating valves discussed above with the concepts on multiphase flow and Nodal Analysis. Table 4 lists the well data required to initiate this design process which will enable us to specify the optimum:

Tubing Outside Diameter	4.5 in
Tubing weight	12.6 lb/ft
Deviation Survey	Vertical Well
Target Production Rate	5000 bfpd
Watercut	40% vol.
Produced Water Density	1.06 g/cm^3
Gas Relative Density	0.65
Packer Setting Depth	9,500ft.
Mid Perforation Depth	10,000 ft.
Wellhead Flowing Pressure	100 psig
Shut In Bottom Hole Pressure	3,700 psig
Productivity Index	0.50 STB/d/psi
Oil Gravity	37° API
Bubble Point	1,200 psig
Gas Oil Ratio	400
Gas Injection (Casing) Pressure	1500 psig
Gas Available For Injection	3 MM scf/d
Ambient Temperature at Surface	70° F
Flowing Temperature at Surface	140° F
Temperature at Mid Perforation	240° F
Kill Fluid Gradient	0.45 psi/ft. *

* In Annulus / Tubing for Unloading Calculations

Table 4 Well Edinburgh-1 Data set for gas lift design

- Tubing size,
- Injection gas supply parameters (pressure and volume),
- Installation depth of operating valve and
- Minimum Wellhead Flowing Pressure.

The first item is to check that gas lift valves can be placed at suitable distances above the operating valve to ensure that the well can be unloaded using the gas lift parameters chosen. The gas lift design will have to be changed if it is found that the well cannot be unloaded. Further, the design will be influenced by the gas lift design philosophy. For example:

A Maximum Production/Expected Case Design would:

- Maximise production by injecting gas as deep as possible,
- Install extra gas lift valves around the operating valve to allow the depth of the operating valve to be adjusted and
- Budget for (some) well entries to be required since the well may stop producing if well inflow conditions change.

Worst Case/Robust Design would be designed to:

- Always work by placing the operating valve at a relatively shallow depth compared to that achievable with the available gas lift pressure. However, this also:
- Results in a lower production rate. Deferred production probably also implies a reduced reserves recovery.

The philosophy chosen for a particular well/field will depend on the operational conditions and the cost scenario.

8.1 Gas Lifted Well Performance Design Example

The first requirement is to study the well's in- and out-flow and confirm that artificial lift is required. This is illustrated in Figure 24. It can be seen that the well production rate will decrease rapidly once well Edinburgh-1 begins to produce water. It will stop flowing when the water cut reaches about 30%. The well needs high wellbore pressure to lift the fluid naturally. Any reduction in the flowing wellbore pressure due to depletion of the reservoir pressure and / or the development of a near wellbore "skin" due to Formation Damage will reduce the well production rate. This will also reduce the critical water cut at which natural flow ceases. It should be remembered that the form of the Inflow Performance Relationship used to describe fluid inflow from the formation (e.g. Vogel or "straight line PI") will also have an impact on these calculations.

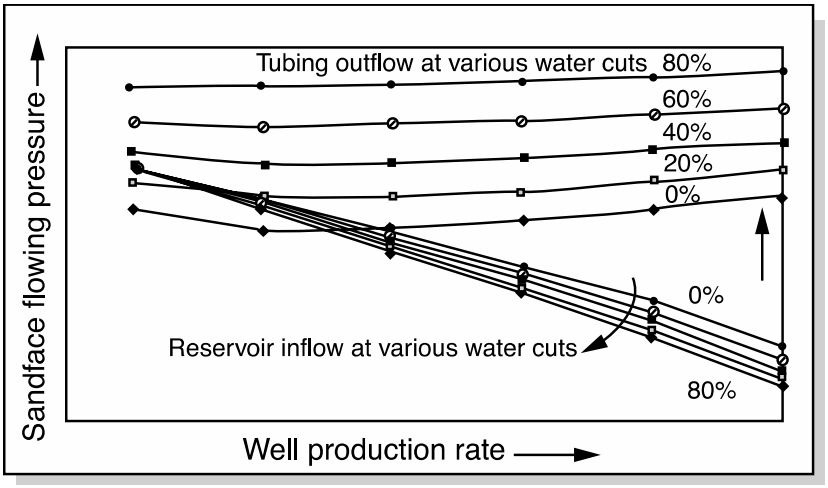


Figure 24 Performance well Edinburgh - 1 at varying water cuts

We will assume that Gas Lift has already been identified as the most suitable form of artificial lift for this well and an operating valve has been installed at a suitable depth. The impact of the injection of varying amounts of gas on the well production rate is evaluated in Figure 25. Figure 26, a plot of production performance against lift gas injection rate can now be derived. It can be seen that the injection of the first 1 MM scf/d of lift gas leads to a rapid increase in production rate. Further increases in the rate of gas injection yields ever reducing benefits until a maximum production rate is reached at 2.5 MM scf/d. The same data are plotted in Figure 27. Here the lift gas injection rate is represented as a Gas-Liquid Ratio – the sum of the Produced fluid gas liquid ratio and the gas injection rate divided by the (gross) liquid production rate. As expected, the graph shows a maximum production at the 2.5 MM scf/d gas injection rate.

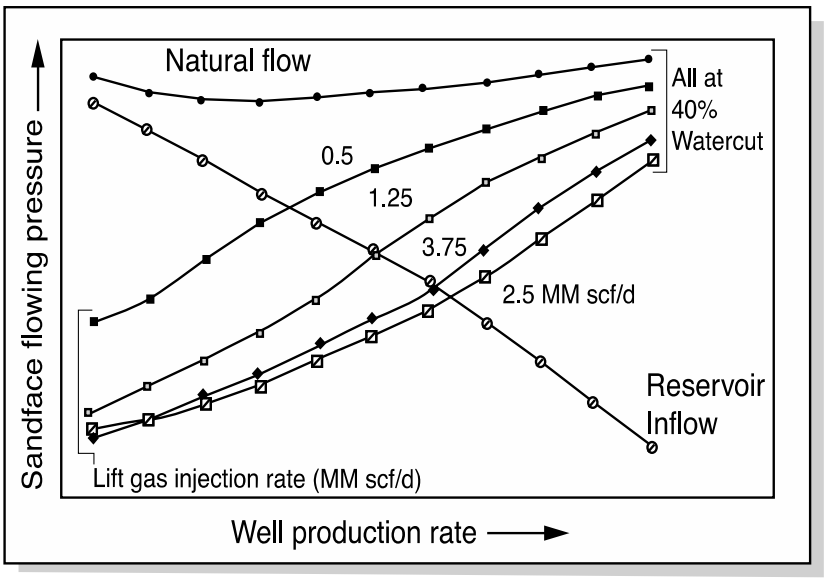


Figure 25 Sensitivity study for tubing outflow to lift gas injection rate at 40% water cut

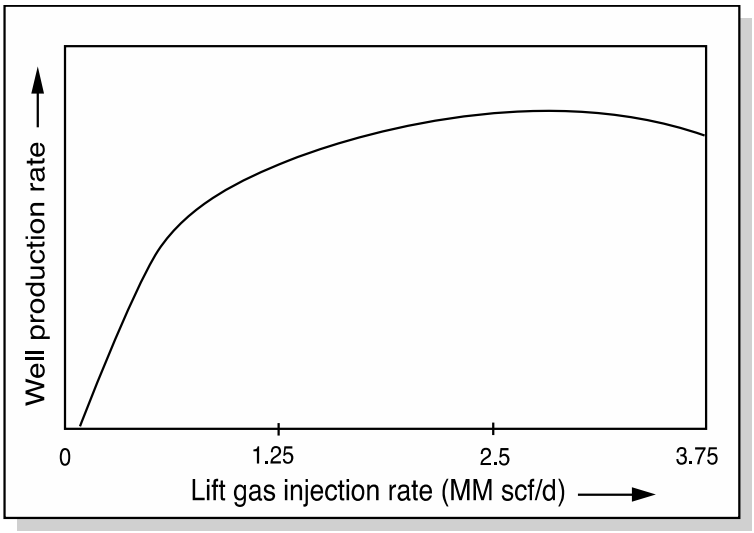


Figure 26 Production performance and gas lift injection rate

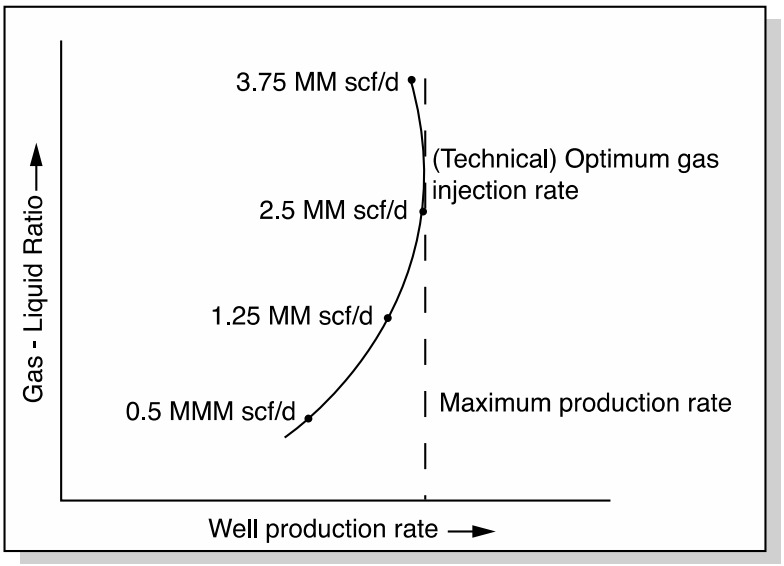


Figure 27 Production performance against gas liquid ratio

Formation Damage – or the presence of a near wellbore skin – will reduce the well productivity. Figure 28 is similar to Figure 25, except that the reservoir inflow from a damaged well (skin = +6) has also been plotted. Figure 28 not only illustrates this loss in well productivity due to the presence of the skin, but also indicates that the conclusion drawn as to the optimum gas injection rate is unchanged.

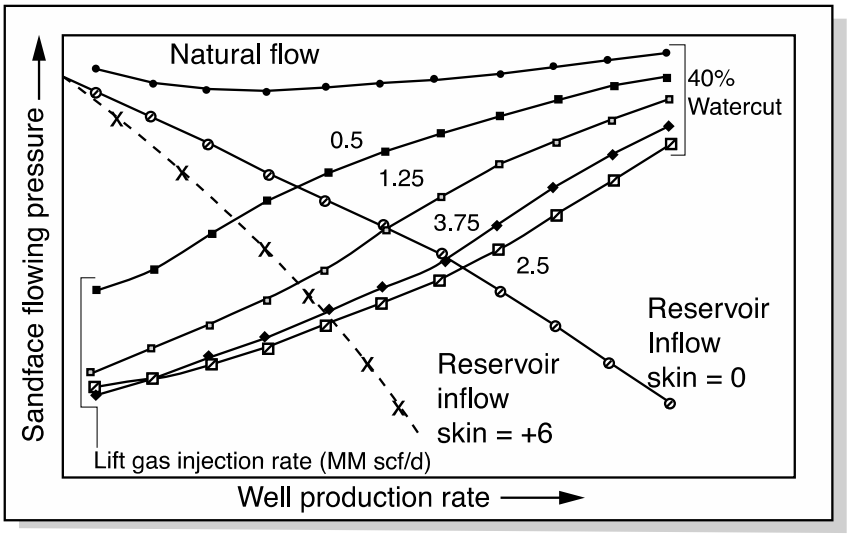


Figure 28 Sensitivity study for tubing outflow to lift gas injection rate at 40% water cut for an impaired well.

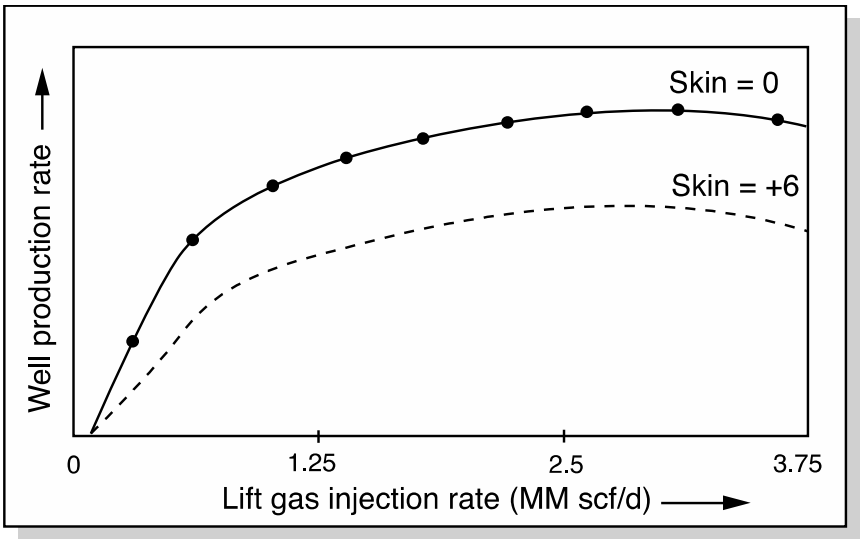


Figure 29 Production performance and lift gas injection rate for an impaired well.

Figure 30 examines the effect of changing the depth of lift gas injection. A deeper injection point creates a greater drawdown leading to an increased production rate and a more efficient GUF (Gas Utilisation Factor or the ratio [Gross production rate increment / Gas Injection Rate increment]).

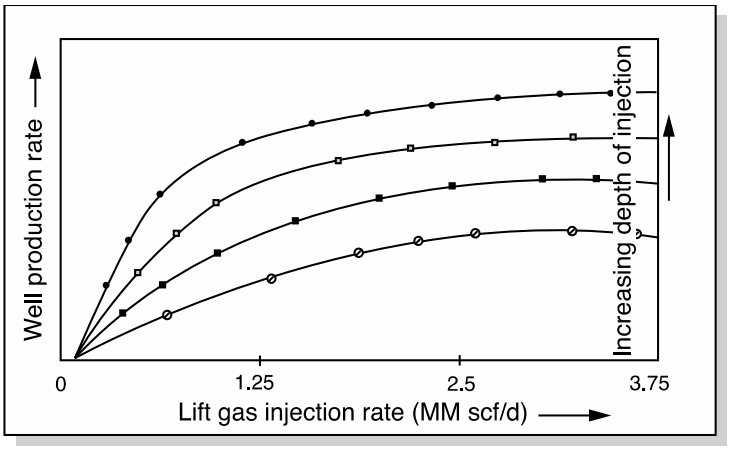


Figure 30 Production performance and lift gas injection depth.

Figure 31 and Figure 32 examine the sensitivity of the well production rate to an increase in the diameter of the production tubing. The production increases rapidly as the tubing OD increases to 4.5 in, but then decreases for the largest tubing (5.5 in). Excessive slip between the gas and liquid phases occurs at the lower flow velocity associated with the larger tubing, resulting in liquid loading and poorer performance as was explained in Chapter 3.

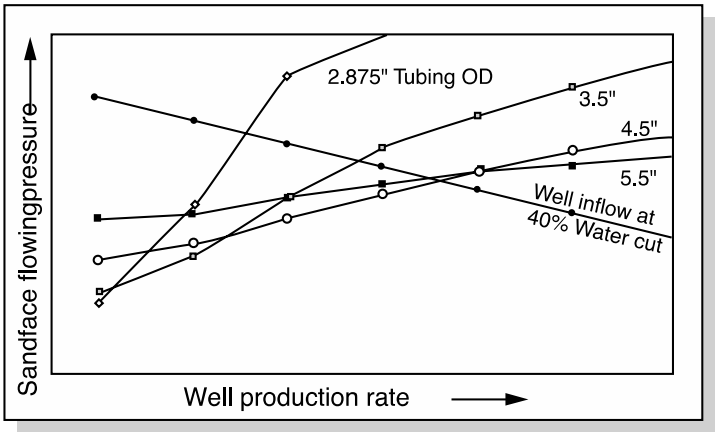


Figure 31 Sensitivity study of tubing outflow at various to tubing diameters.

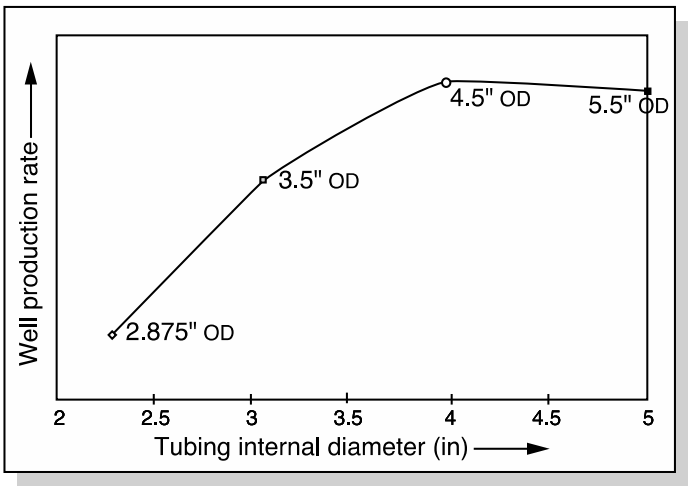


Figure 32 Production performance and tubing diameter.

We showed earlier in this course that separator pressure affected the outflow performance of naturally flowing wells. The same is true for gas lifted wells – Figure 33 shows how the well outflow performance improves as the separator pressure is decreased. This is shown explicitly in Figure 34, where the production rate is plotted as a function of separator pressure. In general, the lower the separator pressure, the higher the production rate. *(By contrast, the lower the separator's pressure the lesser flow rate it can process as will be seen later in this course, so there must be a compromise solution).*

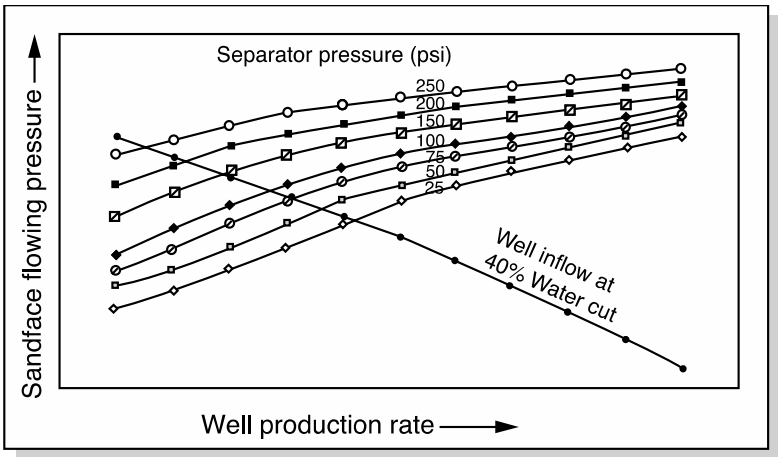


Figure 33 Sensitivity study of tubing outflow to separator pressure.

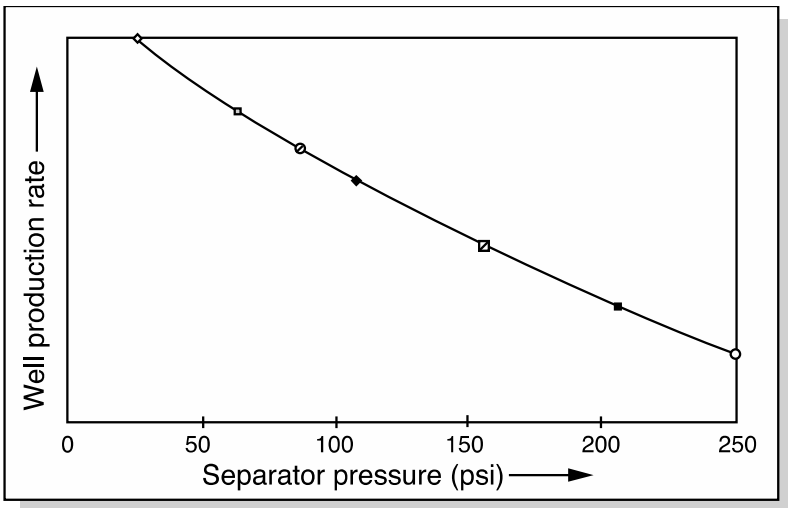


Figure 34 Production performance and separator pressure.

It should be emphasised that, in addition to the separator pressure, a back pressure on the well performance is created by pressure losses across:

- Christmas tree valves (should be fully opened to minimise any pressure losses).
- Choke (if installed).
- The flowline (particularly pipe elbows) and long, narrow diameter, tortuous flow lines with the separator mounted at a higher elevation than the wellhead.
- The wellhead design.

A further parameter that needs to be optimised is the lift gas injection pressure – Figure 35 illustrates the effect this has on the well outflow performance while Figure 36 records the production rate with changes in injection gas pressure.

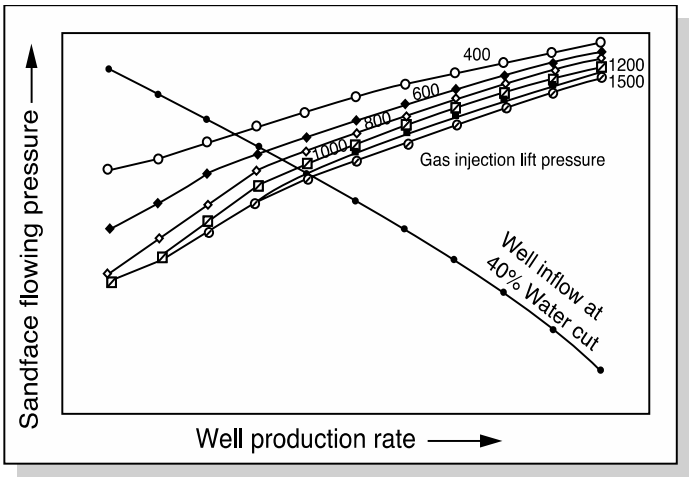


Figure 35 Sensitivity study of tubing outflow curves to gas injection pressure (operating valve is at same depth in all cases).

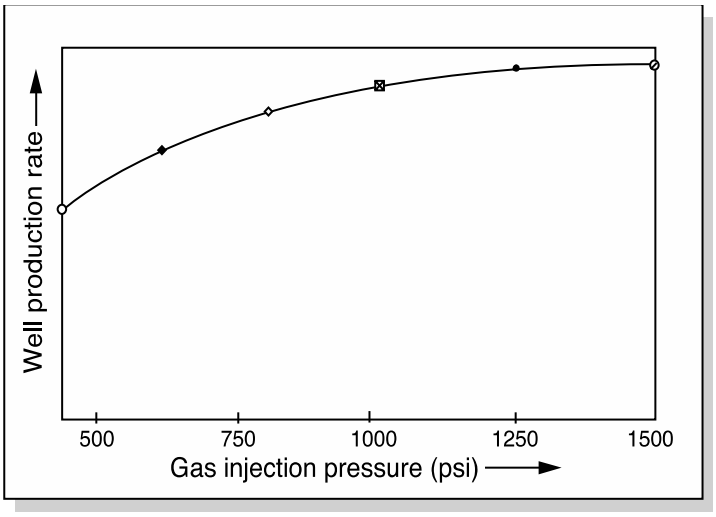


Figure 36 Production performance and gas injection pressure.

The conclusions reached from the above sensitivity studies are valid for the Edinburgh-1 well producing under the chosen combination of Reservoir Pressure and water production studied. The conclusions need to be tested for robustness by repeating the sensitivity analysis for combinations of water cut and reservoir pressures that are expected to be encountered during the well's lifetime. Planned recompletions e.g. extension of the perforated interval, should also be included in this. Figure 37 is a typical example of the deterioration of the Reservoir Inflow Performance at various times (T_1, T_2 and T_3) under the twin influences of the decrease of reservoir pressure and increasing water cut. The tubing (outflow) performance is plotted for the optimum gas injection rate that maximises the well production for each reservoir inflow curve i.e. the optimum gas injection rate changes with time.

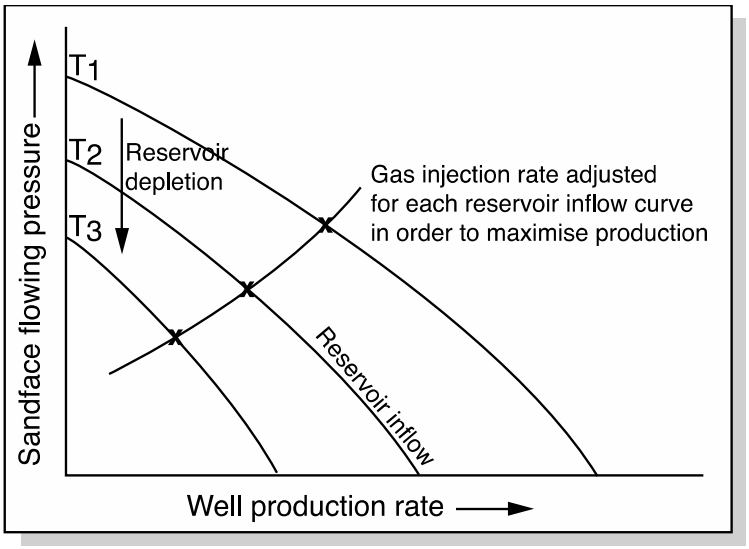


Figure 37 Performance of well Edinburgh – 1 at various times.

The GUF will decrease with time due to the:

- Increasing average liquid density (increasing water cut).
- Decreasing (own) gas production rate (decreasing net oil production and associated gas) and
- Decreasing reservoir pressure.

Figure 38 records the decreasing well production resulting from the changing well inflow and tubing outflow performance curves. It is the same data as presented in Figure 37.

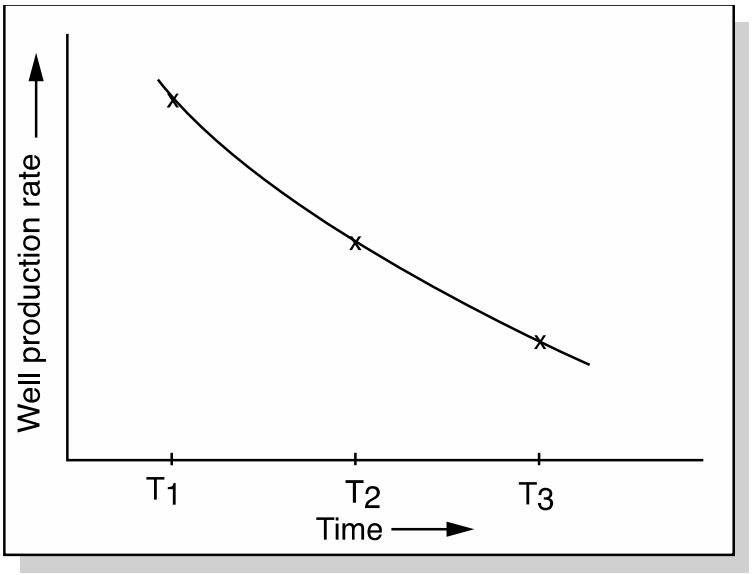


Figure 38 Performance of well Edinburgh - 1 as the reservoir pressure depletes.

One further variable to be discussed is the choice of the multiphase flow correlation used to calculate the well outflow performance. This can have a great influence on the results, as discussed earlier in this course. The flow correlation can be chosen based on the:

- Production experience in other, similar wells in the same field,
- Theoretical considerations based on a comparison of the well type with the parameters originally used to generate the correlation or
- Comparison of predicted and actual well performance.

The latter is the best choice when (field) data is available. The actual and predicted gas lifted well performance need to be compared at a range of gas lift injection rates. Figure 39 illustrates how the use of an inappropriate correlation can lead to incorrect prediction of well production rate. Flow correlation number 4 refers to "Hagedorn and Brown", one of the most frequently used to describe the performance of gas lifted wells. The preferred flow correlation for the gas lifted well may be different from that previously used to describe the same well's performance under natural flow. *For instance,* Table 5 *illustrates the correlations used by one operator (not universally!) based on their field experience to achieve the most accurate predictions based on such monitoring programme.*

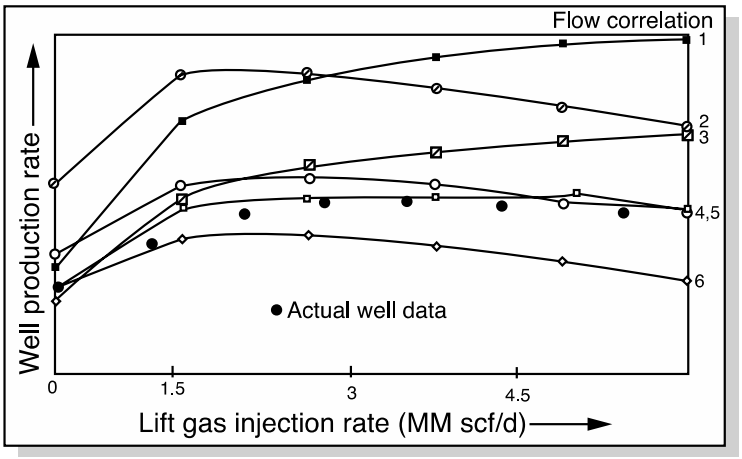


Figure 39 Sensitivity of production performance under gas injection to the choice of multiphase flow correlation.

Inflow	< 50% Water Cut	Vogel
	>50% Water Cut	"Straight Line" PI
Outflow	< 10,000 bfpd	Hagedorn and Brown
	> 10,000 bfpd	Duns and Ross

Table 5 Suggested correlations for gas lifted wells.

Tubing Size	4.5"(O.D)
Separator Pressure	As low As Possible$^{\phi}$
Gas Injection Pressure	1000 or 1200 psi*
Gas Injection Rate	1MM scf/d
Flow Correlation	Hagedorn and Brown

* Depends on detailed cost calculations

$^{\phi}$ Some operators have profitably reduced back pressure on the well by "twinning" the flow line to the separator

Table 6 Summary of chosen gas lift parameters.

Table 6 summarises the conclusions from the above gas lift design exercise. 1 MMscf/d gas injection rate was chosen because it gives comparable performance while requiring less gas, although this must be further challenged by subsequent economic analysis. Further development of a well/reservoir model may be done to model current and predict future production performance as well as to systematically monitor any differences between this prediction and the actual measured values. Such monitoring process will gather the basic data needed to test whether the chosen inflow and outflow correlations are still appropriate.

8.2 Gas Lift Unloading Calculations

The sections above described how the operating valve location and the design objectives for the gas lift system can be chosen. An illustrative description of the Unloading Process was given earlier. Problems to be avoided by careful design of the unloading process are:

- Well does not unload resulting in the gas being injected at a shallow depth. This can be overcome by placing the unloading valves closer together.
- Well does not lift at an optimal rate since a conservative design philosophy has resulted in the operating valve being situated at too shallow a depth. This can be overcome by carrying out the gas lift design using the expected well properties. (However, the well will be unable to unload the completion or kill fluid if an incorrect choice of well conditions is made.)
- The well is stymied i.e. there is a combination of conditions under which all the gas lift valves close and no more gas can be injected.

(The "deep as possible operating valve" and the conservative approaches are compared in a worked tutorial in this chapter.)

8.3 Further Gas Lift System Considerations

Two further points need to be evaluated.

Flow Velocity. Corrosion/erosion of the tubing can become excessive at a critical flow velocity. Exceeding this limit will lead to excessive maintenance costs e.g. early replacement of damaged tubing or accessories. This is particularly true if significant quantities of formation solids e.g. sand are being co-produced with the formation fluids. The published recommendations in this area tend to be somewhat conservative, one needs to compare them with local experience. The critical value for the onset of corrosion/erosion can be very sensitive to the composition of the produced fluid; in particular the concentrations of carbon dioxide and hydrogen sulphide in the gas phase.

Shear Rates. Increased mixing water and oil at a high shear rate can lead to the formation of emulsions. The produced fluid in the well experiences increased shear when gas lift is introduced. This is due to the increased well inflow rate and the increased gas oil ratio. The increased shear rates can result in the formation of viscous emulsions occasionally downhole but especially when a choke or bean is included in the surface flow lines. It is difficult to predict the precise conditions which will lead to emulsion formation for a particular case. The well model will need to be adapted to the field data by "tuning" the fluid properties if emulsion formation is observed.

> ***Attempt Tutorials*** *1-4*

9. GAS LIFT OPERATIONAL PROBLEMS

Typical problems associated with the operation of gas lifted wells include:

9.1 Gas Quality

Poor gas quality (i.e. presence of solids, liquids, water vapour, H_2S, CO_2, oxygen) can lead to:

- Blockage of gas injection lines due to (solid) hydrate formation during periods of low ambient temperatures. Such blockages are most easily removed by depressurising the line since hydrates are unstable at low pressures, decomposing into their constituent components of gas and water. The problem can be avoided by sufficient drying of the gas so that its water vapour dew point temperature is below the lowest expected ambient temperature.
- Loss of casing integrity due to use of corrosive lift gas. This is associated with the presence of the acid gases (carbon dioxide and hydrogen sulphide) in the natural gas. Guidelines are available to determine at which concentrations corrosion can be expected. Often part of the produced gas will be sold, only sufficient gas being retained in the lift gas system to "top-up" losses. In this case, all the gas is normally treated to sales gas specification. Such specifications will typically limit the carbon dioxide concentration to 2 or 3%, and the hydrogen sulphide levels to below 4 ppm.

  It may be practical to tolerate higher levels of these acid gases if none of the produced gas is sold. The resulting problems from these more relaxed, gas quality specifications include:

- Natural gas containing carbon dioxide is only corrosive in the presence of liquid water rather than gaseous water. Corrosion should be looked for in those points where liquid water can collect (the bottom of pipelines, low points in undulating pipelines etc.) when the partial carbon dioxide pressure exceeds 30 psi.

  Higher carbon dioxide partial pressures require either the specification of special metallurgy e.g. tubing manufactured from 13 chrome stainless steel, or the continuous injection of a (vapour phase) corrosion inhibitor. This corrosion inhibitor will passivate metal surfaces by forming a protective layer. However, if there are high gas flow velocities (typically above 30 - 50 ft/s) they will strip the inhibitor from the metal surfaces and remove this protection.

- Hydrogen sulphide partial pressures of greater than 0.05 psia lead to sulphide stress cracking of many of the steels used in completion systems and pipelines. Higher hydrogen sulphide levels can be allowed by specifying the appropriate tubing metallurgy. Injection of corrosion inhibitors to passivate metal surfaces is possible on a temporary basis to protect against excess hydrogen sulphide levels. It is not normally recommended on a permanent basis since the sulphide stress cracking proceeds rapidly if inhibitor addition is accidentally halted.

9.2 Solids

These may either be produced from the formation (e.g. sand) or formed from the produced fluids {inorganic and organic scales}. Wax is the most frequently encountered solid in gas lift operations. The presence of solids within the production tubing can be expected to result in operational difficulties when carrying out wireline operations such as changing gas lift valves.

Excessive sand production can only be prevented by a suitable completion design e.g. installing a gravel pack. It should be repeated here that gas lift is relatively tolerant towards sand production compared to other forms of artificial lift, such as electric submersible pumps.

Recent developments in Production Chemistry have resulted in the development of scale inhibitors which can be injected into the lift gas at the surface and transported down hole to be injected, via the operating valve, with the lift gas and subsequently mixed with the stream of produced fluids.

N.B. Scale inhibitors are chemicals which, at low concentrations, inhibit (delay) the formation of massive deposits of the material in question from the minute "seed" crystals. These seed crystals are formed when the concentration of the scale exceeds the scale's solubility limit. This occurs because of temperature and pressure reductions undergone by the formation fluids as it is produced to the surface, as well as because of change in the fluid composition e.g. due to its mixing with another fluid.

9.3 Changes in Reservoir Performance

Reservoir Performance will change as the well/field matures. Typically, the water cut (and, consequently, the hydrostatic head of the fluid in the tubing) will increase and the reservoir pressure will decrease. These factors, which reduce the well outflow performance, may also be accompanied by a deterioration of the well inflow performance due to the relative permeability effect brought about by the increasing produced water fraction. Since the production target will be to maintain the same net oil (plateau) production for as long as possible, the well will be produced at a higher drawdown with an increased gross fluid volume produced.

All these changes will require adjustment of the gas injection system parameters e.g. increase in the gas injection rate, moving the operating valve to a different depth (recall the bracketing envelope concept), etc.

9.4 Gas Supply Problems

These usually manifest themselves in one of two ways:

- The volume of lift gas available is less than that required to produce every gas lifted well at its (individual) optimum rate. It then becomes necessary to allocate the gas so that the total field production is maximised.
- Fluctuating compressor suction and discharge pressures. This is due to unstable operation of the process plant, which may in turn be caused by unstable producing well operation. For example, tubing "heading" leads to the production of a large "slug" of liquid followed by a period of gas only or no production at all. The surface gas distribution network should also be designed to minimise the propagation of such pressure transients. Devices like slug catchers can also be employed.

Profitability will be maximised by stabilising the entire production system (wells and surface facilities) since this will maximise the reservoir fluid production and minimise the maintenance costs associated with these fluctuating pressures.

9.5 Well Start-Up (Unloading)

Good practices are required to prevent fluid damage to the lower gas lift valves as the liquid in the casing / tubing annulus is unloaded when starting up a gas lifted well. This is achieved by avoiding excessive fluid flow rates. A suitable Start-Up procedure, as recommended by the API (American Petroleum Institute), is summarised as follows:

- Provision should be made to monitor the tubing and casing pressures and the production rate (both liquid and gas) during the unloading process.
- The tubing head pressure should be blown down to the separator flowline prior to starting the unloading process. Wells that produce under natural flow will be fitted with a choke. This should be fully opened while undergoing the "kick-off" process. Continuous gas lifted wells which do not flow naturally normally do not have a choke installed (this minimises surface pressure losses).
- The Unloading Process is commenced under casing head pressure control (either manual or automatic). The casing gas injection rate is adjusted so that the pressure increases at a rate of 5 psi/min until a pressure of 400 psi is reached. An increased pressure rise rate of 10 psi/min can then be used until the system pressure is reached. The well's production rate can only be used to measure the unloading rate once the liquid level in the tubing reaches the surface. The progress of the unloading process cannot be followed prior to this point in time, unless arrangements are made to measure the fluid level in the annulus e.g. with an echometer.
- The maximum, lift gas injection rate should be less than 50% of the planned design rate. The flow rate of the liquid in the casing/tubing annulus is restricted so that the choke of the gas lift valve is not eroded (cut-out).
- There is often a drop in casing head pressure when gas is first injected into the upper gas lift valve and subsequent, lower lift valves. There will be a change in the gas injection rate, even if this drop in pressure is not observed.
- There is often a period of instability during well start up. Apart from the need to establish a steady state flow regime within the well, there are considerable longer-term changes occurring during well unloading e.g. due to the well heating up. Thus, the pressure exerted by the gas lift valve's nitrogen charge will increase as the temperature increases. This can result in a gas lift valve opening and closing more than once during well unloading.

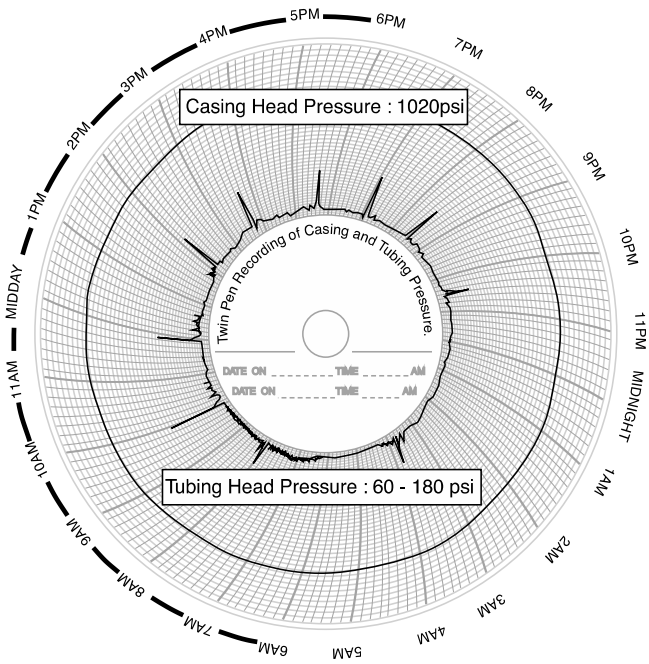
The gas lift valve settings are normally designed using the operating conditions and well temperature profile for the final, planned steady production conditions. There are several published correlations and many commercial programs available to predict this equilibrium temperature profile. By contrast few programs can predict the well conditions during the dynamic unloading process.

It is good practice to check that the well unloading process can still proceed with valve pressure settings based on a cooler temperature profile than that predicted for the equilibrium producing conditions.

9.6 Well Stability

Well instability can take several forms.

- The Casing Head pressure remains constant and the Tubing Head pressure shows significant, but regular, fluctuations. The size and frequency of these pressure fluctuations will depend on the particular combination of factors that are leading to the well instability. An example of tubing heading is illustrated in Figure 40. The casing head pressure is constant at 1000 psi while the tubing head pressure fluctuates regularly between 60 and 180 psi with a cycle frequency time of 90 - 120 minutes.



Well details	
Liquid flow rate	1300 stb/d
Flow rate gas	630 M scf/d
Water cut	98%
Cycle frequency	90 - 120 min
Gas injection rate	350 M scf/d
Well depth	3500 ft
Vertical well	

Figure 40 Example of tubing heading

- Both the Tubing Head and the Casing Head Pressure show regularly fluctuating values

Generally, the well stable flow depends on the stability conditions that exist in either 1) the tubing or 2) casing / tubing annulus. The unstable flow conditions have to exist in both flow conduits before the overall well behaviour is unstable.

The tubing stability depends on whether the changes in tubing inflow and gas injection pressure resulting from chance fluctuations in the tubing head pressure will tend to die away and return the well to the current producing conditions (the definition of stable flow). Thus, a stable well condition requires that a momentary decrease in the downhole pressure will result in a greater influx of (high density) formation fluids relative to that of (low density) injection gas. The combination of these extra inflows result in a relative increase in the average tubing density, counteracting the original, momentary decrease in downhole pressure. By contrast, unstable flow would have resulted in the well moving to a different operating point.

The casing/tubing annulus flow reflects the response of the flow of casing gas to momentary fluctuations in the Tubing Pressure opposite the operating valve when the tubing flow is potentially unstable. Thus, the well is unstable if a momentary decrease in downhole tubing pressure causes the casing pressure to decrease more slowly than the tubing pressure. The resulting increased pressure drop across the gas lift valve will lead to a greater inflow of lift gas, providing the valve is not "choked". This would tend to decrease the bottomhole pressure further – moving the well even further from its previous operating point.

Well stability can be improved by instituting choke control of the casing gas injection pressure. It is more difficult for the well to show unstable behaviour when the pressure drop across the surface choke controlling the gas injection rate is greater than the pressure drop across the downhole operating valve. This arrangement prevents the gas flowing out of the casing annulus and into the tubing at a faster rate than it is being replaced by the lift gas supply to the well. (However, the inclusion of any such extra pressure drop in the gas lift supply system may decrease the maximum gas injection rate and the well production rate.)

If a well is suffering from unstable behaviour, practical considerations will often result in the operator making the easier choice of adjusting the surface choke rather than requesting a wireline unit to change the operating valve to one with a smaller orifice. The pressure drop across the surface choke may thus become the greater pressure drop; resulting in greater tendency for annulus heading (the reverse of what was being attempted!).

- *Feel free to visualise the above instability mechanisms by sketching the system pressure dynamics.*

One further cause of casing and tubing head pressure fluctuations is valve multi-pointing. This occurs when more than one valve is passing gas i.e. gas is being injected into the tubing at several different levels. This can represent an apparently stable situation from the point of view of the Tubing and Casing Head pressures. Fluctuations may also be induced by one valve repetitively opening and closing due to the temperature changes induced by the changing flow conditions.

9.7 Dual Gas Lift

The most common dual gas lift configurations are two small tubing strings run inside a larger casing. Combinations of other sizes or even concentric strings are feasible, but rarely used.

The first problem with Dual Gas Lift completions is the well completion operation itself – there is insufficient width for the gas lift mandrels in the two strings to pass one another. This is overcome by designing the spacing of the side pocket mandrels in the two tubing strings and the dual tubing running procedure so that the gas lift mandrels do not need to pass one another during the well completion operation.

A well with a Dual gas Lift Completion can be treated as a normal single completion if only one tubing string requires gas lift. The difficulty arises in ensuring a proper distribution of the lift gas between the strings if both strings are to be gas lifted i.e. one string may take most of the gas while the second tubing is starved of gas.

One solution to prevent the valves in the different strings interfering with the operation of the other one is to install valves with significantly different operating characteristics in the different strings. E.G. one string uses IPO valves while TPO valves are installed in the second string. The gas allocation between the strings is then controlled by the selection of the chokes installed in the operating valves. An alternative solution is to install TPO valves in both strings, since they do not respond strongly to the annulus pressure. Nevertheless, practical experience shows that multipointing is a common occurrence for this design.

9.8 Trouble Shooting

To sum up, inefficient gas lift operation can be caused by:

Inflow Problems due to:

- Incorrect size of choke (too large or too small),
- Incorrect lift gas (casing) pressure (too high or too low),
- Fluctuating compressor lift gas pressures and
- Incorrect lift gas flow rate (too high or too low).

Outflow Problems can include:

- Inadequate or restricted (due to partial plugging) gas flow through the operating valve,
- Increased hydrostatic gradient across tubing due to increasing water cut and consequent reduction in the Gas-Liquid ratio of the produced fluid.
- The wellhead choke not fully opened, or the separator pressure being set too high.

Downhole Problems. These include:

- A hole in the tubing
- Incorrect operation of valves due to
  - (i) Mechanical problems with the valve operation itself,
  - (ii) Wrong pressure setting of the gas lift valve's nitrogen charge or
  - (iii) Incorrect gas lift valve spacing in the tubing string.

9.9 Trouble Shooting Techniques

Operational problems will be resolved most quickly by carrying out a systematic investigation to identify the fundamental cause of sub-optimum production from a gas lifted well. The analysis techniques used and the data gathered should include the:

- (Computer) modelling of annulus and tubing pressure profile.
- Comparison with a flowing temperature and pressure survey.
- Carrying out a production test with a range of gas injection rates.
- Performing an analysis of the historical well test and production data to identify trends.
- Carrying out an echometer survey to identify the fluid level in the casing/tubing annulus. *The echometer is an acoustic device which measures the transit time for a signal generated at the surface to travel down the annulus and be reflected back to the surface from the liquid level in the casing/tubing annulus. This time measurement can be translated into a depth provided the acoustic velocity is known.*

➢ *Feel free to attempt Tutorial 6*

10. FIELD PRODUCTION OPTIMISATION

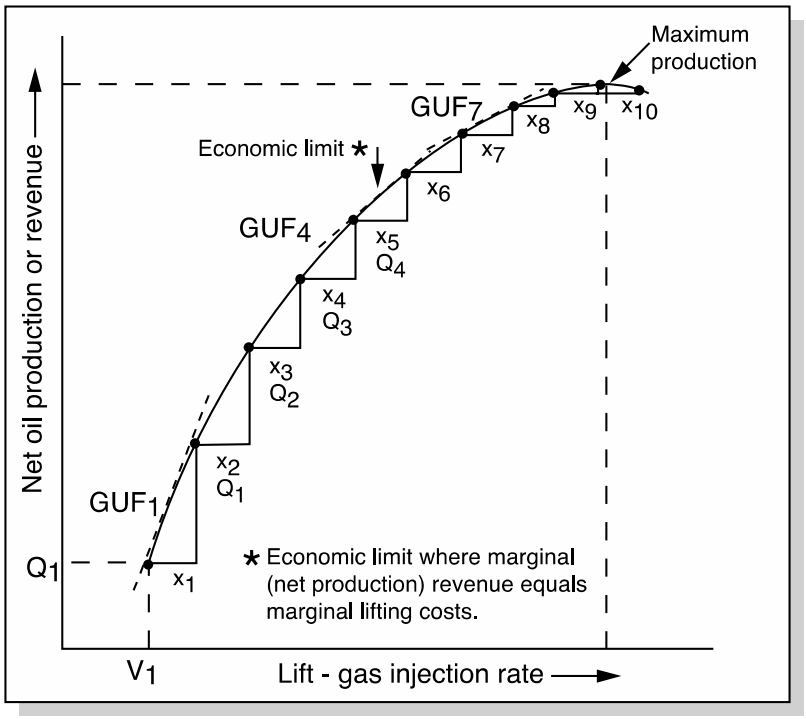
We have already discussed how to maximise the production for a single, gas lifted well. This involved the development of a (theoretical and/or computer) model of the single well's performance and its calibration against the actual well data via carrying out multi-rate well tests. A calibrated model will allow those parameters controlled from the surface {injection gas choke setting, injection gas pressure and separator pressure} to be set to their optimum values. This process requires the systematic collection, verification, storage and analysis of the field data since the (computer) model of the well can never be more accurate than the data against which the model was calibrated.

The individual well performance models for the wells in the field should now be combined to give a total field model so that the field performance can be maximised against the relevant constraints. These constraints can either be:

- Physical constraints imposed by the overall system e.g. the total, available lift gas injection rate, the volume of water that can be handled by the separation system, the (net) oil production from wells producing from different reservoirs may have to be mixed in a certain ratio to ensure that the specified crude oil quality is maintained, etc.
- Individual wells or reservoir specific constraints e.g. certain wells may have to be produced at a specified minimum rate for reservoir management purposes.

The task is then to maximise the NPV (Net Present Value – ultimate project profit in present money) or operating cash income over the life of the wells. This normally equates to maximising the current oil production by ranking each individual well's optimum production response to incremental gas injection. This concept is explained in Figure 41, where the net oil production (or revenue) is plotted against the lift gas injection rate (or production cost). A minimum (or "kick-off") lift gas injection rate, (V_1) is required to bring the well on production at the initial production rate Q_1. The well performance curve is then plotted so that the incremental production increase, (ΔQ_n) can be evaluated for equal increments in the lift gas injection rate, (Δx_n). It can be seen that the incremental GUF {Gas Utilisation Factor or (ΔQ_n / Δx_n)} decreases as the lift gas injection rate increases. In fact, the GUF represents the slope of the well performance curve (see Figure 41). This slope is also related to the factor:

$$\frac{\{\text{incremental (net oil) production revenue}\}}{\{\text{incremental (gas lift \& other) production costs}\}}$$



V_1	"Kick - off" lift gas injection rate
Q_1	Initial oil at "kick - off"
x_n	Equal lift gas rate increments
Q_n	Corresponding incremental oil production or revenue.
GUF_n	Gas Utilisation Factor

Figure 41 The incremental Gas Utilisation Factor decreases with increasing gas injection rate

This factor is plotted against the gas injection rate in Figure 42. The economic limit and the technical maximum oil production are the points at which this factor equals 1.0 and 0.0 respectively.

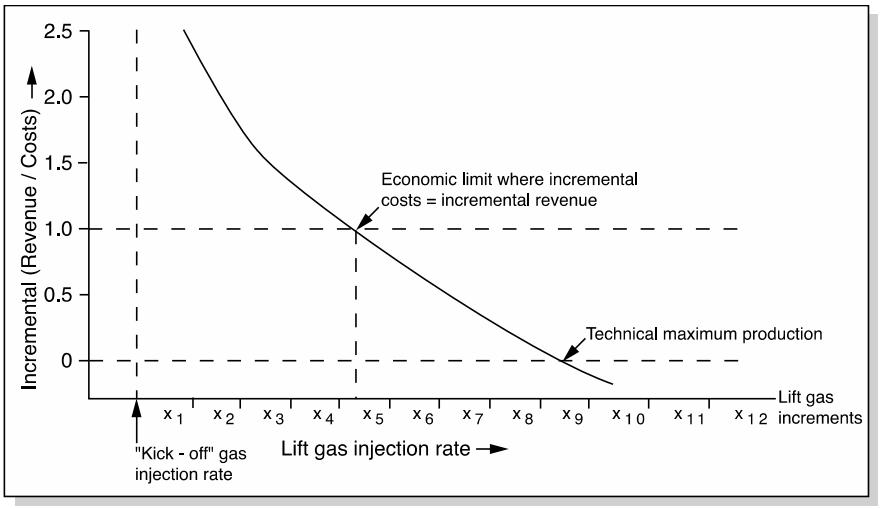


Figure 42 Gas lift incremental cost curve

Allocation of the available lift gas between wells is performed by comparing the GUF values. This calculation is complicated by the:

- Varying well "kick-off" gas requirements (Figure 43 shows three wells exhibiting different "kick-off" behaviour)
- Reservoir and well specific and other production system constraints (e.g. total water handling capacity)
- The numbers of wells involved (large gathering systems can connect more than 1,000 production wells)

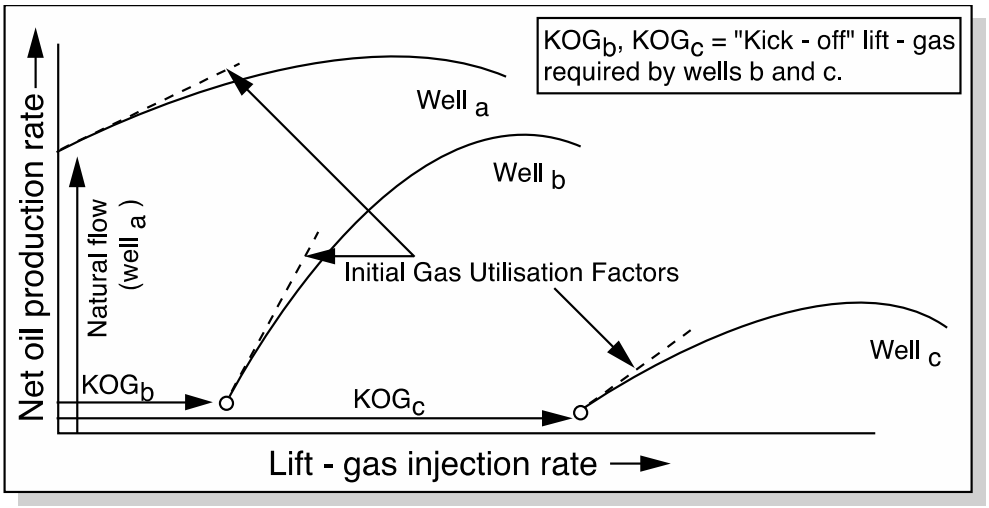


Figure 43 Well performance curves for three wells

Specialist software packages are available from a number of vendors which are capable of optimising such large systems. However, it must always be borne in mind that the optimised production recommendation results will only be as good as the input field data. Once again, this points to the need to ensure that a systematic data collection, validation and management system is installed at the same time as such optimisation packages are purchased.

Experience in many fields has shown that a sustained increase in net oil production can be achieved by a dedicated engineering effort to provide continuous optimisation of the gas lift systems performance. Large fields often require employing an engineer solely to manage gas lift and to obtain the commitment required from the operations staff with respect to data gathering etc. This provides the information required to overcome the typical gas lift operational problems summarised in Figure 44 so that deviations from optimum operation can be identified and rectified as quickly as possible.

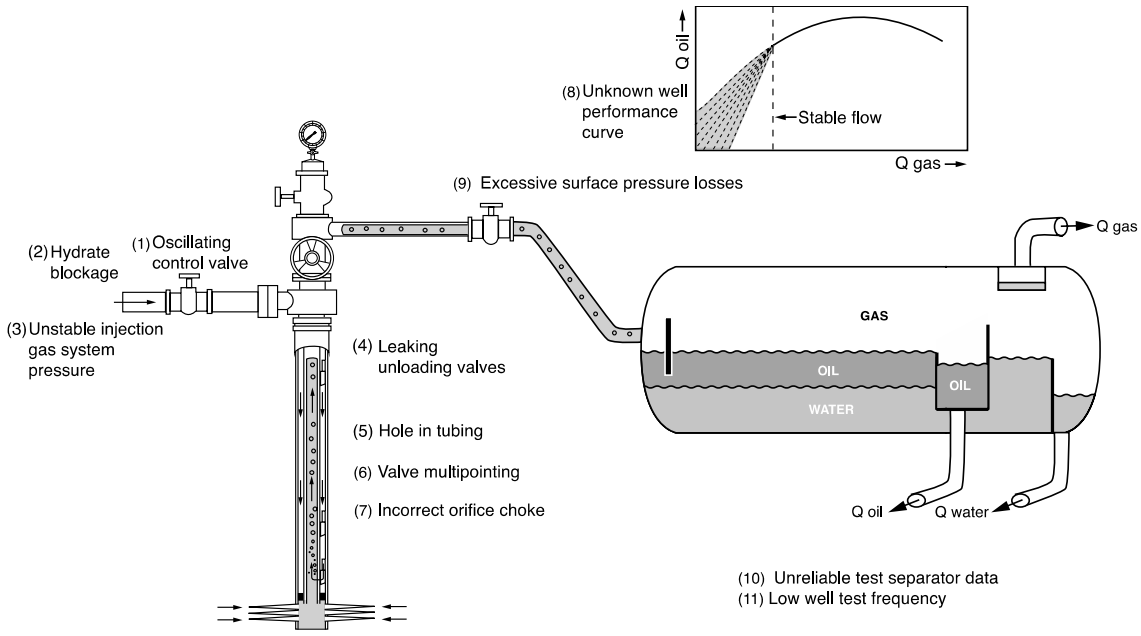


Figure 44 Problems for gas lift system management

➢ *Feel free to attempt Tutorial 5*

11. INTERMITTENT GAS LIFT

All the above has discussed continuous flow gas lift. The intrinsic flexibility of the gas lift concept allows it to be adapted to a wide range of situations; however, it does become inefficient at low formation fluid inflow rates (typically <150 bf/d with a $2^3/_8$ in OD tubing rising to < 300 bf/d for a $3^1/_2$ in OD tubing). A partial answer to the problem is intermittent lift where the gas injection is switched on for a short period of time at regular intervals:

- The formation fluid level in the tubing increases during the periods that the gas lift is switched off.
- The formation fluid that has collected above the valve is lifted out during a period of lift gas injection.
- The flow of lift gas to the well is halted and the cycle is repeated.

A time cycle controller ('intermitter') opens the surface lift-gas valve for a predetermined time period at regular intervals and then shuts it. The process typically produces some 2-5 bbls of liquid per cycle with a frequency of 1-3 cycles per hour (Figure 45 and Figure 46). The valve spread (or difference between pressure needed to open and close the valve) controls the minimum amount of gas used during each intermittent gas lift cycle.

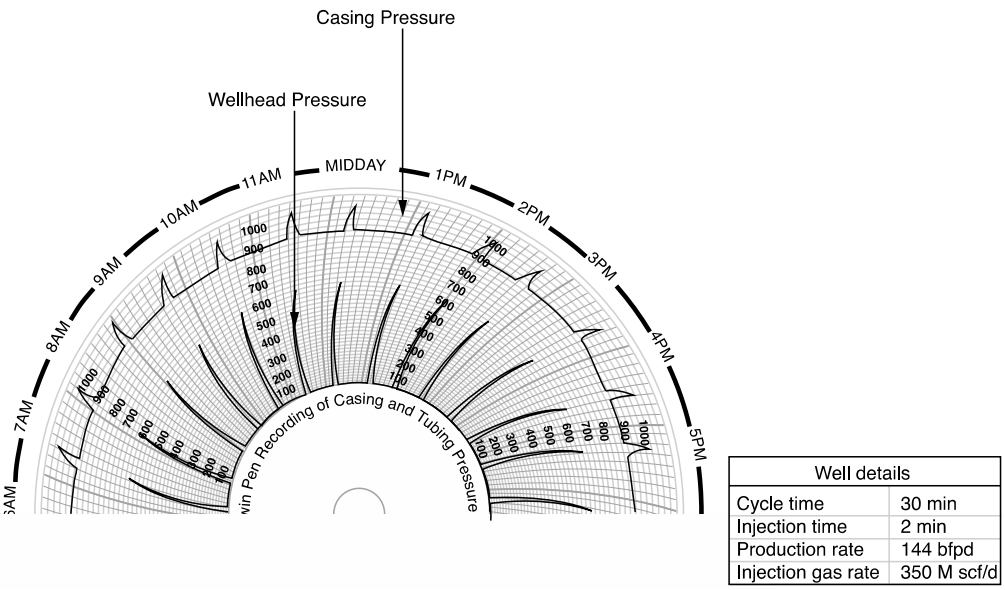


Figure 45 Intermittent gas lift.

This process requires relatively high gas volumes due to the fall back of the liquid (of the order of 10% of the tubing volume) present in the tubing at the time when the gas is switched off. This inefficiency can be removed by incorporating a plunger to displace all the liquid to the surface, the plunger itself having been displaced up the tubing by injecting lift gas underneath {see Figure 6(e)}. The process is as follows:

- The plunger displaces the fluids that have entered the well during the period that the lift gas was shut off.
- The flow of lift gas is halted once the plunger reaches the wellhead and the cycle repeated.

This process is also known as Plunger Assisted Intermittent Lift (PAIL). PAIL also has particular advantages when the well is suffering from severe wax deposition since the regular passage of the plunger ensures the tubing remains clear of wax.

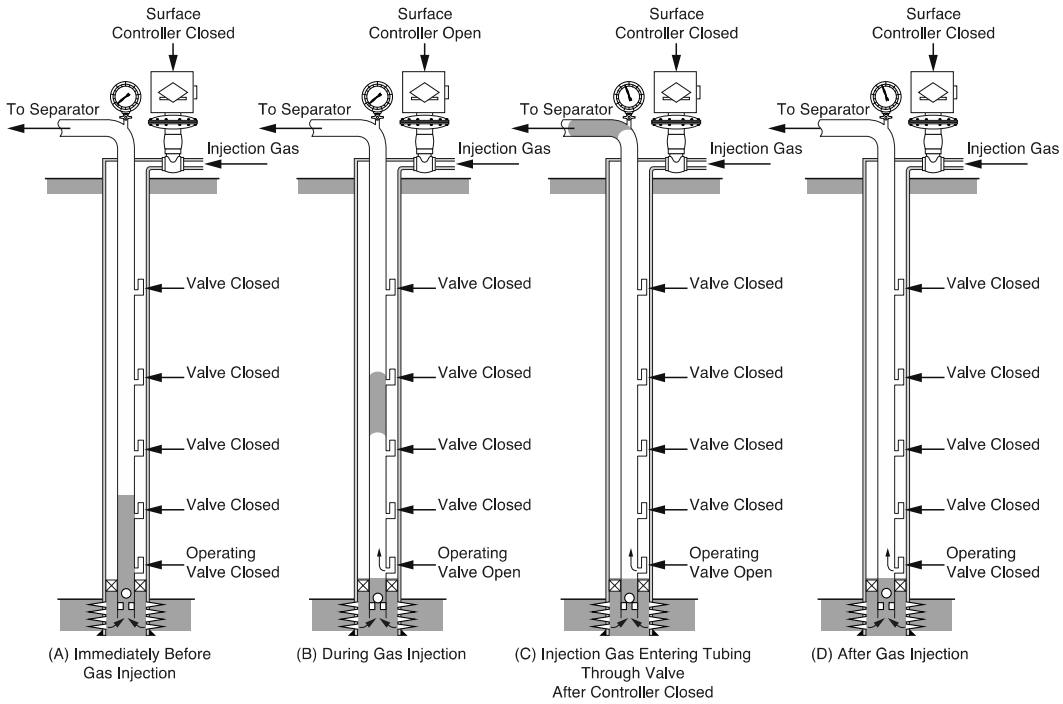


Figure 46 Intermittent gas lift.

It is sometimes more efficient and stable to pressurise a smaller chamber instead of the whole annulus before releasing the gas into the tubing. The chamber may be achieved e.g. between the production packer and a second packer installed above it.

Intermittent lift and/or Plunger lift can also be used in gas or gas-condensate wells to unload liquid at regular intervals. The liquid loading rate must be first detected and further estimated to design the right cycle in this case. Models like Turner's equation to predict the critical gas velocity able to lift liquid droplets are used for this.

12. FURTHER READING

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CHAPTER 6: PERFORATING

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LEARNING OBJECTIVES

(All Examinable)

Having worked through this chapter the Student will be able to:

- Understand the importance of perforation charge design and identify factors that influence charge performance.
- Describe how charge performance is measured.
- Describe and compare the options for perforating gun conveyance into the well.
- Describe the difference between underbalanced and overbalance perforating.
- Understand the conditions affecting the perforation plugging and cleanup.

1. INTRODUCTION

The majority of completions are cased and cemented and require perforation to connect to the reservoir.

Shaped charges, or jet perforators, are now almost exclusively used. Here, a series of explosive charges are lowered into the well; suspended either from a wireline cable, a tubing or a drill string. Once the charges are at the required depth, they are detonated to produce a series of perforations through the wall of the casing, the cement sheath and into the formation. This perforating technology is the focus of this chapter.

(A side note: One alternative to such perforating is high pressure abrasive jetting. This involves pumping of a slurry of abrasive particles that exits the drill string or coiled tubing through a nozzle as a high velocity, focused jet. The nozzle, positioned at the required depth, directs the jet onto the casing wall. The abrasive jet cuts a hole through the casing.)

A properly designed and executed perforated completion provides control of the reservoir depletion process and maximises well productivity/injectivity by:

1. Bypassing formation damage (provided the perforations are sufficiently long).
2. Providing selectivity between intervals through flow control of reservoir fluids produced from different layers (provided the cement sheath is isolating and is not damaged e.g. by the very process of perforating).

➢ *Discuss how the perforation intervals can be selected.*

2. SHAPED CHARGE

In general, the key considerations in designing the perforating programme for a well are Completion Efficiency, Costs and Safety. A large number of design parameters and operational conditions affect the performance of shaped charge perforators, including:

2.1 The Shaped Charge

The basic shaped charge (Figure 1) consists of:

- The main explosive charge in a case or container.
- A conical liner. Its conical shape directs the explosion gas (and the liner's particles) outwards in the form of a jet.
- The primer charge (a.k.a. fuse, booster or detonator). It is actuated by the detonating cord, e.g. due to its heating by electric current.

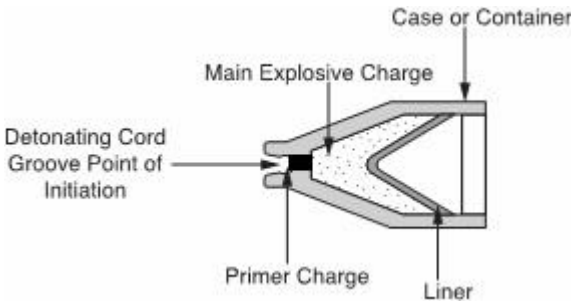


Figure 1 Main components of a shaped charge.

2.2 Explosives

The different types of explosives used in shaped charges are illustrated in Figure 2.

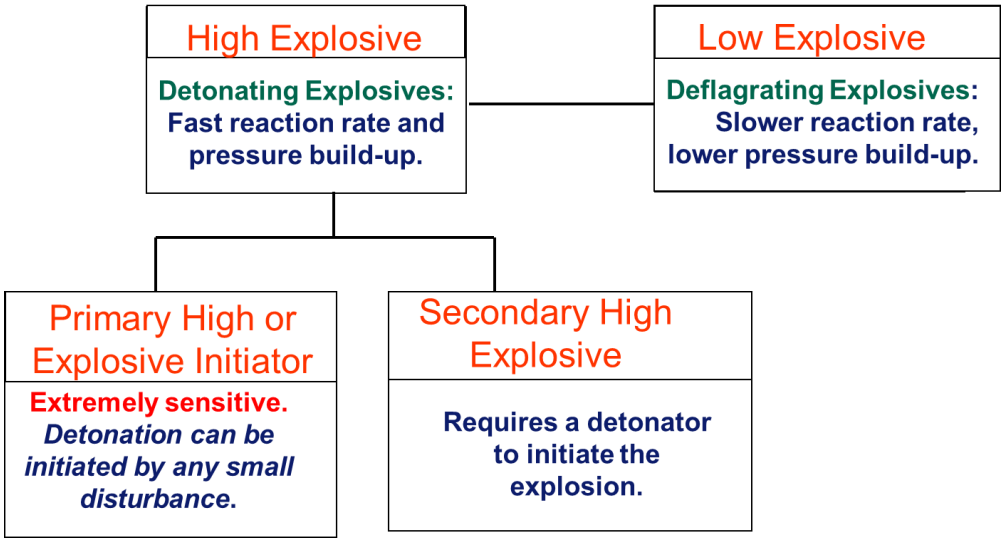


Figure 2 Types of Explosives.

The main (high) explosive charge is a high specific energy, but relatively insensitive, secondary explosive (Figure 2) i.e. it is difficult to make it explode since this requires a detonator; but when it does detonate there is high energy released per unit weight of explosive in a very short time. The detonator can contain either primary or secondary high explosive depending on the expected detonating conditions. Detonation of the main charge is complete after only 100 - 300 μ seconds. *This fast reaction time is typical of a high explosive rather than a low explosive (also called a propellant or a deflagrating explosive, in which the latter's energy release occurs at the much longer time scale of seconds rather than micro-seconds.)*

2.3 Detonation

The design of the shaped charge allows this extremely fast release of the exploding charge's detonation energy to be concentrated on a very limited target area. The main explosive is contained within a container made from either a material that disintegrates into small fragments e.g. ceramic, or from a metal which has the advantage of helping to contain and direct the explosive force onto a specified target area.

The target area depends on both the diameter of the area when the explosion exits from the charge case and the distance between the shaped charge and the target area (a.k.a. 'gun clearance'). The liner concentrates the explosive force; the tighter the cone the longer, but narrower, the perforation is (Figure 3).

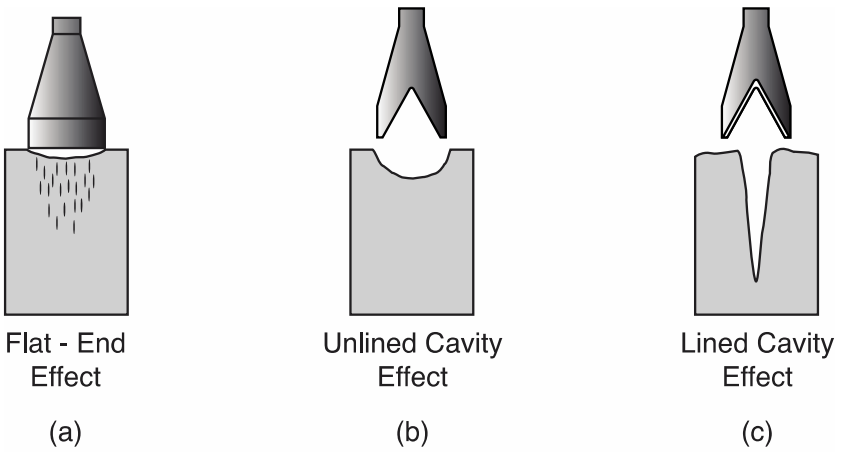
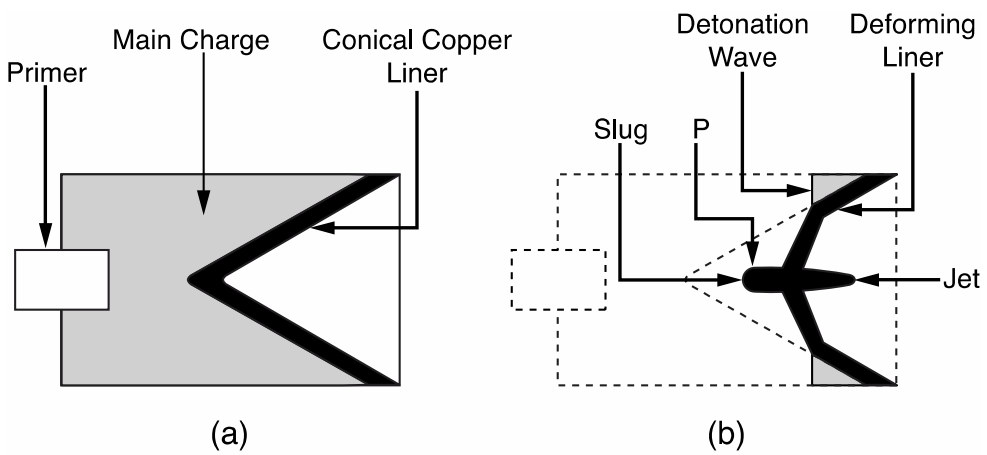


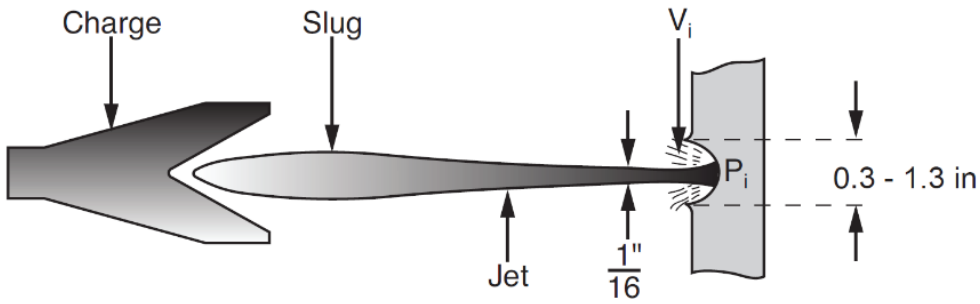
Figure 3 A conical shaped charge with a liner provides the greatest penetration depth.

The explosive detonation is actuated from the surface by either an electrical current (for wireline-conveyed guns) or by mechanical, hydraulic, or electrical means if the gun is tubing-conveyed. This actuates the gun's firing head that triggers the detonation. The detonation wave moves symmetrically through the main explosive charge at a speed of about 30,000 ft/sec. This detonation wave causes the liner to flow towards the centre of the cone (Figure 4) to form a fast-moving jet of gasses and fluidised liner material. The volume of explosive is greatest at the apex of the liner and least near its open end. This means that, as the detonation front advances, it activates a continuously reducing weight of explosive. This reduction in the available energy reduces the liner's speed of collapse; producing a slug or tail of fluidised material (Figure 4c). Approximately ⅓rd of the lining material typically forms the jet and ⅔rds - the slug.

2.4 Creating the Perforation

The penetration depth is proportional to the diameter of the high velocity jet: the jet diameter should be reduced to increase the penetration depth (Figure 5) for a given weight of explosive. The explosive loads vary from a few grams (small charges) to tens of grams (for big, chicken egg – size charges).





(c)

Figure 4 Liner forms the jet during detonation which impacts on the target.

The jet has a velocity of ~ 20,000 ft/sec. and an impact pressure on the casing of > 5 x 10^6 psi {(Figure 4(c)}. This high impact pressure causes the casing to become plastic and flow away from the jet's impact point (creating a burr on the outside wall, and sometimes also a small burr on the inside as well due to inappropriate clearance). The shockwave created by the impact of the jet results in the crushed zone around the perforation tunnel. Part of the displaced cement and rock, along with the charge's fluidised material including the slug, also form debris deposited at the tip of the perforation tunnel plugging this tip.

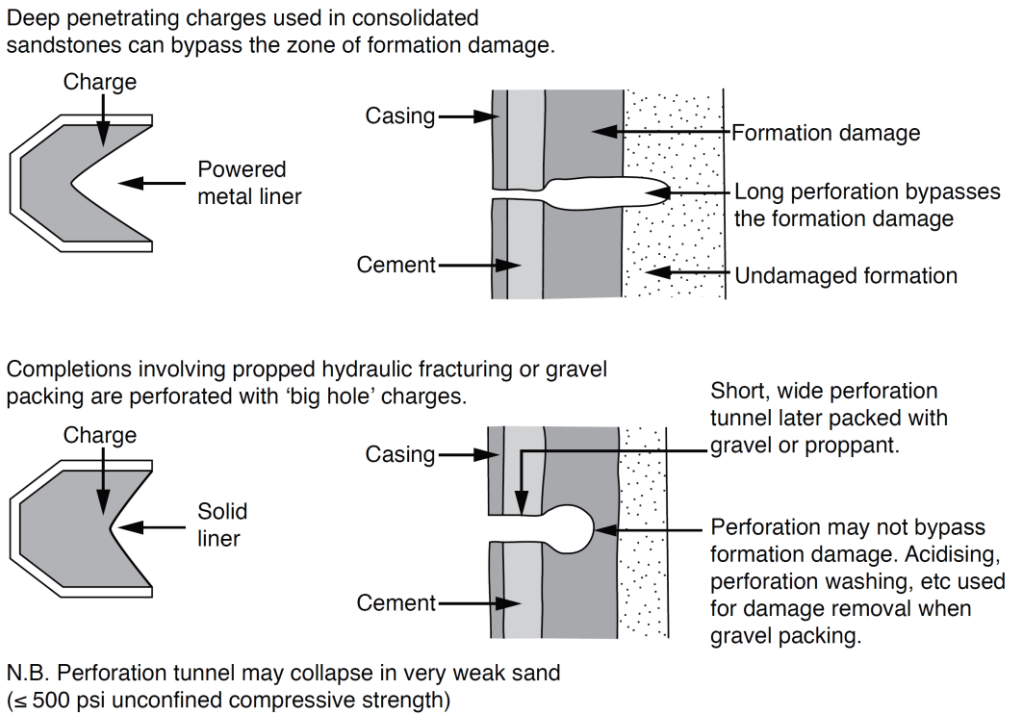


Figure 5 Charge size, shape and liner characteristics all influence the perforating charge's performance.

Figure 6 shows the perforating process. The slug, following the jet at a much slower velocity of ~1000-3000 ft/sec, does not significantly contribute to creation of the perforation.

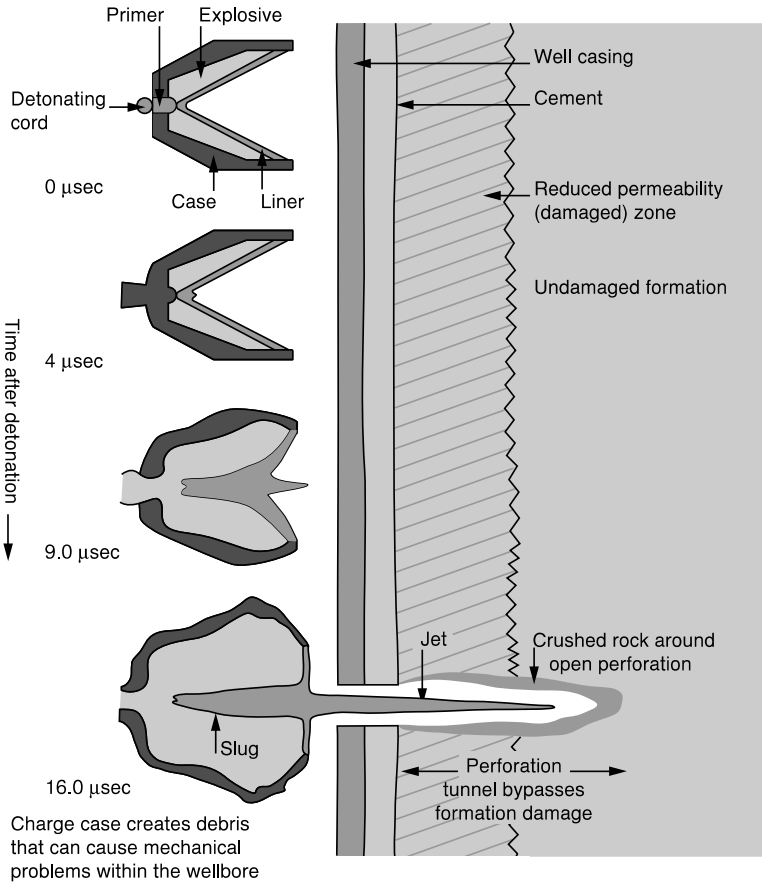


Figure 6 High speed x-ray photographs illustrate shaped charge detonation.

The rock is not vaporised during the process of creating the perforation. Instead, the shockwave created by the penetrating jet both shatters the grains and reduces the porosity, or compacts, the formation rock as it penetrates. The consequent perforation tunnel and surrounding formations will thus consist of several zones in which the natural porosity and permeability of the reservoir rock has been severely degraded (Figure 7).

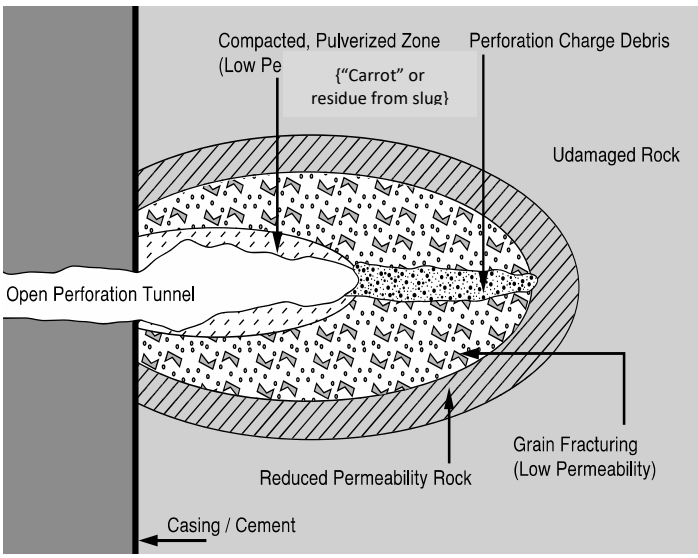


Figure 7 Formation damage around perforation; and debris blocking the perforation tip

As far as the shaped charge's liner design is concerned:

1. Conventional completions employ a deep penetrating charge that aims to bypass any near wellbore formation damage. Deep penetrating charges often employ a sintered metal liner formed into a low angle apex cone in order to create long, but small (~ 0.25-0.5 in.) diameter, perforations.

2. Gravel packed and propped hydraulic fractured completions require wider diameter perforations that can be packed with gravel/proppant grains (such grains can be as large as a few mm in diameter). The main explosive charge in this case is formed into a cone with a wide diameter and normally a copper liner. This design of a shaped charge creates a wide (< 1.0 in.) diameter perforation tunnel that can be filled with gravel or proppant and reduces the pressure losses when fracturing/packing or producing from a fracture/gravel pack.

There are always exceptions to the above rules, e.g. high productivity wells may show high flow turbulence in narrow perforations and thus will require wider ones; or frack-and-pack completions (i.e. the wells completed with a short hydraulic fracture together with a gravel pack) may need a perforation size even bigger than the conventional hydraulically fractured ones.

2.5 Factors Influencing Charge Performance

The performance of a shaped charge is measured by the perforation's length, flow efficiency, diameter, volume, the volume and mass of debris, and the burr height on the inside of the casing around the perforation entrance hole. However, predicting charge performance is a complex matter. It will be affected by the explosive type and load, material and configuration, the dimensions and shape of the charge and, most importantly, the characteristics of the conical liner, the gun clearance, the strength characteristics of the formation and the wellbore conditions. The characteristics of the conical liner were already discussed above. The perforating charge supplier normally provides software or models to predict the charge penetration as a function of the following conditions:

2.5.1 GUN SIZE/EXPLOSIVE CHARGE SIZE

The size of the perforating gun and perforating charge dictates the maximum explosive load of each charge and the gun clearance. In general, both the penetration and the diameter of the entrance hole will increase as the gun diameter, and hence the maximum possible size of explosive charge, increases.

2.5.2 WELLBORE FLUID PRESSURE, TEMPERATURE AND DENSITY

The impact of well pressure on charge performance is small with respect to penetration.

Elevated well temperatures and extended exposure times will significantly degrade the charges with consequent poor performance. Employing a high temperature explosive (HMX or HNS) for the main charge rather than the standard RDX will mitigate this. The short exposure time associated with wireline rather than tubing conveyed gun is also advantageous here (Table 1).

Explosive type	Wireline conveyed (~1 hour exposure)	Tubing conveyed (100 hour exposure)
RDX	160° C	110° C
HMX	200° C	140° C
HNS	260° C	230° C

Table 1 Typical maximum allowable reservoir temperatures for different types of explosive.

2.5.3 GUN CLEARANCE

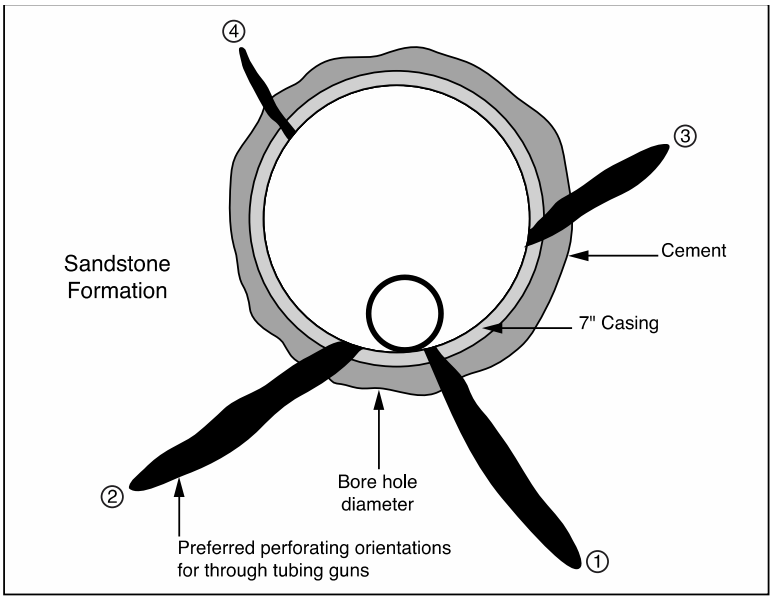


Figure 8 Perforating performance with a small diameter gun in a large diameter casing.

Centralisers are not always employed while perforating due to the risk of the gun becoming stuck due to the centralisers being damaged by the shock wave created during the perforating process. The length of the perforations created by firing a perforating gun of slightly smaller outside diameter than the casing's internal diameter will all be similar. The orientation of the charges will not be important. Gun clearances of around 0.5" are often optimal, though they should

- not be too small (which results in a high impact on the casing. The guns also slightly 'swell' after perforating and can get stuck on the way back if too big)
- nor too big (the jet's energy is dissipated on the way to the casing, Figure 8).

By contrast, a small diameter, through tubing gun in a large casing will show very different penetration depths for the different perforation orientations (Figure 8). This occurs because the perforating gun will always lie against the low side of the hole since wells are never perfectly vertical. This problem is solved for a small diameter gun by having all the perforating charges oriented/pointed in the same direction {called 'in-line' or '0° phasing' perforation, see Figure 9 and Figure 10 (a)} or by having only two lines of perforations at 90° to each other (like e.g. perforations 1 and 2 in Figure 8). Further, a magnetic positioning device and/or a swivel sub can be used to orientate the gun so as to ensure there is a minimum clearance between these perforating charges and the casing wall.

In horizontal wells, in the cases where vertical perforations are preferred (being more stable i.e. not collapsing nor producing much sand) to decrease the risk of sand production, specialised perforating systems have been developed recently which are capable of orientating multiple, perforating gun sections with a total length of more than 1,000 ft. to within ± 10° of the vertical. The orientation system consists of weighted spacer sections that gives a vertical orientation, low friction swivels which align the individual gun sections with one another and locking adaptors which stop the gun sections rotating and twisting relative to one another, e.g. when the guns pass through a dogleg.

2.5.4 COMPRESSIVE STRENGTH OF FORMATION ROCK

The charge penetration decreases with increasing rock compressive strength and formation in-situ stress.

2.5.5 STRENGTH OF CASING AND RADIAL SUPPORT BY THE CEMENT SHEATH

A thick casing constructed from high grade tensile steel will absorb more perforation energy than a thin, lower strength casing.

On a side note: perforating reduces the structural integrity of the casing. This reduction is normally 20% or less providing the perforation diameter is less than 1.0 in. and the perforation density is less than 12 shots/ft. The detonation of through tubing guns however, with their in-line series of charges, can cause splits in the casing, though modern gun designs reduce this risk.

2.6 Perforation Charge Arrangement

Preparing the perforation gun consists of assembling a number of charges on a charge carrier (see examples in Figure 21). The distance between adjacent perforations determines the number of shots per unit length of gun (the shot density). The shot density varies from low (< 1 shot per ft or SPF) to high (> 12 SPF). The chosen shot density will depend on the required well productivity (e.g. see notes on the "limited entry" skin in Chapter 3), the need for injection or production control along the completion interval, and the reservoir rock's vertical permeability and strength.

- *Feel free to attempt Tutorial 1*

The charges are orientated to shoot in specific directions. The angle between adjacent perforations is called 'phasing'. Figure 9 shows some of the many options available.

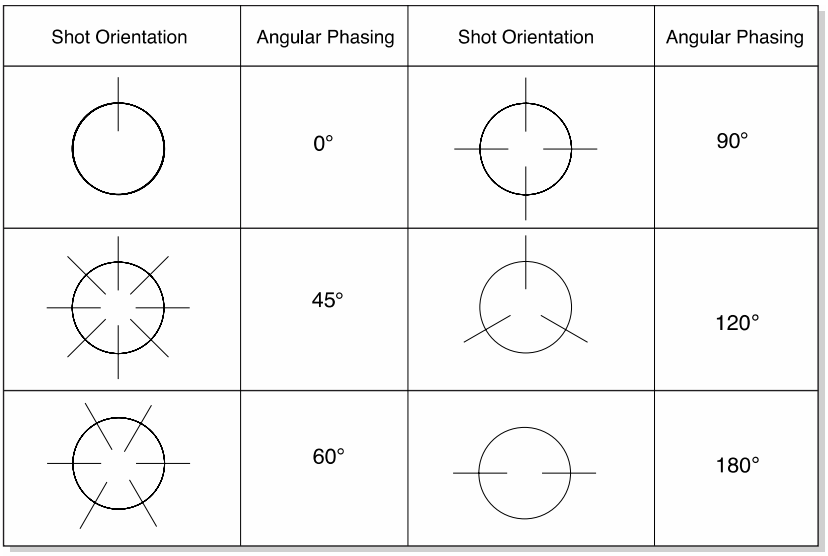


Figure 9 Perforation phasing.

Many perforation phasing options exist for each shot density e.g. 4 shots fired at 0° (a.k.a. 360° phasing) and 90° are illustrated in Figure 10.

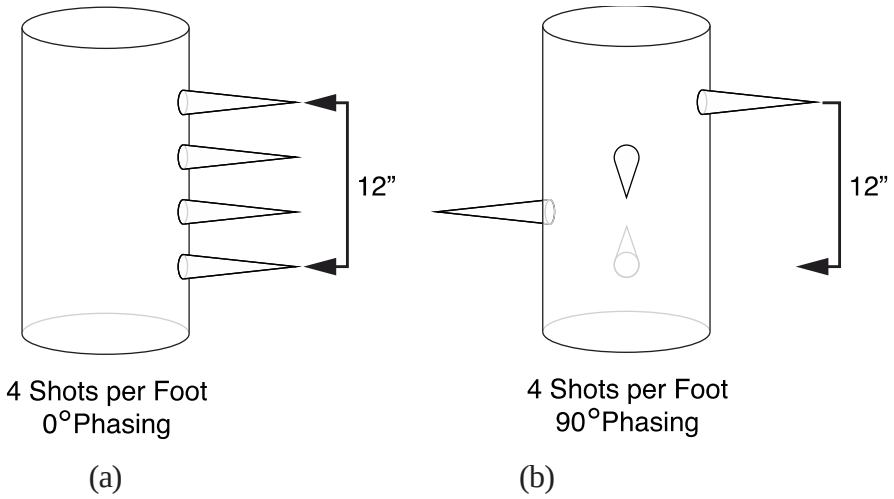


Figure 10 Perforation arrangement for a four shots per foot (i.e. 4 SPF) gun fired at 0° and 90º phasing.

2.7 Impact of Perforation Design on Flow Performance

Field observations and perforation flow performance models allow modelling and selecting a perforation design in order to achieve the desired productivity or injectivity. Such observations or models however cannot accurately describe all the multitude of in-situ factors affecting every given perforation, and thus they provide only approximate estimates, so their primary use is often to compare relative difference between alternative designs when proposing one. It should also be noted that one of the major factors defining perforation success: the fraction of unplugged, effective perforations clean of debris and other solids and actually flowing is difficult to predict or measure. It is also not uncommon to have only 25% or less of the created perforations effectively flowing, with the rest plugged. The observations listed below in this section discuss such effective (i.e. flowing) perforations.

The popular perforation flow performance models used to predict the well's perforation skin include the ones by Locke; Karakas and Tariq; Hagoort; and others. Many of them calculate the total perforation skin as a combination of the skins due to: the effective perforation length, phasing, density (this skin also depends on the vertical permeability), crushed zone, formation damage, and wellbore size. The perforation description model is often simplified to an open cylinder (Figure 11):

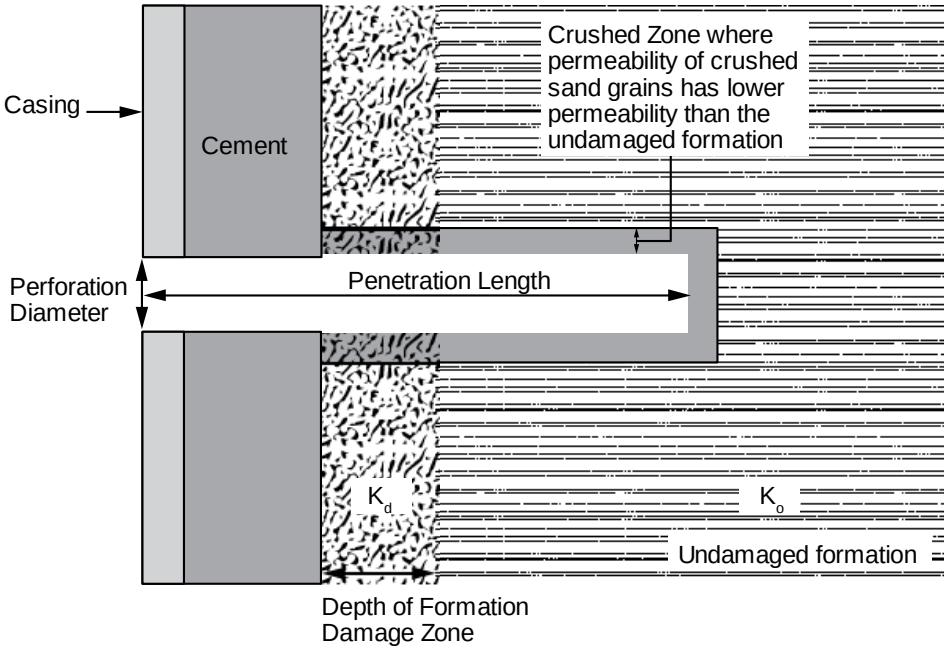


Figure 11 The perforated completion model. The penetration length is actually the effective (clean) length open to flow.

The resulting well performance is known to be affected by the:

- **Perforation length** – longer perforations are more productive since they increase the effective wellbore radius. However, very long perforations *(over 7 in)* often show limited improvement. Often what's more important is the perforation length relative to the:

- **Depth of the Formation Damage and its Permeability reduction**

Near-wellbore the formation damage reduces the well productivity significantly (Figure 12). Deep penetration perforating charges that have one third of their length beyond the formation damage zone effectively by-pass the formation damage and can even provide productivity/injectivity greater than the equivalent open hole well.

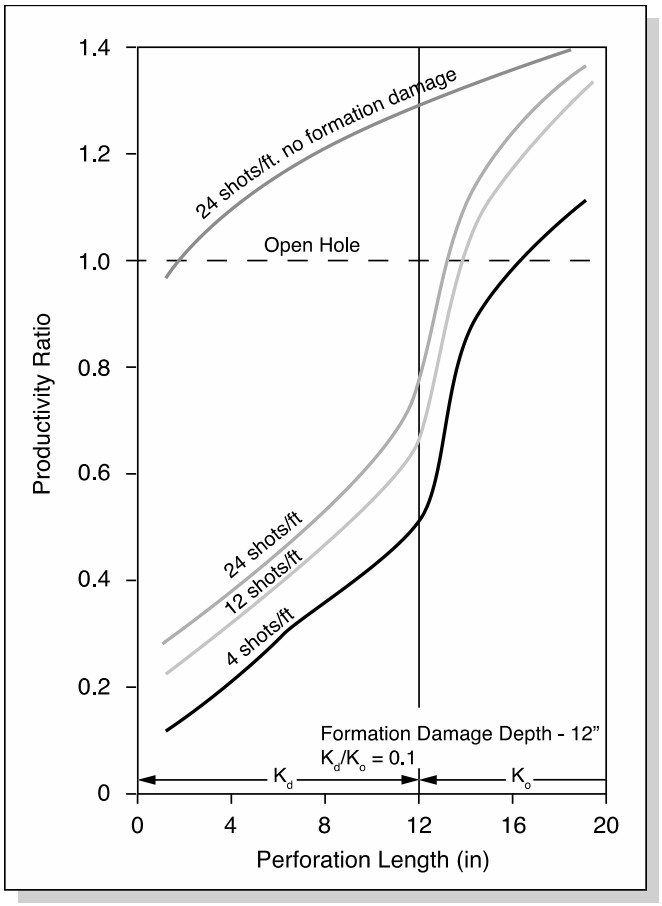


Figure 12 Perforation penetration through damage zone increases well productivity.

Naturally, as a minimum the effective perforation also has to bypass the cement sheath, which may be a problem in washed-out wellbores the diameter of which was significantly increased during drilling and was later cemented.

For some specific completions like hydraulically fractured or frack-packed wells the length of the perforation may be less important, as long as the cement sheath is bypassed, since the subsequently created fracture will extend into the formation. In other applications like perforating gun-type tubing punchers (unlike the mechanical punchers discussed in Chapter 2) the perforation length should be very short, only to perforate through the tubing to allow subsequent well circulation.

- **Perforation diameter** – In conventional applications a perforation diameter of around 0.25-0.5" is sufficient.

Wider perforations will show a reduced frictional pressure loss along the length of the perforation. This is usually only required in wells with a high flow rate per perforation to reduce the turbulence effects (see e.g. Figure 16). *Also, in gravel packed and fractured wells so that the perforations can admit gravel/proppant as was mentioned above.*

- **Perforation phasing** – a smaller angle between adjacent perforations increases the well productivity as it approximates radial inflow (Figure 14). However, it is commonly observed that as long as the phasing is not around 0º (i.e. if it is 180º or 90º or so) the phasing effect is limited.

Figure 13 illustrates how perforations with 0º phasing force the fluids to flow "round the casing", creating an extra pressure drop.

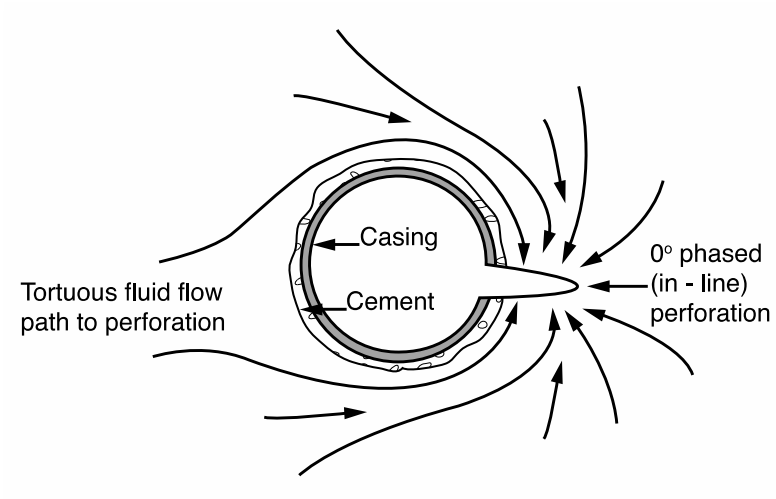


Figure 13 0° phasing (in-line) perforations reduce well productivity.

In special applications like wells planned for hydraulic fracturing, small phasing may be preferred, e.g. 45° or 60° to reduce the angle between the fracture orientation and the perforation directions (at least for some perforations).

- **Perforation density** – reducing the distance between perforations will increase the well productivity, especially when the permeability in the vertical direction is significantly lower than the horizontal value (Figure 14 and Figure 15). Otherwise, in the formations with good vertical permeability and not very high production rates the shot density often has limited effect after 4 SPF.

  Special cases like gravel packed wells may need high perforation densities to increase the area open to flow.

Figure 14 compares the effect of perforation density and phasing. In this typical example, avoiding the tortuous flow paths associated with 0° phasing has a greater influence on the well productivity than the perforation density.

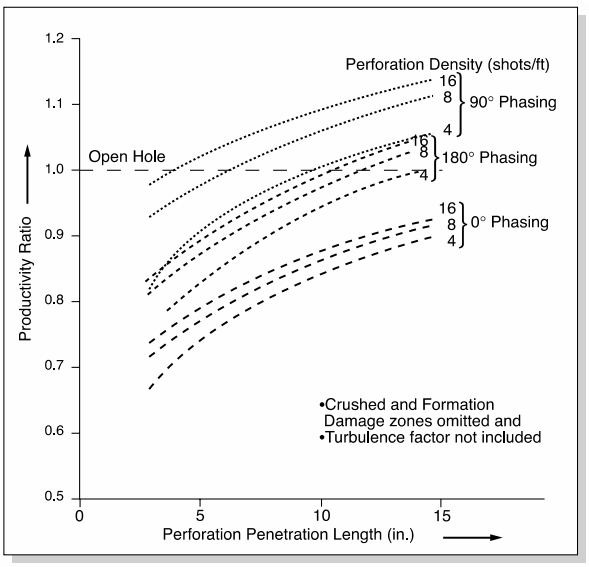


Figure 14 Influence of perforation density and phasing.

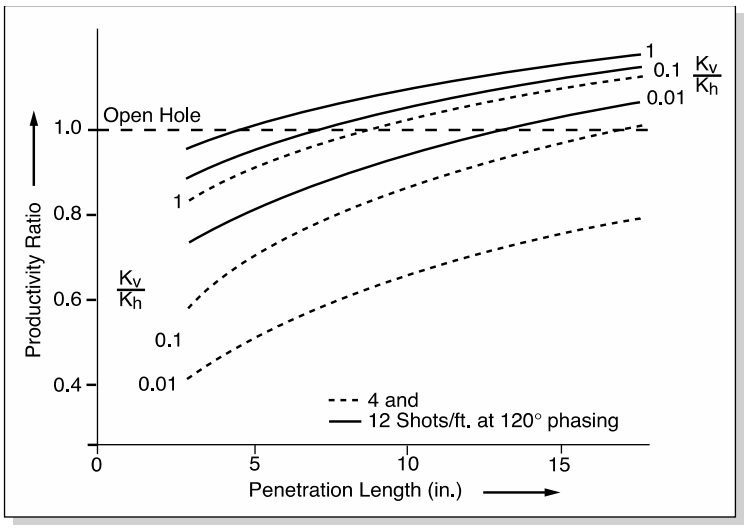


Figure 15 Influence of vertical and horizontal formation permeability and perforation density on well production.

- **Permeability and depth of the crushed zone around the perforation**. This can add significant pressure loss (Figure 16). The typical crushed zone thickness of 0.2-0.4" with the permeability of less than 20% of the original permeability can add extra skin of over 10. Perforation clean up procedures should remove the crushed zone prior to production being initiated.

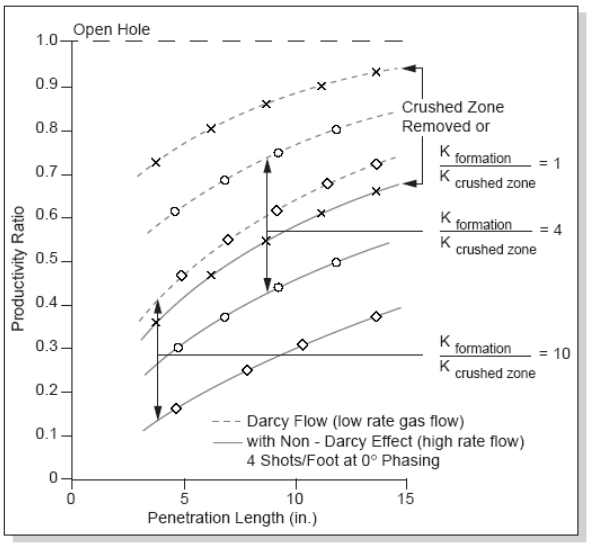


Figure 16: Example illustrating impact of the crushed zone permeability and turbulent (non-Darcy) flow on well productivity

- **Flow Rate and properties of the produced fluids** – high gas flow rates through the perforation and very high oil flow rates lead to extra pressure losses due to non-Darcy flow effects in the formation (Figure 16).

➢ *Feel free to attempt Tutorial 2.*

➢ *Propose a well and reservoir configuration situation and discuss what perforation design would suit it.*

3. ASSESSMENT OF PERFORATING CHARGE PERFORMANCE

3.1 Standard Charge Performance Tests

There have been developed a multitude of perforating charges. The American Petroleum Institute's Recommended Practice 19B (API RP 19B) describes of a series of standard tests that allow a comparison of the performance of the many available perforating charges.

N.B. API RP 19B is the successor to API RP 43. API RP 19B, though similar to the earlier API RP 43, has a more detailed specification of the test preparation procedures and includes the section 5 test. Further, API RP 19B also requires the tests to be witnessed by an independent third party.

Section 1 of this practice compares the perforations created by firing multiple charges in a short length of gun under standard firing conditions. Section 2 assesses the impact of confining pressure on the physical dimensions of the perforations created in a sandstone sample confined by a simulated over burden pressure. Sections 3 and 4 deal with the effects of temperature on charge performance and assess the flow capacity of the perforations respectively. Section 5 quantifies the volume of debris created with expendable charges. The results of these tests are extensively used in models and correlations to predict the actual charge performance in a given well, so as to select the right charge and gun design. Therefore, some more details about these tests are provided below.

3.2 API RP No 19B Section 1

The section 1 test evaluates the perforating systems under surface conditions. A perforating gun system is fired into a casing which has been cemented with concrete into a drum (Figure 17) with a minimum compressive strength of 4,000 psi. The clearance and position (eccentricity) of the gun containing several charges is measured prior to perforating. The following is measured after the perforating: the

- Burr height (if any) on the inner wall of the casing.
- Entry hole (EH) diameter, average diameter and length of each perforation.

The Section 1 test provides comparative data on the dimensions of the perforations produced under standard conditions by the many types of shaped charges. The performance for a specific reservoir lithology or with realistic in situ stresses is not measured i.e. it does not predict quantitative information on the actual perforation characteristics that might be achieved when perforating a real, downhole completion.

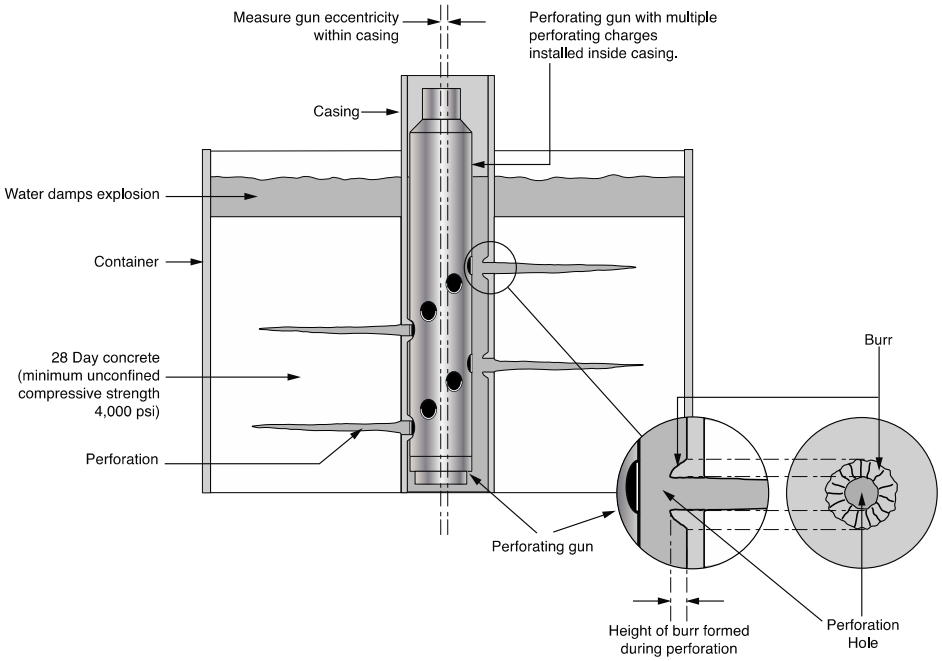


Figure 17 API RP 19B Section 1 fires a short perforating gun into a drum of concrete

3.3 API RP No 19B Sections 2, 3 and 4

Section 2, 3 and 4 tests perforate a 4" diameter Berea sandstone core with a single charge (Figure 18). *(Berea sandstone, mined in the US, has fairly uniform permeability and porosity, which makes it an excellent rock to be used in many benchmark tests in petroleum engineering).* Section 2 evaluates the effect of the casing grade and its thickness, the cement strength and thickness as well as the rock strength including the overburden stress. Section 3 examines the effect of exposure to high temperature on charge performance. The Section 4 test evaluates the perforation's flow performance, though the flow regime limited by the core size (Figure 18) is a simplification of reality. However, it does provide a useful comparison between the performances of different perforation charge designs.

The perforation geometry measured in these tests, apart from the EH and the average diameter, include the perforation lengths:

- Overall perforation (OAP) length: measured from the casing entry to the tip;
- Total target perforation (TTP): equals OAP minus the perforation end plugged by debris;
- Total core penetration (TCP): similar to TTP but measured from the core entry.

The ratio of the perforation flow rate and the flow rate from a hole drilled with the same average diameter and TCP is called Core Flow Efficiency (CFE). It is usually about 0.7-0.9 due to the additional pressure losses in the perforation across the crushed zone.

The Effective Core Penetration (ECP) is defined as TCPxCFE. Either TCP or ECP are used as the 'perforation length' in the perforation skin calculation models (e.g. in the open perforation model in Figure 11).

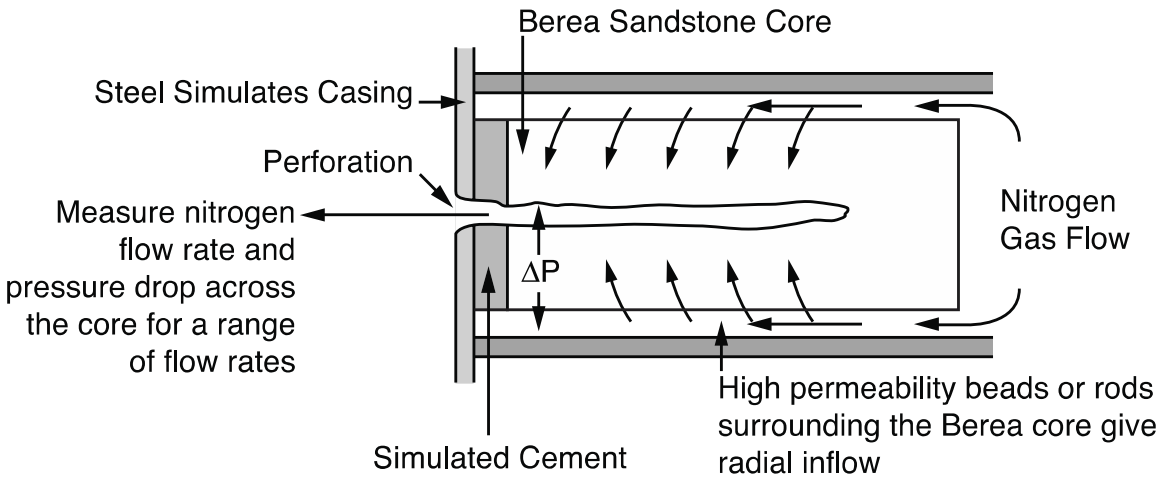


Figure 18 API RP 19B Section 4 single perforation flow test.
N.B. Section 2 and 3 tests use the same equipment, but without flow.

The flow test can be either *positive* where the 'wellbore' fluid pressure is higher than the core fluid pressure (thus simulating overbalance perforating) followed by the decrease in the wellbore pressure to simulate perforation cleanup; or *reverse* for underbalance perforating simulation.

3.4 API RP No 19B Section 5

The volume of debris created by an (semi or completely) expendable perforating gun during its recovery can cause problems during subsequent well operations. E.g. the weight of debris in a long perforation interval (hundreds of meters) can reach several tons, with subsequent problems of circulating it out and/or leaving in the sump (a.k.a. 'trash dump'. The drilled and cased interval below the production zone) hole, if there is one. Section 5 of API R 19B measures the volume of debris using the Section 1 test experimental equipment with a perforating gun with a length of at least 2.5 m.

3.5 Prediction of Inflow Performance of a Perforated Completion using API RP 19B test data

The results of these tests can be used in the models developed to approximately predict the charge performance at a given well's conditions (the conditions such as in-situ pressure and temperature, rock strength, casing and cement specifications, and fluid properties). A mathematical model must be developed to translate the comparative data generated for a particular perforating charge under the API specified laboratory test conditions into an absolute, inflow performance prediction for specific downhole conditions. Different models for prediction of the perforation's length exist and show different results. The right model should be selected with care.

However, a qualitative understanding of the influence of the various factors that affect the perforating charge's performance under specific conditions helps. It is observed that, for the same perforating charge, the effective perforation length:

1. **Decreases**:
   - As the strength or the thickness of the casing increases.
   - As the sand grain size increases
   - With increasing formation uniaxial, compressive strength.
   - With increasing formation effective stress
   - With increasing reservoir pressure

2. **Is unaffected by:**
   - Stand-off from the inside of the casing wall for a big hole charge.

3. **Is shorter:**
   - In a gas reservoir compared to a liquid-saturated one *(partly because gas has lower capacity to clean out the perforation debris, resulting in a smaller effective i.e. clean perforation length).*
   - If the stand-off of a deep penetrating charge is greater than 30% of the gun diameter (and/or more than 0.5 in).

The supplier of the perforating services normally analyses their test data into a computer model that predicts the perforation length and diameter as a function of the above and other parameters. However, note the above comments about the accuracy of such predictions.

➢ *Feel free to attempt Tutorial 3.*

4. GUN TYPES, CONVEYANCE, AND PERFORATING CONDITIONS

Perforating gun systems and conditions are classified by the:

i. **Gun conveyance method**: wireline (both e-line and, since relatively recently, slickline); coiled tubing or snubbing pipe; drill string; or tubing string.

ii. **Pressure in the wellbore at the time of perforating**. It can be:
   - **Less** than reservoir pressure, i.e. an **under-balanced** (UB) pressure condition or
   - **Greater** than reservoir pressure, i.e. an **over-balanced** (OB) condition.
   - **Much greater** than reservoir pressure, i.e. Extreme Overbalance perforating (EOB or EOP a.k.a. really overbalance perforating ROPE) – a less common, relatively recent method.

iii. **Extent to which the gun, the charges and/or charge carrier are recovered** to the surface after perforating.
   - **Retrievable** with the perforating charges often mounted inside a steel tube (a 'carrier gun' like in Figure 21b) or
   - **Expendable** with the perforating charges often mounted on a metallic strip and exposed to the well fluids (a 'capsule gun' like in Figure 21d). Some carrier guns, like those used in tubing-conveyed perforating, can also be disposable provided there is a sump hole.

iv. **Time of Perforating:** either
   - **Before** completion of the well i.e. delivered (**through) casing**
   - **After** well completion i.e. either delivered **through tubing** or on a tubing.

As far as the gun conveyance is concerned, many wells are perforated using wireline conveyed guns. Through tubing (small diameter) wireline guns are run after installing the completion tubing. They are run down inside of the tubing, out of the tailpipe and perforate the casing at the selected depth (Figure 20a).

Alternatively, the (larger diameter) guns can be lowered into the wellbore casing prior to installation of the production tubing (Figure 20b).

Finally, the perforating guns can also be tubing conveyed; either on the end of a temporary test string (e.g. the drill string), on a coiled tubing or on the permanent completion string {Figure 20(c)}. In the latter case the gun is usually dropped into the well sump after perforation and left as part of the completion process. Alternatively, the gun will be retrieved after the well has been "cleaned-up" (produced to remove the formation damage from the completion fluid and drilling mud) when a temporary tubing string was used; followed by installation of the permanent completion string.

All these guns can be fired in an under-balanced or an over-balanced pressure condition. The wells perforated by the through-tubing wireline and tubing conveyed guns can be afterwards immediately put on production, while in the case of casing guns and drill string conveyed ones the subsequent installation of the completion normally requires that the well is killed after perforating. This will cause wellbore fluid leak off into the perforations possible, partly plugging them. For example, placing a drilling mud in the wellbore that forms a filter cake that plugs the perforations (Figure 19a, b and c) is not recommended. When the well is placed on production, only a limited clean up of the debris within the perforation well occur (Figure 19d). Besides, once the first perforations are cleaned up (often in the high permeability intervals) it is difficult to further reduce the wellbore pressure and clean up the rest of the perforations, often leaving the lower permeability intervals disadvantaged.

The preferred procedure is to:

- Perforate in an underbalanced pressure regime so that the perforation immediately cleans itself after perforating (Figure 19e), and then

- Protect the perforations from being impaired during subsequent overbalance completion operations by a downhole valve (where completion allows) or by use of a clear (solid free) completion fluid. In the latter case it may be necessary to prevent excessive volumes of fluid leaking off to the formation by increasing the wellbore fluid viscosity (i.e. by perforating when the wellbore bottomhole is filled with a volume of viscosified completion fluid: the 'viscous pill') or by adding a granular bridging material to the workover fluid (the 'kill pill'), that would temporarily plug the perforations and can be removed or dissolved later.

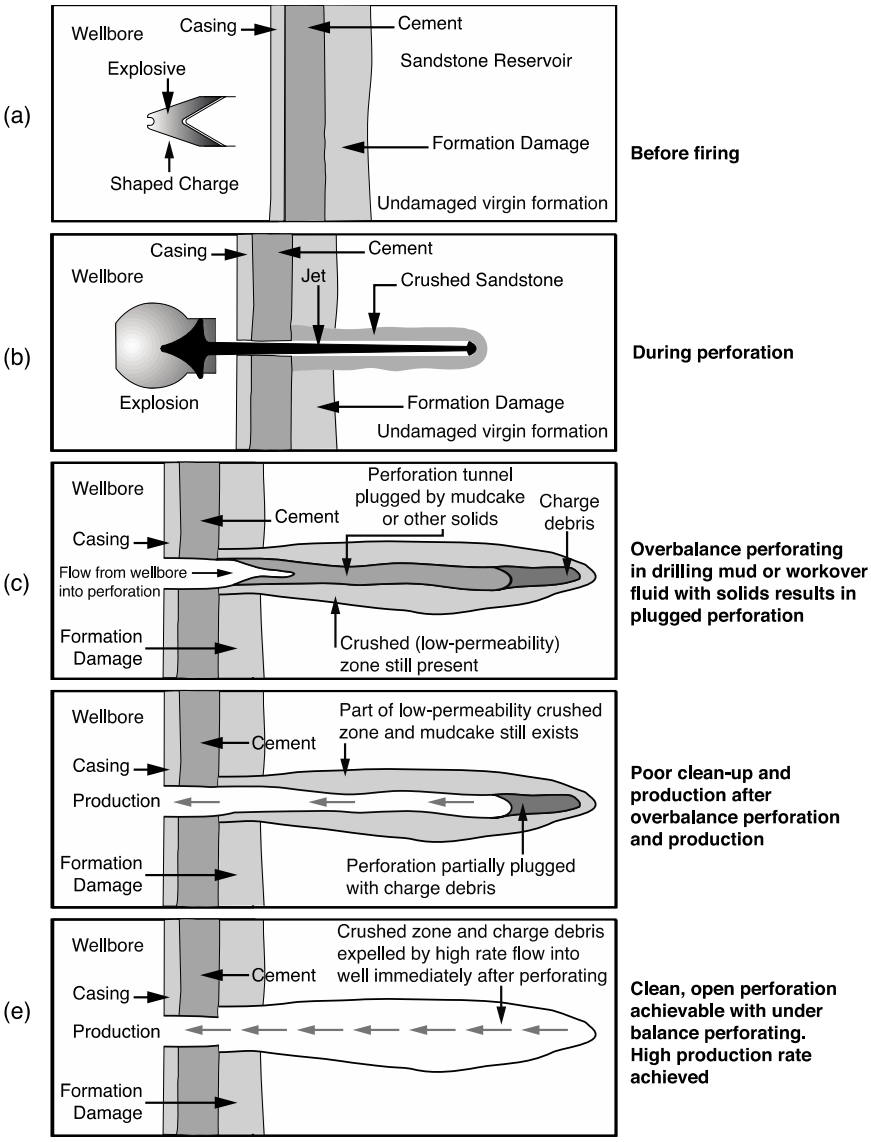


Figure 19 Perforation (a-b) plugging prior to flow caused by solids invasion from the fluid in the wellbore (c-d) and the case where this is avoided by underbalanced perforating (e).

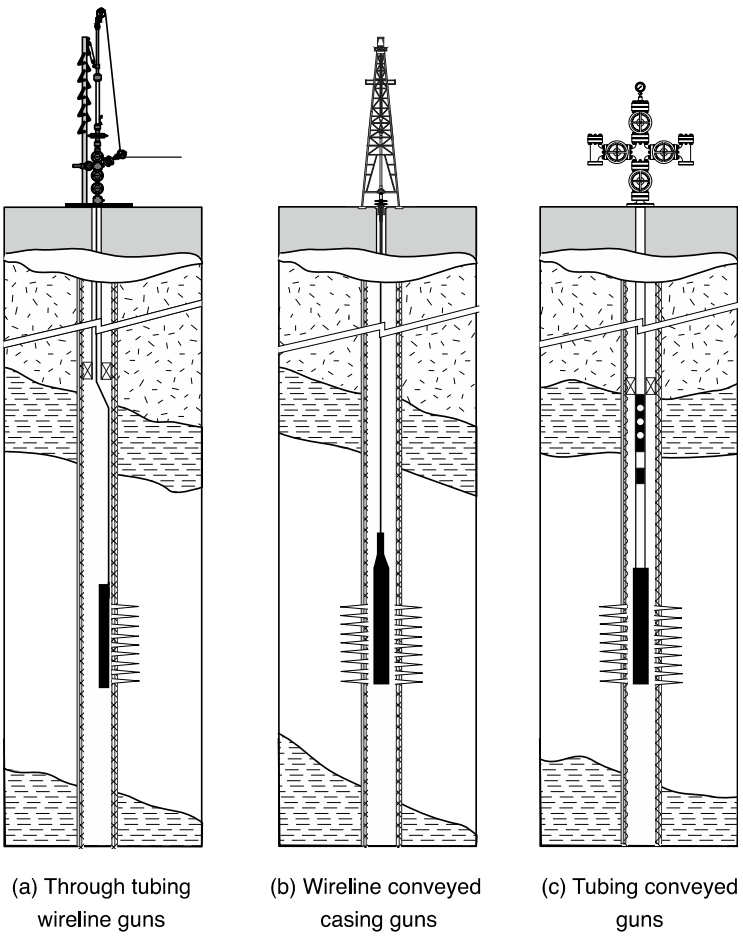


Figure 20 Perforating gun conveyance techniques.

Gun Type	Advantages	Disadvantages
Retrievable	• Robust and less liable to damage during running. • Charges protected from: (a) well fluids (b) well pressure (c) well temperature • Fast running speed into the well bore. • No debris	• Gun length is limited due to surface handling problems or lubricator length (normally 60′ max). • Large intervals require multiple gun runs or use stackable guns. • Pressure, temperature and exposure time may limit the use of certain charges (Table 1).
Expendable	• Flexible, can be run in longer lengths (up to 200ft per run). • More economical in terms of gun cost and time required.	• Debris left in wellbore. • Perforating charge and connecting detonating cord exposed to well fluids. • The gun is neither rigid nor durable, it may limit running in speeds or tension to be pulled if gun becomes stuck.

Table 2 Comparison of retrievable and expendable perforating guns.

As mentioned, perforating guns and charges also vary according to the extent to which they are expendable, i.e. to the volume of debris left downhole after firing the gun. The individual perforating charges in both **retrievable** and **expendable through tubing** guns (Figure 21) are fitted onto a carrying strip and then connected to the primer charge or to a detonating cord. Table 2 lists the advantages and disadvantages of **retrievable** and **expendable** guns.

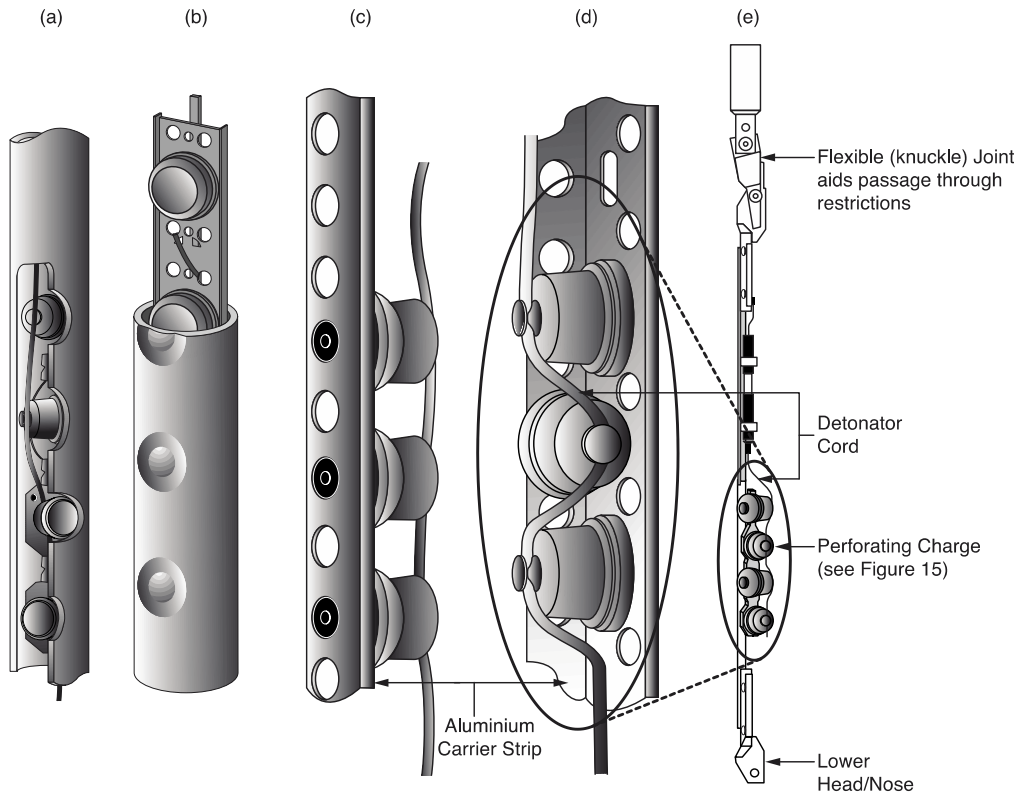


Figure 21 Wireline, Through-Tubing, Perforating Gun

Running the guns requires extra operational considerations because explosives must be handled with extreme care. The guns that are detonated by an electrical signal may particularly need further precautions (to prevent the gun from being accidentally detonated by a stray electrical current), including radio silence when arming, no high-current activity on the rig, daylight operations, etc.

4.1 Through Tubing Guns

Though-tubing guns have a sufficiently small diameter (normally between $1^3/_8$ in. and $3^1/_2$ in) that they can pass through the minimum diameter present in the completed well. The maximum length of gun is controlled by either the weight which can be safely suspended by the wireline, or by the length of lubricator into which the gun is retrieved after perforating. Thus, when perforating multiple and/or long intervals with wireline, though tubing guns, multiple runs are required. (Often only the first perforation can be done at a significant underbalance, with the underbalance of the following ones limited due to the reservoir fluid inflow. For this reason, the lowest permeability intervals that are more difficult to clean up are sometimes perforated first).

An example of how the limitations of the perforation conveyance systems can be overcome is the relatively recently introduced pivot gun, applied in specialist cases. The carriers for the pivot gun's charges are orientated vertically when running into the tubing {Figure 22(a)}. This results in the spacing between adjacent perforations being greater than normal. The charger carriers swivel to the horizontal position once the gun passes through the tubing tail pipe and into the casing {Figure 22 (b)}. The perforation's penetration is now similar to that of a casing gun.

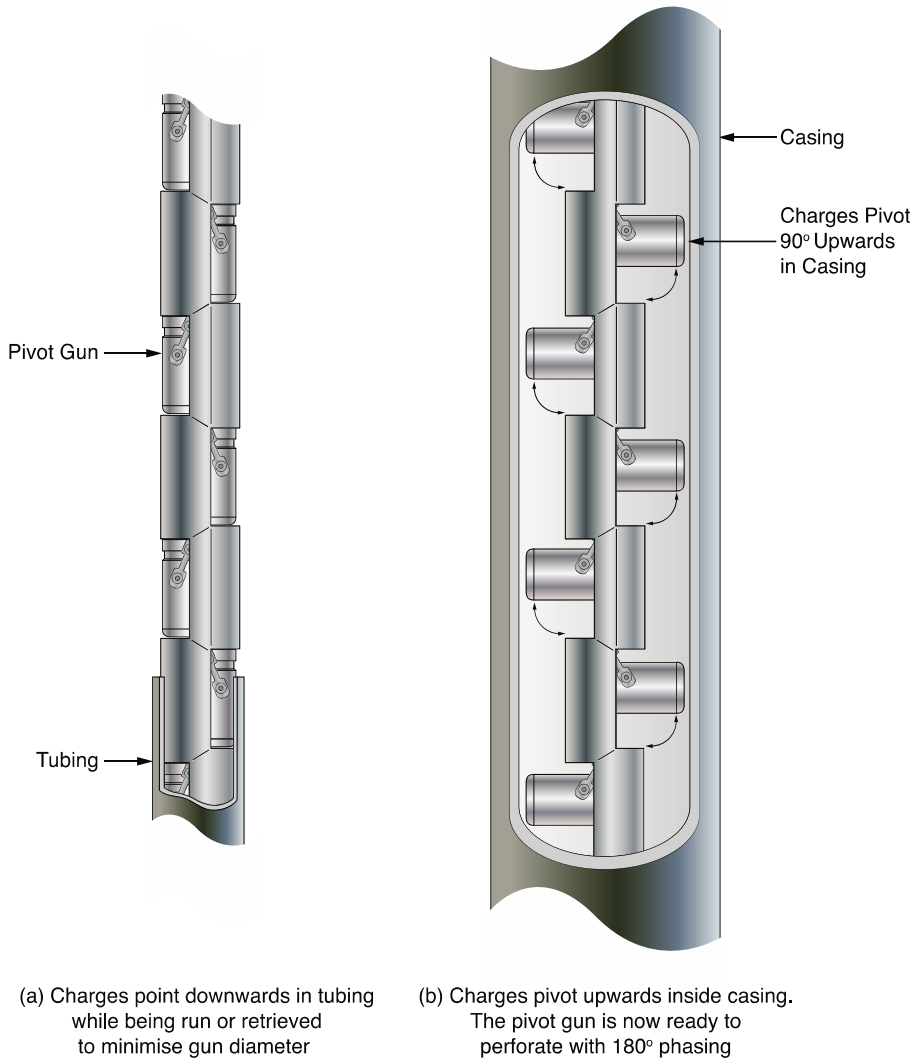


Figure 22 Pivot, Through Tubing, Perforating Gun

The pivot gun has the advantages described above, but also presents operational difficulties due to its complexity. For example, there are more parts than for a conventional perforating gun. Further, after firing, any unfired charges must return to the vertical position for gun recovery, otherwise it will not be possible for the gun to pass through the tubing's tail pipe. The fired charges are not retrievable, being left downhole.

4.1.1 EXPENDABLE AND RETRIEVABLE GUNS

Expendable Guns: self-destruct on detonation {(Figure 21 (c), (d) and (e)}. Only the connectors and depth correlation equipment being retrieved from the well. The gun comprises a number of charges which are strung together on an aluminium connector. A friable (e.g. ceramic or aluminium) material that disintegrates on detonation is used for the charge's case (Figure 23). This case must be sufficiently robust to provide a reasonable degree of protection to the charges during surface handling and running into the well.

Retrievable Guns: The carrier strip with charges is inserted into a steel carrier tube (Figure 21(a) and (b)). The steel tube is then sealed to protect the charges and electrical connections from the well fluids

while the gun is run downhole on the wireline. The steel tube also prevents debris from the perforating charges e.g. their cases from falling into the well. The diameter of a retrievable gun's steel tube slightly increases ('swells') after firing. This expansion during gun recovery is allowed for by specifying the guns maximum allowable diameter to be ½ in. smaller that the tubing's minimum diameter.

The scallop gun {Figure 21(b)} provides improved perforating performance compared to a simple, metal tube. Part of the tube's wall has been removed opposite the perforation charge, reducing the fraction of the jet's energy that is consumed as it perforates the steel tube. Alternatively, a carrier with ports opposite the charges can be used (Figure 25a) (*such carrier can be reusable*).

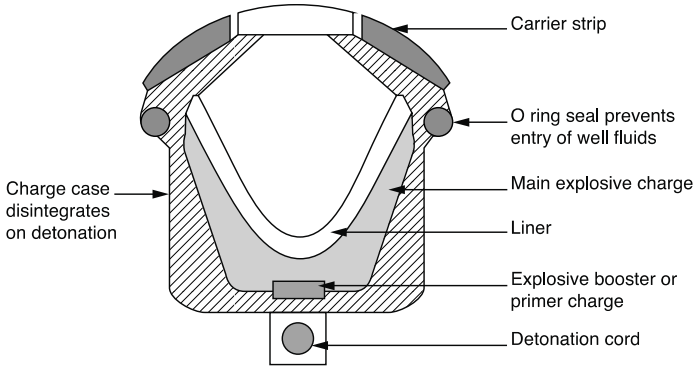


Figure 23 Expendable shaped charge for a through tubing gun.

4.1.2 SLICK-LINE CONVEYED PERFORATING

Until recently an electric line (e-line) was required for wireline conveyed perforating in order to monitor the depth correlation and positioning logging tool (e.g. a GR, a CCL, a Neutron log, or a GR detecting a 'pip' from a radioactive source preinstalled in the tubing) as well as to actuate the gun. Recent improvements in computer memory and battery technologies (capacity and allowable operating temperature) have allowed many of the wireline, e-line operations to be instead performed with a slick (or solid) wire. (A slickline operation is often less expensive.) For example, a conventional production log can be generated by recording measurements of the flow-rate, phase fraction and density at closely spaced, downhole locations onto a memory chip followed by surface "play-back" after the tool is returned to the surface. Perforation of the well is also possible.

The technology that made this possible was the development of accurate depth-correlation equipment. An accurate measurement of the depth of the tool string is achieved by the combination of a:

1 CCL (Casing Collar Locator) log which inductively recognises the presence of the increased metal thickness associated with the tubing or casing tool joints (where two lengths of tubing are joined together) and a

2 Drag arm which momentarily extends against the inner wall of the tubing or casing each time the CCL passes a tool joint. The increased friction created by the drag arm's extension is observed at the surface as an increased tension on the wire.

The perforating guns can then be fired once it has been confirmed that the guns are positioned at the correct depth. This can be achieved by, for example, a series of surface, pressure pulses.

Another example is timed firing. For extra reliability, the firing head in this case may be designed to become live only at a pre-set pressure or when the gun has been stationary for sufficient time.

4.1.3 PERFORATING LONG INTERVALS

As mentioned, the length of a gun which can be used, in the case of retrievable or semi-expendable guns, is limited by the lubricator length and, in the case of larger diameter guns, the tensile strength of the cable. A typical gun length is 15 - 40 ft., though longer ones are possible. Multiple runs with perforating guns will be necessary for long completion intervals since a lubricator is required to provide the necessary well control because the well will be live after the first run.

Perforating normally starts at the lowest interval in the zone and moves upwards on successive runs. This avoids the gun running into debris left from earlier runs. Recent developments have enabled perforating long intervals with through-tubing guns simultaneously.

It is possible to run a stackable gun system when operating with a short lubricator or when it is desirable to perforate a long zone in one operation. The system, which can be either wireline or coiled tubing run, is explained in Figure 24.

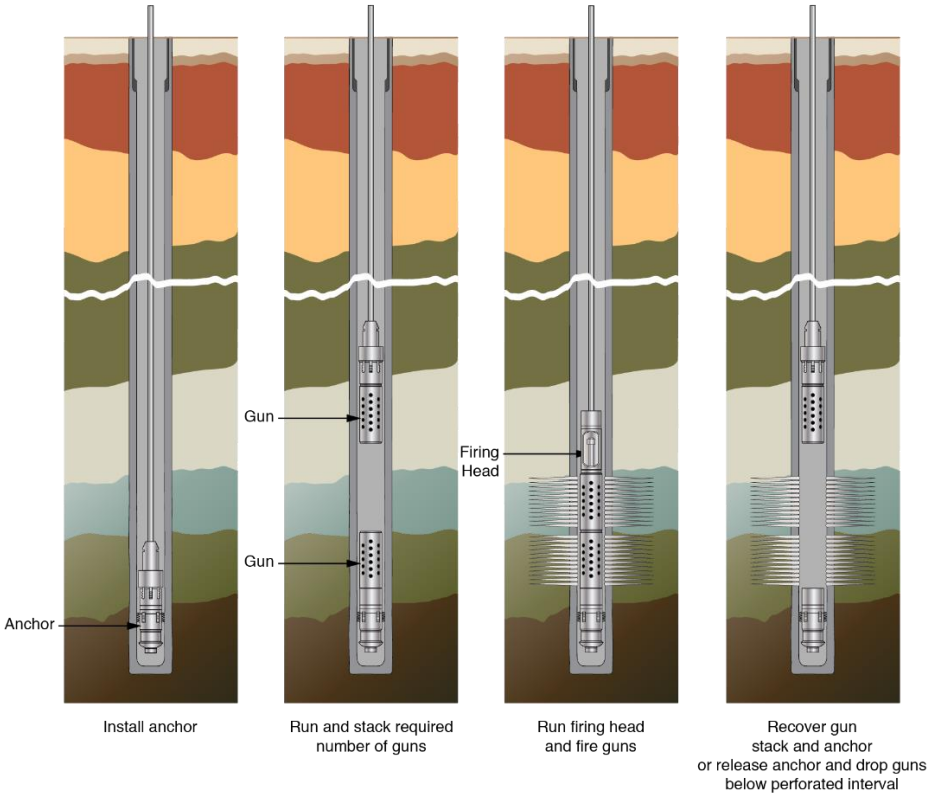


Figure 24 Gun stack may be run on wireline or coiled tubing. Guns can be through-tubing as well as through-casing.

Alternatively, where the lubricator length (i.e. the distance between the lubricator top and the swab valve) is the major limitation on the gun length, the swab valve can be 'moved' downhole by installing an additional valve in the tubing string. This can be e.g. a ball-type SCSSV-type valve installed above the major SCSSV. This downhole swab valve can be operated from surface via a control line. Alternatively, a reservoir isolation valve can be installed that is closed by the gun on the return trip (though there are mechanical risks of this).

As for perforating separate zones using a single gun, a switch system can be used for this. This could be used, for example, if three intervals each of 10ft. in length are to be perforated. Longer zones will normally be perforated with separate guns.

4.2 Casing Guns

Wireline (through-)casing guns (Figure 25) are all **retrievable** i.e. the charges are enclosed inside a steel tube. They have an outside diameter in the range of $3^3/_8$" to 7" for use in casings with an internal diameter of at least $^1/_2$ in. larger. The casing gun's larger diameter allows larger perforating charges with a greater weight of explosive than for a through tubing gun.

The maximum length of the gun is controlled by either the weight which can be safely suspended by the wireline or by the length of the lubricator into which the gun is retrieved after perforating.

The largest gun diameter permitted by the casing's internal diameter is usually chosen. The large gun size reduces the standoff or clearance between the gun and the casing. This allows all shot phasings to be employed (90° or less); larger explosive charges; and higher densities.

Smaller gun diameters are employed if there is a risk of sand flowing into the well and trapping the gun after perforating.

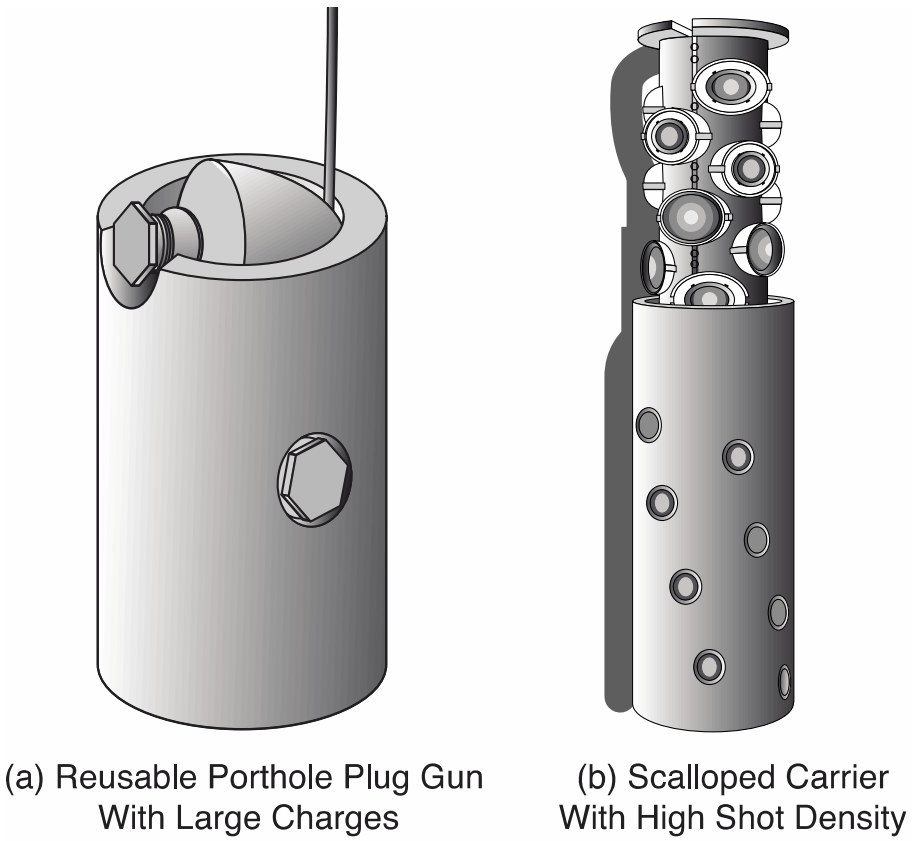


Figure 25 Wireline casing guns.

4.3 Tubing Conveyed Perforating (TCP) Guns

The tubing conveyed perforating gun can be employed as follows:

1. **Running the guns with a conventional drill stem test assembly** (Figure 26). The well is produced "clean" followed by killing the well prior to retrieving the test string and the spent gun. The

permanent completion can then be run.

2. **Running and retrieving the gun on coiled tubing.** The coiled perforating may be done prior to or after the completion has been installed; i.e. it can either be a through tubing or a casing operation.

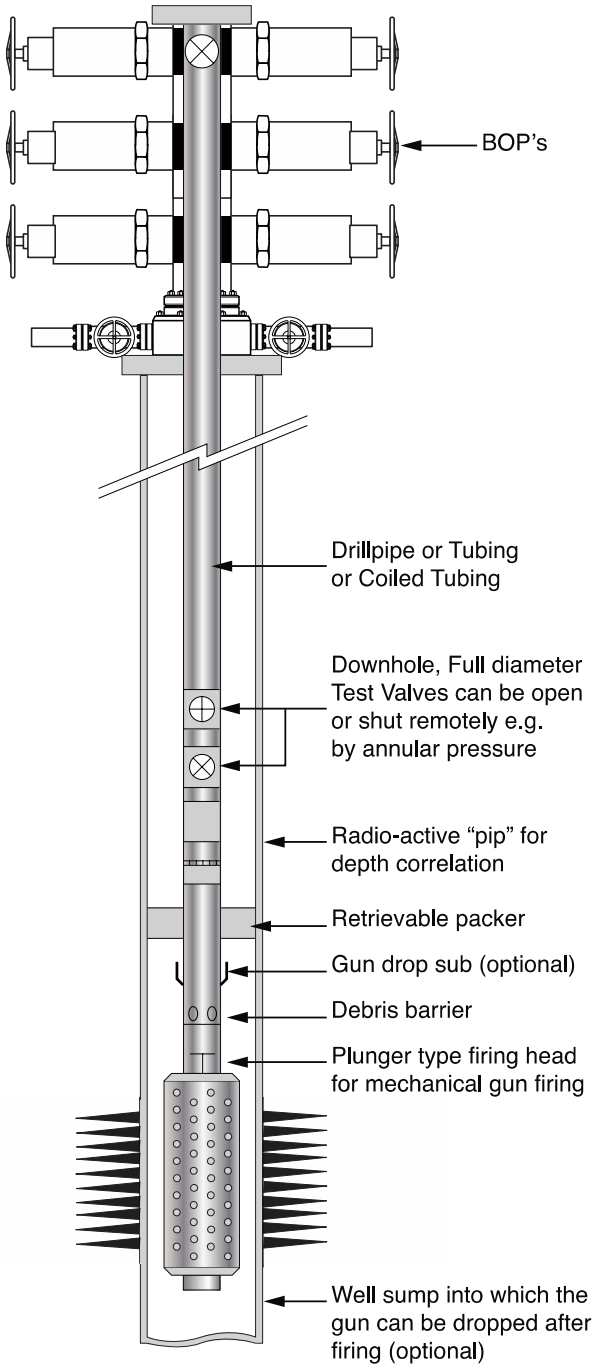


Figure 26 Tubing Conveyed Perforating as part of a drill stem test.

3. **Run the gun as part of the completion string.** The gun is attached to the tailpipe below the packer. The string is run into the hole, landed in the wellhead, the packer is set and the gun is detonated under drawdown. The well does not need to be killed afterwards, and the guns are normally detached and dropped into the sump if production logging is required across the producing interval later in the well's life.

Including the perforating gun as part of the completion is more common than in the past due to the increased efficiency (reduced rig time) and increased well productivity resulting when the well is not killed after the perforating. The development of "Through Flow" perforating guns which allow the produced fluids to flow up the gun further increases the attractiveness of this option.

The above is particularly important when the well is perforated underbalance. In general terms, the higher this underbalance differential pressure is the more effective the resulting clean-up process of removal of damage from the perforation tunnel will be.

The other advantages of tubing conveyed guns are:

- The ability to use large charges at high shot densities.
- The guns can also be delivered to target depth in deviated and horizontal wells.
- The perforating operation can be completed in one run even for long intervals, benefiting well clean up and productivity.
- The well is not perforated until after it has been completed and it is safe to allow well fluids to enter the wellbore.
- Perforating with wireline conveyed guns under drawdown creates the danger that the guns will be damaged or blown up the wellbore if too high a flow rate is induced by the drawdown used (although this can be prevented by using a gun anchoring system). The TCP's mechanical strength allows high differential pressures to be used e.g. > 2,500 psi.

The disadvantages of Tubing Conveyed Perforating (TCP) are:

- If a misfire occurs, then gun retrieval will require a round trip which is both time consuming and costly. There is also a safety concern as to why the gun has not detonated.
- If the gun is not detached but remains opposite the perforated interval, it will prevent production logging or through tubing wireline below the tailpipe. (On the other hand, if the gun is to be dropped from the tubing, the cost of drilling the additional sump (or 'rat hole') length must be considered.)
- The running time for the guns is long compared to wireline. The charges will be exposed to the high well temperatures for an extended period with the consequent charge degradation.
- The costs of Tubing Conveyed Perforating are higher than conventional wireline perforating. This cost difference however will decrease or even revert as the length of interval to be perforated increases.

4.3.1 TUBING-CONVEYED GUN FIRING OPTIONS

Several techniques are available to detonate tubing-conveyed guns:

- **Mechanical firing** A metal bar is dropped into the well and actuates a blasting cap on top of the gun. This method can be unreliable if debris have accumulated on top of the firing head.

- **Hydromechanical** The annular pressure is increased via pumping fluid into the casing. Once this increased differential pressure is sufficient to fracture a (weak) shear pin it causes the firing pin to be driven down against the detonator. It can also be combined with the mechanical option. For example, the mechanical firing head may only become 'live' when the hydrostatic fluid pressure reaches a pre-set value; indicating the gun is 'on-depth'.

- **Electric Line Firing**: a wet connect is run on electric line after the guns are positioned. This wet connect attaches to the firing head which can then be fired by passing electrical current down the cable from surface.

➢ *Propose a well completion case and discuss what gun deployment methods would suit it most.*

4.4 Underbalanced Perforating

As was explained, overbalance perforating is done at 'killed well' conditions and as such is safer and simpler. However, it does usually result in many perforations not cleaning up. *This may be less of a problem in loose formations though where the perforations are likely to clean up with time anyway due to sand flow.*

Underbalance perforating prevents solids from the wellbore from blocking the perforation tunnel where the resulting fluid production into the casing from the perforation flushes out loose material lodged within the perforation tunnel or the surrounding matrix. This significantly improves the chance of having more effective perforations compared to the overbalance perforating.

In general terms, the higher the differential pressure the more effective the resulting clean-up process of removal of damage from the tunnel itself will be. However, this has a limit as the use of excessive drawdowns can lead to collapse of the newly made perforation tunnel, large scale sand production into the casing or tubing or even collapse of the casing itself.

There are several minimum recommended underbalance pressure (ΔP) formulae available, e.g. the one by Tariq: for oil wells: $\Delta P = 3{,}100/k^{0.37}$ and gas wells: $\Delta p = 3{,}000/k^{0.40}$ where k is the formation permeability (in mD). Other models may additionally include the perforation diameter d (in inches) and formation porosity φ (in %) in the formulae, e.g. Behrmann's criteria:

For $k > 100$ mD $\Delta P = 1{,}480\ \varphi d^{0.3}/k^{0.5}$

$k < 100$ mD $\Delta P = 630\ \varphi d^{0.3}/k^{0.3}$

This normally implies the need for several hundred psi underpressure for medium-to-high permeability reservoirs to a few thousand for low permeability ones.

Low wellbore pressure, required for underbalance, is normally achieved by pre-filling the well with lighter fluid (e.g. nitrogen) or by pre-filling it with completion fluid only partly. The underbalance conditions can be achieved either before the gun firing, as described above (static underbalance), or shortly after, as in:

Dynamic underbalance, a relatively recent technology, is a series of very short surges and shock waves aimed at agitating and cleaning the perforation material. Note that the internal pressure inside the carrier gun is atmospheric pressure. Once the gun is fired the fluid next to the gun is sucked into it. This effect can be further employed by having a perforating gun loaded with two types of charges. The wellbore pressure opposite the completion zone will initially increase when the (limited number) of short penetration, perforating charges are fired. This is due to the gun swelling (increasing in volume) due to internal pressures created by detonation process. Less than 0.001 s later this is followed by a decrease below the static pressure of the fluid column in the tubing i.e. a dynamic underbalance is created by fluid inflow into the "empty" atmospheric volume inside the perforating gun. The second (deep penetrating) type of perforating charge is fired during this low-pressure period; inducing a transient flow towards the wellbore that cleans the perforations, as described above. The local, in-situ nature of these surges also means the perforations are cleaned relatively independently of each other's performance.

Back surging is achieved e.g. by having part of the tubing (e.g. like between the test valves in Figure 26) at atmospheric pressure, or by having the tubing only partly filled with completion fluid. Once the lower valve opens the large drawdown is applied to the perforations.

4.5 Extreme Overbalance Perforating (EOP)

EOP is a less common, relatively recent method. It involves perforating at the wellbore pressure higher than the reservoir fracture initiation pressure. This can be achieved e.g. the same way as for the underbalance perforating except the wellbore and/or the tubing are filled with high pressure fluid (e.g. highly compressed a.k.a. 'energised' nitrogen), providing this is safe. The isolation valve opening causes the nitrogen to expand into the wellbore resulting in high bottomhole pressure for a short time after the perforating. The wellbore below the packer can be additionally pre-filled with acid that will further improve cleanup once forced into the perforations.

Alternatively, a propellant-type explosive can be used (Figure 2) as a similar method to EOP. E.g. a propellant-filled sleeve on top of the conventional perforating gun is ignited by the charges firing. The propellant takes time to burn releasing combustion gasses in the wellbore, increasing the wellbore pressure. (One must make sure this pressure increase will not damage the well completion).

Either way, this high pressure will initiate small hydraulic fractures propagating from the perforations. This may be useful in the cases where hydraulic fracturing is required to improve productivity, but conventional fracturing can cause problem by e.g. extending the fracture into to an aquifer close to the perforations. Another benefit is the fact that the perforating debris are forced into the fractures and remain 'locked' in them once the pressure decreases and the fractures close, leaving the perforations relatively clean. EOP is also useful in depleted reservoirs that have too low a pressure and flow rate to clean the perforations underbalance.

4.6 Other Ways to Clean Perforations

The other ways to clean perforations once the completion is in place include circulation washing and acid washing. In the former case a washing tool is used: a pipe with a standing check valve and cups designed to direct injected fluid into a small completion interval and return it from an adjacent interval, thus cleaning out the perforations. The tool is slowly moved along the completion interval.

In the latter case acid is forced into the perforations to dissolve the plugging material. Acid spotting (injecting) from a nozzle on a slowly moving coiled tubing often shows good results uniformly cleaning up the perforations.

5. RECOMMENDED READING

1. "Well Completion and Servicing" by D. Perrin, Editions Technip, Paris, 1999
2. "Well Completion Design" by Bellarby, J., Elsevier, 2009
3. "Petroleum Well Construction" by Economides M. J., Watters L. and Dunn-Norman S; Wiley, 1998.
4. "Perforating", by Bell, W.T., Sukup, R.A., and Tariq, S.M.; SPE Monograph, 1995

CHAPTER 7: FORMATION DAMAGE

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LEARNING OBJECTIVES

(All Examinable)

Having worked through this chapter the Student will be able to:

- Explain when and how formation damage contributes to poor well performance.
- Identify the crucial near wellbore area susceptible to formation damage.
- Calculate the loss of production due to formation damage
- Explain the mechanisms of formation damage
- Identify the major sources of formation damage.
- Select appropriate remedial treatments.
- Discuss the causes of production, drilling, completion, and production -related formation damage
- Identify the types of scale encountered in well operations.
- State the scope, underlying cause and remedial action required to deal with scale deposition problem.
- Provide guidelines for minimising formation damage during well operations.
- Indicate how the formation damage can be identified in a production or injection well.
- Discuss the methods used in the formation damage removal and in flow assurance.

1. INTRODUCTION

As was mentioned earlier in this course, the largest pressure changes happen in the near wellbore region as the fluid flows from the reservoir boundary towards the wellbore (Figure 1). This is due to the radial inflow geometry around the well. The flow velocity increases as the flowing fluid converges on the wellbore. If there is gas present, the volumetric flow rate increases even faster due to the gas phase expanding as the pressure decreases towards the wellbore.

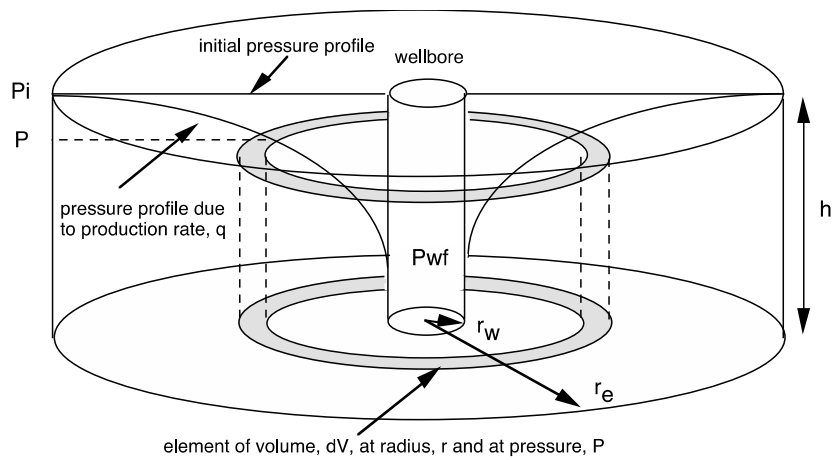


Figure 1 Pressure distribution around a producing well

The condition (permeability) of the near wellbore region has therefore a great impact on the well productivity. Changes from the original formation permeability are characterised by the "skin" value S - a dimensionless number proportional to the extra pressure loss the fluid experiences in the near-wellbore zone.

Formation Damage refers to permeability reduction in the volume of rock that makes up the near wellbore zone. This permeability reduction has many causes – but it always reduces the well's "natural", or undamaged, productivity due to the imposition of an extra pressure drop as the fluid flows towards the wellbore. This Chapter introduces some of the sources of formation damage, its modelling, and explains how to prevent or reduce this damage. Later, Chapter 8 of this course discusses matrix acidizing: a well stimulation treatment that increases the well productivity by reducing or completely removing the formation damage by a chemical treatment.

The potential for the permeability of the near wellbore formation to be reduced (damaged) exists from the moment that the drill bit enters the formation until the well is finally abandoned. It can happen during any well operation: drilling, cementing, perforating, completion/gravel packing, production, injection, workover, stimulation, etc.
Processes which lead to formation damage typically act through a restriction of flow (on a pore throat scale) due to either a:

- *Reduced absolute permeability* by solid particles or swelling clays completely, or partially, reducing the flow area of the pore throat. This is a common source. Some reservoirs may also experience

significant compaction as the reservoir pressure depletes, which also reduces the absolute permeability.

- *Reduced oil or gas (relative) permeability* due to:
  - Multiphase flow effects:
    - Reduced formation saturation of the oil and/or gas phase, e.g. due to presence of mud filtrate or completion brine (including the 'water block' effect).
  - An adverse change in the formation's wettability

The above effects can be further accentuated at high flow rates when non-Darcy flow effects occur.

A well can suffer from productivity or injectivity loss due to skin. There are many ways to prevent or reduce formation damage skin, but neither of them is effective if it's not the formation damage that caused the well's actual skin. It is therefore important to separate the formation damage input into the well's skin from 'pseudoskin' caused by 'pseudodamage' due to e.g. mechanical effects like limited entry, deviated wellbore, plugged perforations, etc.

The total well skin is a composite parameter:

$$S_{total} = S_d + S_{geometry} + S_{completion} + S_{production}$$

S_d is the only part of the Total Well Skin that can be removed by a (chemical) matrix stimulation treatment.

Typical sources of the different components of S_{total} were discussed earlier in this course, including few examples:

- Well Geometry skin ($S_{geometry}$) due to the effects like:
  - Limited entry *(this results in a positive skin, i.e. in an extra pressure loss)*
  - The well is not placed at the centre of the drainage boundary *(positive skin)*
  - A deviated or horizontal well *(negative skin, i.e. there is a pressure gain)*

- Completion Skin (S_{comp}) due to e.g.:
  - Perforations. Inefficient perforations (positive skin) or efficient ones *(negative skin)*
  - Gravel Packing *(positive skin)*
  - Fracture(s) *(negative skin).*

- Production Skins ($S_{production}$) like:
  - Higher pressure drop due to non-Darcy flow effect *(positive, non-Darcy skin)*
  - Reduced relative permeability to oil due to e.g. gas saturation if the wellbore pressure drops below the bubble point pressure, or to gas due to e.g. retrograde condensate dropout ('condensate banking') below the dew point pressure *(positive skin).*

➢ *Feel free to propose other sources of skin not related to formation damage.*

2. THE FORMATION DAMAGE SKIN

Determination of the relative input of formation damage skin and the potential value from its mitigation treatment is most often addressed by the Hawkins equation (Eqn. 1); which calculates the formation damage skin (S_d) resulting from a cylinder of reduced permeability around the wellbore:

$$S_d = \frac{2\pi k_o h\, \Delta P_d}{q_o \mu_o} = \left(\frac{k_o}{k_d} - 1\right) \ln\left(\frac{r_d}{r_w}\right) \qquad \text{(Eqn. 1)}$$

Where:

h	=	formation height
r_w	=	radius of well
r_d	=	radius of formation damage
q_o	=	oil flow rate
μ_o	=	oil viscosity
S_d	=	formation damage skin
k_o	=	formation permeability to oil
k_d	=	damaged permeability to oil
ΔP_d	=	extra pressure drop due to formation damage (Figure 2).

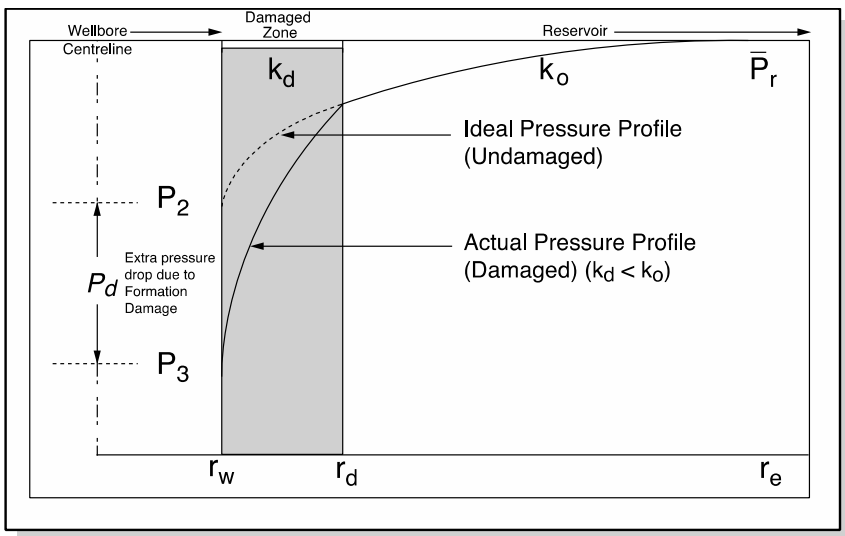


Figure 2 The effect of a formation damage skin on the well inflow pressure profile (for a given flow rate).

Equation (1) shows that the formation damage skin (S_d) increases as the permeability damage ratio (k_o/k_d) increases and/or the radius of damage (r_d) increases. For example, for a well with (r_w) of 10 cm the skin curves are shown in Figure 3.

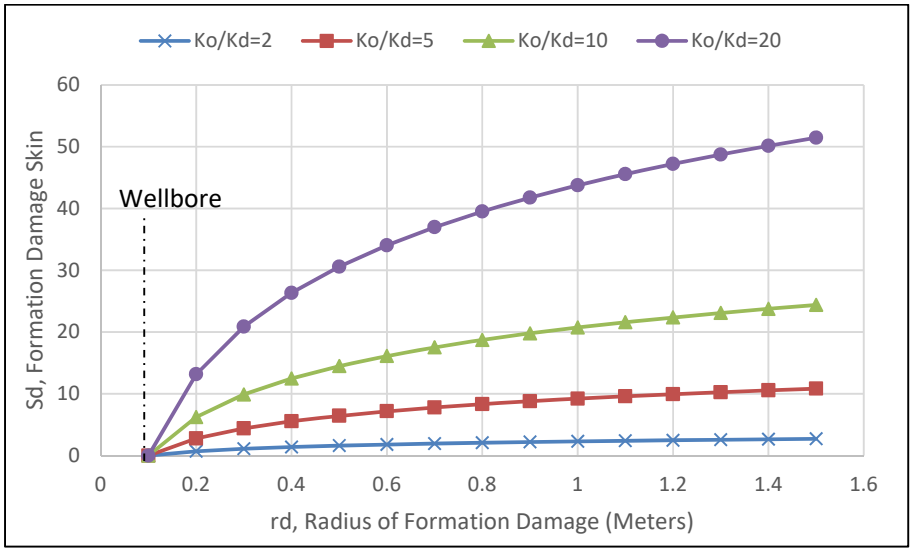


Figure 3 Formation Damage Skin (S_d) increases with the Formation Damage Ratio (k_o/k_d) and the Depth of Formation Damage (r_d).

The impact of the Formation Damage Skin is most conveniently expressed, from the production point of view, in terms of the well Flow Efficiency (FE). Eqn. 2 shows that FE is the ratio of the production rates when both q_d and q_{ideal} are calculated at the same drawdown:

$$F\,E(\%) = \frac{100 \times q_d}{q_{ideal}} = \frac{100\{\ln(r_e/r_w) + S_{ideal}\}}{\{\ln(r_e/r_w) + S_{total}\}} \qquad \text{(Eqn. 2)}$$

Where:

$S_{ideal} = S_{total} - S_d$. i.e. S_{ideal} contains all skin contributions **apart from** formation damage and (q_{ideal}) is the 'ideal' production rate with no formation damage. Typically, in conventional vertical wells:

$$FE(\%) \approx \frac{100 \times (7.5 + S_{ideal})}{7.5 + S_{total}}$$

An example relationship between flow efficiency and skin is pictured as Figure 4 assuming S_{ideal} =0. Note how sensitive the well productivity/injectivity is to the skin factor value.

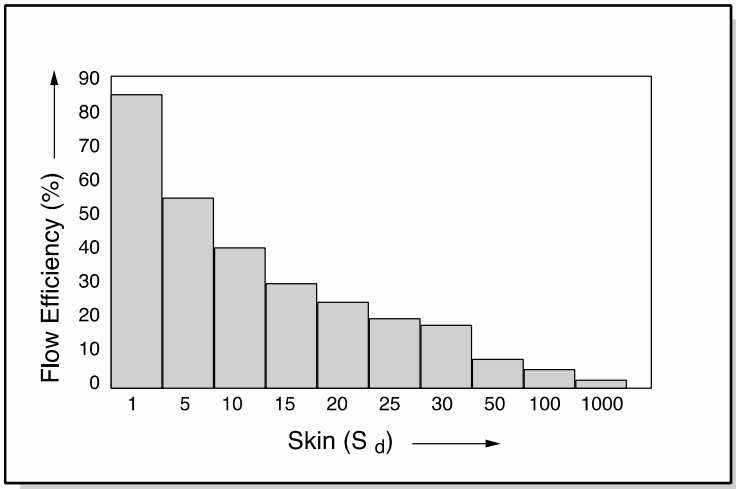


Figure 4 Flow Efficiency decreases with increasing Formation Damage Skin.

Such reductions in flow efficiency will reduce the well's production - delaying project payback as well as reducing Net Present Value (profitability). Further, the extra pressure losses in the near wellbore area mean that artificial lift will have to be installed earlier in order to keep the well on production. This will require an higher early capital expenditure and an increase in the well's operating cost.

- *Feel free to attempt Tutorial 1*

3. FORMATION DAMAGE MECHANISMS

Typical formation damage mechanisms include:

3.1 Plugging and bridging of pores by solid particles

Depending on the size of the particles either introduced externally (e.g. with the drilling mud) into the formation, or mobilised/generated internally (e.g. fines and organic/inorganic deposits), the narrowest pore elements: pore throats, can be completely or partially plugged. For instance, large particles in the drilling muds are "strained" from the drilling mud at an exposed pore throat {Figure 5 (a)}, bridging it from the mud loss and forming a mud (filter) cake. This is a positive effect because the mudcake can be removed later after applying reverse flow from the reservoir at the 'mudcake lift-off' pressure drawdown, when the well is ready for production.

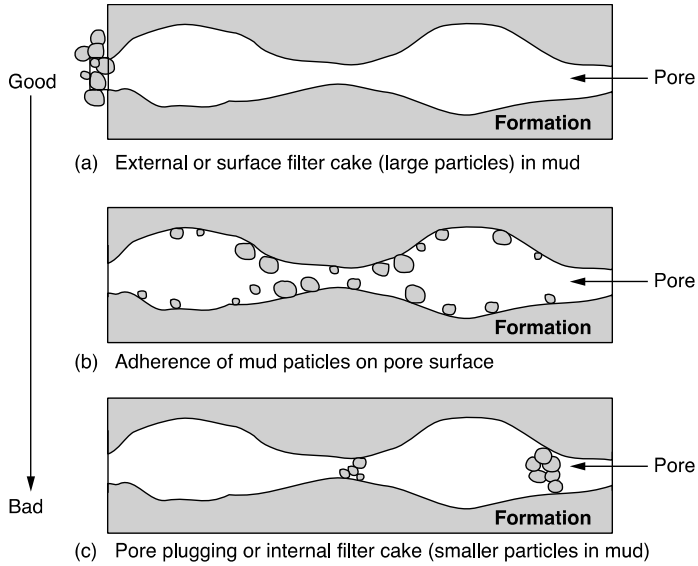


Figure 5 Filter cake formation.

Figure 5 (b) and (c) illustrate what happens when smaller particles invade the pores. They may either adhere to the surface of the pore walls {Figure 5 (b)}; or block internal pore throats {Figure 5 (c)}. *(If the latter is caused by mud particles it is called 'internal mud cake' and can significantly reduce permeability in the first few inches around the wellbore).* The latter blockage is difficult to reverse and often needs to be either bypassed (e.g. by perforations or fractures) or dissolved with acids, though its prevention is normally the best approach.

The various sources of externally introduced particles are discussed later. As for the fines (i.e. the loose particles originally present in the formation pores) – they may mobilise due to various processes. Mobilisation of the fines allows them to move to the pore throats where, if chance dictates that a number of these particles are present at the same time, blockage can occur. The mobilisation processes include:

- Water flow. Figure 6a shows that the small, loose particles present on the sand grain surfaces remain in place during oil flow. However, these fines become mobile once the wetting phase (water, in this case) is flowing at a rate greater than some critical value (Figure 6b), entraining the fines with it.

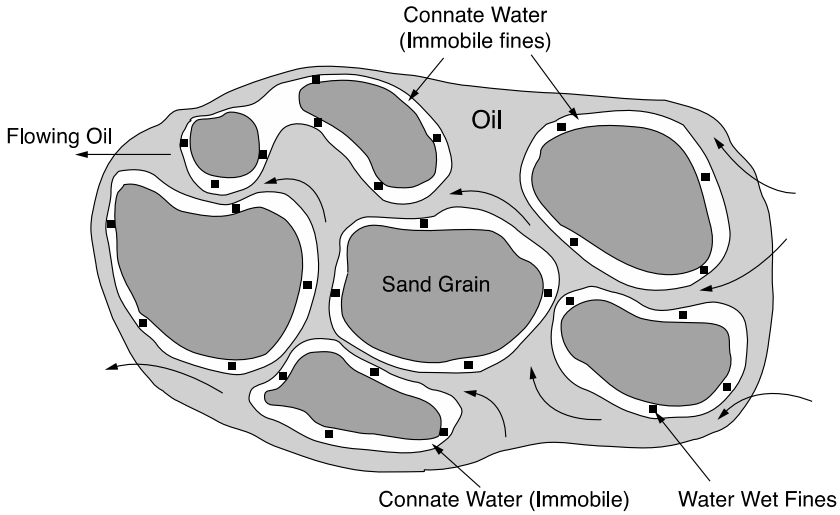


Figure 6*a* Water wet fines are immobile during oil production only.

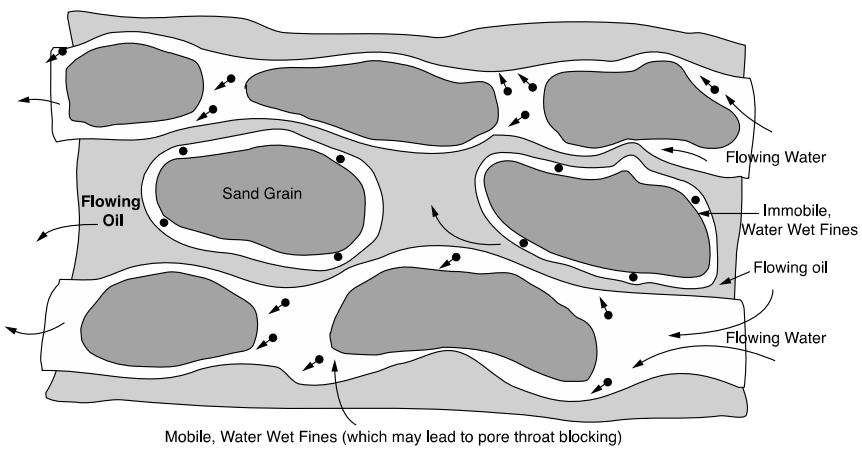


Figure 6*b* Water wet fines become mobile with water production leading to pore throat blockage if a several fines meet at a (small diameter) pore throat.

- Change in the chemical composition of water, in particular the reduction in its salinity due to its contact with lower salinity water (e.g. injection water, mud filtrate, completion fluids, etc.) can cause dispersion of clay particles (the 'water sensitivity' effect) (Figure 7).

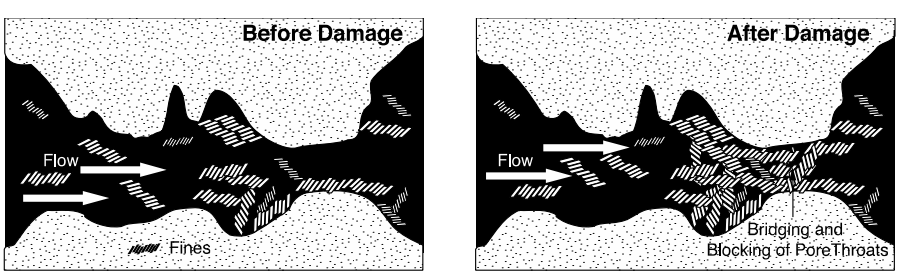


Figure 7 Formation impairment due to fines migration.

The different types of clay can be recognised by their appearance. It's the clays lining the pores and having a large specific area (i.e. surface area per unit mass) that contribute most to the formation damage by: clay swelling (i.e. increase in volume several times by absorbing water at the clay's surface), and clay dispersion. Figure 8 - Figure 11 schematically represent the forms in which the most formation damage-related clay types are frequently found:

- **Kaolinite** forms booklets which bridge pore throats or fill pore walls (Figure 8)
- **Illite** forms fragile wispy filaments which line pore walls and bridge the pore throats (Figure 9)

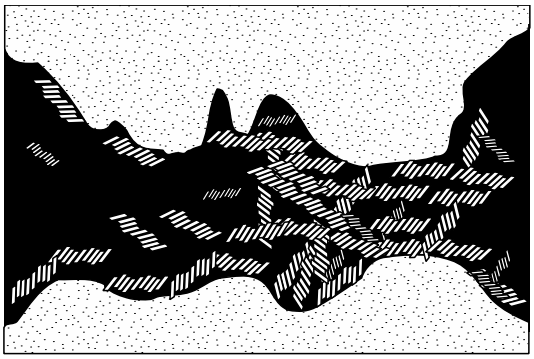


Figure 8 Discrete booklets (Kaolinite).

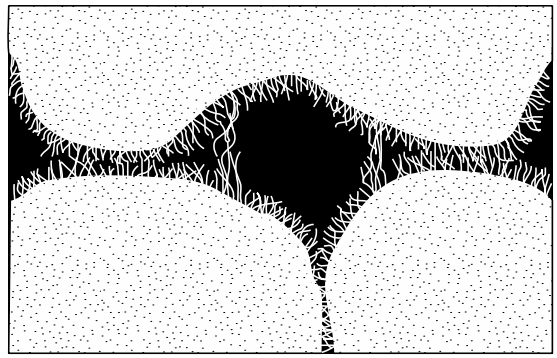


Figure 9 Pore bridging (Illite).

- **Smectite** (including montmorillonite) has a honeycomb structure (Figure 10)
- **Chlorite** is an iron containing clay which lines the pore walls (Figure 11)

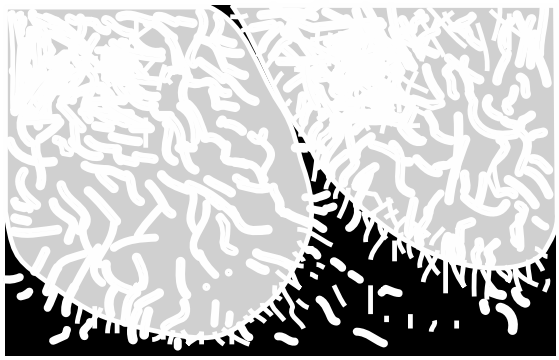


Figure 10 Grain coating (Smectite).

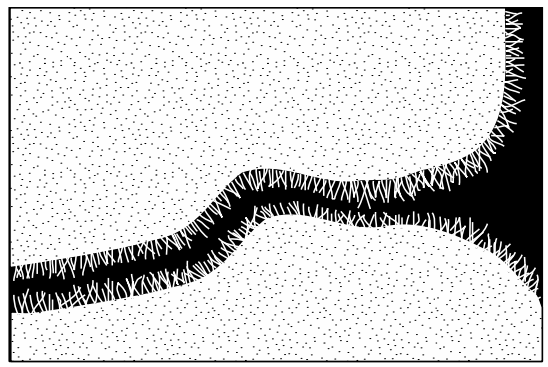


Figure 11 Pore lining (Chlorite).

3.2 Chemical Precipitation

Scales forming in the formation (as well as in the well and surface facilities) can be either inorganic (a.k.a. 'mineral scale' or simply 'scale' deposits precipitating from water) or organic (precipitating from crude oil). They can plug pore throats and thus contribute to the formation damage.

The precipitation of the scales is triggered by a change from the original, in-situ, chemical equilibrium conditions that had been achieved by the reservoir fluid and the rock minerals that make-up the formation over geological times. This can be due to:

- A decrease in temperature during flow in the reservoir, but mostly up the tubing and at the surface.
- A decrease in pressure by reservoir depletion and drawdown, flow up the tubing and, after the wellhead, in the surface facilities.
- Mixing of chemically incompatible fluids e.g. formation waters from two different reservoirs, or injected (sea) water with formation water.

Generally, when ratio of the concentration of compound elements in the solution over their solubility (such ratio is known as the supersaturation ratio SR) exceeds 1 (or its logarithm: 'saturation index SI' exceeds 0), the compound becomes supersaturated and can precipitate. Further, in many types of scales, once the first deposition seed crystals form the deposits keep agglomerating around them forming larger clusters. That's also why some scale inhibitors can be designed to prevent precipitating, some others – to prevent aggregation.

Typical inorganic scales include:

Carbonates. Typical example: calcium carbonate (calcite) $CaCO_3$.

- $Ca(HCO_3)_2$ is originally in equilibrium in the formation water. Addition of elements (e.g. calcium ions) or removal of them (e.g. carbon dioxide CO_2) can shift it from the equilibrium. E.g. precipitation of calcium carbonate is due to either:

- a reduction in pressure followed by evaporation of some carbon dioxide that is dissolved in the liquid or
- mixing with fluids high in calcium. Either way:

$$Ca(HCO_3)_2 \rightarrow CaCO_3\downarrow + CO_2\uparrow + H_2O$$

Sulphates (a.k.a. sulfates). Typical examples: barium and calcium sulphates.

- Calcium sulphate can be precipitated due to cooling. Below a critical temperature, the less soluble form (anhydrite) is precipitated:

$$Ca^{++} + SO_4^{--} \rightarrow CaSO_4\downarrow \text{ (solid anhydrite)}$$

- Precipitation due to mixing of two reservoir brines (normally in the production casing/tubing) or of a reservoir brine (e.g. rich in Barium) and an injected fluid (e.g. sea water containing sulphate ions): Ba^{++} (reservoir fluid) + SO_4^{--} (injected sea water) $\rightarrow BaSO_4\downarrow$ (solid)

Salts.

Precipitation of NaCl (rock salt or halite) due to cooling of well fluids and/or evaporation of the water into the gas phase during production of saturated brines to the surface:

$$NaCl\text{ (soln)} \rightarrow NaCl\downarrow \text{ (solid)}$$

Many other scales (e.g. strontium sulphate) and elements (e.g. elemental sulphur) also cause formation damage. Typical causes and types of scales encountered in oilfield operations are listed in Table 1

Typical Causes and Types of Inorganic Scales Encountered in Oilfield Operations

Scale	Formula	Principal Cause of Scale Formation
Calcium Carbonate (Calcite)	$Ca\ CO_3$	Reduced partial pressure of CO_2 due to pressure reduction
Barium Sulphate (barite)	$Ba\ SO_4$	Mixing of formation water and Sea Water
Strontium Sulphate (celestite)	$Sr\ SO_4$	
Calcium Sulphate (gypsum)	$Ca\ SO_4.2H_2O$	Temperature change - maximum solubility at 40°C
Ferrous Sulphide	FeS	Corrosion followed by contact with Hydrogen Sulphide
Salt	NaCl	Temperature and pressure reduction Gas wells only
Sulphur	S	Temperature and pressure reduction. Very sour (high H_2S) gas wells only

Table 1 Typical causes and types of scales encountered in oilfield operations.

Organic scales

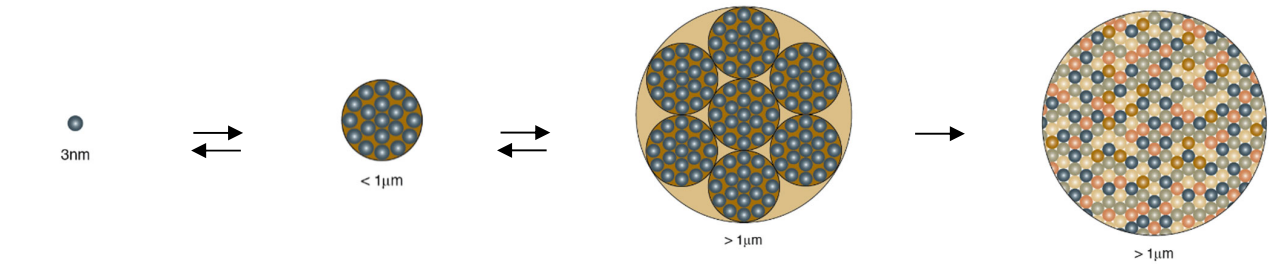
Two common organic scales are wax (paraffins) and asphaltenes.

1. **Solid Wax** (composed of long-chain alkane hydrocarbons) precipitates in many crude oils during cooling. The (solid) wax is dissolved in the crude oil at reservoir temperatures and forms a crystalline precipitate when the temperature decreases below the 'cloud point' or 'wax appearance temperature' (the temperature at which the first (micro) seed crystals appear). The temperature difference between the reservoir temperature and the cloud point ranges from only a few degrees centigrade to many tens of degrees, but is independent of pressure. If the temperature keeps decreasing, the concentration of wax in oil can increase so much that the oil could not be poured out of a glass ('pour point').

2. **Asphaltenes** are amorphous, bituminous, complex compounds which precipitate from some crude oils. Asphaltenes are not dissolved in the crude oil, but are present as a dispersion of very small solid particles called a colloid or nano-aggregate. They have been stable over geological times under the original reservoir conditions. However, they can start to precipitate almost as soon as there is a change in the original reservoir conditions, such as a reduction in reservoir pressure once production is initiated.

   Asphaltene precipitation often begins around the bubble point pressure**.** Laboratory experiments on the effect of pressure on the stability of an asphaltenic crude oil have shown that there are two regions were the asphaltenic nano-aggregate are stable. One of these is normally above the bubble point pressure, mentioned above, while the second stability region is at low pressures.

   Solid asphaltenes are mainly formed at intermediate pressures. The second area of "solubility" at low pressures is of limited practical use because solid asphaltenes do not easily "re-dissolve". This is due to the final stage of particle growth, the formation of the aged "solid-like" phase, not being reversible (Figure 12).



Dissolved Asphaltene	Participated Phase	Aggregated Phase	Aged Phase
Nano-aggregate	Primary Particles	Micro-aggregate	"Solid-like"

Figure 12 The process of Asphaltene precipitation

The following summarises operational field experience from a number of fields:

- The severity of operational problems is **not** related to the asphaltene content of the crude oil. Crudes with relatively low asphaltene contents can present the most difficult operational problems.
- Asphaltene precipitation occurs mainly at a specific place. Hence, for example, asphaltene precipitation may be initially observed in the facilities. As the reservoir depletes, the lowest point of precipitation can move to the top of the tubing and then down the tubing.
- Reports of reservoir formation damage due to asphaltene precipitation are rare.

3.3 Sources of Formation Damage – Bacteria

The other 'solids' that can clog pores are bacteria. The presence of bacterial colonies and, more importantly the residues they produce, can lead to a number of intractable operational problems. They are most frequently associated with injection wells and flowlines. The following summarises some of the most widely found problems:

- **Bacterial Slime/cellular remnants** etc. will physically plug the formation pores if injected into the well. The solution to prevent this is to ensure that the bacterial colonies do not become established in the wells and facilities. All the fluids pumped into the wells should be treated with a sufficient concentration of a bactericide to achieve a high "kill" level.

- **Iron Bacteria** are aerobic bacteria which can establish themselves under an iron deposit that they form themselves. They are typically found in injection flowlines where the fluid is not efficiently deoxygenated. They are difficult to kill with bactericide since they are protected by the surface iron deposit. Regular mechanical removal, e.g. by pigging the line (pipeline cleaning by 'pigging' is explained later in this course), is the most effective treatment.

- **Sulphate Reducing Bacteria** are anaerobic bacteria which generate their energy requirements without using oxygen. They produce large quantities of hydrogen sulphide (H_2S) when both the sulphate anion (usually from sea water) and a carbon source (crude oil) are present. H_2S presents a major safety and corrosions issue. Besides, injection water containing even low levels of the corrosion-caused ferric cation (Fe^{+++}) will precipitate the extremely insoluble solid ferric sulphate (Fe_2S_3) when exposed to H_2S.

3.4 Damage Caused by Fluids

The other mechanism of formation damage is reduction in oil viscosity or relative permeability due to presence of some fluids:

Surfactants present in the drilling and other fluids may change the formation wettability. The relative permeability to oil is lower in an oil-wet than in a water-wet formation for the same oil saturation.

Moreover, some surfactants may cause a viscous emulsion to be formed of the water and the crude oil (Figure 13). The emulsion viscosity is much higher than the oil viscosity. The emulsions may be further stabilised by e.g. clay or iron particles, and thus may become 'tight' and take long time to break.

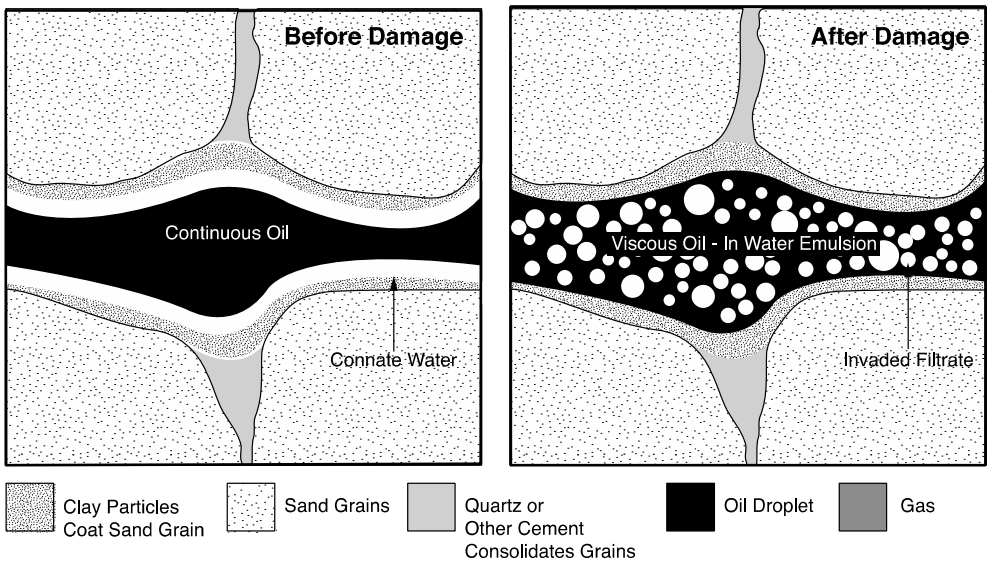


Figure 13 Formation impairment due to water-in-oil emulsion.

During acid treatments, crude oil and acid may form insoluble, highly viscous 'sludge' in the formation.

Increased water saturation caused by the wellbore fluids flowing into formation decreases relative permeability to oil. This is known as 'water block', and may take long time to gradually disappear during production.

3.5 Mechanical Damage and Rock Compaction

As mentioned, rock compaction with reservoir pressure depletion can cause significant porosity and permeability reduction in some reservoirs (particularly in chalks).

Mechanical damage can be caused by shock waves or high stresses. For instance, the case of high damage skin due to the presence of crushed zone around perforations was explained earlier in this course.

4. SOURCES OF FORMATION DAMAGE

As mentioned, formation damage can occur throughout the life of the well. All well activities must be evaluated for their potential to cause formation damage. The aim of the Production Technologist includes achieving an initial well flow efficiency of 100% and maintaining it at this level during the life of the well. This is achieved by ensuring that proper operation practices and procedures are implemented during day-to-day well operations, as well as during the larger scale drilling and workover campaigns. Examples of formation damage are discussed in the following sections.

4.1 Drilling and Completion

Well drilling and completion operations are often the ones causing most of formation damage. It is worth discussing this in more detail.

(Most) drilling fluids contain particulate materials e.g. clays, weighting agents etc. and drill cuttings. The (over) balance pressure between the drilling fluid and the reservoir pressure required to maintain well control will result in these mud particulates being forced into the formation (unless the well is drilled underbalanced).

A filter cake will be formed on the surface of the wellbore, but some particles will also invade into the formation. These solids will not always easily flow into the wellbore when the pressure gradient is reversed (i.e. the well is placed on production). Formation damage has thus been created.

Formation damage is minimised by ensuring that the solids that make up the drilling mud rapidly form a low permeability filter cake (a.k.a. mud cake) at the surface of the wellbore. This not only reduces the rate of filtrate loss, but also ensures that the invasion of the small, impairing particles into the formation is halted as quickly as possible.

The drilling fluid can be chosen in order to reduce the total drilling cost prior to the drill bit entering the producing formation.

However, once the pay zone has been penetrated the drilling fluid should be chosen to maximise the well productivity. Such 'drill in' drilling mud should now be chosen to minimise the Formation Damage, even if this requires changing to a more expensive drilling mud or reducing the drilling rate. Suitably sized solid particulates must be present in the drilling mud to quickly form a thin, low permeability filter cake on the borehole wall.

The relationships between drilling fluid type, cost and the risk of Formation Damage is schematically illustrated in Figure 14.

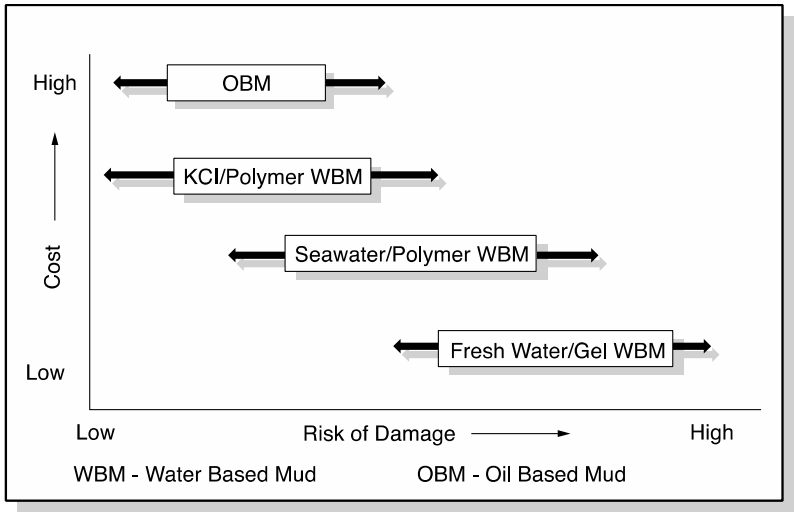


Figure 14 Typical relationships between mud type, cost and risk of formation damage

4.1.1 FACTORS CONTROLLING MUD LOSS INTO FORMATION

Mud loss to the formation is reduced by ensuring a proper mud cake forms. The permeability of both this filter cake and the formation influence the rate at which the drilling mud filtrate invades the formation. This rate of invasion may be calculated from the radial flow equations with a low permeability zone (representing the mud cake) placed next to the wellbore. The results, illustrated in Figure 15, show two regions:

1. The fluid loss rate is controlled by the properties of the filter cake when the filter cake has a much lower permeability (≈ 0.01%) than that of the formation. This is called "Filter Cake Control" since the permeability of the filter cake is controlling the leak-off rate.

2. The horizontal line indicates when the filter cake is no longer a barrier and the formation permeability controls the fluid leak off rate from the drilling mud.

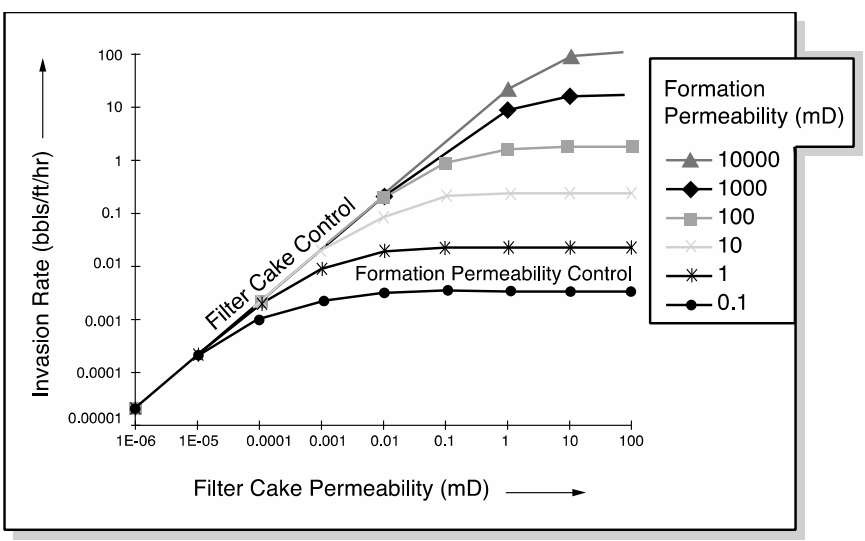


Figure 15 Filter cake control of the rate of fluid loss from the drilling mud.

Many factors, apart from the properties of the drilling fluid, control the depth to which formation damage can occur. These include:

1. **Formation properties.** An increased depth of drill fluid invasion is often observed for formations with a larger pore-size. This can be due to the drilling mud not forming an efficient filter cake against formation layers with a very high permeability. Losses of whole mud into the formation (a filter cake is not formed) has been observed in clastic formations for formation permeability's greater than 1 Darcy. The specific permeability value at which this occurs depends on the individual mud properties and the pore geometry.

   Efficient filter cake formation can be re-established in these higher permeability formations by adding larger particles to the drilling mud. These larger particles are often called fluid loss control additives.

2. **Open Hole time.** Fluid loss is a continuous process - the greater invasion depth occurs with longer open hole times. This implies that there is a greater risk of impairment for the part of the formation drilled first compared to the formations drilled later on. This is particularly important for long horizontal wells where completion intervals are often in excess of 1,000 m.

3. **Overbalance.** Fluid loss/invasion depth increases as the difference in pressure between the drilling mud and the reservoir pressure (overbalance) increases. *Under balance drilling and completion techniques are now being sometimes used in both on- and off-shore drilling.*

   The Production Improvement Factor (PIF), or Production Increase in Figure 16, compares the performance of similar wells when underbalance and overbalance drilling techniques are employed on equivalent wells. The PIF value can be as large as a factor of 11 (i.e. production increase of 1000%) in favourable circumstances (Figure 16).

   Figure 16 shows that employing Underbalance drilling to avoid this type of formation damage can be particularly beneficial in formations that are naturally fractured, have low permeability or are depleted.

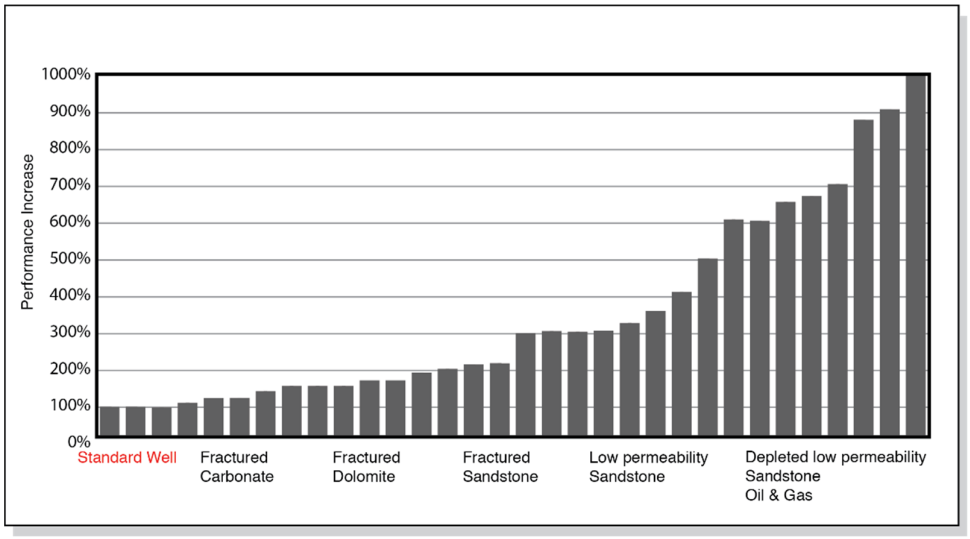


Figure 16 Underbalance Drilling increases well productivity for specific cases.

4. **Borehole Dynamics** has a large effect on the fluid loss:

- High circulation rates increase the dynamic overbalance pressure and the high fluid velocities will also erode the mud cake. A thinner mud cake and a greater overbalance pressure both result in increased fluid leak off.

- Many round trips (e.g. to change the drill bit). Frequent mechanical damage to the mud cake results from the scraping action of the stabilisers, etc. of the Bottom Hole Assembly.

Extra fluid loss occurs in the period before the mud cake is fully restored.

The relative fluid loss rates associated with the various phases of the drilling process are illustrated in Figure 17. The corresponding, relative volumes for each phase are also shown. The relationship between depth of invasion and fluid leak off volume may be quantified by a simple volumetric calculation as shown in Table 2. The table shows that large volumes of fluid have to be lost to achieve substantial depths of invasion in reasonably porous formations.

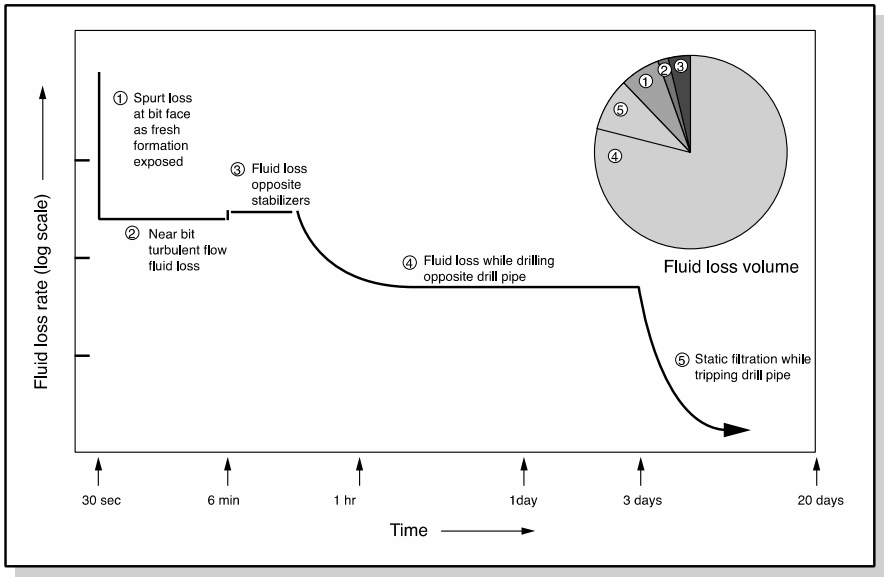


Figure 17 Fluid loss during the drilling process.

Wellbore radius (r_w) = 10.8cm, Perforated interval (h) = 15.5m

Leak-off Volume = $\varphi \pi h \{(r_w + r)^2 - r_w^2\}$ (3)

Depth of Invasion (r)	3 cm	15 cm	30 cm	150 cm	300 cm	600 cm
Porosity (ϕ,%)	Leak Off Volume (m^3)					
10	0.04	0.27	0.76	13	47	184
14	0.05	0.37	1.06	18	66	257
18	0.06	0.48	1.37	23	85	331
22	0.08	0.54	1.59	28	105	405
24	0.09	0.63	1.75	31	114	442

Table 2 Leak Off Volume and Depth of Invasion.

4.1.2 DRILLING AND/OR COMPLETION FLUID

- Filtrate leaking off through the filter cake into the formation from water-based fluids increases the near-wellbore water saturation, reducing the relative permeability to oil (Figure 18). This is particularly important for low permeability rocks, where removal of the "extra" water saturation may take a long time.

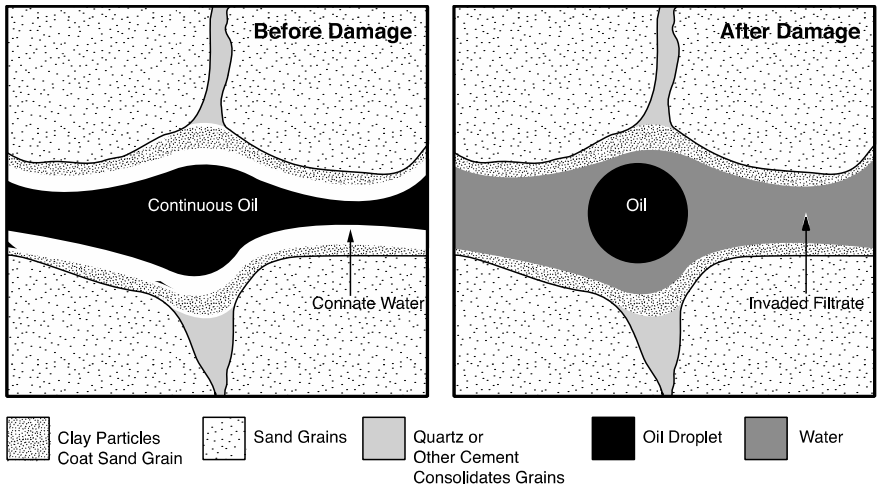


Figure 18 Formation impairment due to increased water saturation (a water block).

In a gas reservoir there is an additional source of Formation Damage, the addition of a third (oil) phase to the already existing gas and water phases will, at least temporarily, reduce the relative permeability to gas when OBM (oil-based mud) is used as the drilling fluid (Figure 19).

- The surfactants present in the mud filtrate (e.g. from an invert oil emulsion mud) may change the formation wettability from more water-wet to more oil-wet as well as cause a viscous emulsion.

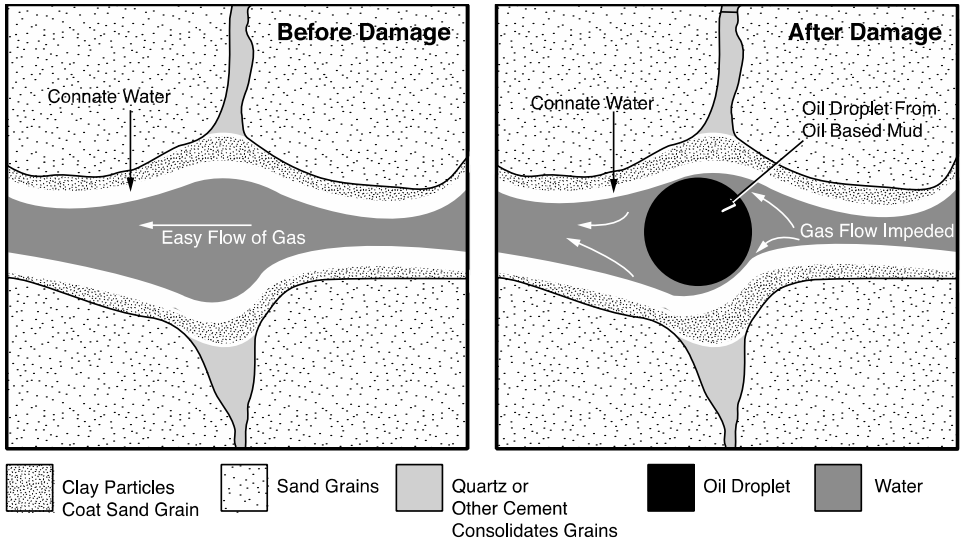


Figure 19 Addition of third phase reduces gas flow.

- The connate water and the mud filtrate or completion fluid may be incompatible with each other. This may result in precipitate formation.

- The mud filtrate or completion fluid may also cause clay swelling (Figure 20) and fines dispersion. Clay particle expansion leads to a reduction in permeability, the magnitude of which will depend on the clay's properties such as the clay chemistry, clay morphology, amount of clay, and chemistry of the mud filtrate – the pH, salinity and chemical composition.

Formulating drilling and completion fluids with 1-3% wt potassium chloride (KCl) or ammonia chloride (NH_4Cl) is an effective procedure to minimise formation/fluid interactions for most formations.

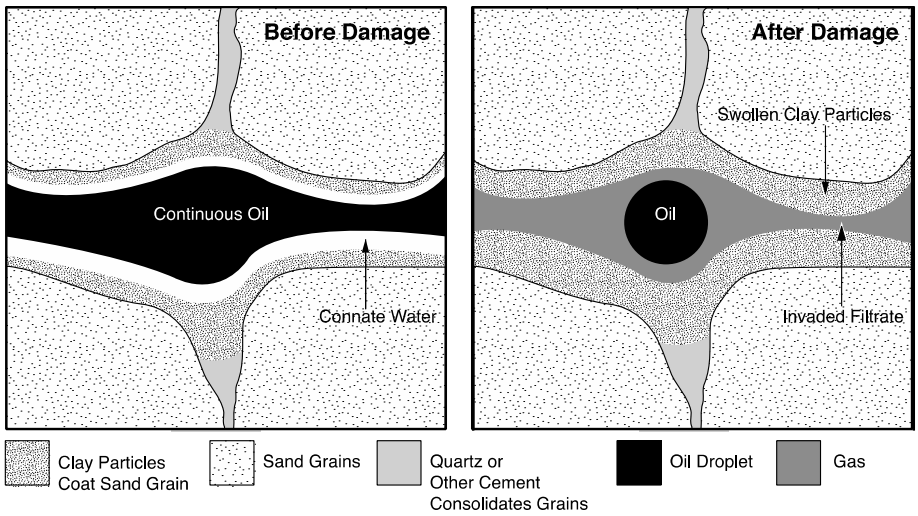


Figure 20 Formation impairment due to clay swelling.

- Polymers dissolved in the mud filtrate may absorb on the formation surfaces, restricting the area open to flow (Figure 21).

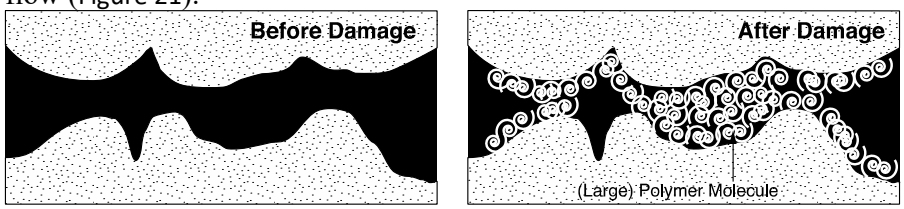


Figure 21 Formation impairment due to polymer absorption.

Well "clean up" (the production time required while the above sources of Formation Damage are being removed, at least partly) can take many months. Only then will the well reach its final well Productivity Index. Sometimes the well continues to show much lower well Productivity Index than expected i.e. a high level of impairment is being observed. Well clean-up through producing the well is thus insufficient and a well treatment, for instance a Matrix Acidizing treatment to dissolve clay particles clogging the pores, or surfactant/acid/alcohols squeeze treatment to reduce water blocks, is required to correct the situation.

- It is clear that design of the right, external filer cake in order to avoid extensive fluid loss causing above damage is important. Let alone some mud particles in both OBMs, WBMs and synthetic muds SBMs can form internal filter cake which also causes damage and should be avoided.

4.1.3. THE FILTER CAKE

The ideal drilling mud will form a thin, impermeable mud-cake with a low rate of fluid leak-off. A well designed drilling fluid rapidly forms an external filter cake on the wellbore surface when the formation face is first exposed by the drill bit.

The filter cake initially has a significant permeability - since it is made up of the larger particles. This is subsequently reduced as progressively smaller particles are retained. Experiments have shown that such external filter cakes can form when the diameter of the pore throat to be bridged is not more than 3 times the typical drilling mud particle diameter.

Special arrangements are required when drilling larger geological features such as open fractures. Larger diameter particles than are normally found in drilling mud are added to promote filter cake formation and prevent uncontrolled losses of large volumes of drilling mud.

Figure 22 is a schematic view of efficient filter cake formation using a drilling mud with a wide range of particle sizes (Figure 23).

Very small diameter particles will pass through the pore throats without blocking. Which of the above processes occurs depends mainly on the [particle/pore throat] size ratio (Table 3) and the particle concentration.

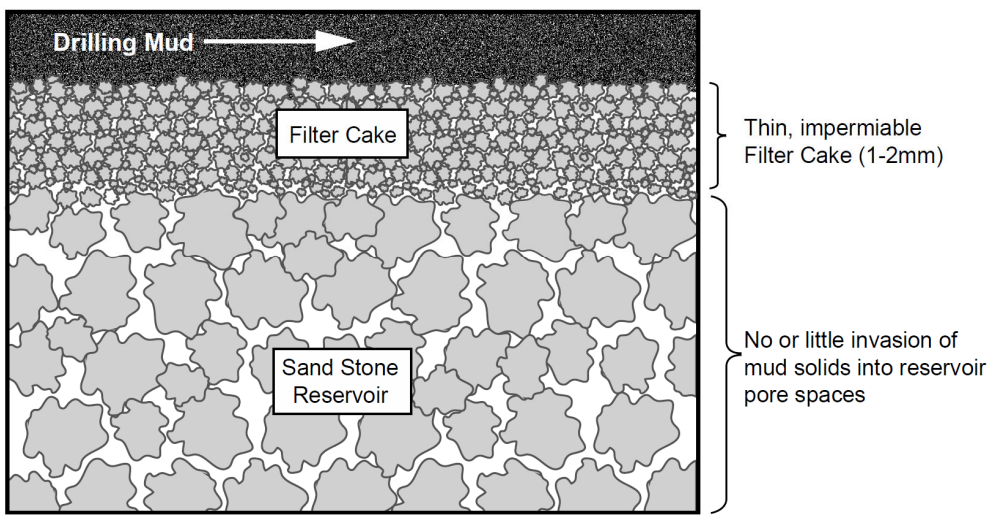


Figure 22 Schematic view of an efficient filter cake

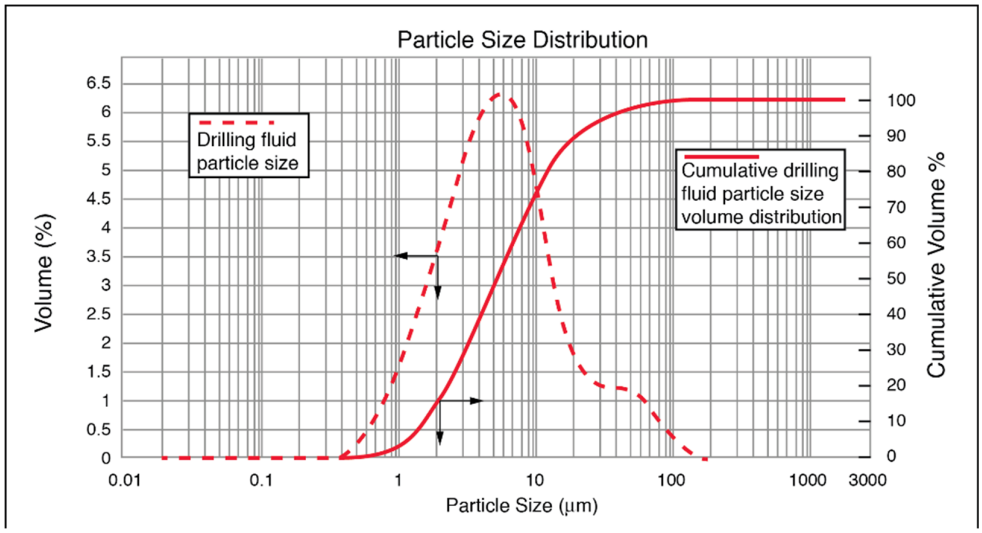


Figure 23 A wide range of particle sizes encourages efficient filter cake formation

Size Ratio	$d > 0.33d_{pt}$	$0.33\ d_{pt} > d > 0.1\ d_{pt}$	$d < 0.1\ d_{pt}$
Process	Forms filter cake at formation surface if bridging solid particle concentrations > 5%	Forms internal filter cake at depth in the formation	Particles flow through pore throats without causing formation damage
Removal	Remove by wellbore acid wash	Matrix acidising. Difficult to remove damage if injectivity = 0.	Not necessary - No formation damage
Bypass	Requires sufficiently long perforations *(≈ 1.5 times formation damage depth)*		

d_{pt} = diameter of a pore throat d = diameter of a particle

Table 3 Filter Cake formation process depends on the particle/pore throat diameter ratio.

Finally, the extent of damage discussed above depends on the invasion profile:

4.1.4 DRILLING FLUID INVASION PROFILE

The combined interaction between the many factors discussed above affect the solids and filtrate invasion profile into the formation. Figure 24 plots the invasion profile of a typical water-based drilling mud as a function of permeability.

The maximum depth of drilling mud and/or filtrate that has leaked off into the formation is routinely measured in a new well when the hydrocarbon phase saturation in the completion zone is measured using the long and short spaced resistivity logging tools. One step in the analysis of the logged data is the calculation of the invasion depth of the water-based mud filtrate.

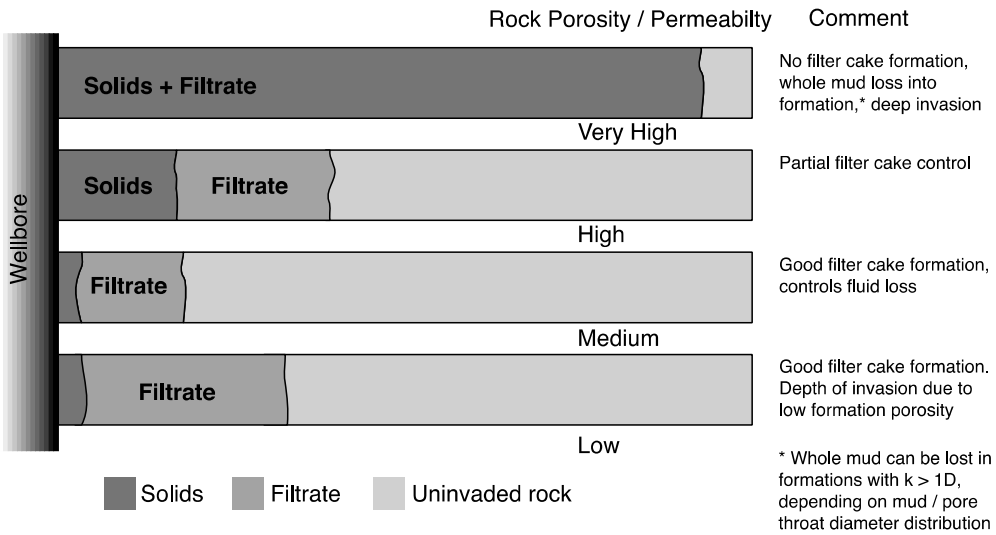


Figure 24 Drilling Fluid Invasion profile summarised.

➢ *Feel free to attempt Tutorial 2.*

4.2 Perforating

Interestingly, the quality of drilling process and drilling mud also affects the perforating efficiency and associated damage. Figure 25 illustrates the effect of drilling an over-gauge hole on the perforating efficiency - the perforating gun was sufficiently powerful for the vertical perforations to penetrate the cement sheath, but was insufficient in the horizontal direction. The well productivity will be reduced since the density of perforations will be only half the design value. Further, the remaining perforations will contact less formation than in the ideal case. Drilling an on-gauge hole (dashed line in Figure 25) avoids this problem.

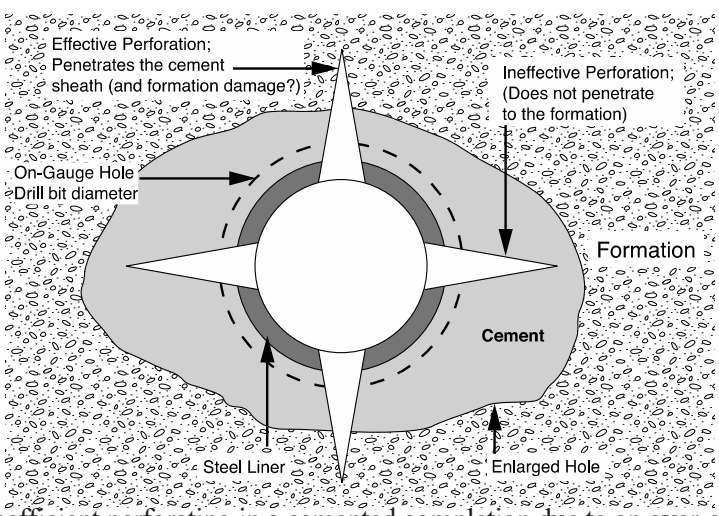


Figure 25 Inefficient perforating in a cemented completion due to an over-gauge hole.

The other extra skin sources induced during well completion, e.g. during perforating due to the perforation blocking by debris and flow impairment across the crushed zone were discussed earlier in this course. Some other types of completion damage (e.g. associated with gravel packs or screens) are also discussed, later in this course.

4.3 Formation Damage During Cementing

The success of a casing or liner cementation is dependent, among other things, on the prior removal of the mud cake so that the liquid from the cement slurry can leak off (at a controlled rate!) while the cement is hardening. This is often achieved by pumping prior to cement various washes containing dispersant additives (surfactants). The removal of the mud cake triggers increased fluid loss.

Filtrate lost from the cement slurry is highly reactive to any formation clays due to its highly alkaline (high pH) nature. It also has a high concentration of calcium cations which can lead to precipitation of calcium carbonate, calcium hydroxide (lime) or calcium silicate. Further, cement slurries have a very high natural fluid loss unless controlled by suitable additives. *(Proper fluid loss control is a necessity since excessive dehydration of the slurry will lead to failure of the cement job. If this occurs the slurry becomes too viscous to pump, halting displacement of the cement, possibly with some of the cement slurry remaining in the casing.)*

Nevertheless, despite the damaging nature of the cement fluid loss, it is not normally a problem since the filtrate volume (and depth of invasion) is normally limited to just a few inches and can be bypassed by the perforations.

A second form of formation damage occurs when cementing a formation which is naturally fractured. The fluid loss control additive added to the cement slurry will be ineffective in such wider diameter features. Cement slurry will flow into the fractures, potentially permanently blocking them, resulting in reduced well productivity. *(Because such fractures, if not blocked, often significantly contribute to the well productivity.)*

Change of the completion design to open hole is the simplest way to avoid this problem. The integrity of the hole may be protected by a slotted liner or screen. This is normally possible since the naturally fractured formation is often strong: it must have been strong enough in the first place to support open fractures under the prevailing reservoir stress conditions.

4.4 Production

Many sources of formation damage taking place when the well is under production/injection, include:

- Fines movement.
- Use of incompatible workover and injection fluids.
- Inorganic and organic scale formation.
- Pressure reduction.
- Well Stimulation.

4.4.1 SOURCE OF FORMATION DAMAGE – FINES MOVEMENT

As mentioned, the "fines" like small mineral particles (clays, feldspars, etc.) which are found on the surface of the sand grains which make up the rock fabric have come into equilibrium with the reservoir fluids during geological time. Sometimes, the conditions were such that the fines remained as discrete particles rather than being cemented together and to the sand grain rock fabric. This equilibrium state is disturbed once a well is drilled and placed on production – high fluid flow velocities are experienced in the near wellbore region. It has been observed in the field, particularly for wells located in young, unconsolidated sediments, that a dramatic reduction in well productivity can occur when the well production rate is increased too quickly.

Movement of fines is controlled by:

- Concentration and nature of the fines present on the sand grain surfaces and within the pores
- Flow velocity of the fluid wetting phase
- Wettability state of the "fines"

It was observed that the permeability to oil flow remained constant, even at reasonable flow velocities, while the permeability began to be reduced at a critical flow velocity when the core was subjected to a combined oil/water flow regime (Figure 26).

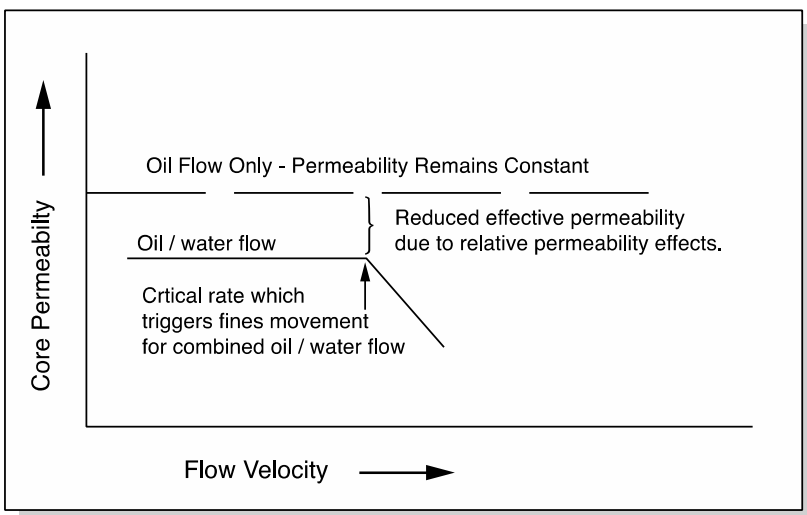


Figure 26 Effect of flow velocity on permeability.

Remedial measures include:

- Controlled, slow bean up of the well reduces the number of particles that are mobilised at any one time, leading to a lower chance of blockage at the pore throats. Small increases in production rate allow the fines to be "cleaned out" of the formation at low rates (and concentrations); so that the desired well production rate (and drawdown) can be achieved while maintaining the near-wellbore rock permeability by preventing pore throat bridging.
- Fines control treatments. These either consolidate the small particles on to the reservoir rock surface (with consequent reduction in formation permeability) or use surfactants to change the formation wettability. *(However, experience shows that many such wettability treatments have a limited lifetime and the formation reverts to its original wettability.)*

4.4.2 COMPLETION, WORKOVER AND INJECTION FLUIDS

- As mentioned, workover, injection and completion fluids must have a very low solids content. Otherwise, they can clog pores. Filtration of the fluid with a 5μ (micrometer) nominal filter decreases the rate of impairment, which is often further decreased by using an even finer (2μ) filter (Figure 27).

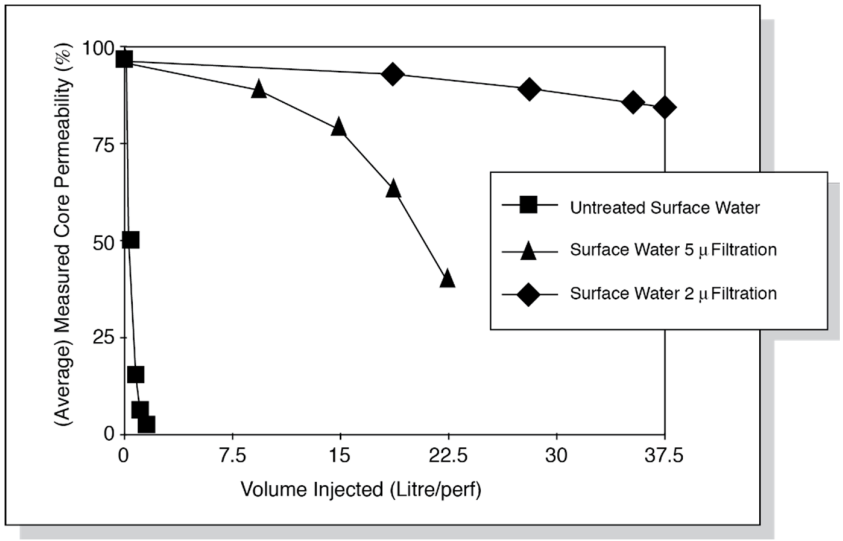


Figure 27 Core test results rank injection water quality after filtering.

Also, it's a good practice to minimise contamination of the filtered brine used as the completion or workover fluid by: cleaning the surface facilities (or using dedicated ones) and tubing string (e.g. with acid like the 'tubing pickling' method described later in this course) or use coiled tubing; minimum use of pipe dope on the connection threads when running tubing; minimise the workover fluid loss rate by reducing the overbalance (200 psi is the standard safety margin) or adding fluid loss particulates that can be easily removed or dissolved later (e.g. gravel, or wax soluble in hot oil, salt soluble in fresh water, calcite soluble in hydrochloric acid, etc.). In the cases where tophole (i.e. above production packer) workover is performed the isolation of the bottomhole interval by e.g. a plug is recommended. Many servicing operations (e.g. perforating) can also be performed underbalance.

- Workover and completion fluids must also be chemically compatible with the formation. In particular, they should not react with the clay in the formation. Formation damage due to the use of incompatible brines is normally permanent. As mentioned, formulating fluids with 1-3% wt potassium chloride (KCl) or ammonia chloride (NH_4Cl) is effective in water sensitive formations.
- Finally, workover, completion and injection fluids must also be compatible with the formation water to minimise chemical precipitation.

4.4.3 WELL TREATMENTS

Well stimulation and other pumping interventions involve pumping liquids into the well. Many adverse effects can take place if the treatment fluids are not designed and treated appropriately, including water blocks, wettability change, precipitation, emulsion and sludge forming, clay swelling, fines migration, rock destabilisation, etc. More on this type of damage is provided later in this course.

4.4.4 PRESSURE REDUCTION

The reservoir pressure of most hydrocarbon reservoirs decreases during their production lifetime, often causing a number of operational problems such as the precipitation of inorganic and asphaltenic scales discussed earlier. Reductions in reservoir pressure increases the formation effective stress. The impact of this increased stress can lead to formation failure resulting in:

1. **Sand production**
2. **Compaction** of the reservoir producing interval, and subsequent loss in porosity and permeability.
3. **Fault creation or reactivation.** 'Mini-earthquakes' downhole that can be large enough to cause wellbore damage. Creation of extra faults may lead to improved inflow; while fault reactivation may result in previously sealing faults becoming "leaky." Wells may be damaged by the casing becoming oval, reducing the maximum diameter of equipment that can be run into the well, or by being sheared if the casing passes through a fault.
4. **Reservoir multiphase flow** effects may be falsely attributed to formation damage. A sufficient reduction in pressure so that the reservoir fluid passes the bubble or dew point results in the presence of an extra phase in the reservoir which will reduce the (relative) permeability to oil or gas flow.

- *Suggest a well drilling, completion and production scenario and list the measures you would recommend to minimise formation damage.*

5. RECOGNISING THE PRESENCE OF FORMATION DAMAGE

Production Logging is traditionally used to recognise problematic production/injection intervals, e.g. by the means of a flow meter, GR (for shaliness profiling), fluid capacitance metering, etc.

- *Feel free to revisit Chapter 2 and explain how PL can help detecting under-producing intervals.*

Fluid sampling is also important, preferably sampling 'live' fluids downhole in multiple wells and flow conditions. Tests like wax appearance temperature, asphaltene titration, total acid number (TAN) etc. for oil; or composition analysis, corrosion, scaling, etc. for water can be performed.

The **efficient removal** of formation damage by a matrix chemical treatment requires that both the TYPE (or CAUSE) and LOCATION of the formation damage be identified **before** its removal is attempted. This identification process often involves:

1. Examining the well records to identify operations that might have resulted in formation damage.
2. Possibly carrying out specific laboratory testing, such as reservoir core flushing or fluids compatibility tests, to determine if the identified operations did indeed lead to core damage for the particular combination of the fluids in question and the reservoir formation.
3. Examining the damaged core with sophisticated analytical techniques such as the scanning electron microscope to confirm the damage type and the damage location; making it possible to develop ideas on how to remove it.

The many possible types of formation damage discussed in this chapter indicate why formation damage studies have to be carried out in a systematic manner. It will also be seen that each source of formation damage has its own, specific cure.

6. FORMATION DAMAGE REMOVAL AND FLOW ASSURANCE

Prevention of Formation Damage is often the best. Different types of formation damage and their prevention methods have already been discussed in this chapter. More details on acidizing treatments aimed at reducing formation damage caused by clays, fines and calcite scales is discussed in the following chapter.

Some problems causing formation damage, including organic and inorganic scale deposition and emulsions, also manifest themselves in both the well production system and surface facilities: i.e. in perforations, gravel packs, tubing string, restrictions and valves, pumps, chokes, flowlines, heat exchangers, etc. (In fact, they are often more likely to appear in the facilities first than in the formation). Such problems in these facilities (along with hydrate forming, erosion and severe slugging) are related to 'flow assurance' or 'cash assurance' as they can notably restrict or even interrupt fluid flow. It thus makes sense to discuss the scale and emulsion reduction treatments both from the formation damage and flow assurance perspectives:

- **Emulsions:**
  The mechanisms, consequences, and prevention measures of emulsion forming both in the formation and facilities have been explained earlier in this course.
  - The basic emulsion treatment is adding de-emulsifiers, though this may be less efficient in the formation than in the production facilities.
  - Mutual solvents (i.e. liquids that can dilute both oil and water) are also sometimes efficient.
  - In the facilities the cause of emulsion can be eliminated. E.g. where emulsions form due to the mix of oil and water at high shear conditions, the fraction of water can be reduced e.g. by plugging/isolating the watered (a.k.a. 'wet') zones, while the shear rate can be reduced by changing or removing the component where it happens, e.g. a nipple, a valve, an ESP, etc.

(Treatment of emulsions and other problems in the separators is discussed separately, in Chapter 11).

- **(Inorganic, or mineral) scales:**
  Typical reduction or mitigation measures include:
  - Dissolving the scale (in the formation, well or facilities) using a suitable solvent. For example, salt (NaCl) crystals can be dissolved by fresh water, Calcium Carbonate ($CaCO_3$) by hydrochloric acid (HCl), barium sulphate by EDTA, etc. The treatment contact (or soaking) time must be sufficient.

  - Inhibiting *(or preventing)* the formation of large-scale crystals with a scale inhibitor is the preferred technique. The inhibitor often works by preventing the initially formed, small, seed crystals (nuclei) from agglomerating and forming massive scale crystals i.e. the minute particles of the scaling mineral are retained in suspension. Thus, the inhibitor is slowing down the kinetics

of scale crystal growth, not the thermodynamics of scale precipitation.

The inhibitor volume and type can be carefully selected and squeezed into the formation on a regular basis, normally to the radius of a few meters around the wellbore. It is then adsorbed by the formation, and slowly desorbs during production, inhibiting scales formation in the near-wellbore zone and in the well. Regular fluid sampling and production water analysis indicate when the inhibitor is depleted and the well is due for the next squeeze treatment.

When scaling happens only in the upper completion, continuous injection of scale inhibitor via annulus or control (macaroni or capillary) lines through the chemical injection valve downhole is an option. *Figure 28 shows a recovered tubing from a producing well with a significant scaling problem.*

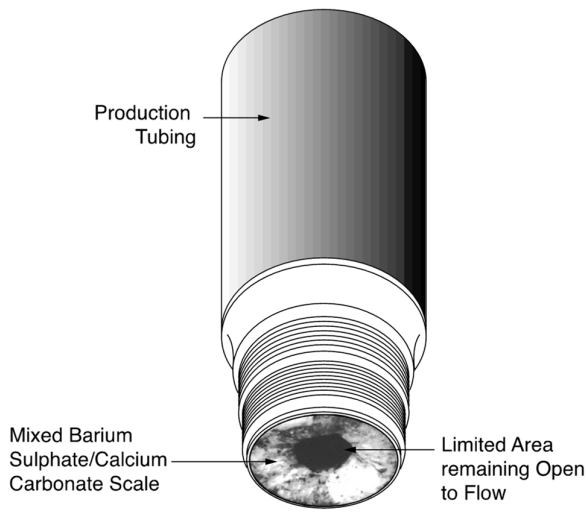


Figure 28 A tubing from a production well that shows extensive scale precipitation

(If pipeline flow is an issue, injection of inhibitors and other chemicals at the wellhead is common, as well as pipeline cleanup ['pigging']).

- Changing the flow thermodynamic conditions to the ones less favourable for scale deposition is an option *(this applies to both organic and inorganic scales)*. E.G. keeping the production fluid hot by insulating the production tubing, and/or keeping the pressure high by controlling drawdown and minimising tubing pressure losses are useful.

- Apart from the thermodynamic conditions (temperature, pressure, pH), scaling can be caused by mixing formation and injection waters. For instance, sea water used in injection is often high in sulphates and bicarbonates, while the formation water is high in calcium and barium cations. Reservoir management to either avoid mixing (e.g. isolate watered zones, modify flood front, control water coning, etc.) or use formation water for injection (e.g. re-use produced formation water, use water from the aquifer by the means of dump flooding, etc.) is helpful. Treatment of the injection sea water, like installation if a water desulphation plant, or injection of scale inhibitors can be expensive but sometimes are necessary.