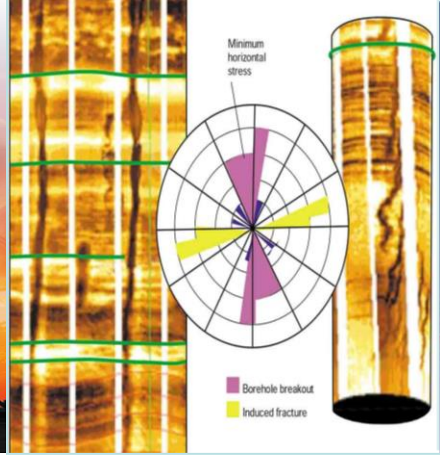

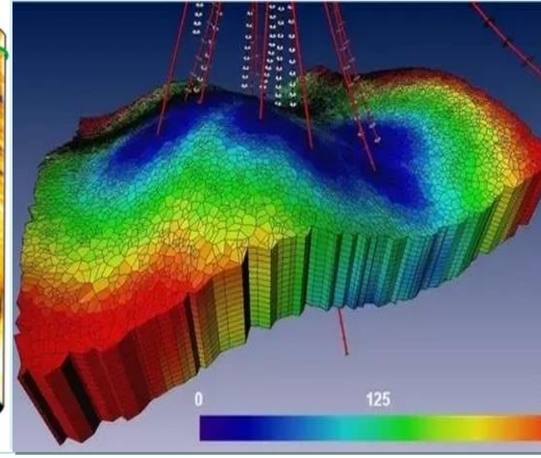

Fundamentals of petroleum Engineering

Part : 5
Production Engineering

By
Petroleum Engineer
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Iraq / Missan / 2020

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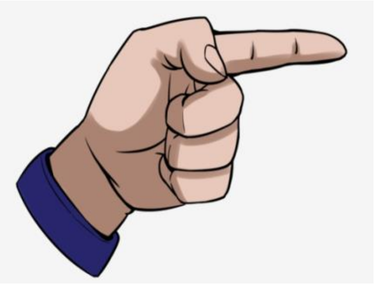
Production Engineering Fundamentals



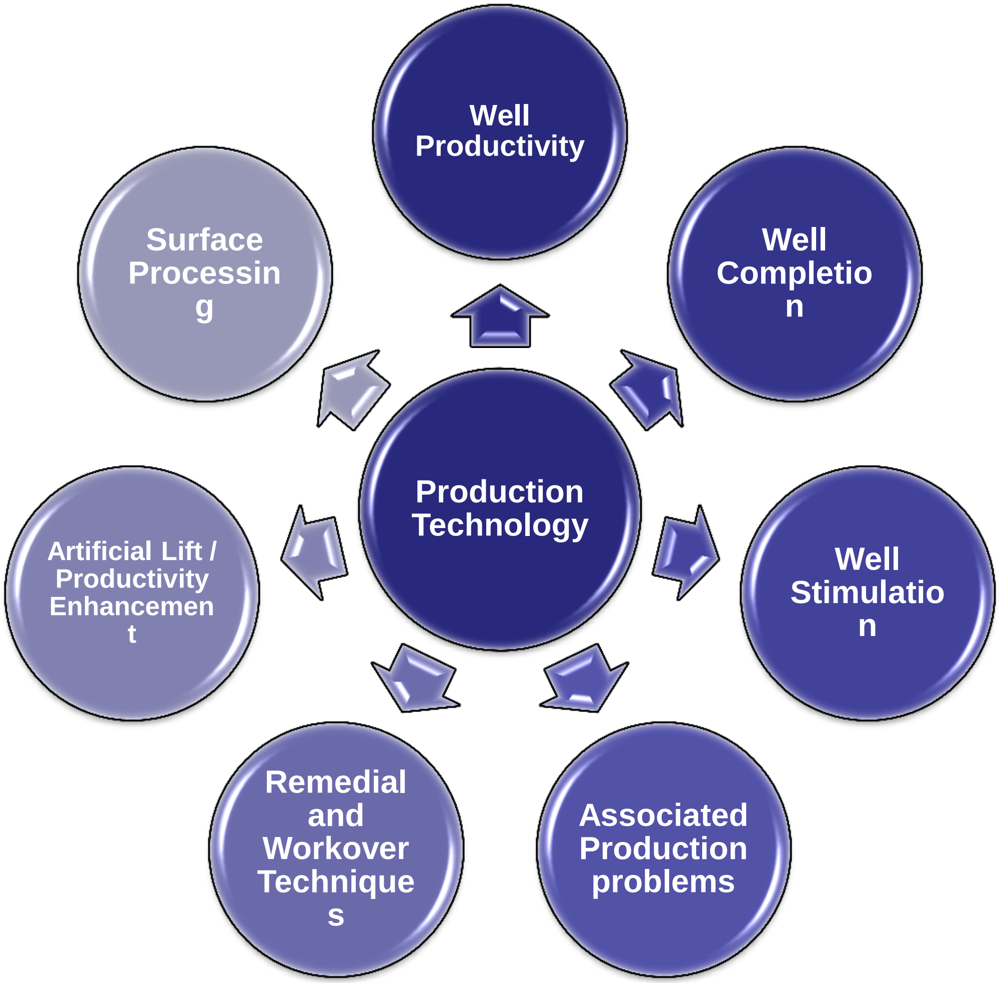
(1) Introduction to production technology

Introduction to production technology

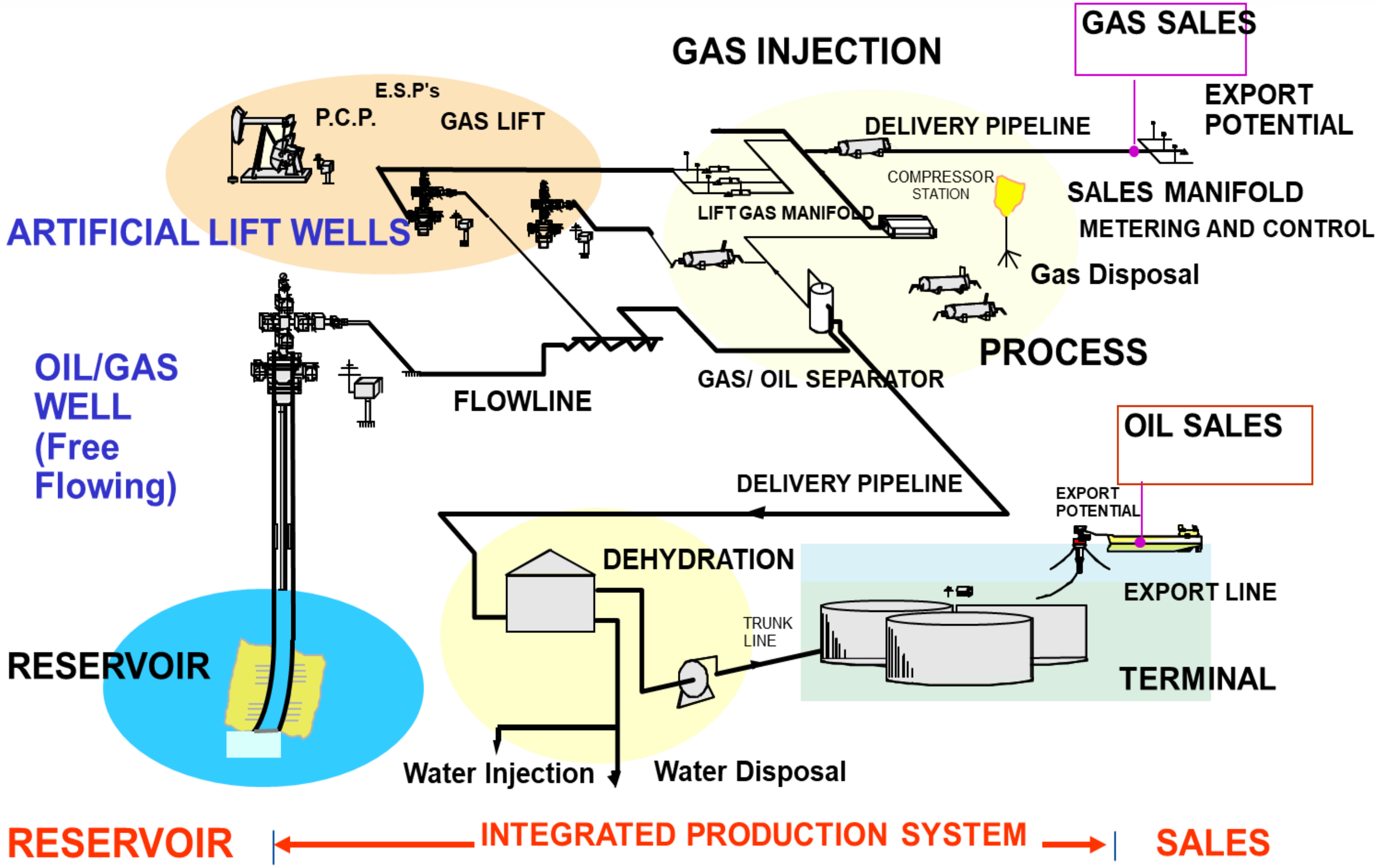
Production technology :
Petroleum production, recovery of crude oil and, often, associated natural gas from Earth.

After finish drill the well have many activities to put well into production such as well completion , well stimulation …etc

Production technology including many parts , please see the chart .



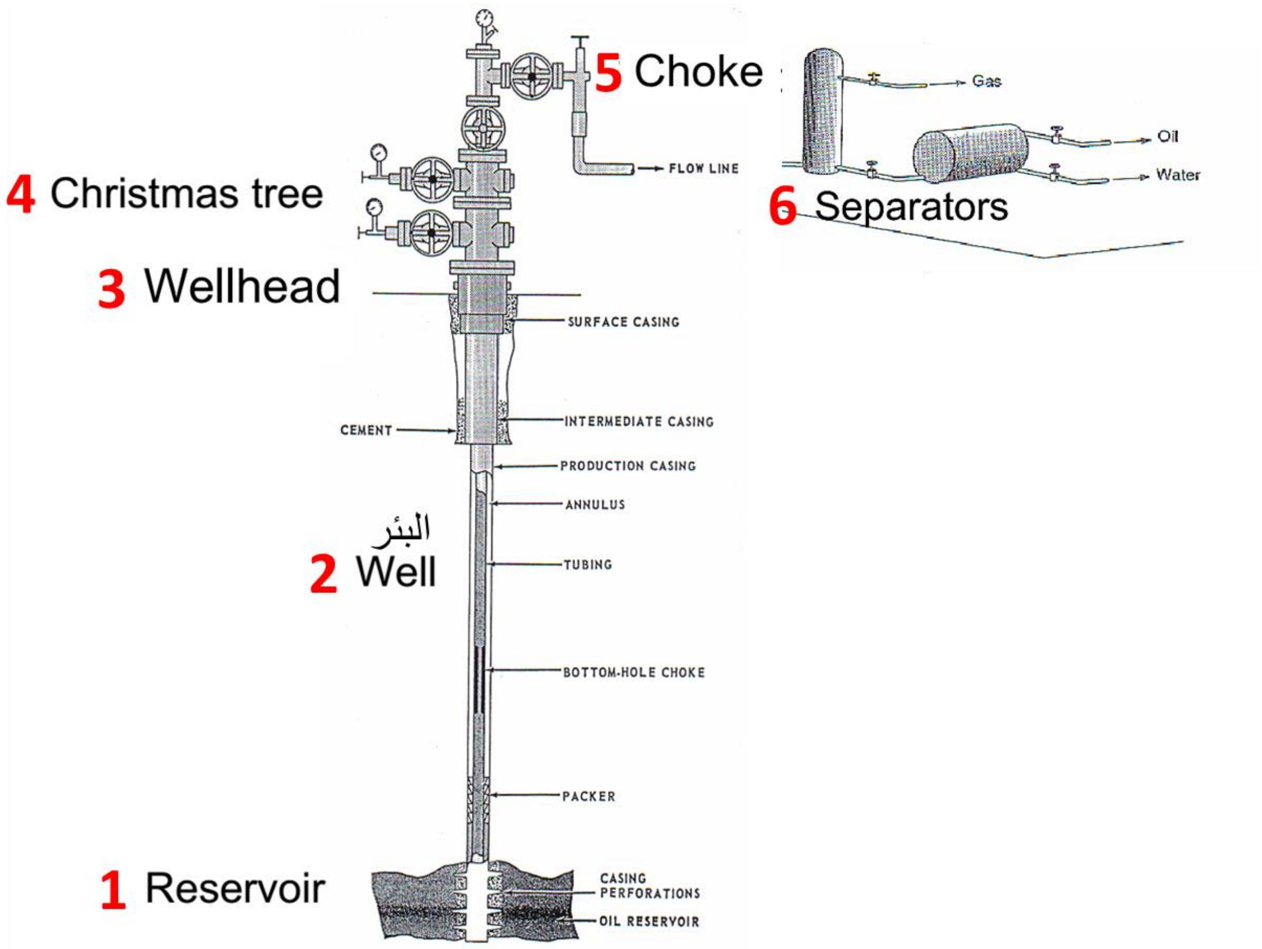
Integrated Production Systems



simple production system.

Production System

- Reservoir
- Well
- Wellhead
- Christmas tree
- Choke
- Flow line
- Separators

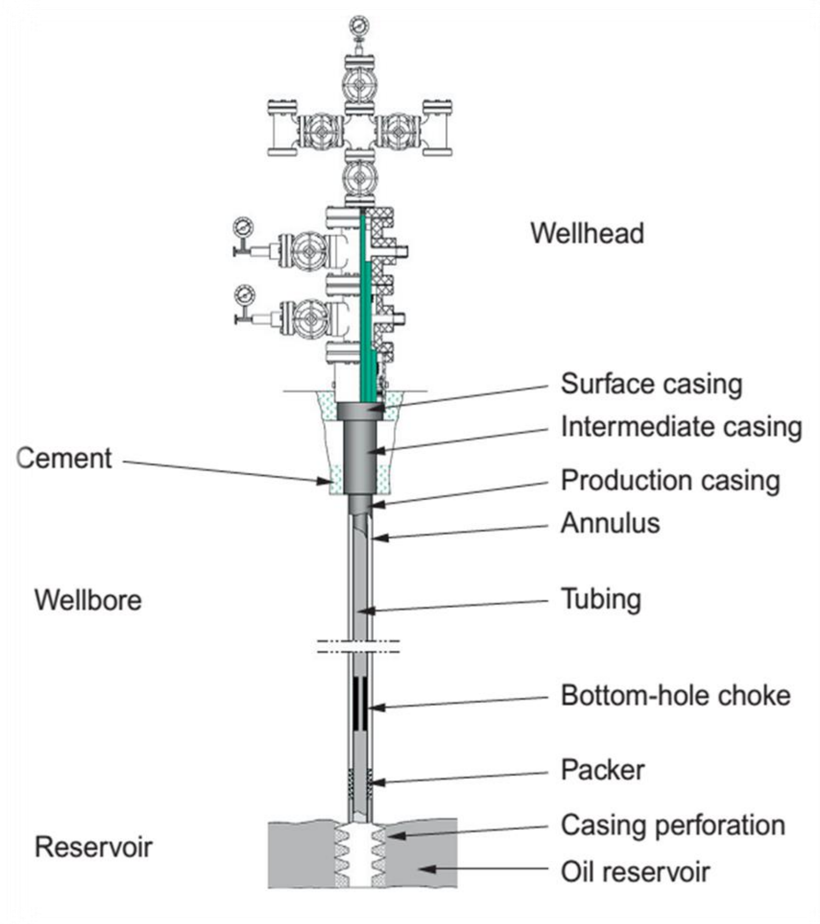


A simple producing system

A typical flowing oil well

a typical flowing oil well, defined as a well producing solely because of the natural pressure of the reservoir. It is composed of :

1. casings,
2. tubing,
3. packers,
4. down-hole chokes (optional), wellhead,
5. Christmas tree,
6. surface chokes.

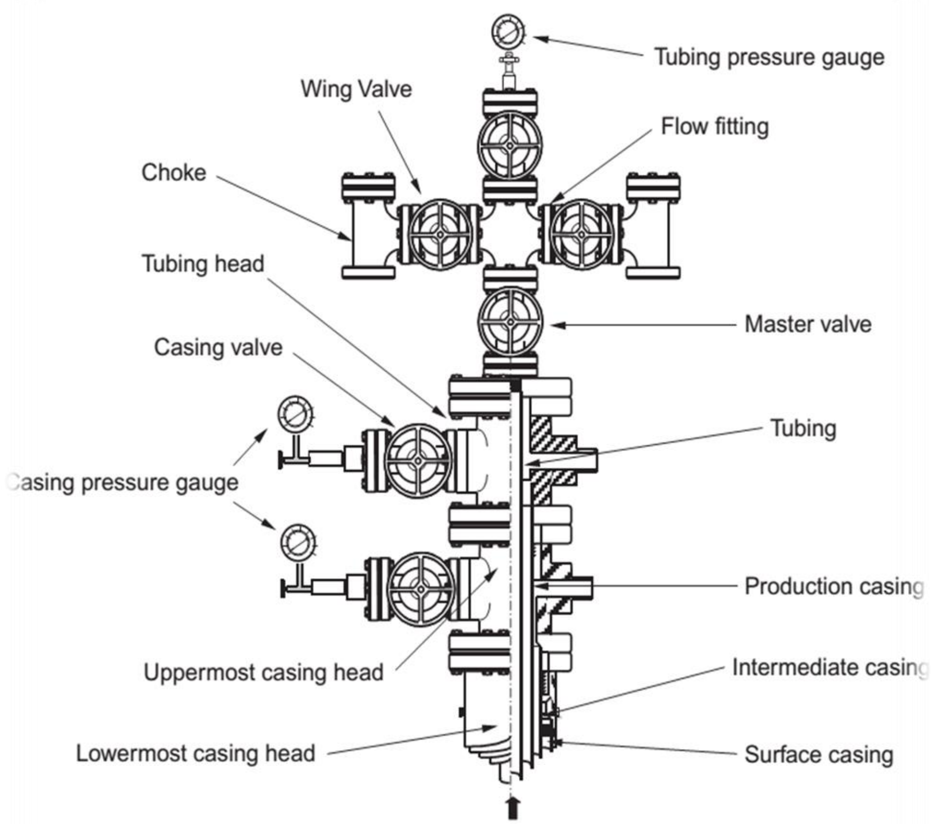


A sketch of a typical flowing oil well

Well Component

1-Wellhead

The “wellhead” is defined as the surface equipment set below the master valve. it includes casing heads and a tubing head. The casing head (lowermost) is threaded onto the surface casing. This can also be a flanged or studded connection.

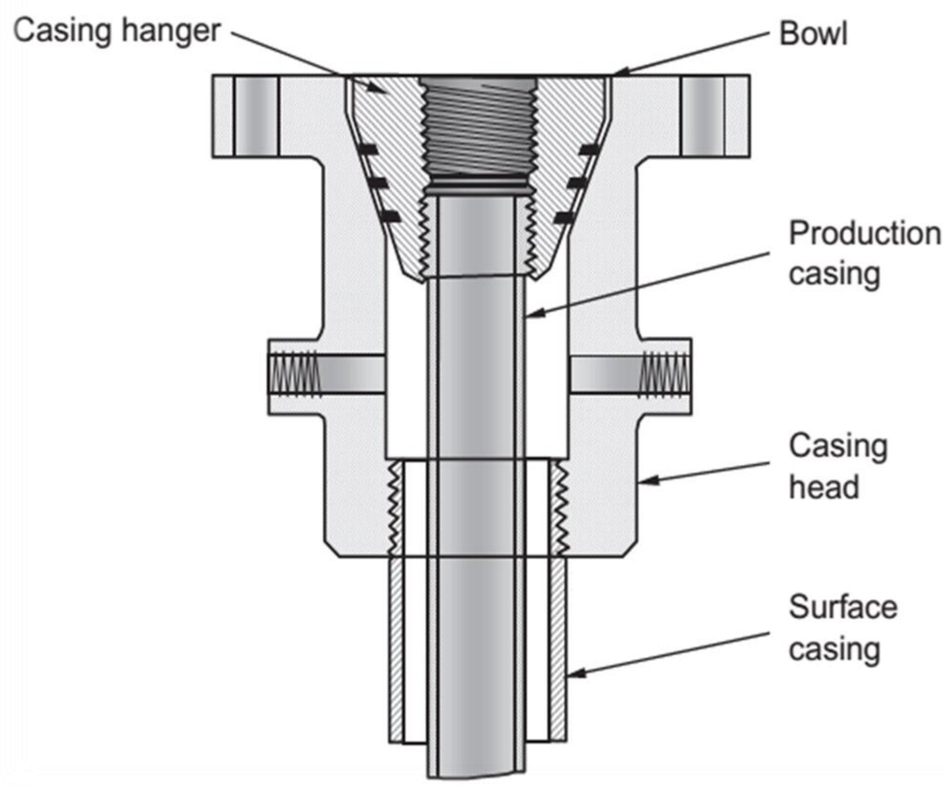


A sketch of a wellhead.

2-Casing head.

A "casing head" is a mechanical assembly used for hanging a casing string . Depending on casing programs in well drilling, several casing heads can be installed during well construction. The casing head has a bowl

that supports the casing hanger..

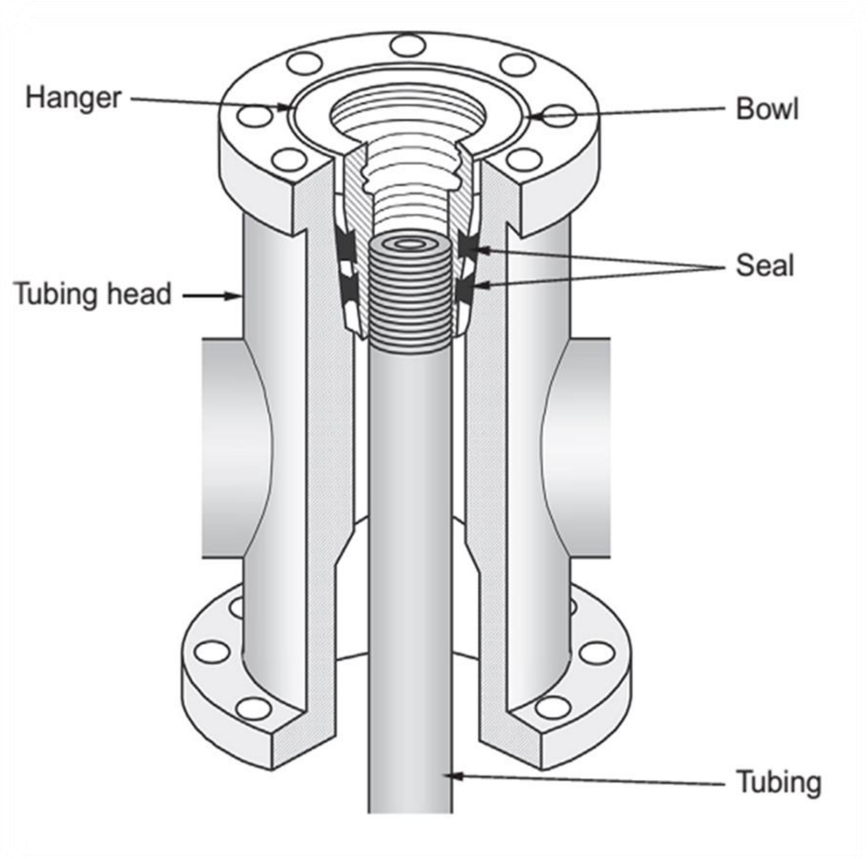


A sketch of a casing head.

Well Component

3-Tubing head

the tubing head is used for hanging tubing string on the production casing head . The tubing head supports the tubing string at the surface (this tubing is landed on the tubing head so that it is in tension all the way down to the packer)..



A sketch of a tubing head.

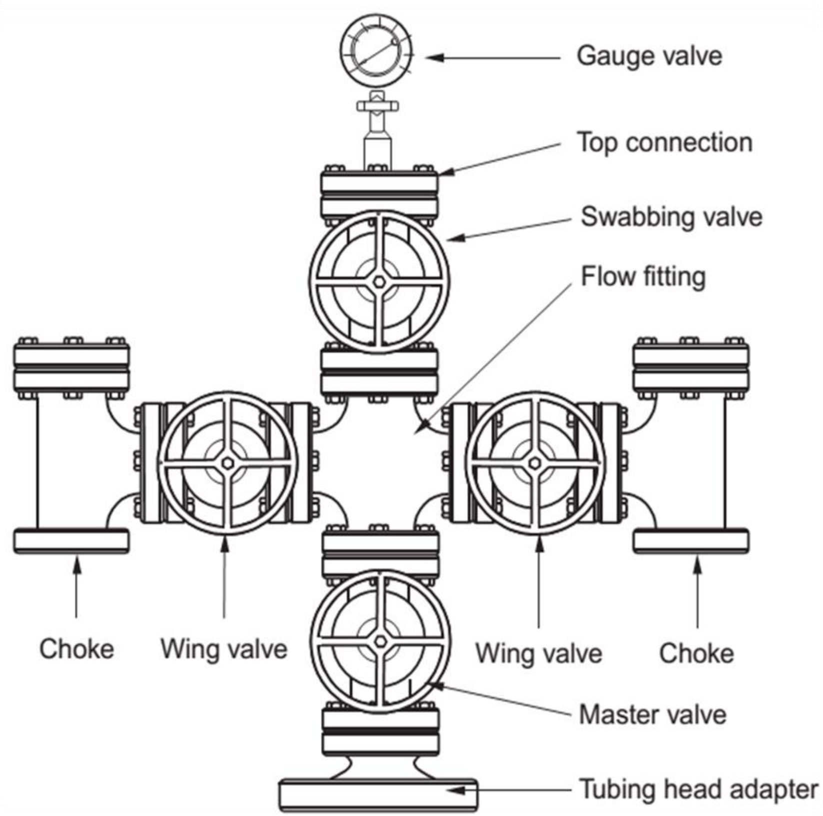
Well Component

4-Christmas tree

The equipment at the top of the producing wellhead is called a "Christmas tree and

it is used to control flow. The Christmas tree is installed above the tubing head. An "adaptor" is a piece of equipment used to join the two. The Christmas tree may have one flow outlet (a tee) or

two flow outlets (a cross). The master valve is installed below the tee or cross. To replace a To replace a master valve, the tubing must be plugged

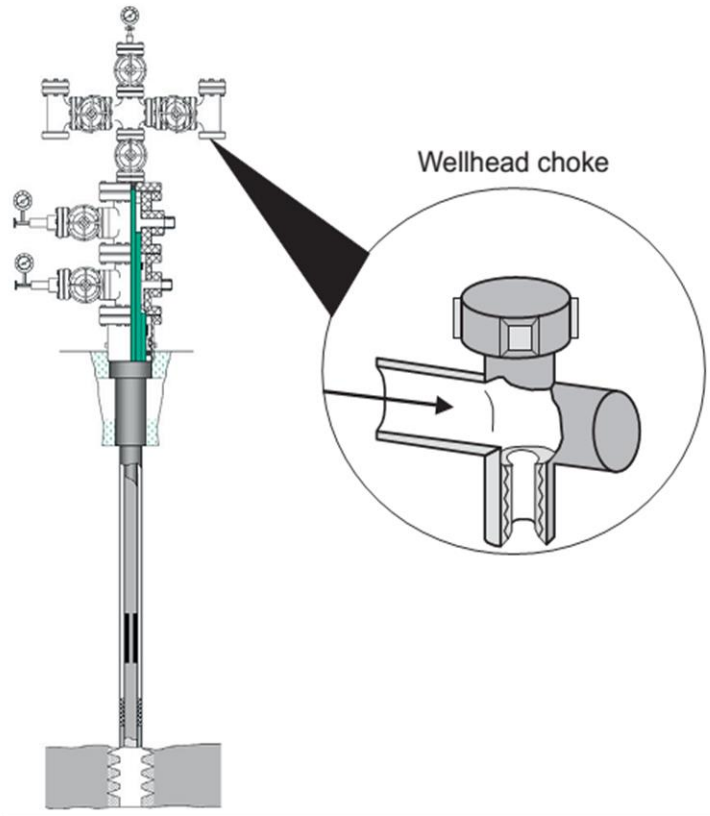


A sketch of a "Christmas tree."

Well Component

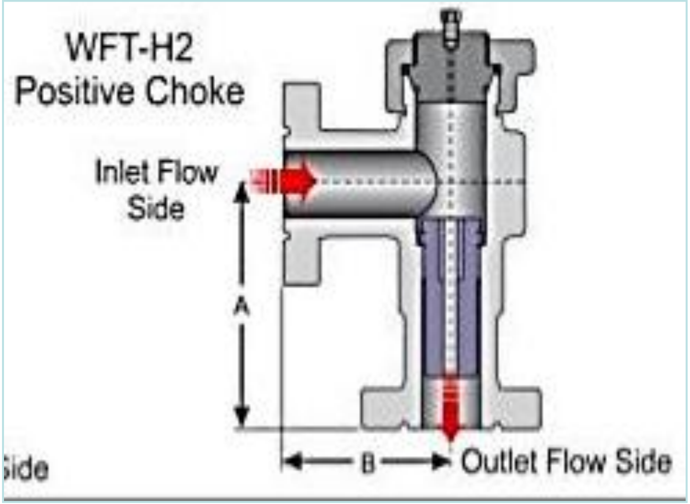
5-wellhead choke

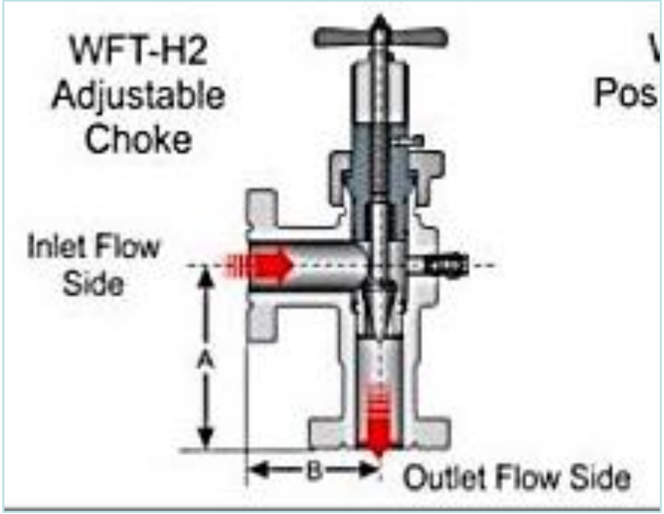
Wellhead chokes are used to limit production rates for regulations, protect surface equipment from slugging, avoid sand problems due to high drawdown, and control flow rate to avoid water or gas coning. Two types of wellhead chokes are used. They are (1) positive (fixed) chokes and (2) adjustable chokes.



A sketch of a wellhead choke.

Most Common Chokes :





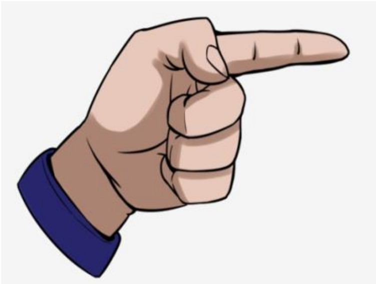
Positive choke :

– Fixed orifice

– Disassemble to change bean

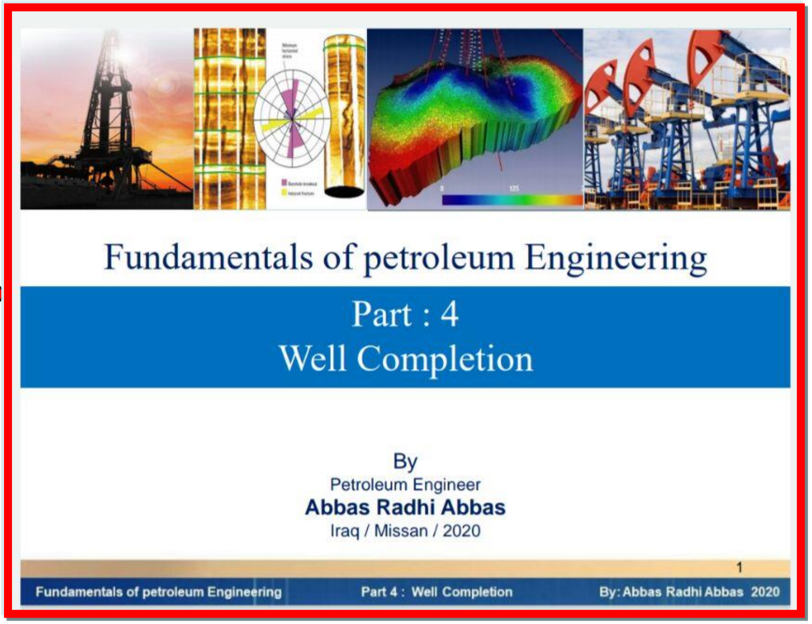
- Adjustable choke :

– Provides variable orifice size through external adjustment



(2) Introduction to Well completion

Note : All details about well completion in Part 4



Well completion

A well completion consists of a series of operations that are necessary to enable a well to produce (and to sustain the production of) hydrocarbons following the installation and cementing of the casing.

1.• Well completion operations include:-
2.• Casing installation
3.• Tubing string / tubing hanger installation
4.• Sub-surface safety installations (i.e. SSSCV)
5.• Production packer setting
6.• Perforating and Sand control
7.• X-mas tree installation

• Finally It is a satisfactory communication between reservoir and the surface

Factors Affecting Well Completion

❑Reservoir Considerations
❑Mechanical Considerations

Well completion

❑Reservoir considerations

1. Producing Rate , i.e. size of production tube.
2. Multiple Reservoirs i.e. multilayer well.
3. Reservoir Drive Mechanism water drive , depletion ,..
4. Stimulation , acidizing , fracture,…..
5. Rock & Fluid Properties (sand production , gas , oil , water cut , H_2S , CO_2)
6. Producing naturally or Artificial Lift gas lift , pumping
7. Work over Requirements i.e. permanent packer , retrievable backer , additional perforation deepening,side track.

❑Mechanical Considerations

1. Functional Requirements blast joint , expansion joint , sand screen
2. Operating Conditions high tubing grade for high pressure , carbon steel or 13 % chrome or super 13 chrome for H_2S and CO_2 production.
3. Component Design SPM spacing , SSD depth
4. Safety SSSCV , ability to isolate any layer.

Well completion

❑ Rules of Completion Design

1. Design the well from the bottom to up and inside to out . start with pay zone depth then production casing depth and finally up to the surface casing depth.
2. So it start with production tubing size based on the expected flow rate then production casing size and finally out to the surface casing and conductor size.
3. It is a must to spend time on well objectives , production forecasting , max rate , depletion rate, natural production or artificial lift requirements .
4. Include W/O requirements.
5. Talk to other people about your design

.

❑ Completion classifications

1. Based on the well bore & reservoir interface

- Open hole completion
- Un-cemented Liner Completions
- Cased and Cemented Completions

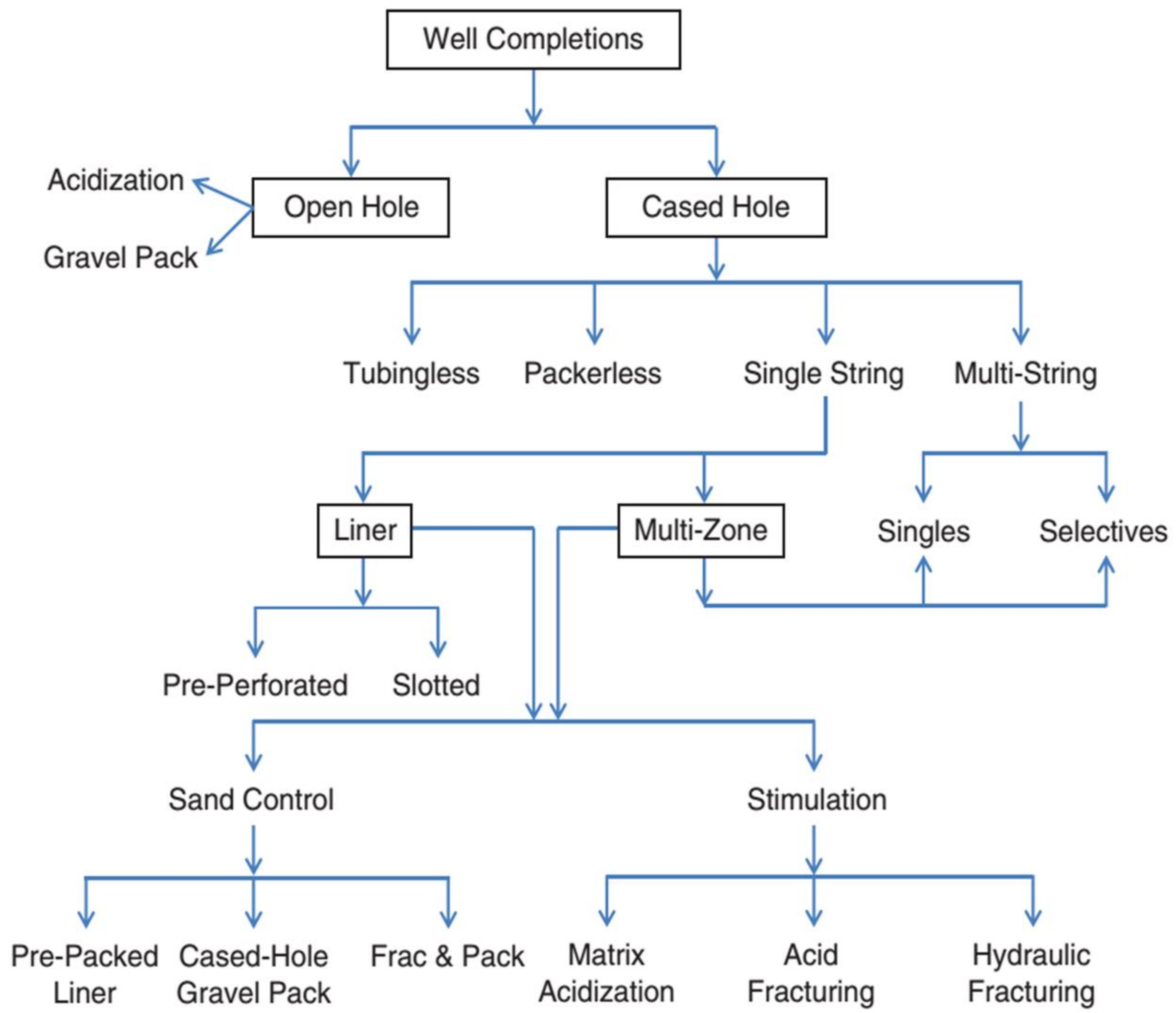
2. Based on production methods

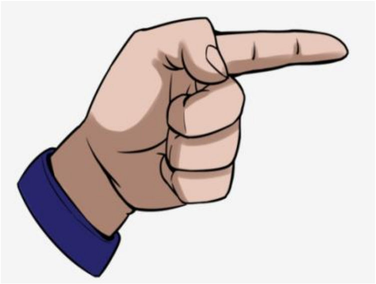
- Natural flowing
- Artificial

3. Based on the producing zone

- Single zone
- Muti-zones single completion
- Muti-zones dual completion

Well completion





(3) Production Optimization

Production Optimization

1- what is production optimization ?

- Well optimization is the fine tuning of the conditions applying to the well performance, that results in the maximum return of oil and gas consistent with a draw down of reservoir pressure to ensure the best commercial return over the predicted life of the well.

- Well optimization involves a number of different methods of tuning to achieve the optimum performance. The principal methods covered in this topic are the adjustment of flow and pressure conditions at the wellhead and water flood injection. Other methods of well optimization involve secondary recovery techniques, such as gas lift, and are covered elsewhere.

2- why do production optimization ?

- The fluids flowing from the wells are a combination of three phases – oil, gas, and water. The optimum flow rate is one that achieves the best commercial product flow, while not depleting the pressure of the reservoir too quickly. The oil and gas have value commercially and it is important to realize the best combination to recover the most oil for sale. The water does not have any value, and as such is considered a by product that is incidental to the hydrocarbons production.

3- where do production optimization ?

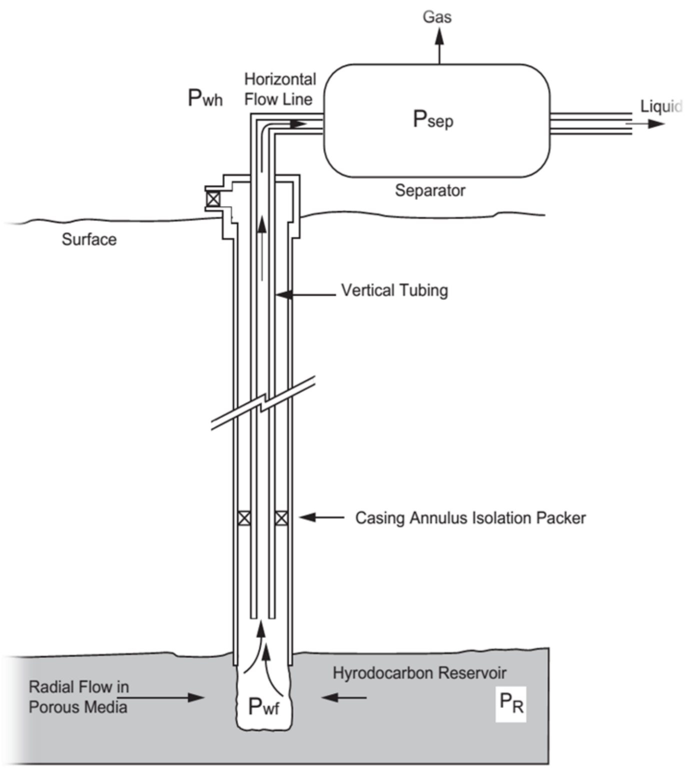
- The well optimization operation is carried out at individual wells, using process data, the Test Separator, and water cut analysis to determine the flow rates, pressure, temperature and phase proportion of each well stream flow.

- Each wellhead Xmas Tree has a pressure indicator to measure the well stream fluids. The choke valves are used to regulate the flows

Simple Production Systems includes :

1. Reservoir (Inflow Performance Relationship)
2. Wellbore (Completions, Tubing etc)
3. Surface Facilities (Flow lines, Separator, Pipelines, etc)

- Production systems can be very simple to complex
  - Simple – Reservoir, completion, tubing, surface facilities
  - Complex- Artificial lift system, Water injection and Multiple wells



A simple producing system

Production Optimization

Production Optimization refers to the various activities of measuring, analyzing, modelling, prioritizing and implementing actions to enhance productivity of a field: reservoir/well/surface . Production Optimization is a fundamental practice to ensure recovery of developed reserves while maximizing returns. Production Optimization activities include:

1-Near-wellbore profile management

- gas–water coning and fingering,
- near-wellbore conformance management

2-Removal of near-wellbore damage

- matrix stimulation or acidizing

3-Maximize the productivity index

- hydraulic fracturing
- maximum-reservoir-contact well with multilateral completion

Production Optimization

4-Prevention of organic and inorganic solid deposition in the near-wellbore/completion/pipeline

5-Well integrity

- prevention and remediation of casing and cement failure

6-Design of well completion

- optimization of artificial lift performance at field and well level
- sand control management

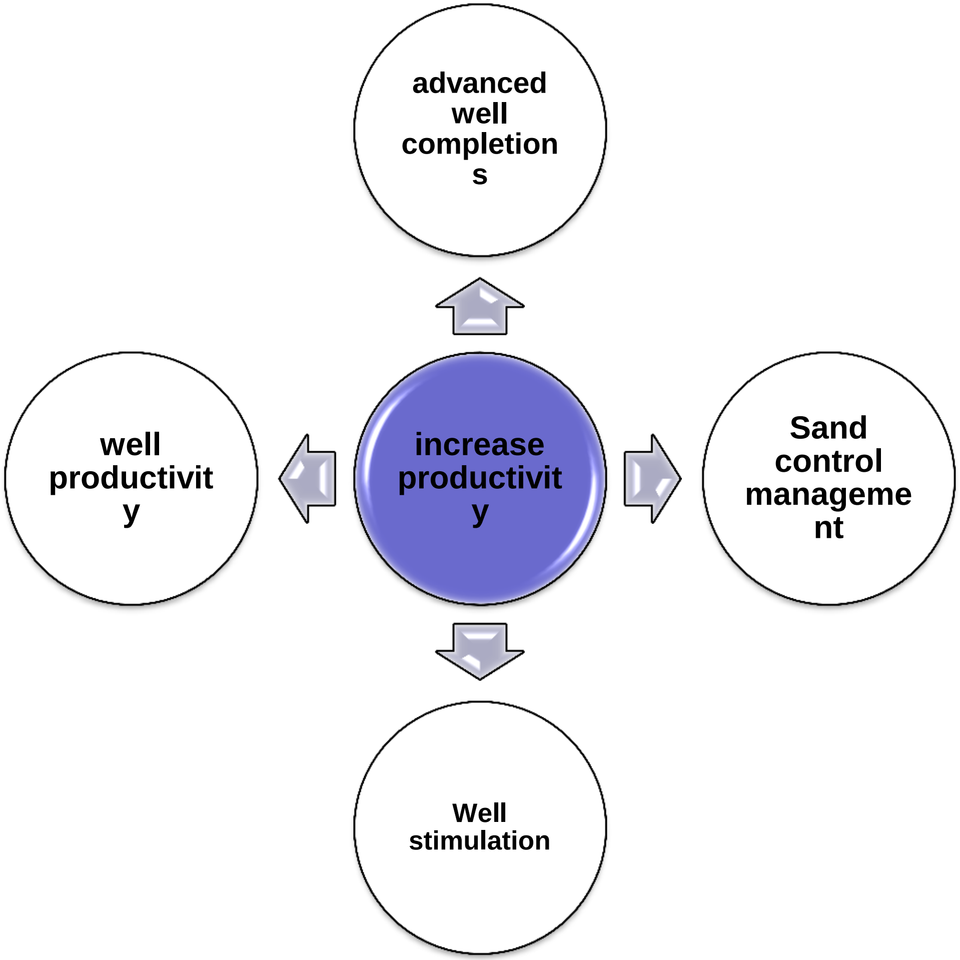
7-Efficiency of oil and gas transport
8-Design of surface facilities and fluid handling capacity
9-Production system debottlenecking

Production Optimization

increase productivity :

Production optimization allows to increase productivity from existing field and uses encompass several areas of interest by using different technologies :

1. advanced well completions.
2. well productivity (nodal analysis)
3. Well stimulation
4. Sand control management

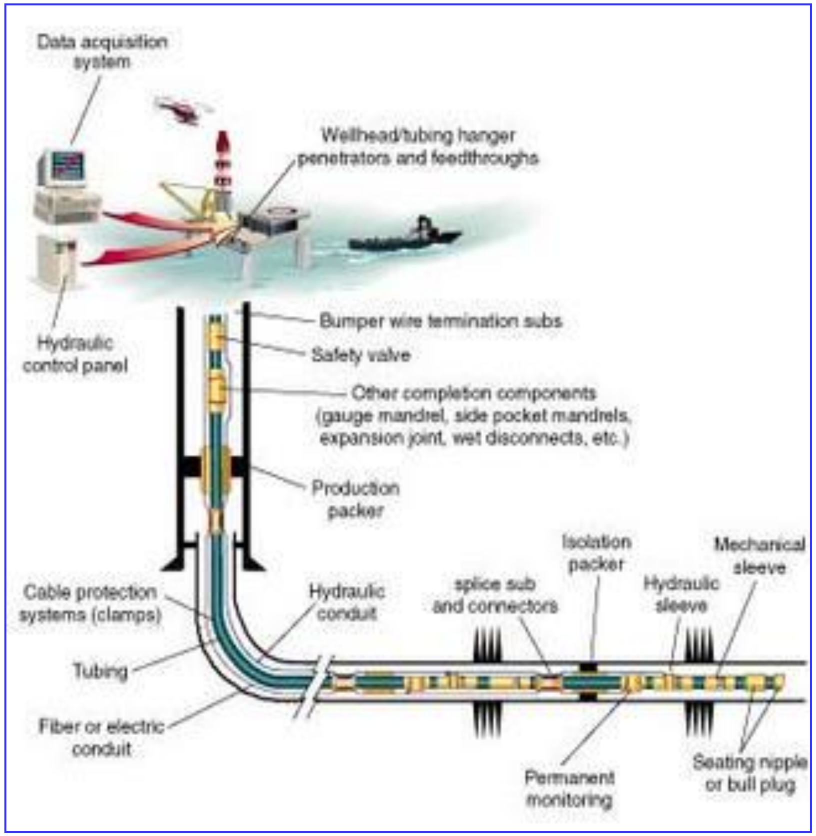


Production Optimization

1-Advanced well completions

An Intelligent (Smart) completion is a well that contains a “Remotely Operated Adaptive Completion System” which provides real-time data and the capability to re-configure the well architecture without well interventions.

The system is able to collect, transmit, and analyze reservoir production data and to proof completion integrity, and to enable remote action to better control reservoir, well, and production processes.



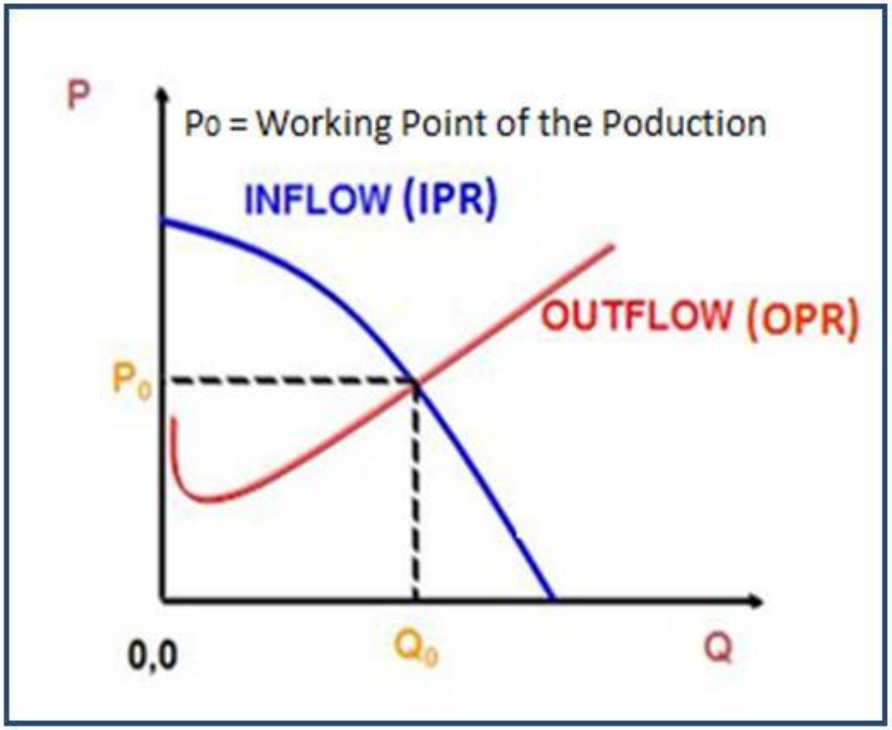
Production Optimization

2-well productivity (nodal analysis)

- Inflow Performance Relationship (IPR) is defined as the functional relationship between the inflow production rate and the inflowing pressure at node

- Outflow Performance Relationship (OPR) is defined as the functional relationship between the outflow production rate and the outflowing pressure at node

- The interaction of IPR and OPR is the Working Point of the system.



IPR and OPR interaction

3-Well stimulation

Well stimulation is a term describing a variety of operations performed on a well to improve its productivity. Stimulation operations can be focused on the wellbore or on the reservoir. They can be conducted on old wells and new wells and they can be also designed for remedial purposes.

There are two main types of stimulation operations:

1. matrix stimulation
2. hydraulic fracturing.

Matrix stimulation : is performed below the reservoir fracture pressure in an effort to restore the natural permeability of the reservoir rock. Well matrix stimulation is achieved by pumping acid mixtures (acidizing) into the near-wellbore area to dissolve the limestone and dolomite formations or the formation damage particles between the sediment grains of the sandstone rocks.

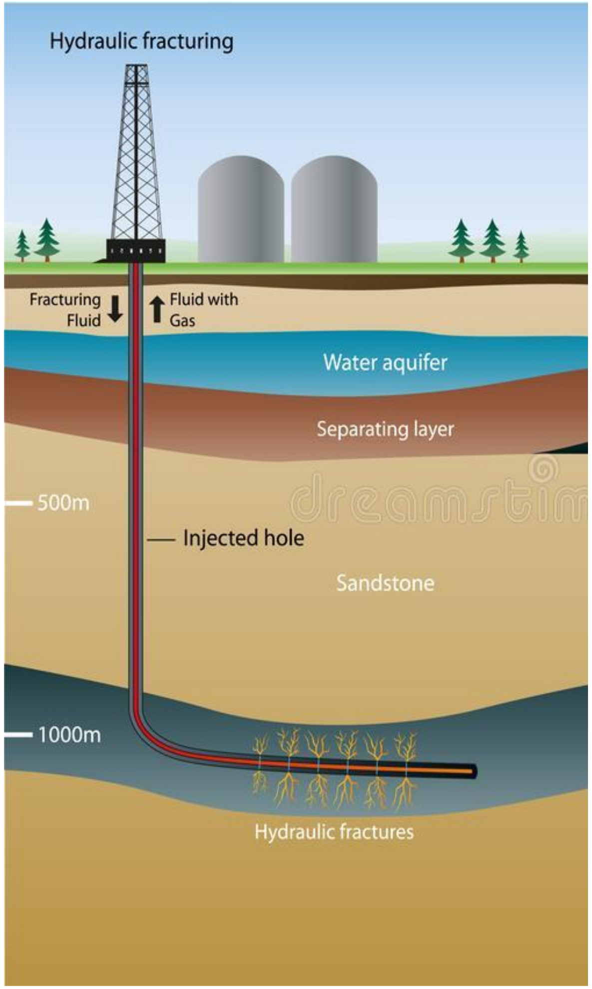
Production Optimization

Hydraulic fracturing :

Hydraulic fracturing is the most common mechanism for increasing well productivity.

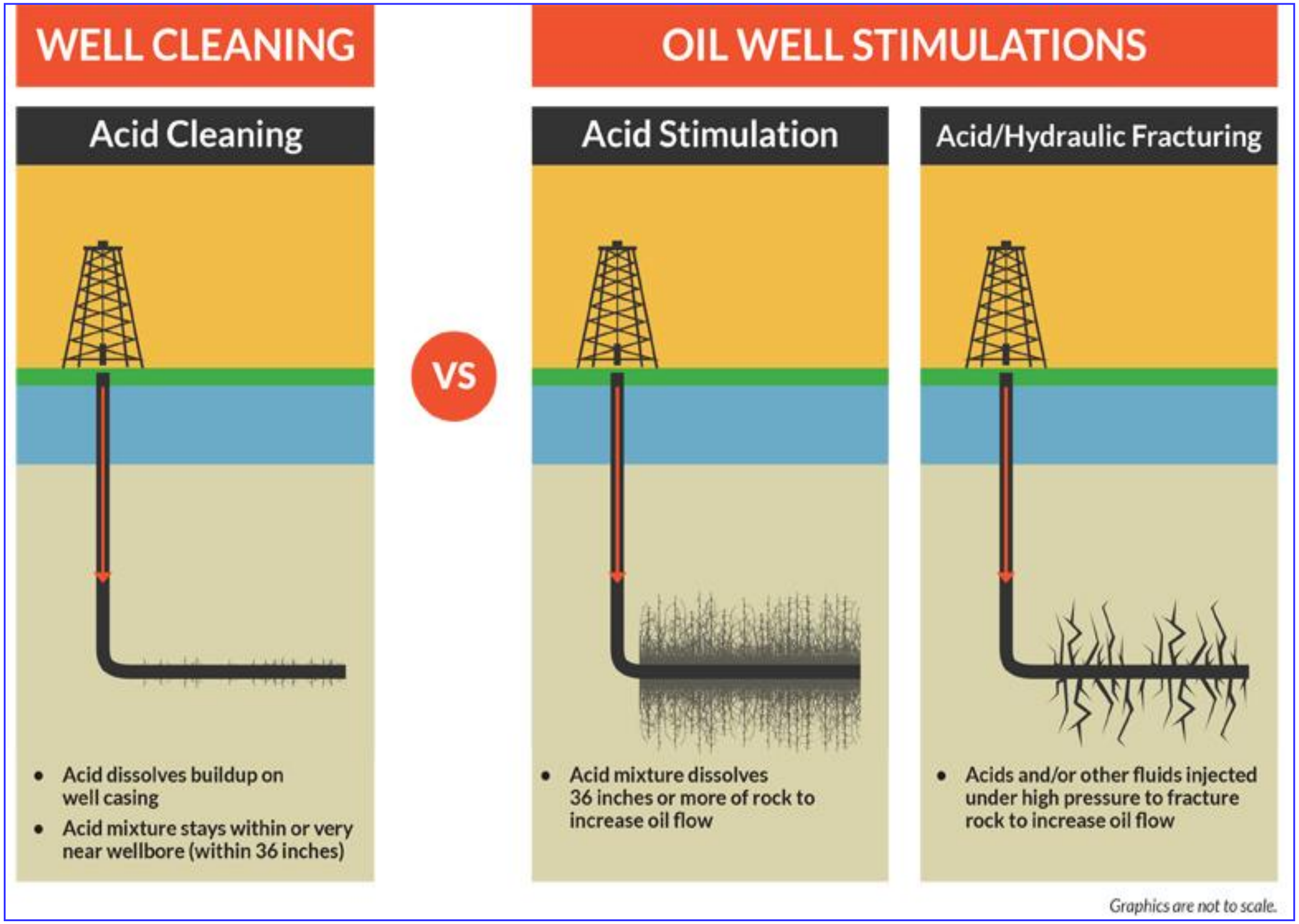
- ❑ In certain hard carbonate reservoirs “Acid Fracturing” is performed;
- ❑ In other soft carbonate and in all sandstone reservoirs “Propped Fracturing” is used.

Hydraulic fracturing id used to by-pass near wellbore damage and Increase well production by changing flow regime from radial to pseudo-linear, to reduce sand production and to increase access to the reservoir from the well bore.



Production Optimization

Acid cleaning , acid stimulation and hydrologic fracturing

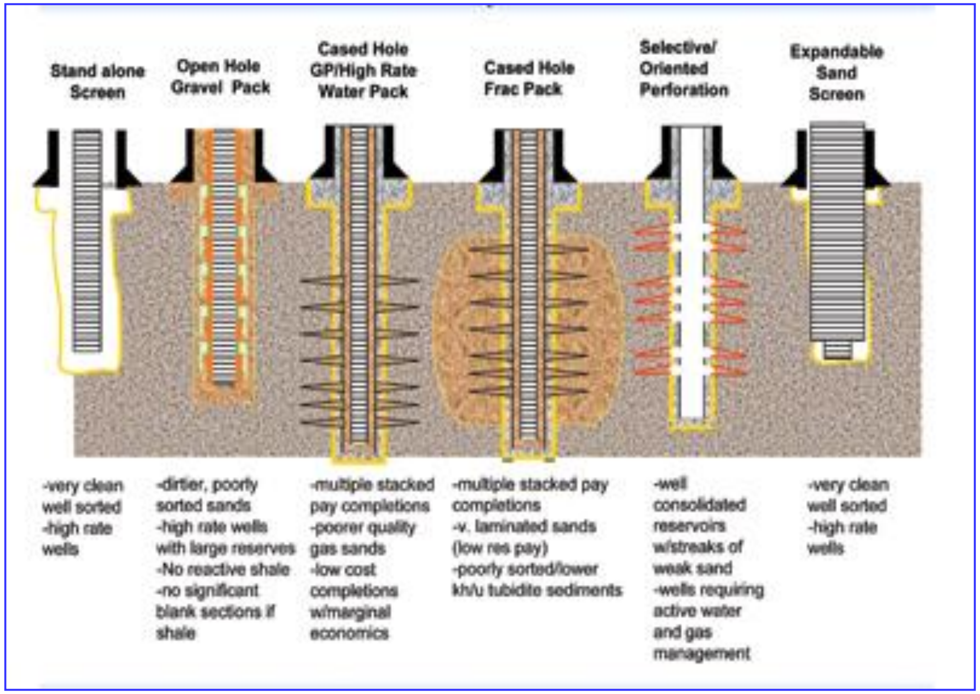


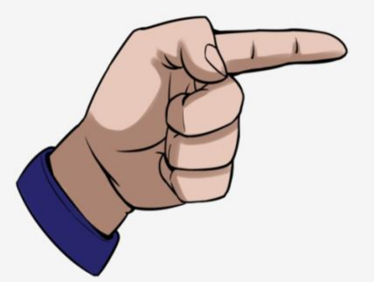
4-Sand control management

When oil is produced from relatively weak reservoir rocks, small particles and sand grains are dislodged and carried along with the flow. This sand production can create erosion in flow-lines and other equipment. Sand management can be considered as a key issues in field development in most of world's oil and gas fields. Sand control management can be counted as an activity which shares risks (safety, environmental, process and cost) of producing sand to the surface vs. the risks of trying to keep it down in the reservoir using different mechanical or chemical control techniques..

Sand Control Methods

1. Open Hole and Cavities
2. Cased and Perforated
3. Stand Alone Screen
4. Slotted Liner
5. Expandable Screen
6. Resin Consolidation
7. Cased Hole Gravel Pack
8. Open Hole Gravel Pack
9. High Rate Water Pack
10. Fracturing
11. Tip Screen Out Fracture





(4) Nodal Analysis

Nodal Analysis

Introduction:

Nodal analysis is the application of systems analysis to the complete well system from the outer boundary of the reservoir to the sand face, across the perforations and completion section to the tubing intake, up the tubing string including any restrictions and down-hole safety valves, the surface choke, the flow line and separator. It uses a combination of :

1.Well inflow performance.
2.Down-hole multipurpose flow conduit performance (vertical or directional conduit performance).
3. Surface performance (including choke, horizontal or inclined flow performance and separator).

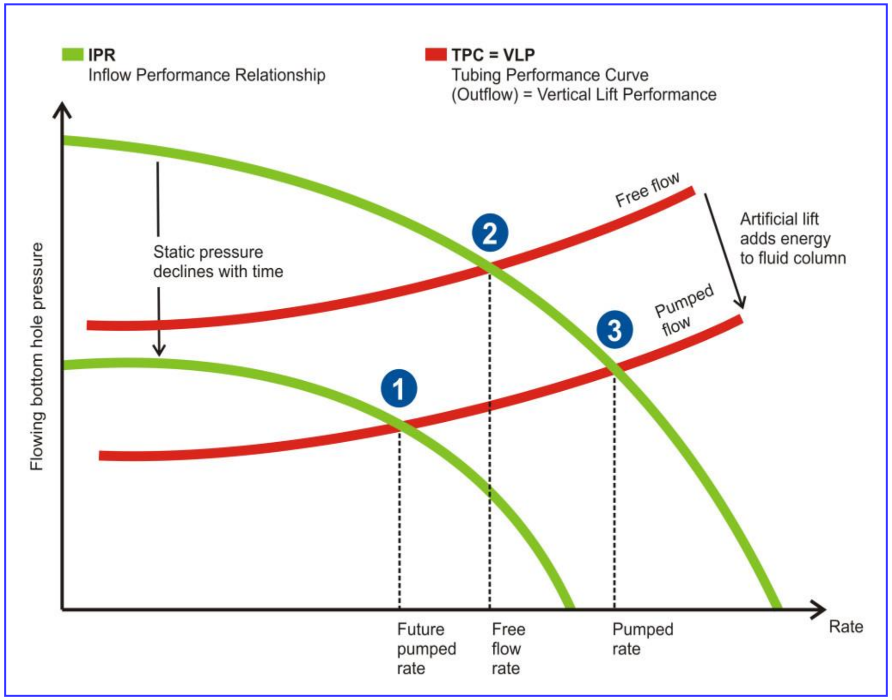
Applications of Nodal analysis :

1. Selecting Tubing Size
2. Selecting Flow line Size
3. Gravel Pack Design
4. Surface Choking Sizing
5. Subsurface Safety Valve Sizing
6. Analyze Abnormal Flow Restriction
7. Artificial Lift Design
8. Well Simulation Evaluation
9. Analyze the effect of compression on gas well
10. Analyze the perforating density
11. Predicting the effect of depletion
12. Allocating Injection gas among gas well lift
13. Analyzing the multi well producing system
14. Relating field performance to time

Nodal Analysis

well productivity :

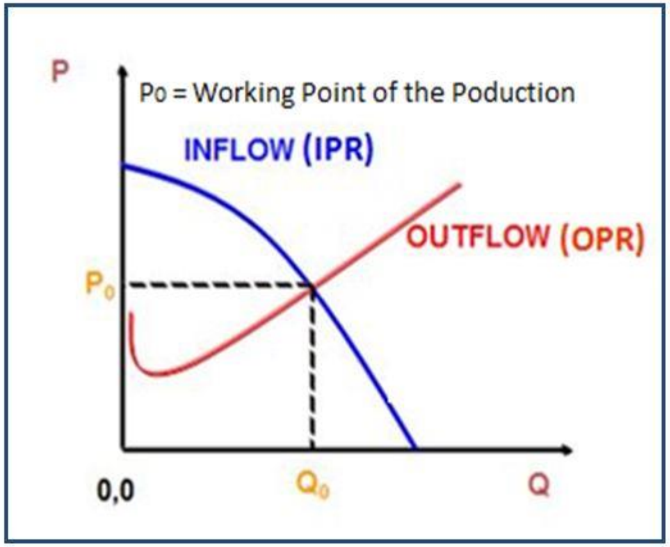
An ideal well productivity is the final goal of Production Optimization. In particular, well productivity is determined by a well inflow performance and in this context, a common approach is "Nodal Analysis". It is a system analysis approach applied to analyze the performance of systems composed of interacting components.



Node is a point where :

- Flow into the node equals flow out of the node
- Only one pressure exist in the node

❑ Upstream of node is called (inflow)
❑ Down stream of node is called (outflow)



Node pressures are

➢ Inflow to the node

$$\bar{P}_R - \Delta P_{upstream} = P_{node}$$

➢ Outflow from the node

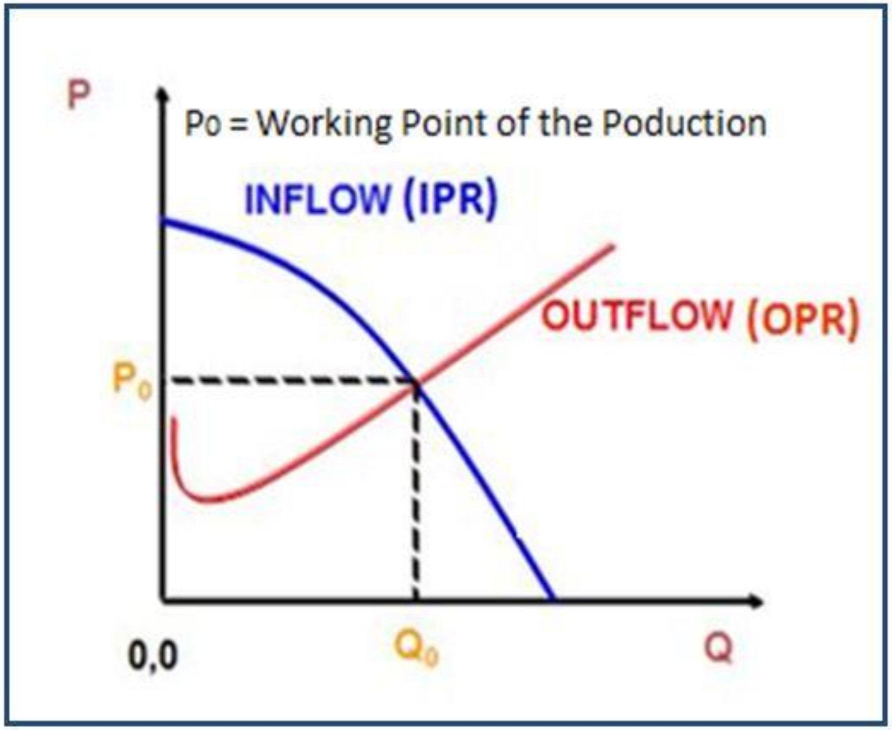
$$\bar{P}_{sep} + \Delta P_{downstream} = P_{node}$$

Well Performance Analysis

- Inflow Performance Relationship (IPR) is defined as the functional relationship between the inflow production rate and the inflowing pressure at node

- Outflow Performance Relationship (OPR) is defined as the functional relationship between the outflow production rate and the outflowing pressure at node

- The interaction of IPR and OPR is the Working Point of the system.



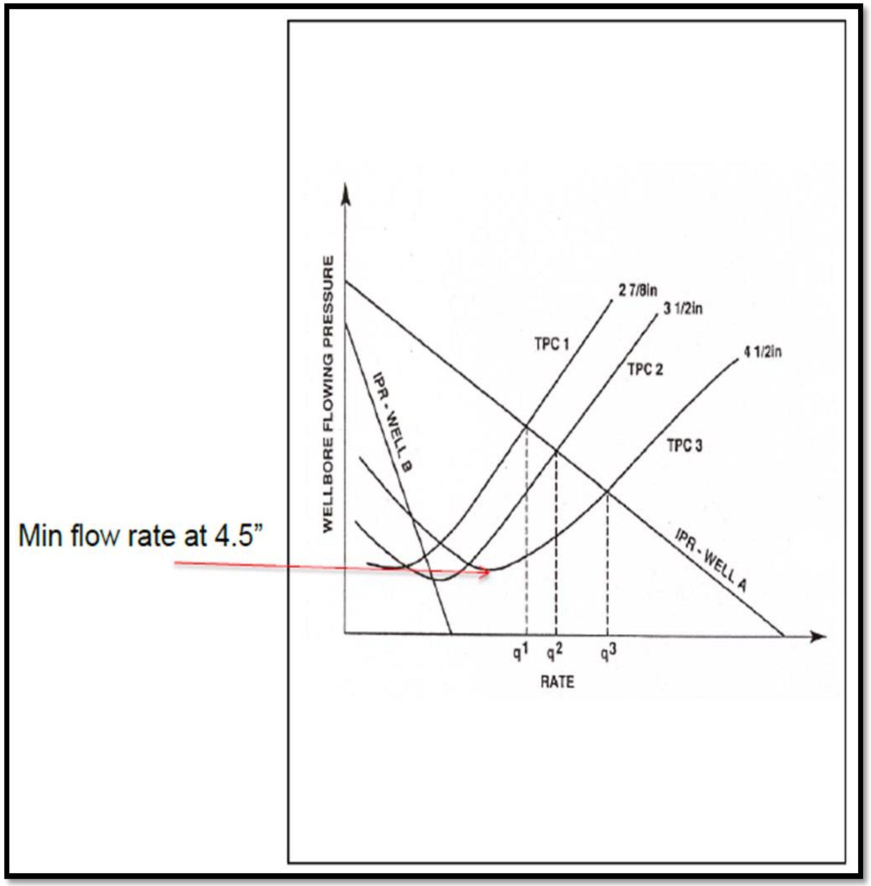
IPR and OPR interaction

Nodal Analysis

Vertical lift performance (VPR) is concerned with the movement of reservoir fluids from the wellbore at the depth of the reservoir to the production choke on surface.

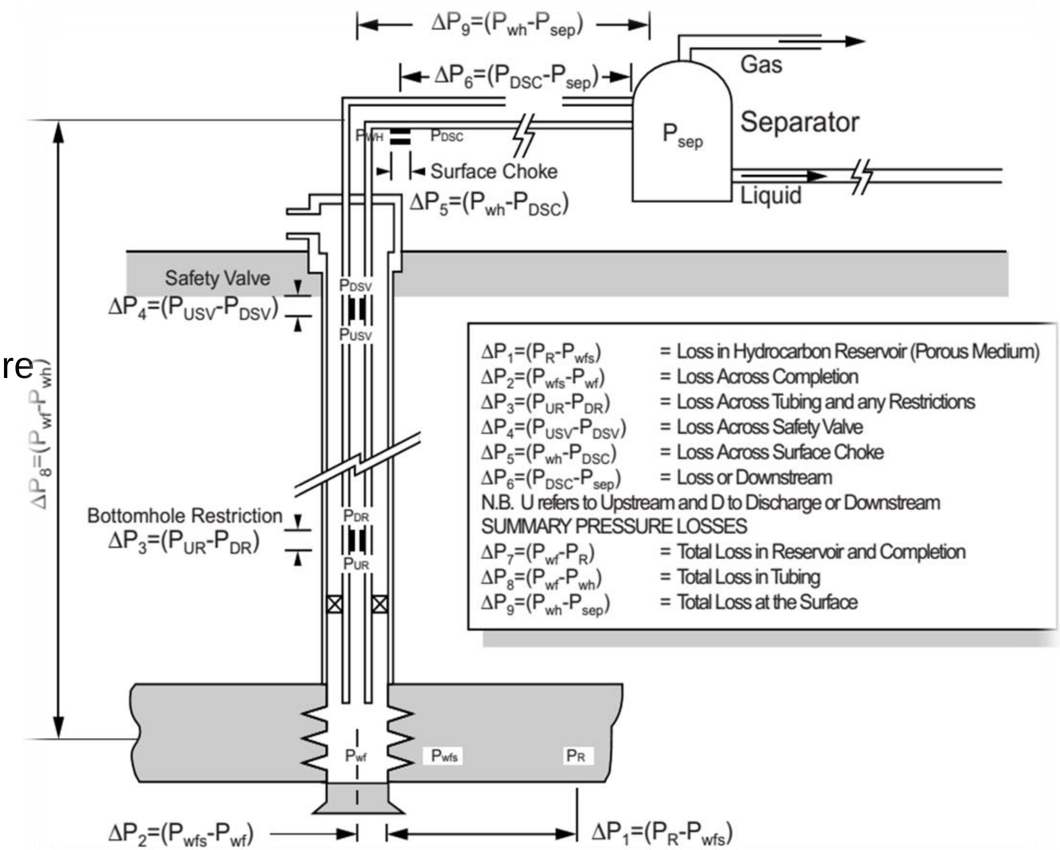
VPR curves are dependent on:-

- Tubing intake pressures,
- Tubing head pressures,
- Tubing ID,
- Tubing pressure losses,
- Fluid properties,
- Fluid phase behaviour
- Choke performance.



Pressure losses during production

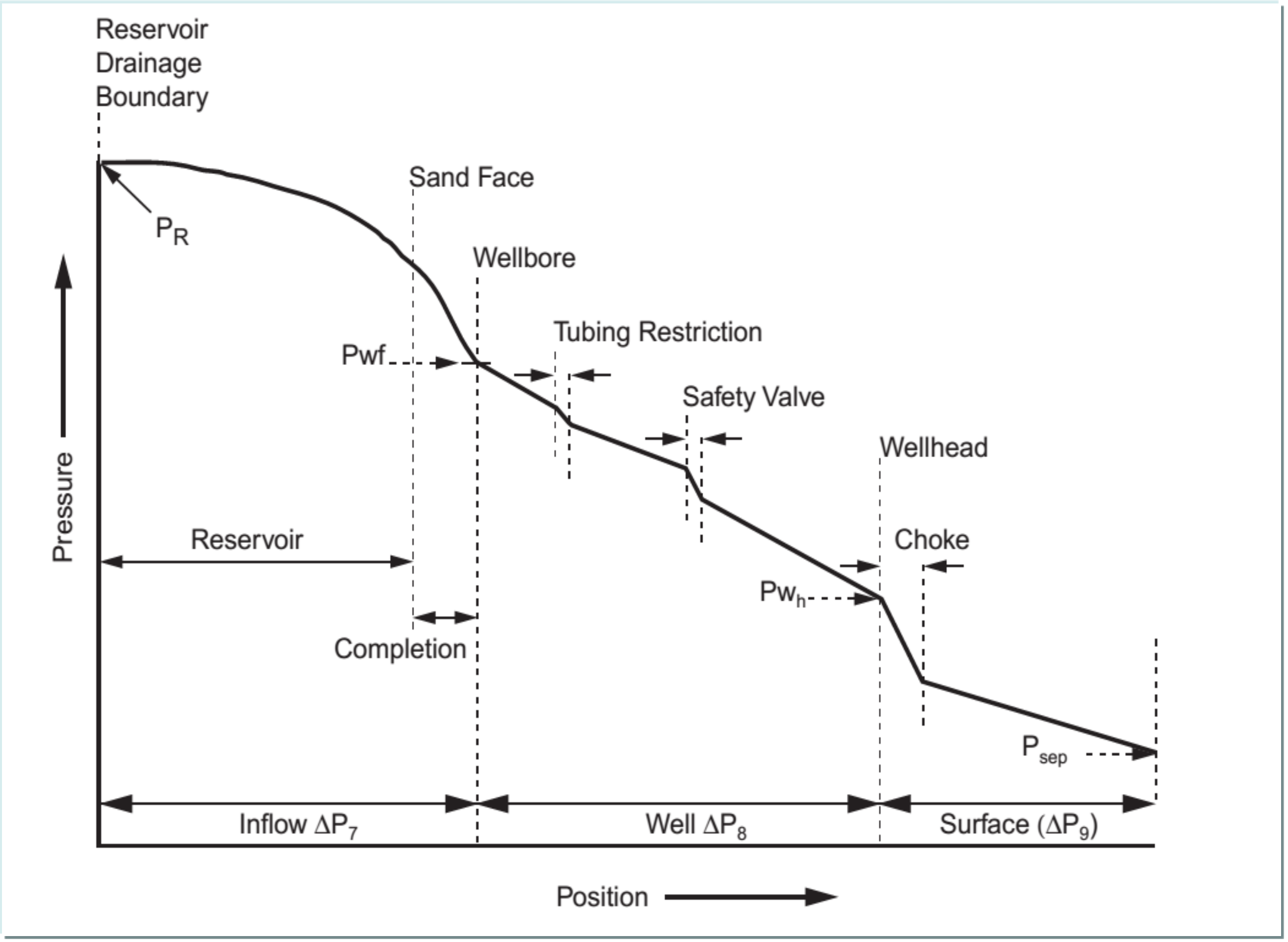
1. PR: Reservoir Pressure
2. Pwfs: Flowing sand face Pressure
3. Pwf: Flowing Bottom Hole Pressure
4. PUR: Upstream Restriction Pressure
5. PDR: Downstream Restriction Pressure
6. PUSV: Upstream Safety Valve Pressure
7. PDSV: Downstream Safety Valve Pressure
8. PWH: Well Head Pressure
9. PDSC: Downstream surface Choke Pressure
10. Psep : Separator Pressure



Pressure losses during production

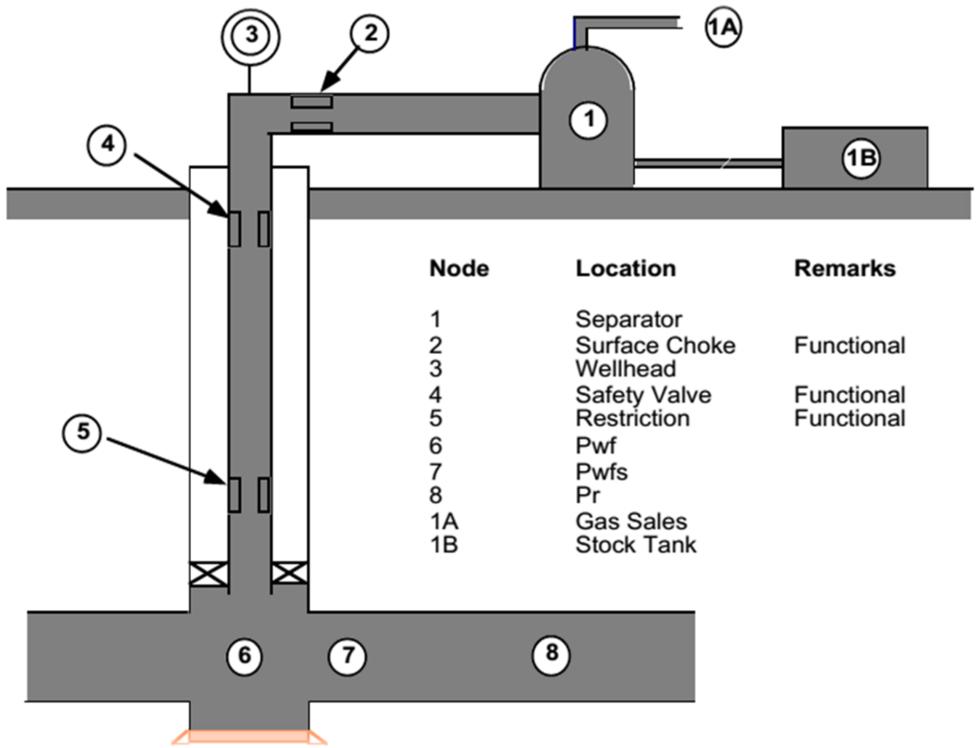
Nodal Analysis

Pressure losses during production



Nodal Analysis

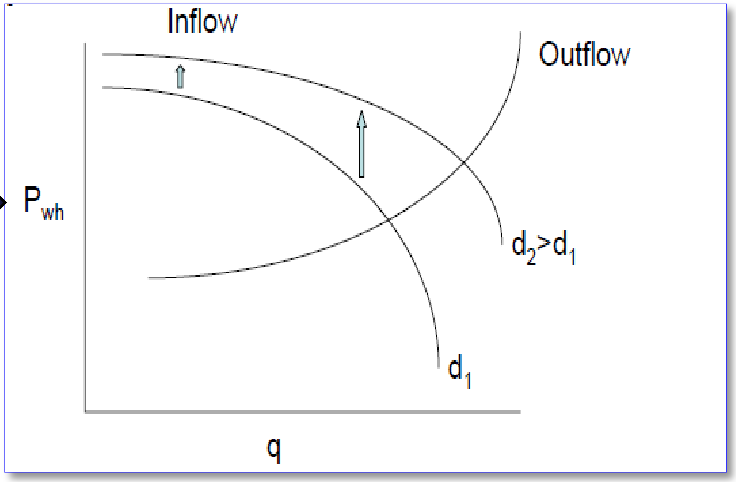
- Node can be select any where in the production system :
- List of possible positions of node :
  1. Separator
  2. Surface Choke
  3. Wellhead
  4. Safety Valve
  5. Restriction
  6. Bore hole Pwf
  7. Sand Face Pwfs
  8. Reservoir



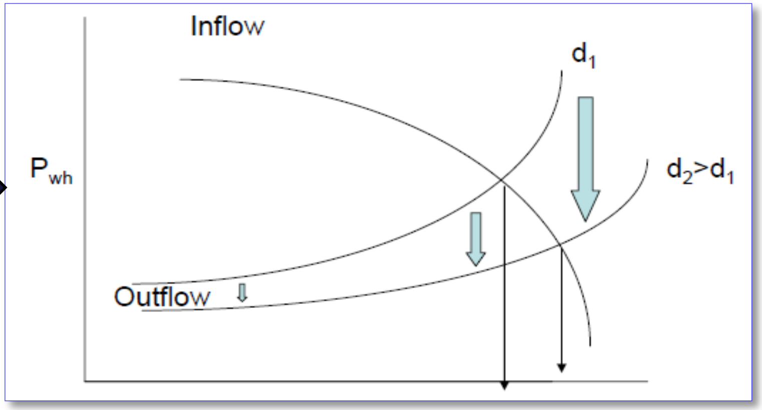
Nodal Analysis

- Optimum Tubing Size

❑ If tubing size increases- which will give less pressure drop so the inflow curve move upward



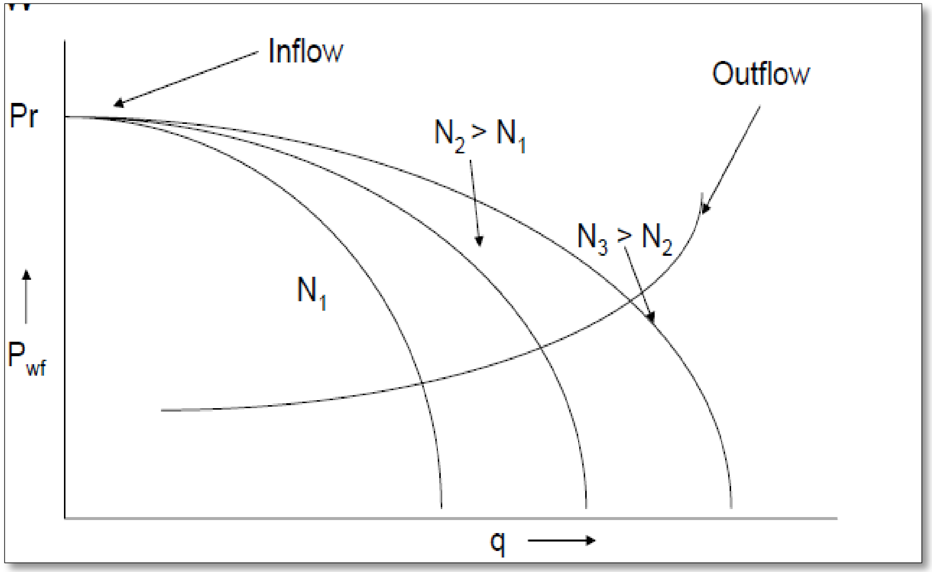
❑ If flow line diameter increases then the out flow curve will shift downward



Nodal Analysis

Optimize Perforation

- Select bottom hole flowing pressure as a node
- Inflow relationship is pressure drop through rock and pressure drop through perforations.

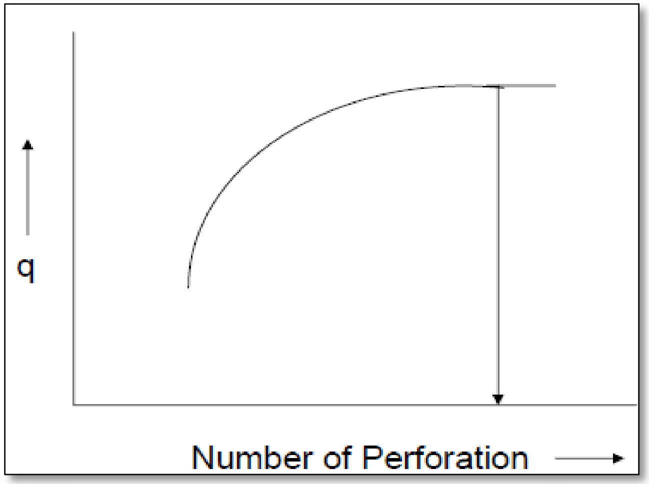


- Inflow to Node

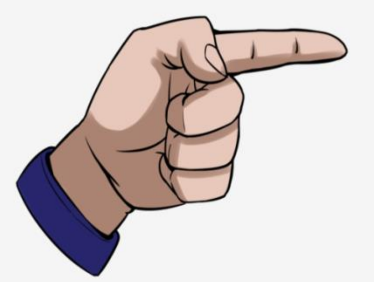
$$\bar{P}_r - \Delta P_{res} - \Delta P_{perfs} = P_{wf}$$

- Outflow from Node

$$\Delta P_{tubing} + \Delta P_{flowline} + \bar{P}_{sep} = P_{wf}$$

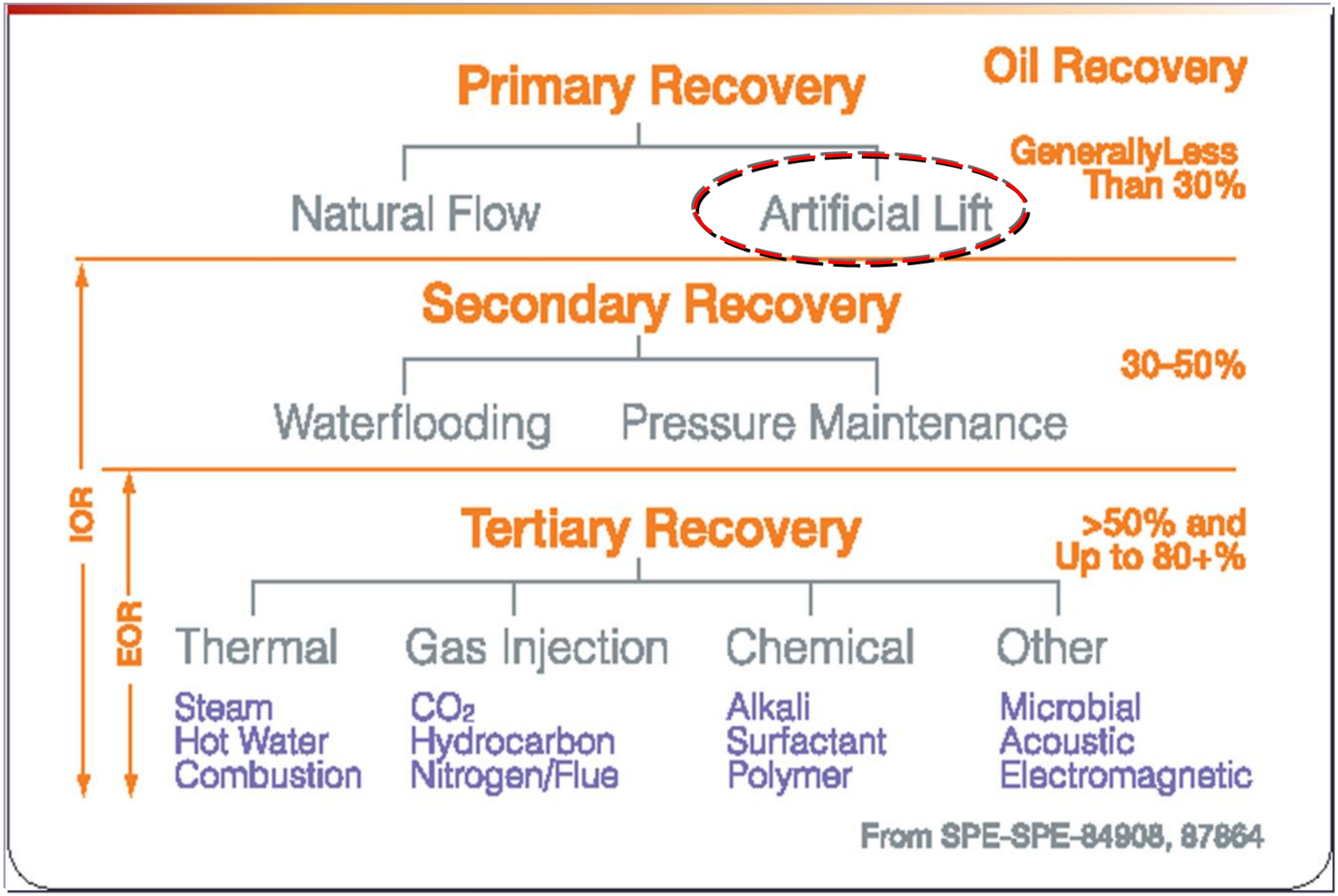


- Increase in perforation number increases flow



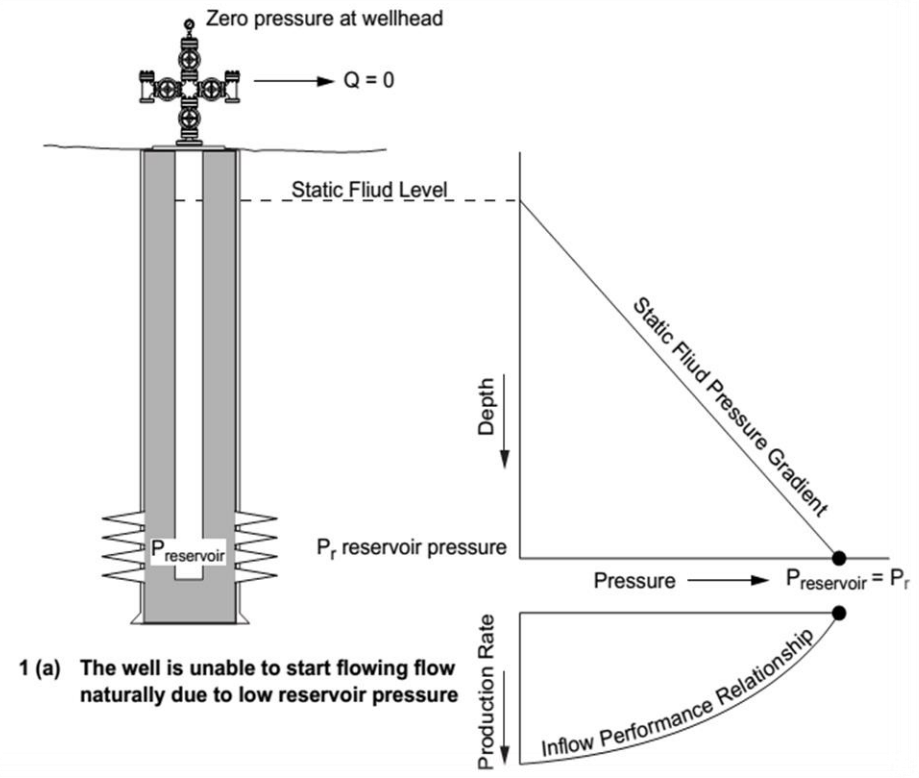
(5) Artificial Lift

Artificial lift



Artificial lift :

Artificial lift is required when a well will no longer flow or when the production rate is too low to be economic. See Figure , illustrates such a situation - the reservoir pressure is so low that the static fluid level is below the wellhead



The well is unable to initiatenatural flow

Artificial lift

Artificial lift

Is a technique used for increasing the productivity of wells with low reservoir pressure and/or heavy fluids (water, heavy oil) and enabling them to flow to surface either by introducing lighter weight fluid (gas) into the stream deep in the well or by providing a down hole pumping system (electrical or hydraulic submersible pumps – ESPs /HSPs).

The need of artificial lift:

- ❑ Maintain or increase the flow rate
- ❑ Decrease the effect of water cut
- ❑ Reduce the effect of flow-line back pressure

What types of Artificial Lift techniques are used in the Oil Industry?

- ❑ Artificial Lift System

Pumping System	Lifting System
Beam Pumping/Sucker Rod Pumps (Rod Lift)	Continuous Gas-Lift
Progressing Cavity Pumps (PCP Pumps)	Intermittent Gas-Lift
Subsurface Hydraulic Pumps (Jet Lift, Piston Lift)	Gas-Lift Pack-off
Electric Submersible Pumps (ESPs)	Auto Gas-Lift

Artificial lift

Artificial lift :

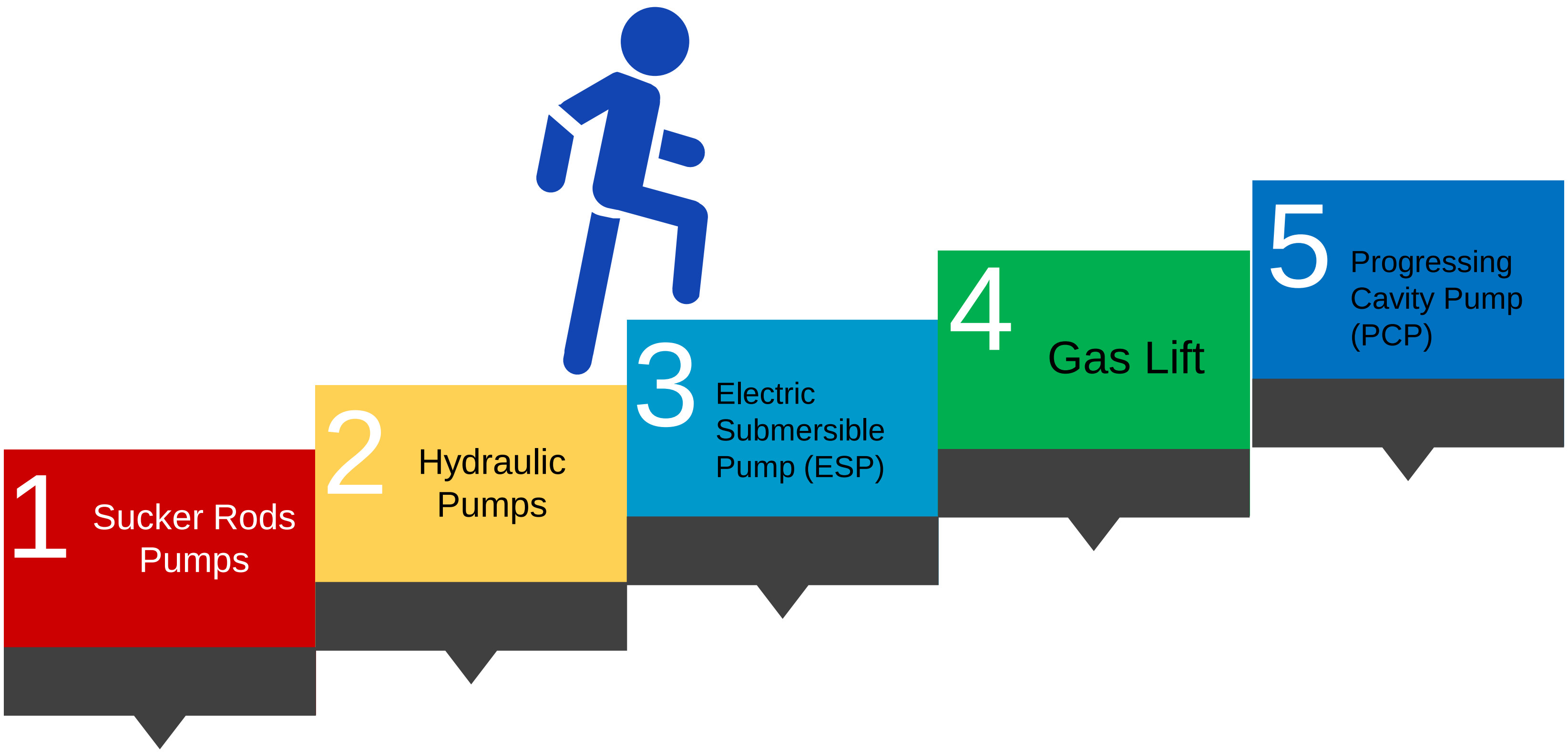
Is a technique used for increasing the productivity of wells with low reservoir pressure and/or heavy fluids (water, heavy oil) and enabling them to flow to surface either by introducing lighter weight fluid (gas) into the stream deep in the well or by providing a down hole pumping system (electrical or hydraulic submersible pumps – ESPs /HSPs).

The need of artificial lift:

1. Maintain or increase the flow rate
2. Decrease the effect of water cut
3. Reduce the effect of flow-line back pressure

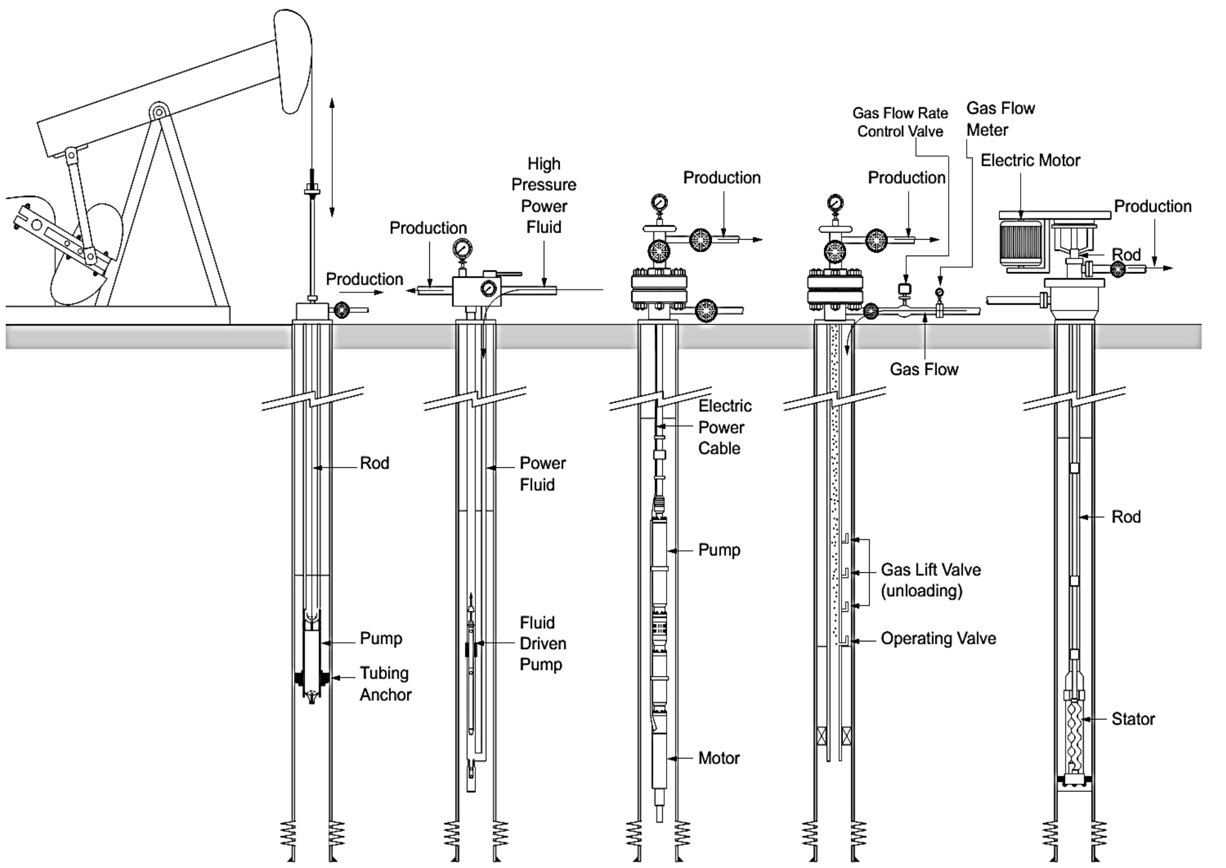
Artificial lift

The most popular forms of artificial lift :



Artificial lift

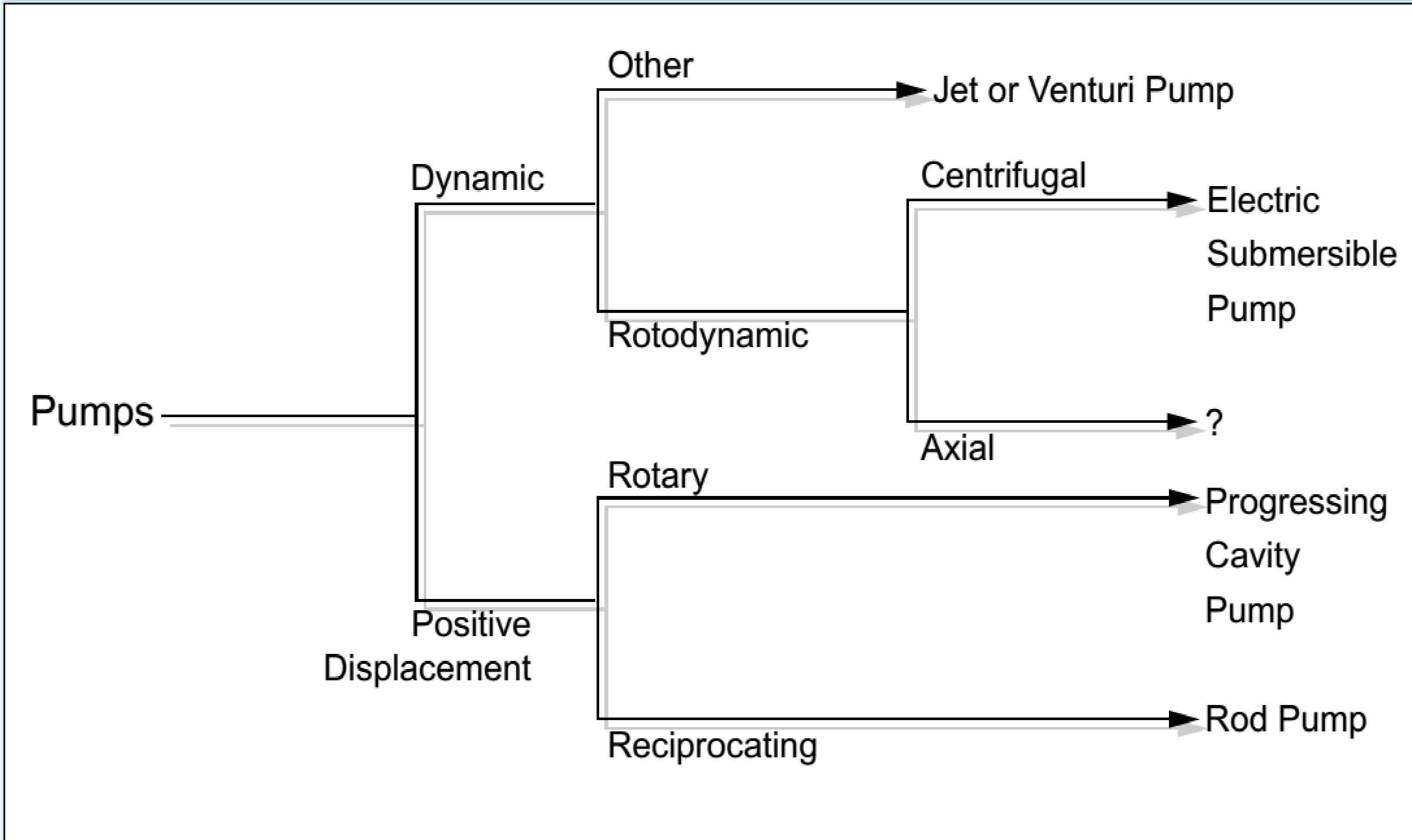
The most popular forms of artificial lift are illustrated in figure



(i) Rod Pump (ii) Hydraulic Pump (iii) Submersible Electric Pump (iv) Gas lift (v) Progressing Cavity Pump (May also be driven by electric submersible motor)

Artificial lift

the major classes of pumps



Artificial lift

Advantages of major artificial lift methods

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 elevation / 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

Dis-advantages of major artificial lift methods

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	Elastanes swell in some crude oils Pump off control difficult Problems with rotating rods (windup and after spin) increase with depth

Artificial lift

The Purposes of any artificial lift method is to;

- Create a tubing intake pressure so that the formation can produce the target flow rate and lift the fluids to the surface with suitable WHP to overcome the separator pressure & back pressures

- Required to increase productivity of natural flow wells

- Decreases backpressure against reservoir, which increases pressure difference (draw-down) between reservoir and wellbore.

- When reservoir pressure not sufficient to lift the fluids to the surface due to depletion or increased water production

Artificial lift

Artificial lift method Refers to :

- The use of artificial methods to increase the flow of liquids , like crude oil, water.
- This is usually done by the use of some sort of mechanical device placed inside the well (a pump or velocity string) or by decreasing the weight of the hydrostatic column (the weight of the liquid in the production tubing) by injecting gas into the liquid as deeply as possible in the well
- Artificial Lift is needed when the reservoir has insufficient pressure (energy) to produce the fluids in the well to the surface and into the production system.
- Artificial lift is often used in wells that can flow naturally to increase the amount of liquid the well produces above what would flow normally, thus also addressing ultimate recovery.

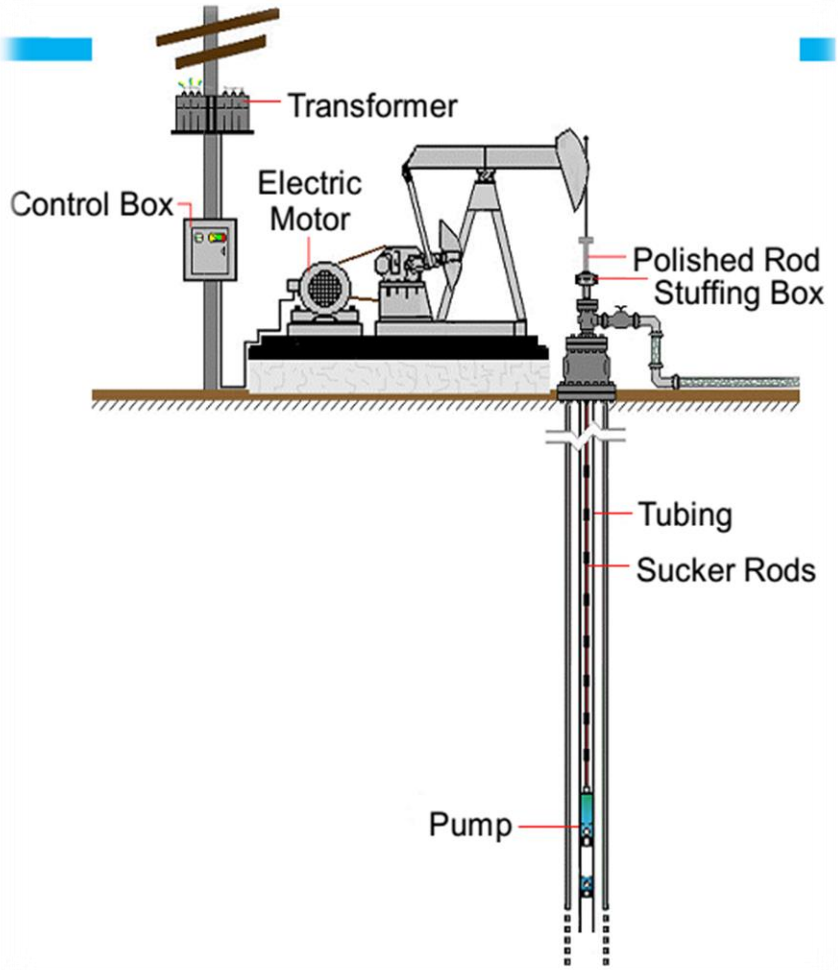
Artificial lift - 1.(Sucker Rods Pumps)

Most commonly used method worldwide

❑Used massively in the US and in significant number of wells in Russia, China and South America

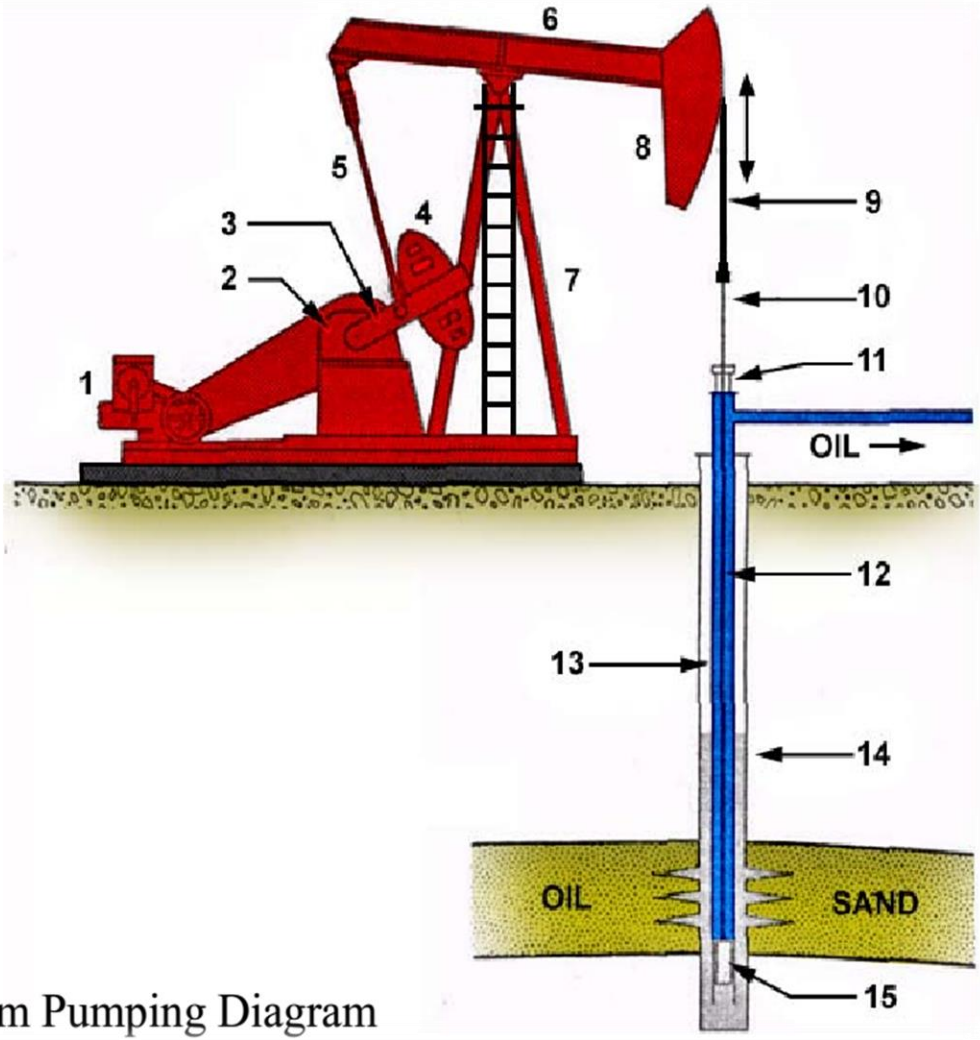
❑ Simple to operate and inexpensive compared to other

❑methods, but usually lower pumping capacity



Artificial lift - 1.(Sucker Rods Pumps)

1. Engine or Motor
2. Gear reducer
3. Crank arm
4. Counter weight
5. Pitman arm
6. Walking beam
7. Sampson post
8. Horse head
9. Bridle
10. Polished rod
11. Stuffing box
12. Sucker rods
13. Tubing
14. Casing
15. Pump



Beam Pumping Diagram

Artificial lift - 1.(Sucker Rods Pumps)

Most commonly used method worldwide …….

- ❑Problems with high GLR, small tubing, deep wells, crooked or deviated wells, sand production, high viscosity fluids wells

- ❑Can achieve very low bottom hole flowing pressure making it ideal for very depleted reservoirs

- ❑The oldest and most commonly used form of artificial lift
- ❑Familiar to most engineers and operators
- ❑Low capital investment for low production at shallow to medium depths
- ❑High investment for high flow rates in deep wells
- ❑Adaptable to scale and corrosion problems
- ❑Limitation with casing size
- ❑Easily installed in remote locations with an internal combustion engine

Artificial lift - 2.(Hydraulic Pumps)

Hydraulic systems transfer energy down hole by pressurizing a special“ power fluid”, usually a light refined or produced oil, that flows through well tubing to a subsurface pump , which transmits the potential energy(lift) to produced fluids. Once on surface the commingled fluids (produced oil and power fluid) need to be separated

Three types of hydraulic pumps :

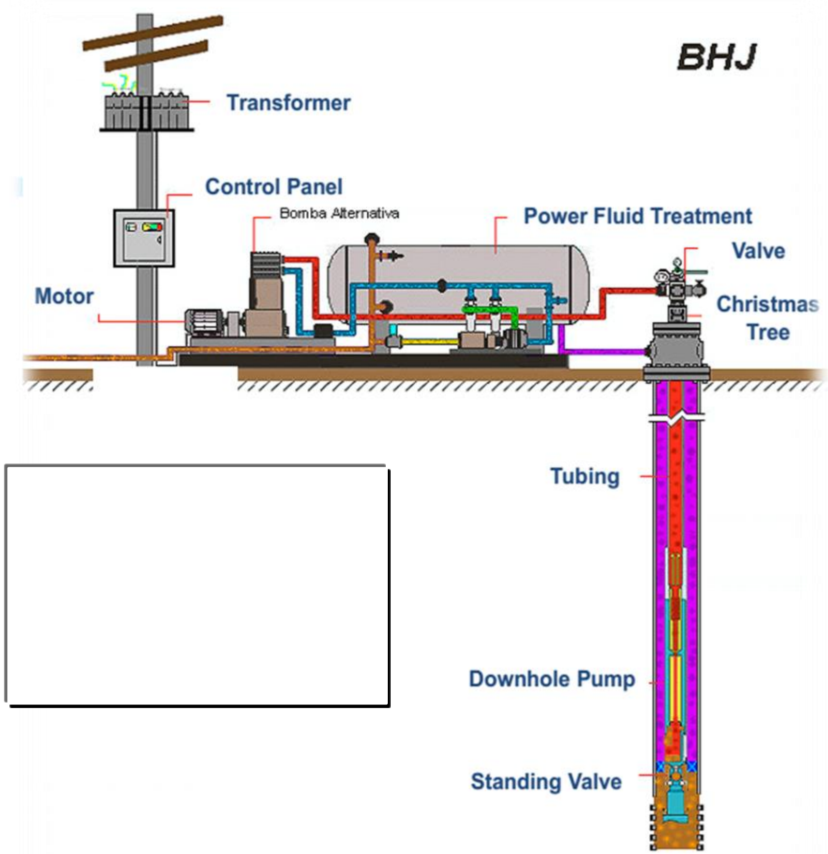
1.Hydraulic jet Pumps

2-Piston pump

3-Turbine pump

1.Hydraulic jet Pumps

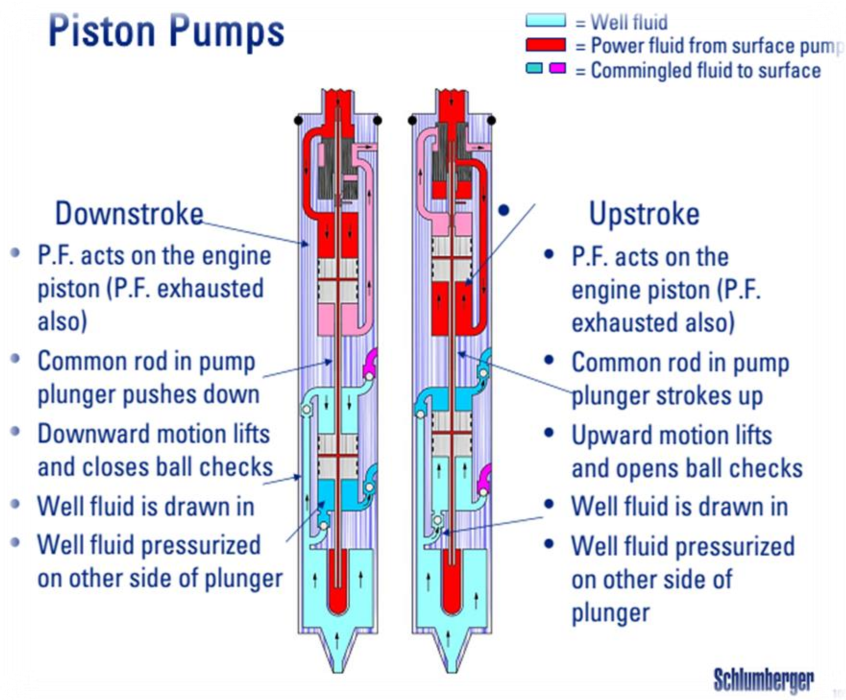
Very beneficial for high-viscosity crudes where blending with a light power fluid can help in the processing of heavy crudes



- Very simple method
- From all artificial lift methods this is the one that has
- the biggest depth application range
- The use of a light oil as the power fluid makes this a very interesting method for high viscosity fluids
- Requires an injection of 5 to 7 times the volume of liquid produced
- No moving parts, applicable to deviated and crooked wells
- Pump can be back-circulated to the surface

2-Piston pump

- Power fluid provides the motive force to a down-hole piston pump assembly that lifts the well fluid to surface
- Separation is required.
- Can be single or double pump ends
- Can be single or double engine pistons for higher lift
- Offered as an alternative to jet pumps
- Higher efficiencies (up to 95%)
- Hydraulically retrievable
- Similar flexibility in design and application to jet pumps.



Artificial lift - 2.(Hydraulic Pumps)

2-Piston pump

Advantages of Piston pump

Flexible AL method for:

- Remote & urban locations
- Offshore platforms
- Low profile on surface
- Flexible production capacity
- Multiple wells from single surface system = less $ per well
- Maximize drawdown
- Maximize efficiency (up to 95%)
- Hydraulically retrievable

For challenging applications:

- Deep Wells
- Corrosive fluids
- Gas & water
- Fleavy oils (as low as 8 API)
- Complex well completions
- Retrofit applications
- Deviated & crooked wells
- Producing from multiple zones

Artificial lift - 2.(Hydraulic Pumps)

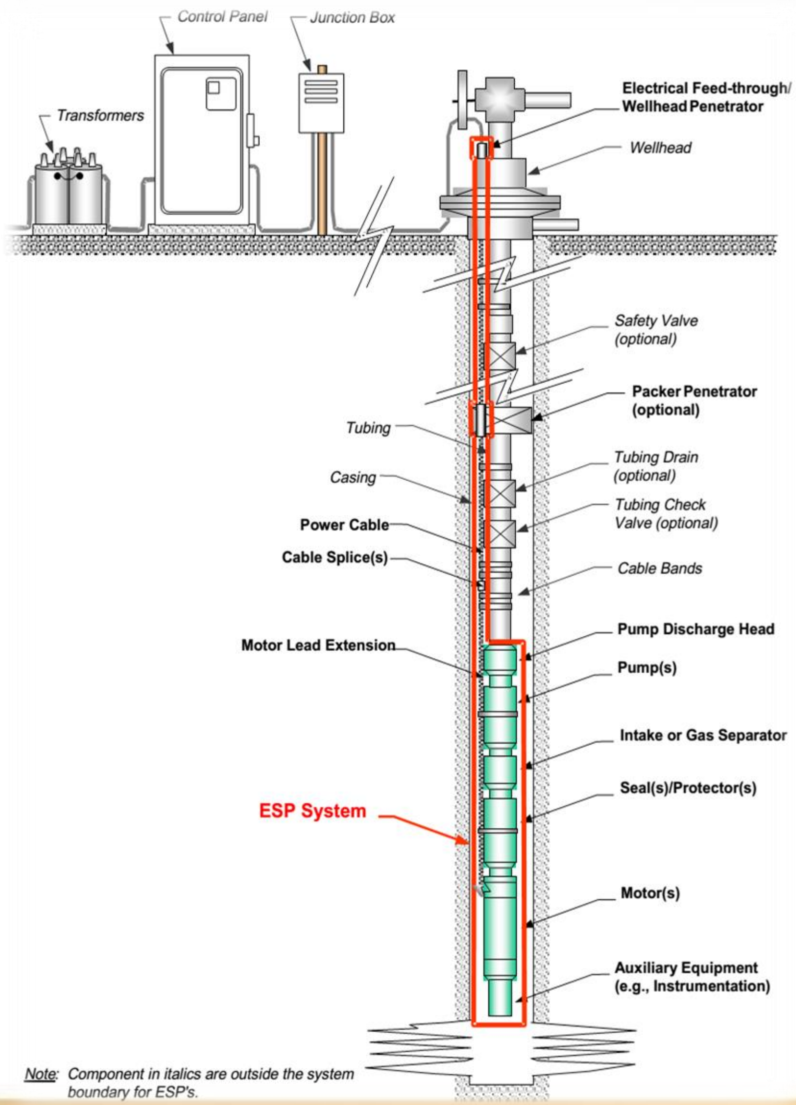
2-Piston pump

Disadvantages of Piston pump

- Require cleaner liquids
- Close tolerances on moving components
- Not as easy to service as a jet pump
  - \- Technician require detailed training
  - \- 'Workshop only' rebuild
- The industry is not familiar with the systems due to past monopoly supply & poor marketing/product knowledge

Artificial lift - 3.(Electric Submersible Pumps (ESP))

Electric submersible systems use
multiple pump stages mounted in series within a housing, mated closely to submersible electric motor on the end of tubing and connected to surface controls and electric power by an armor protected cable.



Artificial lift - 3.(Electric Submersible Pumps (ESP))

- The main function of an Electric Submersible Pumping (ESP) System is to bring fluid from the reservoir to surface.
- The ESP was introduced as a means of Artificial lift by REDA in the late 1920s.
- There are a variety of pump sizes, capacities, motor horsepower, and voltage ranges for different applications.

Artificial lift - 3.(Electric Submersible Pumps (ESP))

ESP equipment

1 surface equipment

1. Transformers (Primary an Secondary)
2. Switchboard or Variable Speed Drive or Soft Start
3. Junction Box
4. Wellhead

2 Subsurface equipment

1. Cable
2. Cable Guards
3. Cable Clamps
4. Pump
5. Gas Separator (Optional)
6. Seal Section
7. Motor
8. Sensor (Optional)
9. Drain Valve
10. Check Valve

Artificial lift - 3.(Electric Submersible Pumps (ESP))

1. Surface equipment :

2. Transformers (Primary an Secondary)
3. Switchboard or Variable Speed Drive or Soft Start
4. Junction Box
5. Wellhead

1-Surface equipment

Shown here is the surface related equipment required for most down-hole electrical submergible pump systems.

Transformers

VSD's

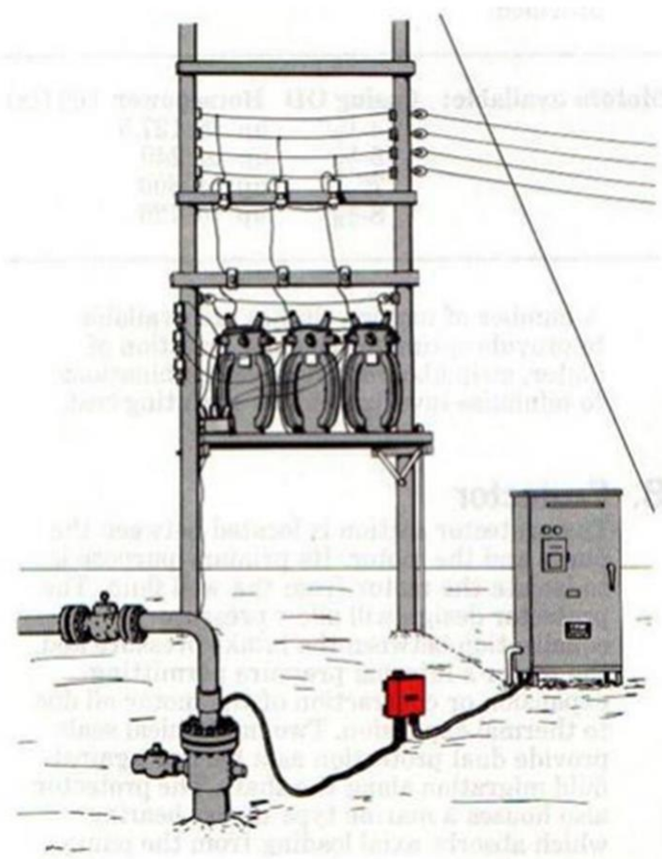
J-Boxes

Wellhead Connectors

Artificial lift - 3.(Electric Submersible Pumps (ESP))

Primary Transformers

- **Power transmission over long distances is usually carried out at high voltage levels**
- **High voltage transmission enables**
  - **Smaller losses**
  - **Smaller cable sizes**
- **Most equipment is not designed to operate at high voltage levels**
- **A transformer is a device by which the voltage of an alternating current system may be changed**
- **Primary transformer is used to reduce the voltage of the primary source to a voltage handled by the switchboard, Variable Speed Drive or Soft Start**
- **It can be a single tri-phase auto-transformer or a bank of three single-phase transformers**
- **It consists of an iron core surrounded by coils of insulated wire. Usually both core and coils are immersed in oil which serves as an insulator and helps to cool the transformer**
- **The input circuit of a transformer is referred to as the primary and the output circuit as the secondary**

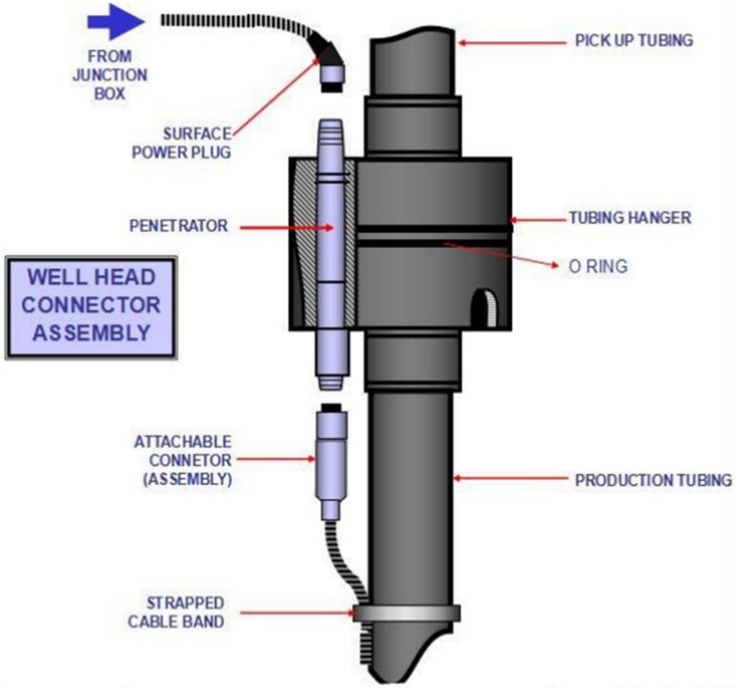


Secondary Transformer

- Is used when a Variable Speed Drive is used, to boost the voltage according to the motor requirements. Is commonly known as “Step up transformer”
- It can be a single tri-phase auto-transformer or a bank of three single-phase transformers

Well head

- **Must provide means for installing the cable with adequate seal**
- **May include adjustable chokes, bleeding valves**
- **Usually onshore wellheads have a rubber seal for the cable**
- **Usually offshore wellheads have a electric mandrel**



VSD

The variable speed controller allows for flexibility of the downhole system for flow control capabilities.

It provides a constant ratio of between voltage and frequency for proper operation.

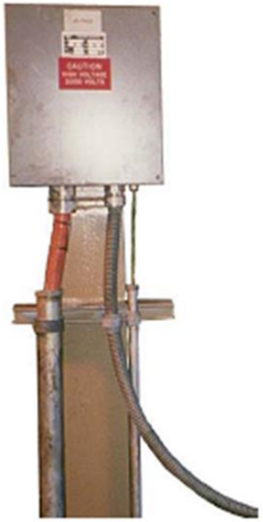
Junction box

A Junction box or vent box:

Provides a connection point for the surface cable from the motor control panel to the powe cable in the wellbore.

Allows for any gas to vent that may have migrated through to the power cable.

Provides easy accessible test point for electrically checking downhole equipment.



Schlumberger Private

ESP Motor Controllers - Switchboards

The controller is a device that can be used as to drive the motor and provide protection capabilities (overload, under load, etc).

The controller also provides the capability to monitor the REDA Production system with the use of a recording instrument.

The two types of controllers offered are electro-mechanical relays (switchboard) or solid-state control circuitry (VSD).

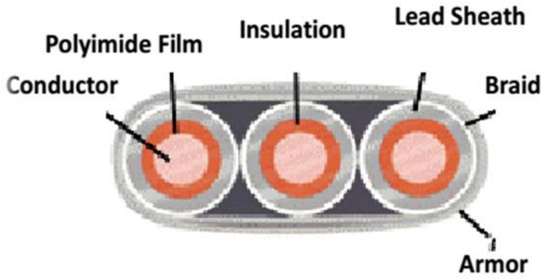
Artificial lift - 3.(Electric Submersible Pumps (ESP))

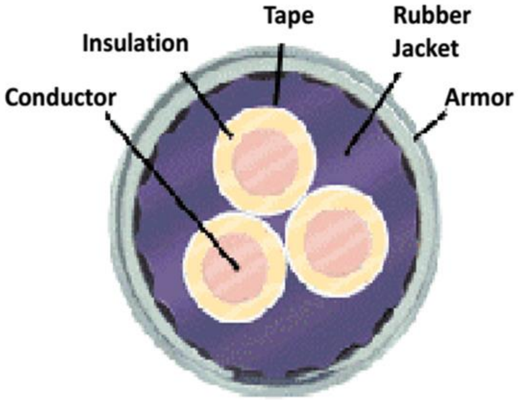
Subsurface equipment :

1. Cable
2. Cable Guards
3. Cable Clamps
4. Pump
5. Gas Separator (Optional)
6. Seal Section
7. Motor
8. Sensor (Optional)
9. Drain Valve
10. Check Valve

Electric Cable

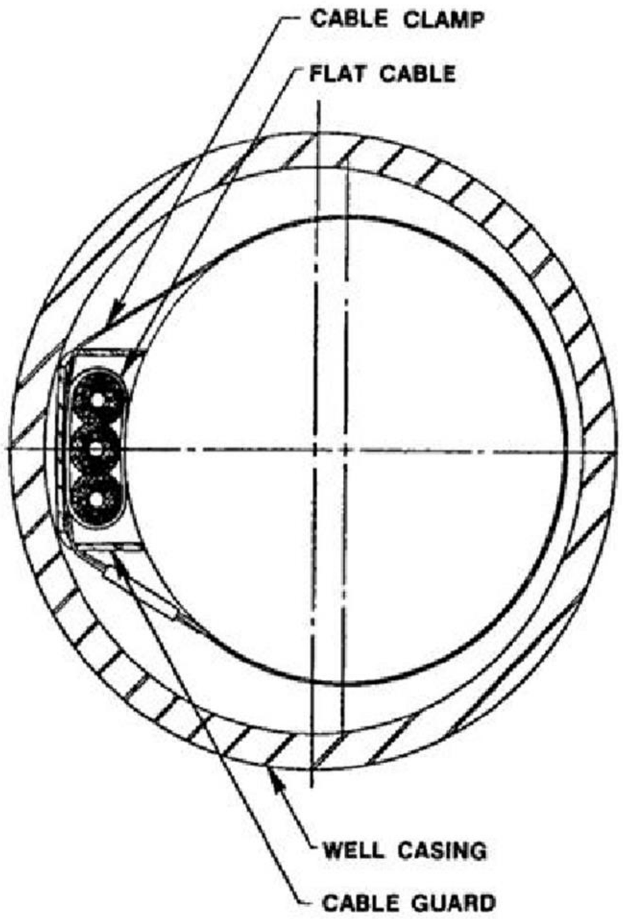
- **Must guarantee power supply to motor**
- **Made of different conductor materials cased in protective jacket that assures its integrity under operating conditions and environment**
- **Voltage drop, temperature and surrounding fluids must be considered during design and selection process**
- **Two basic configurations: flat and round**





Cable Protection

- **Cable Guards**
  - Usually used to protect the motor lead cable avoiding the direct contact of the cable with the casing. Standard length 8 ft
- **Cable Clamps**
  - Used to tie the cable to the tubing
  - Usually made of stainless steel. Several lengths depending on diameter of the tubing (22”, 32”, 40” and 42”)
  - Usually used one clamp per tubing joint



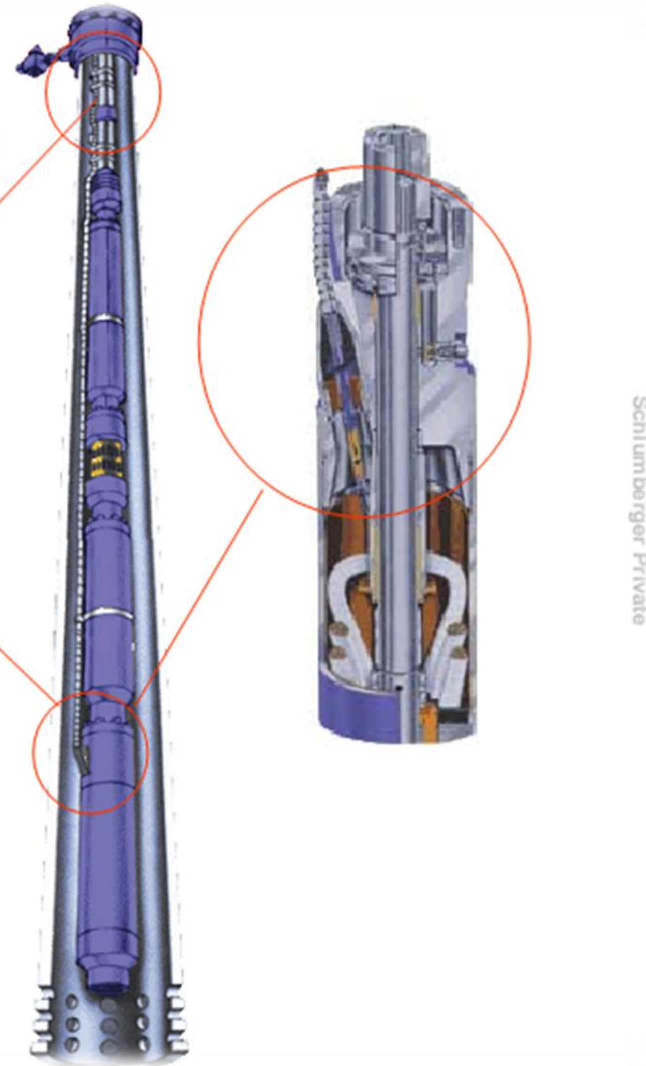
Artificial lift - 3.(Electric Submersible Pumps (ESP))

Power cable

And Motor Lead Extension

Electric power is transferred to the assembly through an electrical cable attached to the tubing.

MLE Cable



Artificial lift - 3.(Electric Submersible Pumps (ESP))

Power cable

Electrical power cable is used to transmit the power from the surface to the submersible motor.

Power Cable consists of three copper conductor wires extending from the top of the motor flat cable lead to the wellhead.

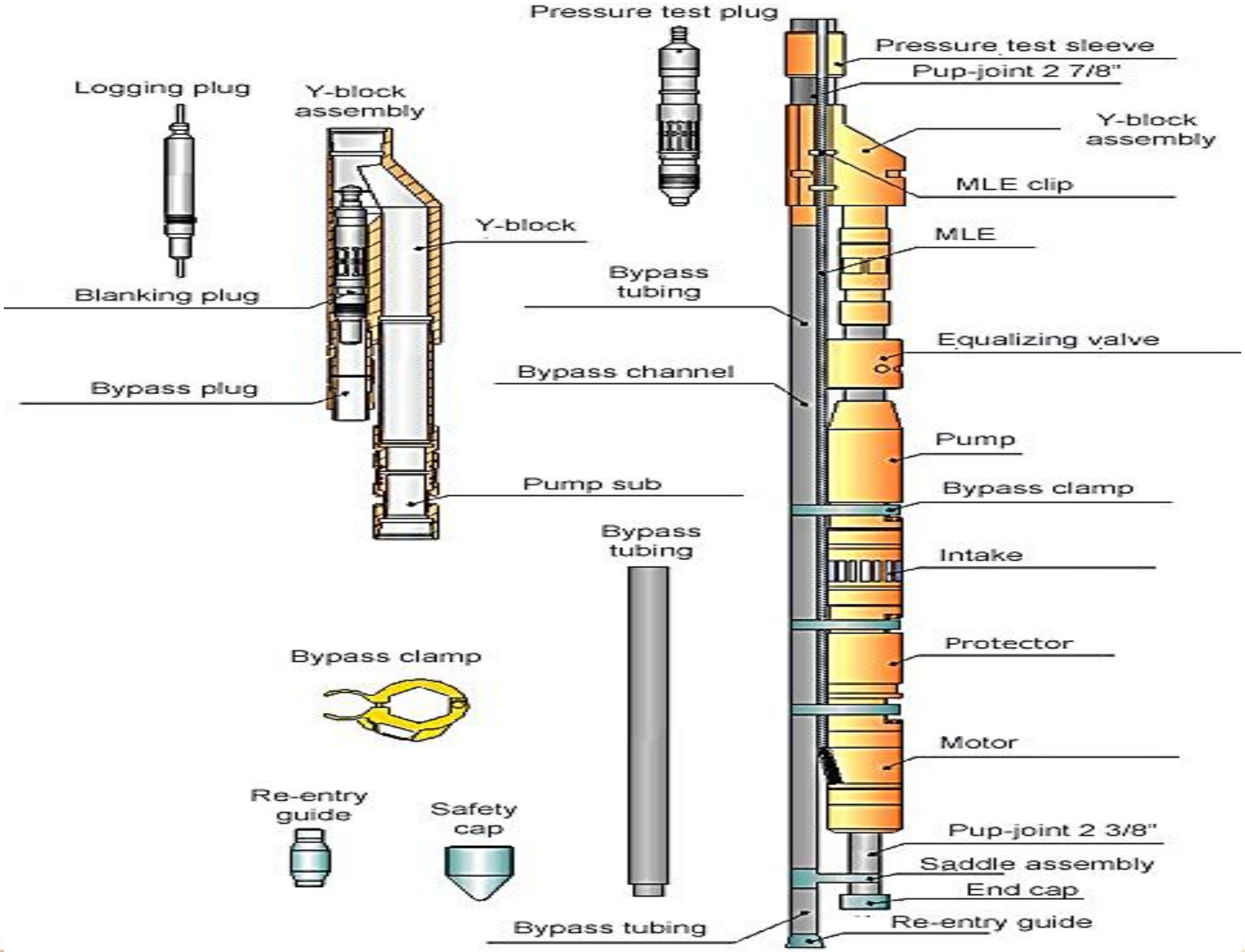
The size of the cable selected is based on amperage and voltage drop.

Bottom hole temperature is critical for the selection of cable.

The electrical cable has been refined over the years to be used specifically for oilwell applications.

Artificial lift - 3.(Electric Submersible Pumps (ESP))

Y- tool



Artificial lift - 3.(Electric Submersible Pumps (ESP))

Centrifugal pump

The multistage centrifugal pump consists of numerous impellers and diffusers (application dependent) to provide the lift (pressure) required

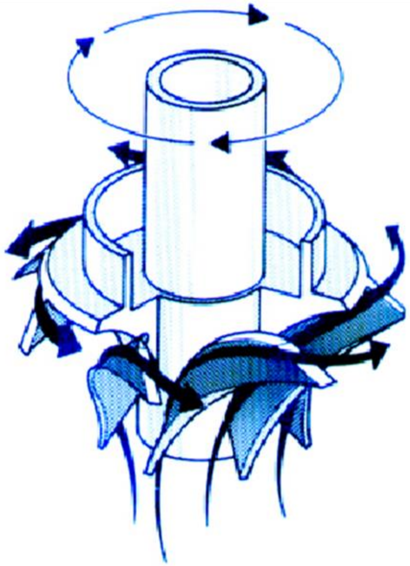
Artificial lift - 3.(Electric Submersible Pumps (ESP))

ESP - Pump

A Centrifugal Pump is a machine that moves fluid by spinning it with a rotating impeller in a stationary diffuser that has a central inlet and a tangential outlet.

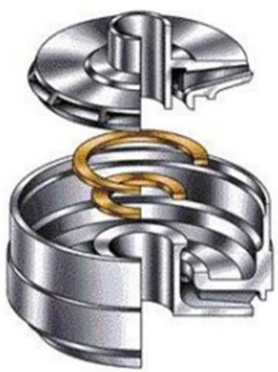
The path of the fluid is an increasing spiral from the inlet at the center to the outlet tangent to the diffuser.

The pressure (head) develops against the inside wall of the diffuser as the curved wall forces fluid to move in a circular path upwards and into the impeller and diffuser above.

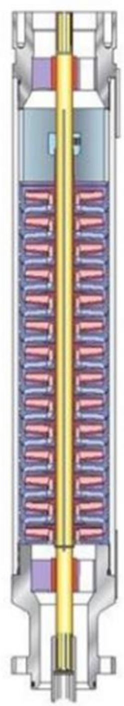


Pump Type

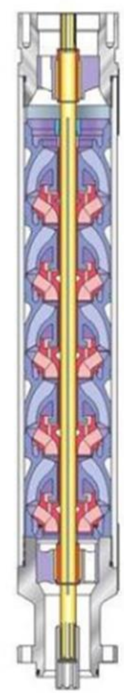
- **The hydraulic design of the stage can be classified as:**
  - **Radial Flow**
  - **Mixed Flow**



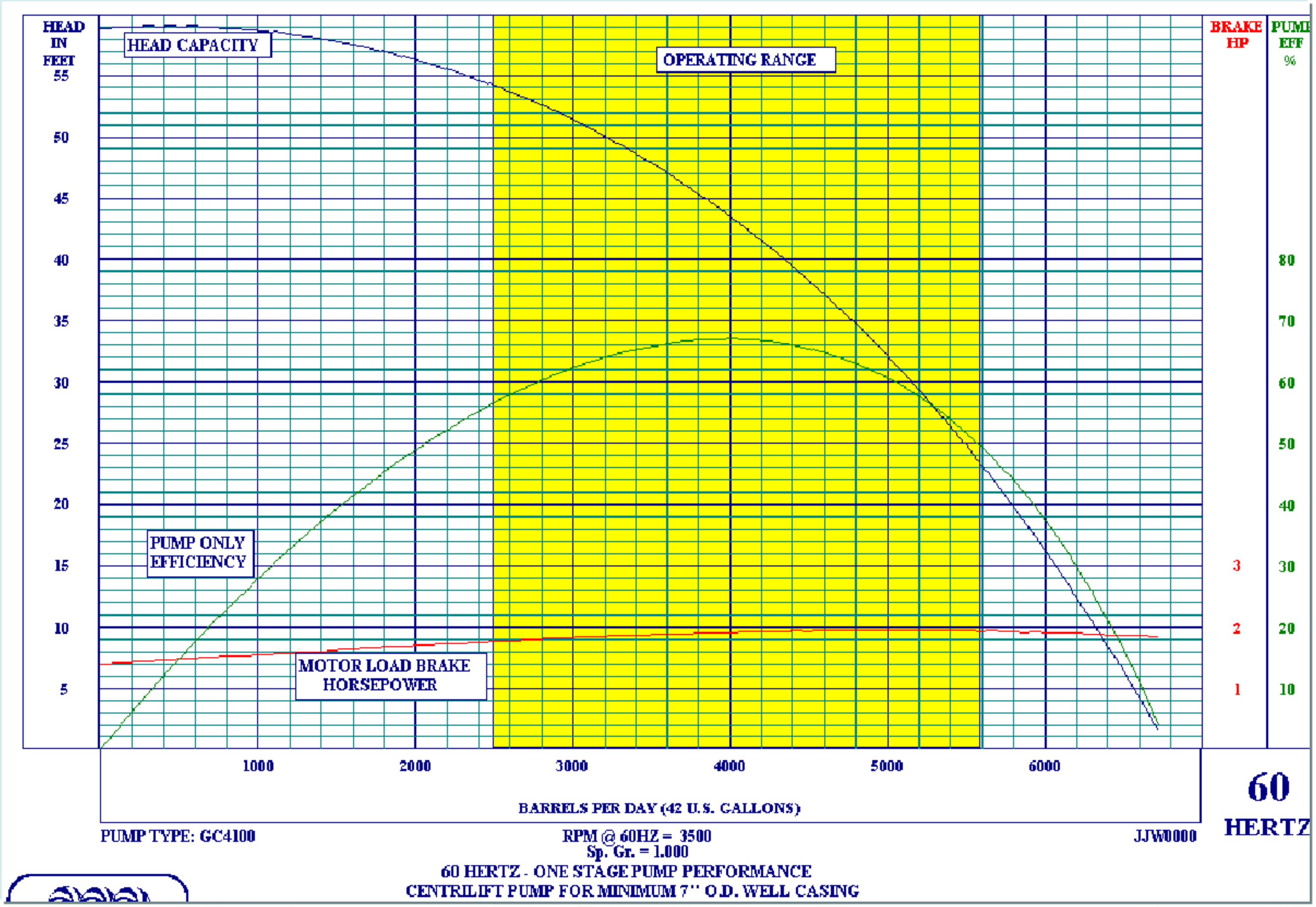
Radial Flow Pump



Mixed Flow Pump



Pump performance curve



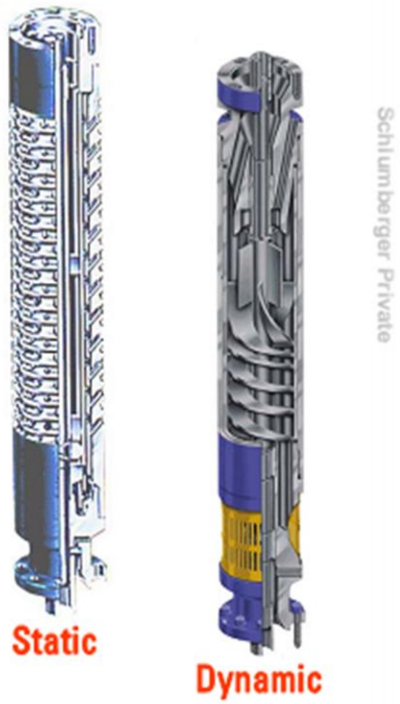
Gas Separator

A gas separator is still an intake, but with some special features designed to keep free gas from entering the pump.

Static Type - Allows the well fluid to enter past a multitude of passages where reversals in flow direction occur, creating a pressure drop, and seperating gas from solution to escape to the annulus.

Since this type of gas separator does no real "work" on the fluid, it is also called a "static" gas separator.

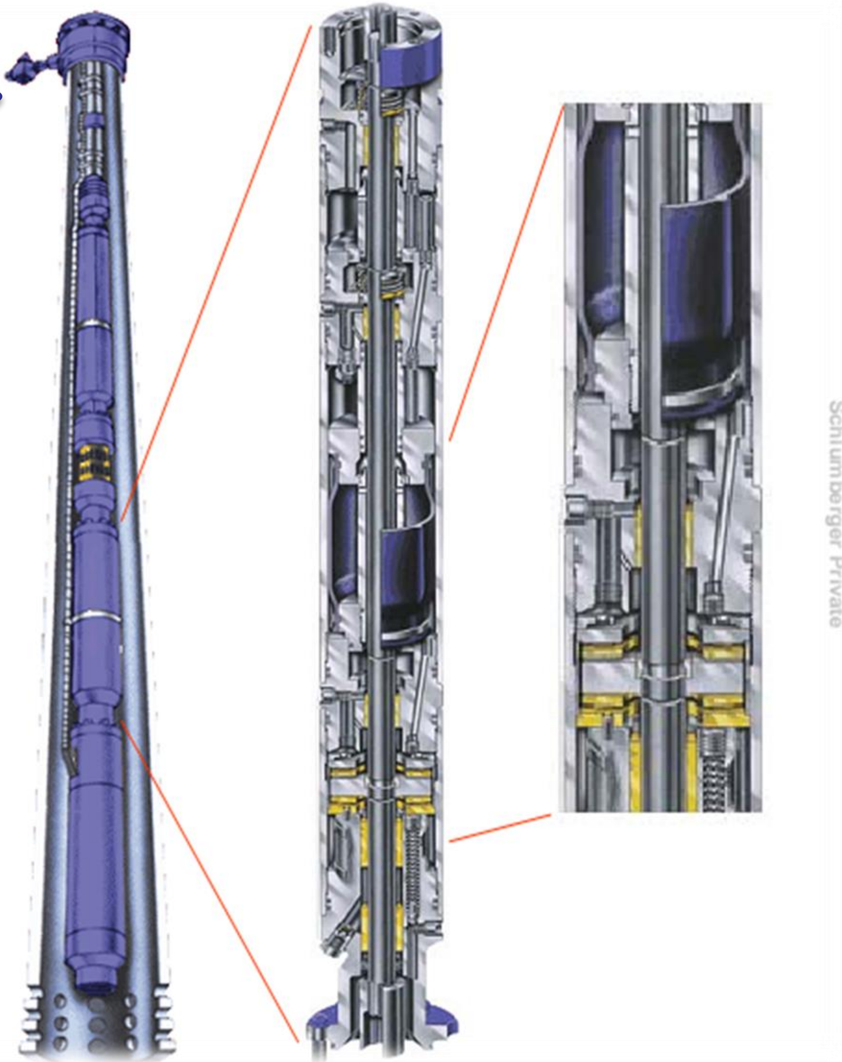
Dynamic Type - Allows entry of fluids and gas at the base of the separator into a rotating centrifuge with and inducer and straightenting vanes. Heavier fluids move to the outside and the gas to the inside. Gas passes through a crossover and up the annulus.



Artificial lift - 3.(Electric Submersible Pumps (ESP))

Protector

The protector is the piece of equipment that is located directly above the motor.



Artificial lift - 3.(Electric Submersible Pumps (ESP))

Protector function

- Couples the torque developed in the motor to the pump via the protector shaft.
- Prevents entry of well fluid into the motor.
- Provides pressure equalization.
- Houses the Bearing to carry the thrust developed by the pump

Artificial lift - 3.(Electric Submersible Pumps (ESP))

Downhole Sensors

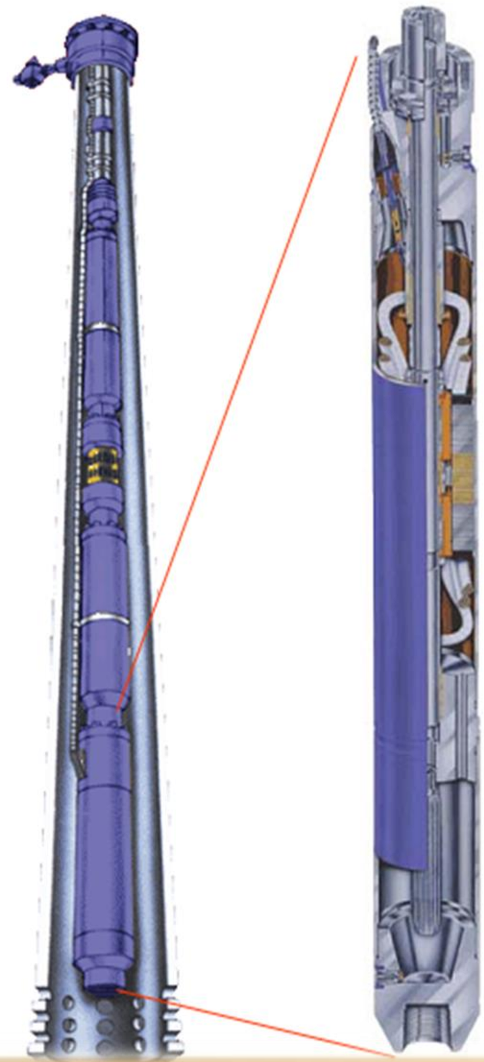
- Variety of sensors available
- Installed according to specific requirements
- Allow better and safer control of ESP operations by means of monitoring and equipment protection devices

Artificial lift - 3.(Electric Submersible Pumps (ESP))

ESP - motor

The motor is a three phase, squirrel cage, two pole induction design.

It's the "heart" of the system since it provides the torque required by the downhole pump.



Artificial lift - 3.(Electric Submersible Pumps (ESP))

Advantages of ESP	Disadvantages of ESP
1.Can be installed in deviated wells (<80…) 2.High production rates 3.Suitable for high water cut wells 4.Controllable production rate 5.Efficient Energy usage (>50% possible) 6.Access below ESP via "Y" tool 7.Comprehensive down-hole measurements available 8.Can pump against high Flowing-Tubing Head Pressure 9.No extra flow lines required 10.Minimum surface footprint - 6ft well spacing 11.Low surface profile for Urban and offshore environments 12.Quick restart after shut down 13.Concurrent drilling and production safer compared to gas lift 14.(high pressure gas not present in annulus) 15.Long run pump life possible	1.Susceptible to damage during completion installation 2.Tubing has to be pulled to replace pump 3.Not suitable for low volume wells (<150bpd) 4.Pump susceptible to damage by produced solids (sand / scale / asphaltene) 5.High GOR's presents gas handling problems 6.Power cable requires penetration of well head and packer integrity 7.Viscous crude reduces pump efficiency 8.(Viscous) emulsions form over a range of water / oil ratios 9.High temperatures can degrade the electrical motors

Artificial lift - 3.(Electric Submersible Pumps (ESP))

Required Data for ESP design

Well Data

- Casing or liner size, weight and grade,
- Tubing size, weight, grade and thread,
- Deviation survey
- Perforated or open hole interval,
- Top perforation,
- Pump setting depth,

Production data

- Wellhead tubing and casing pressures (WHP and CHP),
- Present production rate or desired production rate,
- Producing fluid level and/or pump intake pressure (dynamic level),
- Static fluid level and/or static bottom-hole pressure,
- Datum point (a reference point from which calculation or measurements are be taken),
- Bottom-hole and tubing head temperatures (BHT and WHT),
- Gas-oil ratio and Water cut (GOR and WC)

Fluid Properties

- Water Specific Gravity,
- Oil API or Specific Gravity,
- Gas Specific Gravity,
- PVT data (Bubble-point pressure, oil viscosity, formation volume factor...)

Power sources

- Available primary voltage,
- Desired frequency range,
- Power source capability

Possible problems

- Sand, scale deposition, corrosion (H_2S, CO_2...), praffin, emulsion, high GOR, high tempera

Artificial lift - 3.(Electric Submersible Pumps (ESP))

ESP - Steps
Design Procedure

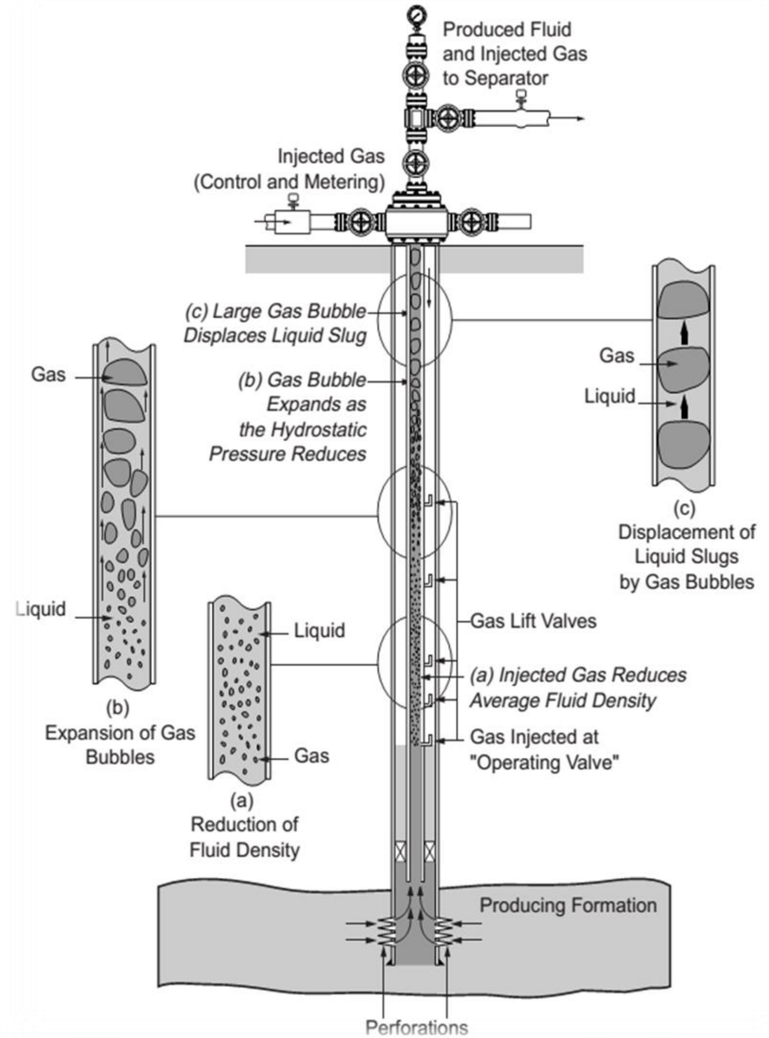
- Step 1: Basic Data
- Step 2: Production Capacity
- Step 3: Gas Calculations
- Step 4: Total Dynamic Head
- Step 5: Pump Type
- Step 6: Optimum Size of Components
- Step 7: Electric Cable
- Step 8: Accessory & optional Equipment
- Step 9: The Variable Speed Pumping System

Artificial lift - : 4.(Gas lift)

Gas Lift uses additional high pressure gas to supplement formation gas. Produced fluids are lifted by reducing fluid density in wellbore to lighten the hydrostatic column, or back pressure, load on formations

Two types of Gas Lift :

- 1-Continuous Gas Lift
- 2-Intermittent Gas Lift

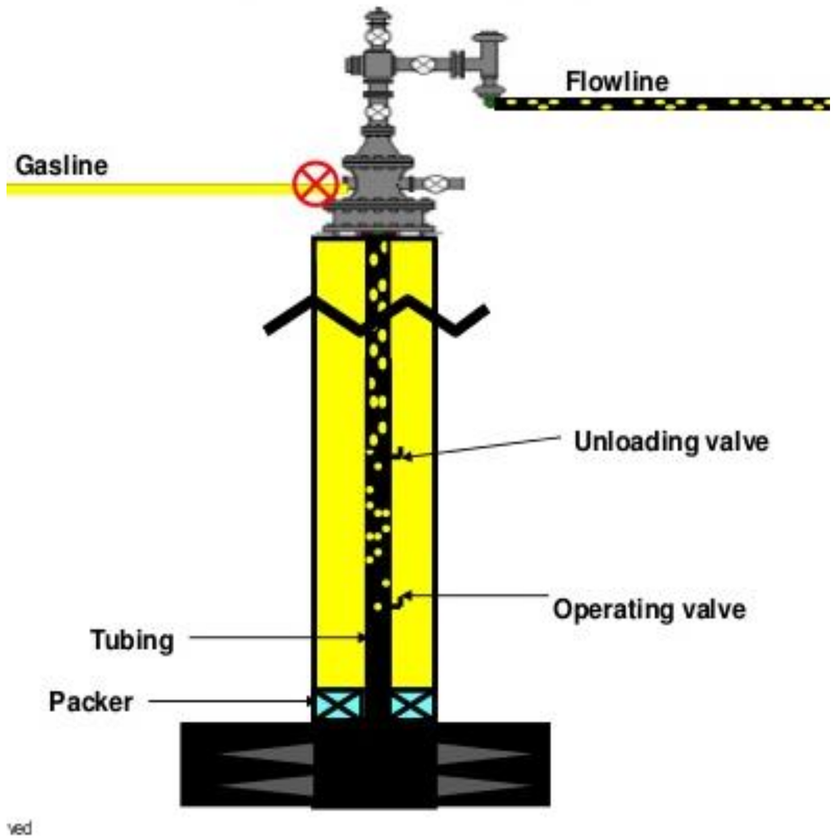


1-Continuous Gas Lift

- Very flexible and service through wireline is inexpensive. Tolerant to sand and solids production, tolerant to high GLR, no problems with deviated wells

- Requires a stable source of high pressure gas and loses efficiency as bottom hole flowing pressure declines and may require the use of another artificial lift method as reservoir ages

- The high reliability of the method makes it the first choice for offshore deepwater production



Artificial lift - : 4.(Gas lift)

1-Continuous Gas Lift

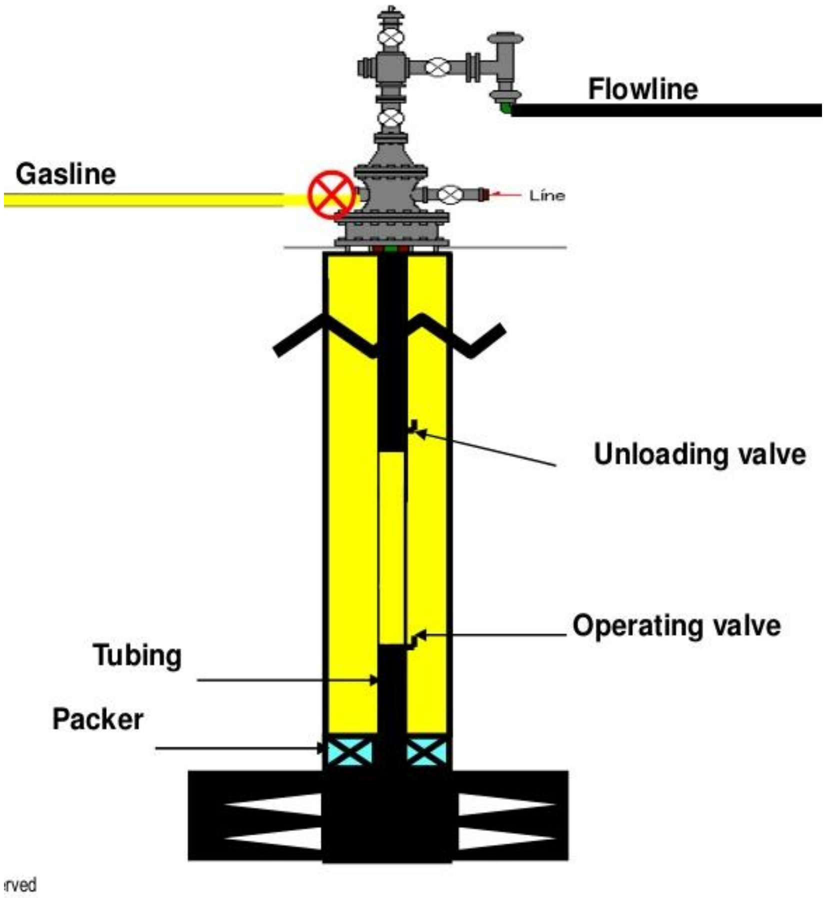
- Very simple method seen as an extension of natural flow
- Requires a source of high pressure gas and casing and lines must withstand injection pressure

- Low investment for deep wells if high pressure gas is available
- No problem with sand and crooked wells. Can be used in deviated
- wells but highly deviated wells may have problems retrieving valves with wire line

- Very flexible and simple design, applicable in a wide range of flow-rates from 50 bpd (macaroni tubing) to 40,000 bpd (casing flow)
- There is a relation between the minimum possible bottom hole flowing pressure, the depth and the fluid properties
- Most design modification and repairs can be done through wire line intervention without the need of a workover

2-Intermittent Gas Lift

1-Very beneficial for wells with a reasonably high reservoir pressure but low productivity where stimulation is not an option and high gas liquid ratio makes the use of beam pump difficult



Artificial lift - : 4.(Gas lift)

2-Intermittent Gas Lift

2-Despite the name this is a “pumping” method. The pump is a “gas piston” that expands and accelerates to the surface propelling a liquid slug on top

3-Same general characteristics of continuous gas lift

4-Usually used for low flowrate range

5-Intermittent gas injection and liquid production can disrupt the separation system as well as can interfere with other wells

6-High instantaneous consumption of injected gas

Artificial lift - : 4.(Gas lift)

Advantages of Gas lift

- 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 <60 .
- Provides full bore tubing access for coiled tubing or other well service work.
- High fluid 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.

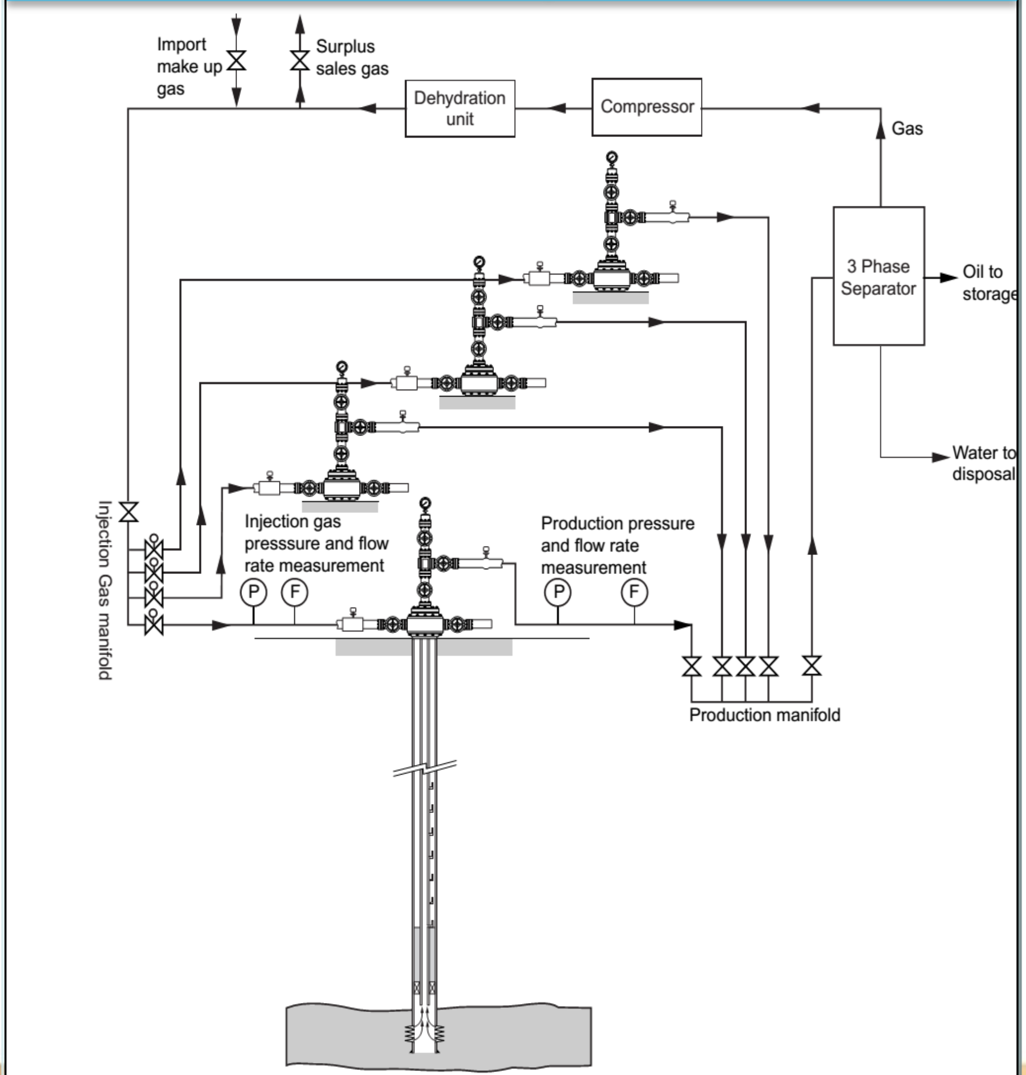
Artificial lift - : 4.(Gas lift)

Gas lift – limitation

- High back pressure on sandface due to fluid in the tubing restricting production.
  - e.g. 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 potential loss of reserves.
- 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 difficult and 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
- inadequately dried.
- Lifting of low fluid volumes is inefficient due to gas slippage.
- Good data management and complete network modelling required for efficient /
- maximum profitability operation.

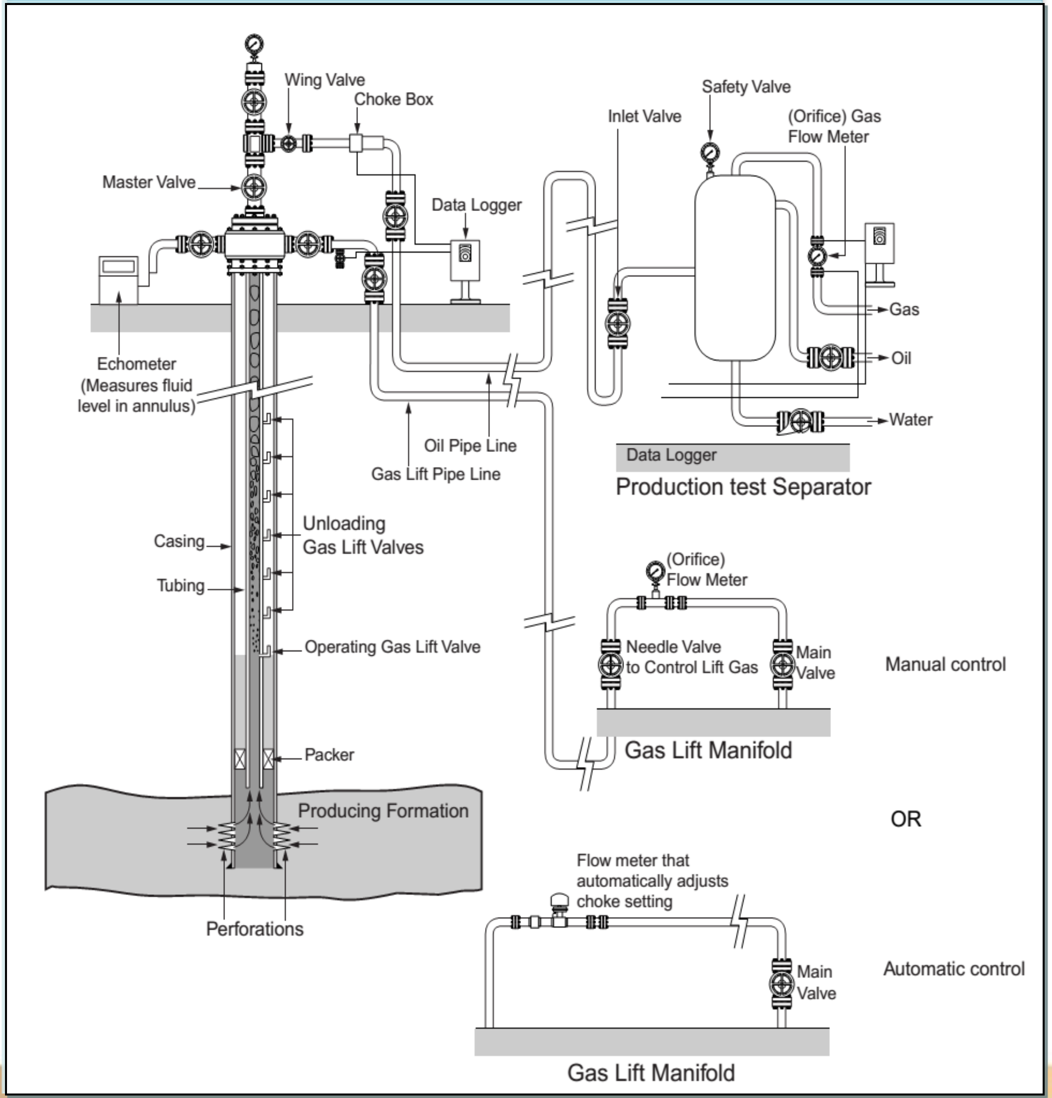
Artificial lift - : 4.(Gas lift)

Gas-lift system



Artificial lift - : 4.(Gas lift)

Metering and control of a gas lifted well.

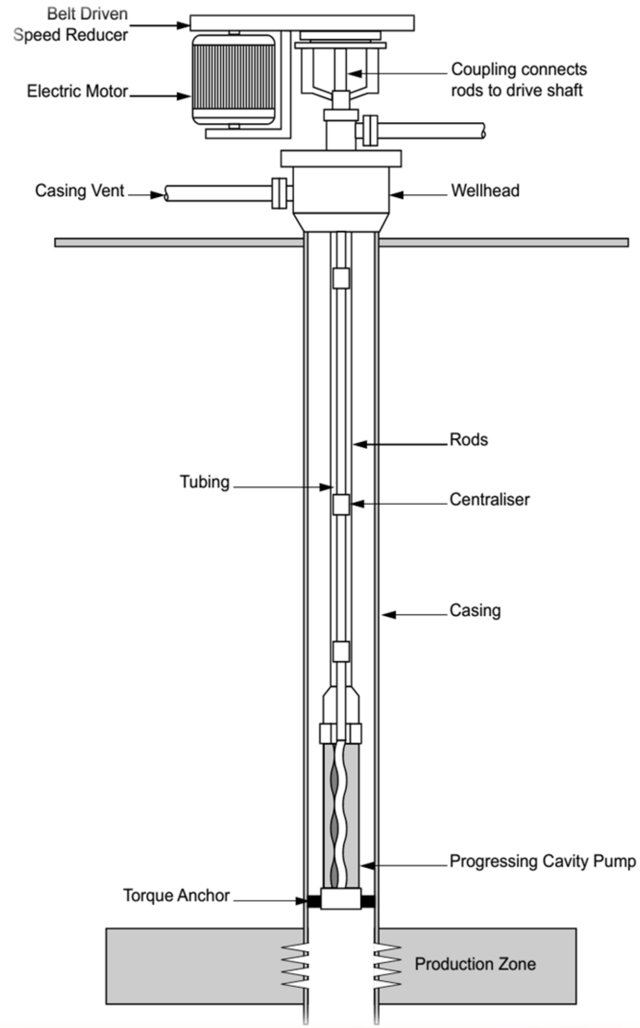


Artificial lift - 5. progressing cavity pump (PCP)

- Less expensive than other methods and
  tolerant to solids and sand production

- Ideal for heavy oil production

- Selection of materials (elastomer for the stator) very dependent on temperature and fluids composition



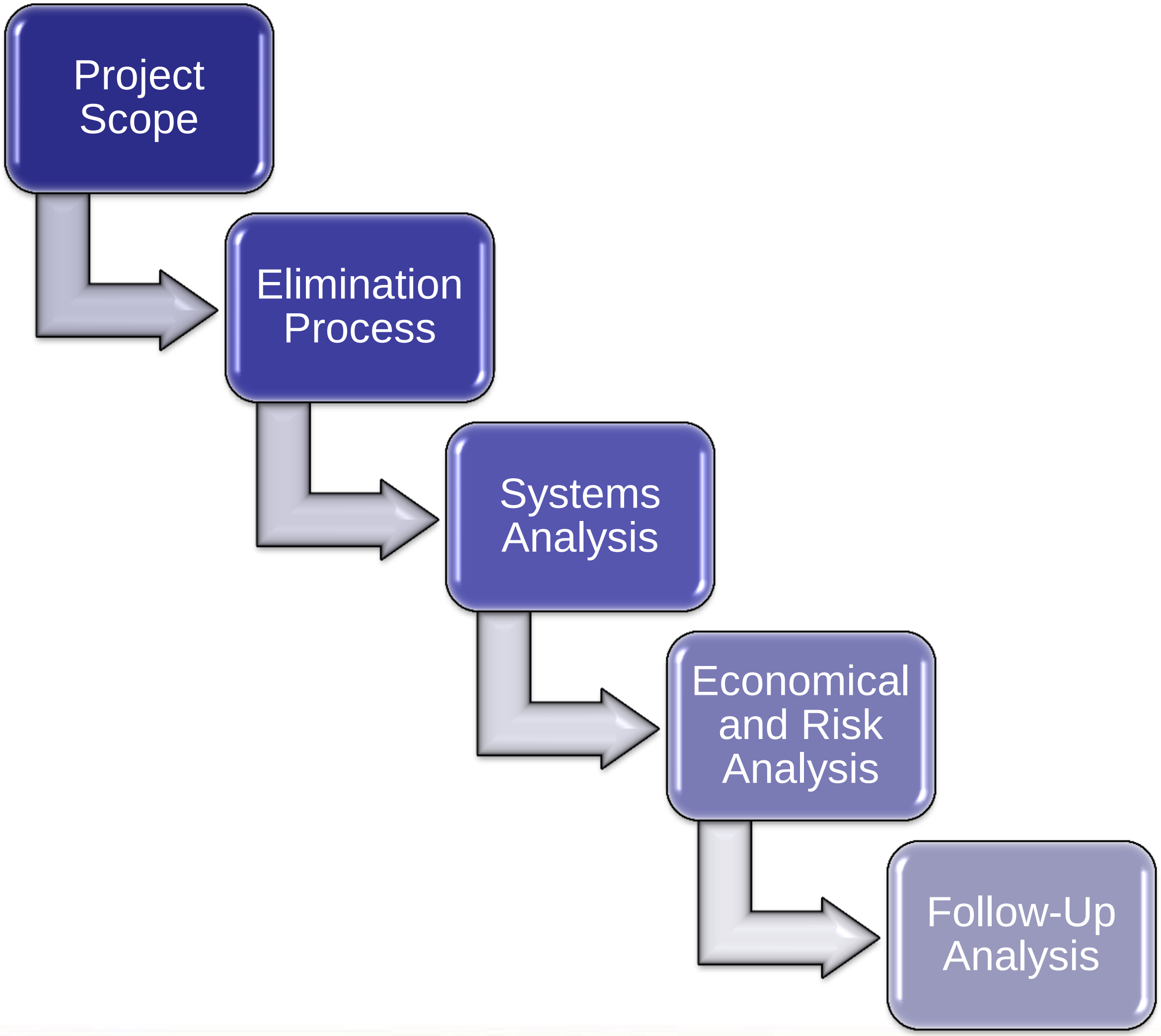
Artificial lift - 5. progressing cavity pump (PCP)

- Is a positive displacement pump that does not rely on valves to pump fluids
- Usually has a stator made of an elastomer. Stator material is sensitive to oil composition (aromatics) and Temperature
- Has higher tolerance to free gas than beam pumping, but excess gas can also cause lack of lubrication and cooling as well as chemical problems with the
  Elastomer
- May have problems with deviated and crooked wells
- Applicable for low to medium flowrates

Artificial lift - 5. progressing cavity pump (PCP)

Advantages of PCP	Disadvantages of PCP
1. Simple design	1. High Starting Torque
2. High volumetric efficiency Efficient design for gas anchors available	2. Fluid compatibility problems with elastomers in direct contact with aromatic crude oils
3. High energy efficiency	3. Gas dissolves in the elastomers, at high bottom hole pressure
4. Emulsions not formed due to low shear pumping action	
5. Capable of pumping viscous crude oils	

Artificial Lift Selection Process

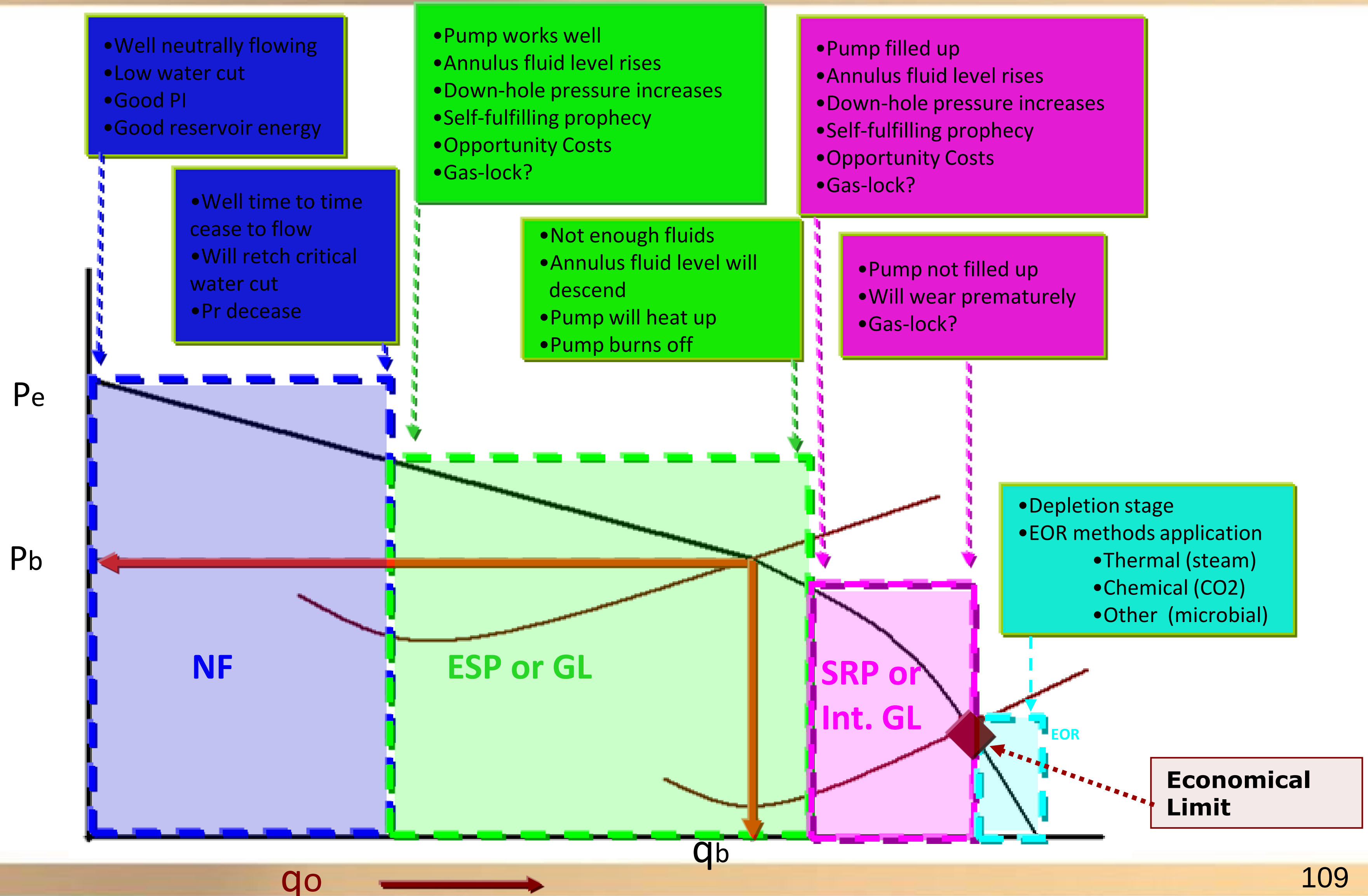


Artificial Lift Selection Process

Some of the most important aspects :

1. Reservoir producing mechanism
2. Inflow performance
3. Expected liquid flowrate
4. Water cut
5. Producing gas liquid ratio
6. Fluid properties (Rs and Bo)
7. Depth
8. Size of tubing and casing
9. Deviation
10. Recovery plan
11. Surface facilities
12. Flowlines
13. Location
14. Power supply
15. Sand production
16. Paraffin
17. Hydrates
18. Scale and corrosion
19. Personnel

Artificial lift strategy



Strategy Process

to address artificial lift system Why, When, What.

Why:

- Artificial lift refers to the use of artificial means to increase the flow of liquids, such as crude oil or wat
from a production well
  - By use of a mechanical device inside the well (known as pump or velocity string)
  - By decreasing the weight of the hydrostatic column by injecting gas into the liquid some distance down the well.

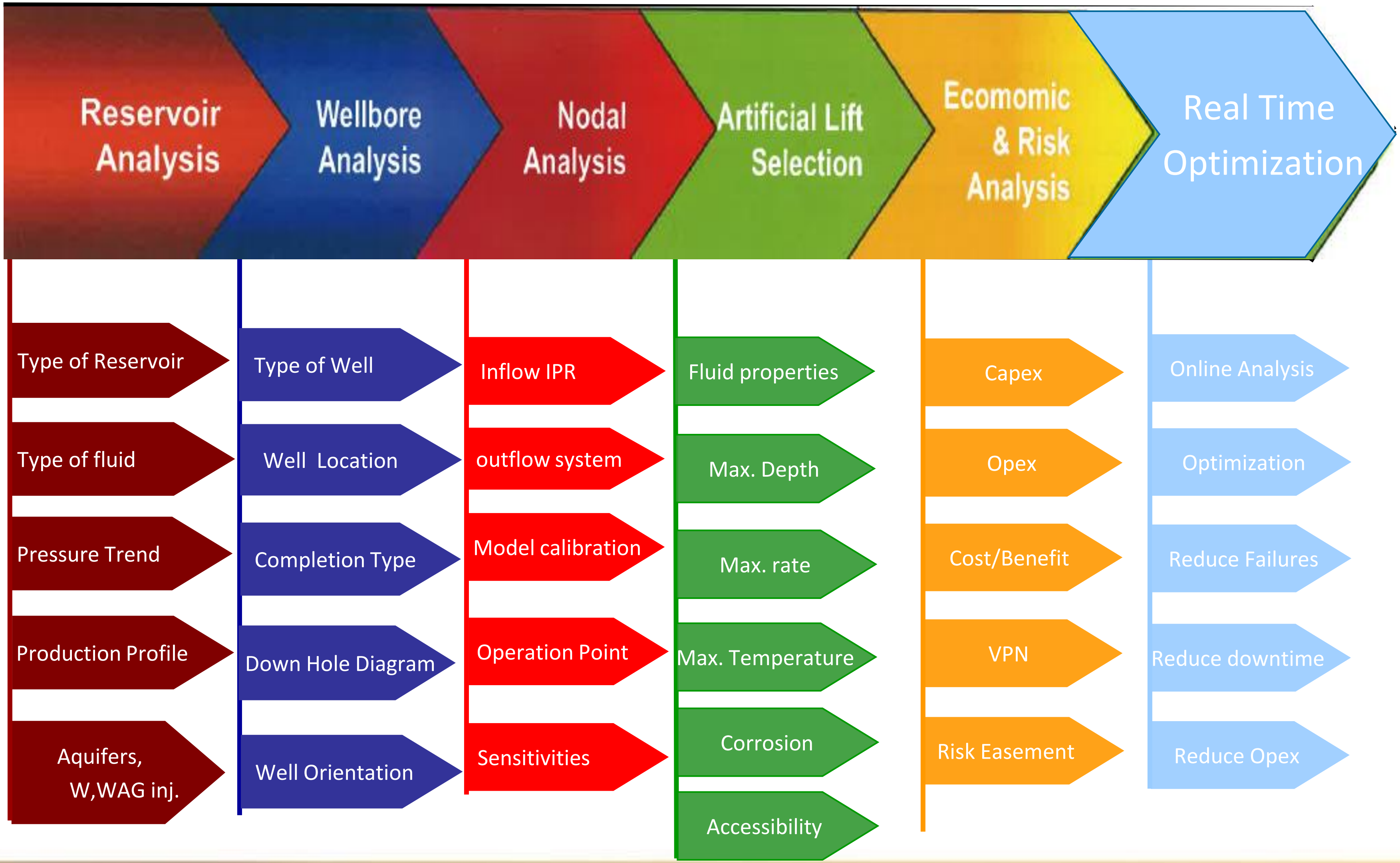
When:

- A/L needed in wells when there is insufficient pressure in the reservoir to lift the produced fluids to the surface (inactive strings)
- A/L needed for naturally flowing wells (which do not technically need it) to increase the flow rate above what would flow naturally
- when we need to flip from high productive to low productive methods at the depletion stage like continuous gas lift to Intermittent gas lift or ESP to SRP

What:

- Selecting the right lifting configuration and system for a specific well or field which requires an in-detail analysis of well conditions, field and client requirements, equipment capabilities and associated costs.

Artificial lift strategy



Artificial Lift Economics

- Initial capital cost
- Monthly operating expense
- Equipment life
- Number of wells to be lifted
- Surplus equipment availability
- Expected producing life of well(s)

Qualitative artificial lift Selection

Form of Lift	Rod Lift	Progressing Cavity Pumping	Gas Lift	Plunger Lift	Hydraulic Lift	Hydraulic Jet	Electric Submersible Pumping	Capillary Technologies
Maximum operating depth TVD (ft/*m*)	16,000 *4,878*	12,000 *3,658*	18,000 *4,572*	19,000 *5,791*	17,000 *5,182*	15,000 *4,572*	15,000 *4,572*	22,000 *6,705*
Maximum operating volume (BFPD)	6,000	4,500	50,000	200	8,000	20,000	60,000	500
Maximum operating temperature (°F/*°C*)	550° *288°*	250° *121°*	450° *232°*	550° *288°*	550° *288°*	550° *288°*	400° *204°*	400° *204°*
Corrosion handling	Good to excellent	Fair	Good to excellent	Excellent	Good	Excellent	Good	Excellent
Gas handling	Fair to good	Good	Excellent	Excellent	Fair	Good	Fair	Excellent
Solids handling	Fair to good	Excellent	Good	Fair	Fair	Good	Fair	Good
Fluid gravity (°API)	>8	<40	>15	>15	>8	>8	>10	>8
Servicing	Workover or pulling rig		Wireline or workover rig	Wellhead catcher or wireline	Hydraulic or wireline		Workover or pulling rig	Capillary unit
Prime mover	Gas or electric		Compressor	Well's natural energy	Multicylinder or electric		Electric motor	Well's natural energy
Offshore application	Limited	Limited	Excellent	N/A	Good	Excellent	Excellent	Good
System efficiency	45 to 60%	50 to 75%	10 to 30%	N/A	45 to 55%	10 to 30%	35 to 60%	N/A

Artificial Lift Design Considerations and Overall Comparisons

	Sucker Rods Pumps	ESP	Gas-lift (continuous flow)
Capital cost	Low to moderate: increases with depth and larger units.	Relatively low if electric power available, costs increase as horsepower increase.	Well equipment costs low, but lines and compression costs may be high, central compression system reduces cost per well.
Down-hole equipment	Requires good design, selection, operating, and repairing for rods and pumps.	Requires proper cable, motor, pumps, seals, etc. Good design, operation	requires valve design . Moderate cost for well equipment (valves and mandrels).
Efficiency (output hydraulic horsepower divided by input hydraulic horsepower)	Excellent total system efficiency. Full pump fillage efficiency typically about 50 to 60%.	Good for high rate wells with system efficiency is about 50% but decreases for < 1000 BPD. efficiency is <40%.	Fair: increases for wells that require small injection GLR's. Low for wells requiring high GLR's. efficiencies of 20%

Artificial Lift Design Considerations and Overall Comparisons

	Sucker Rods Pumps	ESP	Gas-lift (continuous flow)
Flexibility	Excellent: can alter stroke speed and length, plunger size, and run time to control production rate.	Poor: pumps usually run at a forced speed. Requires careful sizing. VSD provides more flexibility but added cost.	Excellent: gas injection rate varied to change rates.
Miscellaneous problems	Stuffing box leakage may be massy and a potential hazard (Antipollution stuffing boxes are available).	Requires a highly reliable electric power system. Method sensitive to rate changes.	A highly reliable compressor with +95% run time required. Gas must be dehydrated properly to avoid gas freezing.
Operating costs	Very low for shallow to medium depth (<7500 ft) land locations with low production (<400 BPD).	Varies: If HP is high, energy costs are high. High pulling costs result from short run life. Often repair costs are high.	Well costs low. Compression costs vary depending on fuel cost and compressor maintenance.

Artificial Lift Design Considerations and Overall Comparisons

	Sucker Rods Pumps	ESP	Gas-lift (continuous flow)
Casing size limits	Problems only in high rate wells requiring large plunger pumps. Small casing sizes (4.5” and 5.5”) may limit free-gas operation.	Casing size will limit use of large motors and pumps. Avoid 4.5” CSG and smaller. Reduced performance inside 5.5” CSG, depending on depth and rate.	The size of 4.5” and 5.5” CSG with 2” nominal TBG normally limits rates to <1000 BPD. For rates >5000 BPD, use >7” CSG and >3.5” TBG needed.
Depth limits	Good: rods or structure may limit rate at depth. Effectively, about 500 BPD at 7500 ft and 150 BPD at 15000 ft.	Usually limited to motor horsepower or temperature. Practical depth about 10000 ft.	Controlled by system injection pressure and fluid rates. Typically, for 1000 BPD with 2.5” nominal TBG, 1440 psi lift system, and 1000 GLR, has an injection depth of about 10000 ft.
Intake capabilitie s	Excellent: <25 psig feasible provided adequate displacement and gas venting. Typically about 50 to 100 psig.	Fair: if little free gas (i.e. >250 psi PIP). Poor if pump must handle >5 % free gas.	Poor: restricted by the gradient of the gas-lifted fluid. Typically moderate rate is limited to about 100 psi/1000 ft injected depth. Thus, the backpressure on 10,000 ft well may be >1000 psig

Normal Operating Considerations (continued)

	Sucker Rods Pumps	ESP	Gas-lift (continuous flow)
Surveillance	Excellent: can be easily analyzed based on well load, fluid levels, etc. Analysis improved by use of dynamometers and computers.	Good: downhole pump performance can be analyzed from surface electrical data, well test, fluid levels, etc.	Good/excellent: can be analyzed easily. BHP and production log surveys easily obtained.
Testing	Good: well testing is simple with few problems using standard equipment and procedures.	Good: simple with few problems. High water cut and high rate wells may require a free water knock-out.	Fair: well testing complicated by inj. gas volume/rate. Formation GLR obtained by subtracting total produced gas from inj. gas. Gas measurement errors commen.
Time cycle and pump-off controllers application.	Excellent: if well can be pumped off.	Poor: soft start and improved seals/protectors recommended.	Not applicable

Artificial Lift Considerations

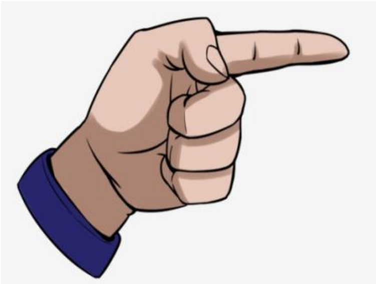
	Sucker Rods Pumps	ESP	Gas-lift (continuous flow)
Corrosion/scale handling ability	Good to excellent: batch treating inhibitor down annulus used frequently for both corrosion and scale control.	Good to fair: batch treating inhibitor only to intake unless shroud or capillary tube.	Good: inhibitor in the injection gas and/or batch inhibiting down tubing Steps must be taken to avoid corrosion in injection gas line.
Crooked/deviated holes	Fair: increased load and wear problems. High angle deviated holes (>70^{o}) and horizontal wells are being produced. Some success in pumping 15^{o}/100 ft using rod guides.	Good: few problems. Limited experience in horizontal wells. Requires long radius wellbore bends to got through.	Excellent: low W/L problems up to 70^{o} deviated for W/L retrievable valves.
Dual application	Fair: parallel 2" x 2" low rate dual feasible inside 7" CSG. Duals inside 5.5" CSG currently not in favor. Gas is a problem from lower zone. Increased mechanical problems	No know installations. Larger casing would be needed. Possible run and pull problems.	Fair: dual GL common but good operating of dual lift complicated and inefficient resulting in reduced rates. Parallel 2" x 2" nominal TBG inside 7" CSG and 3" x 3" TBG inside 9 5/8" CSG feasible.

Artificial Lift Considerations (continued)

	Sucker Rods Pumps	ESP	Gas-lift (continuous flow)
Gas-handling ability	Good: if can vent and use natural gas anchor with properly designed pump. Poor if inlet pump > 50% free gas.	Poor for free gas >50% . Rotary gas separators helpful if solids not produced	Excellent: produced gas reduces need for injection gas.
Offshore application	Poor: must designed for unit size, weight, and pulling unit space. Most wells are deviated and typically produce sand.	Good: must provide electrical power and service pulling unit.	Excellent: most common method if adequate injection gas available.
Paraffin-handling capability	Fair/good: hot water/oil treating and use of scrapers possible, but they increase operating problems and costs	Fair: hot water/oil treatments, mechanical cutting, batch inhibition possible.	Good: mechanical cutting sometimes required. Inj. gas may increase the problem.
Temperature Limitation	Excellent: currently used in thermal operations (550 ^{O}F)	Limited to <250 ^{O}F for standard and <350 ^{O}F with special motor and cable.	Excellent: max. of 350 ^{O}F . Need to know temp. to design bellows charged valves.

Artificial Lift Considerations (continued)

	Sucker Rods Pumps	ESP	Gas-lift (continuous flow)
High-viscosity fluid handling capability	Good for <200 cp fluids and low rates (400 B/D). Rod fall problem for high rates. Higher rates may require diluents to lower viscosity.	Fair: limited to about 200 cp. Increases HP and reduces head.	Fair: few problems for <16 ^{O}API or below 20 cp viscosity. Excellent for high water cut lift even with high viscosity oil.
High-volume lift capacities	Fair: restricted to shallow depths using large plungers. Maximum rate about 4000 BFPD from 1000 ft and 1000 BFPD from 5000 ft.	Excellent: limited by needed HP and can be restricted by CSG size, in 5.5 in CSG can produce 4000 BFPD from 4000 ft with 240 HP.	Excellent: restricted by TBG size and inj. gas rate and depth. Depending on reservoir pressure, with 4” TBG, rates of 5000 B/D from 1000’ with 1440 psi inj. gas and GLR of 1000.
Low-volume lift capacities	Excellent: most commonly used method for wells producing <100 BFPD	Generally poor: lower efficiencies and high operating costs for < 400 BFPD.	Fair: > 200 BFPD from 4000 ft.
Solid/sand handling ability	Poor/Fair: for low viscosity (<10 cp) production. Improved performance for high viscosity (>200 cp) cases. May be able to handle up to 0.1% sand with special pumps.	Poor: requires < 200 ppm solids	Excellent: limit is inflow and surface problems. Typical limit is 0.1% sand for inflow and outflow problems.

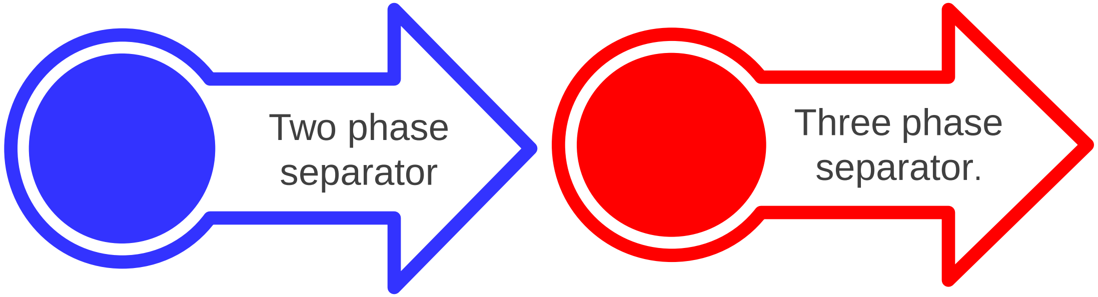


(6) Separators

classification of separators

1. Based on phase
   - Two phase
   - Three phase
2. Based on shape
   - Horizontal
   - Vertical
   - spherical
3. Based on function
   - Test separator
   - Production separator
4. Based on operation pressure
   - Low pressure separator
   - Intermediate pressure
   - High pressure separator

1-Classification by phase :



- **Two phase separator** : gas is separated from the liquid with the gas and liquid being discharged separately.

- **Three phase separator**.

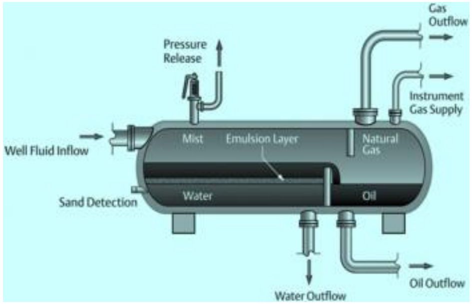
In three-phase separators, well fluid is separated into gas, oil, and water with the three fluids being discharged separately.

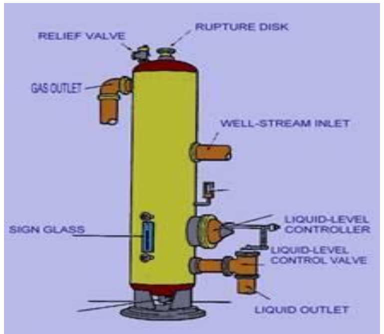
2- Classification by Operating Configuration (shape)

Horizontal Separators

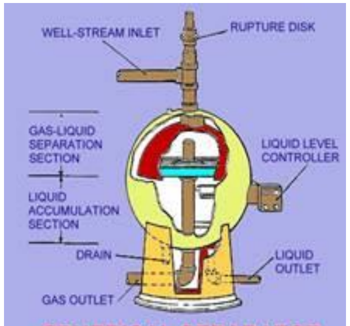
Vertical Separators

Spherical Separators





VERTICAL SEPARATOR



SPHERICAL SEPARATOR

classification of separators

2- Classification by Operating Configuration (shape)

1 Horizontal separator.

may vary in size from 10 or 12 in. in diameter and 4 to 5 ft seam to seam (S to S) up to 15 to 16 ft in diameter and 60 to 70 ft S to S.

3 Vertical separator.

vary in size from 10 or 12 in. in diameter and 4 to 5 ft S to S up to 10 or 12 ft in diameter and 15 to 25 ft S to S.

3 Spherical separator.

usually available in 24 or 30 in. up to 66 to 72 in. in diameter.

Horizontal Separators

Advantages - Horizontal separator :

1. Easy to hook-up, controls and easy to reach safely.
2. More successful in handling foaming crude because of the large interface area in relation to the liquid volume.
3. More efficient at handling large volumes of gas than vertical separators since the interface area is larger in a horizontal separator than a vertical separator, it is easier for the gas bubbles, which come out of solution as the liquid approaches equilibrium
4. In the gravity-settling section of the vessel, the liquid droplets fall perpendicular to the gas flow, and, thus, are more easily settled out of the gas-continuous phase

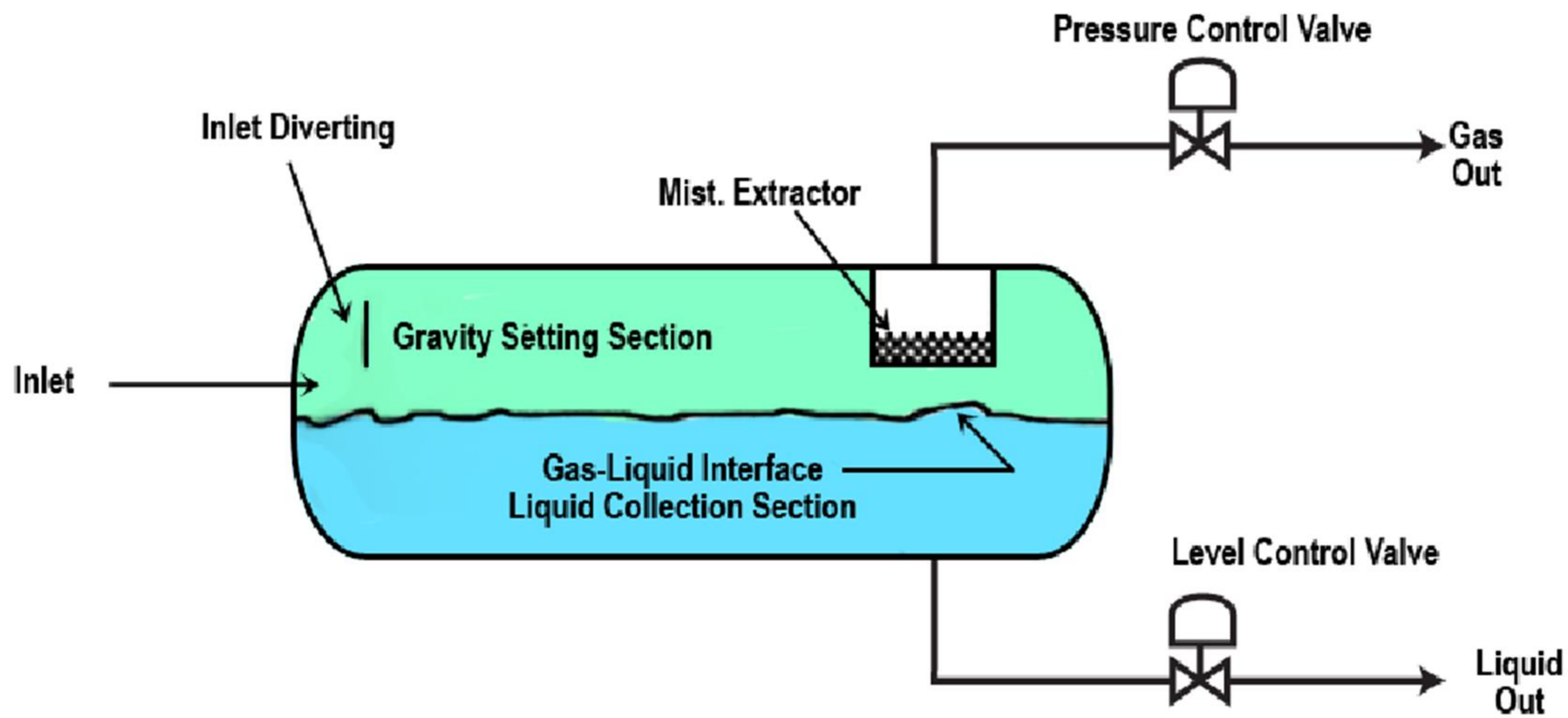
Horizontal Separators

Disadvantages - Horizontal separator

1. Difficult to clean, preparations should be made for cleaning the separator during shutdowns, and if necessary during operations, by installation of water jets and additional drains.
2. Require more floor space.
3. Limited liquid surge capacity. Since the gas travels horizontally over the liquid where a rise in liquid level will immediately reduce the gas space and consequently create an increase in gas velocity resulting in lower the setting efficiency.(gravity effect will be minimized at high speed)
4. Liquid level control more critical.

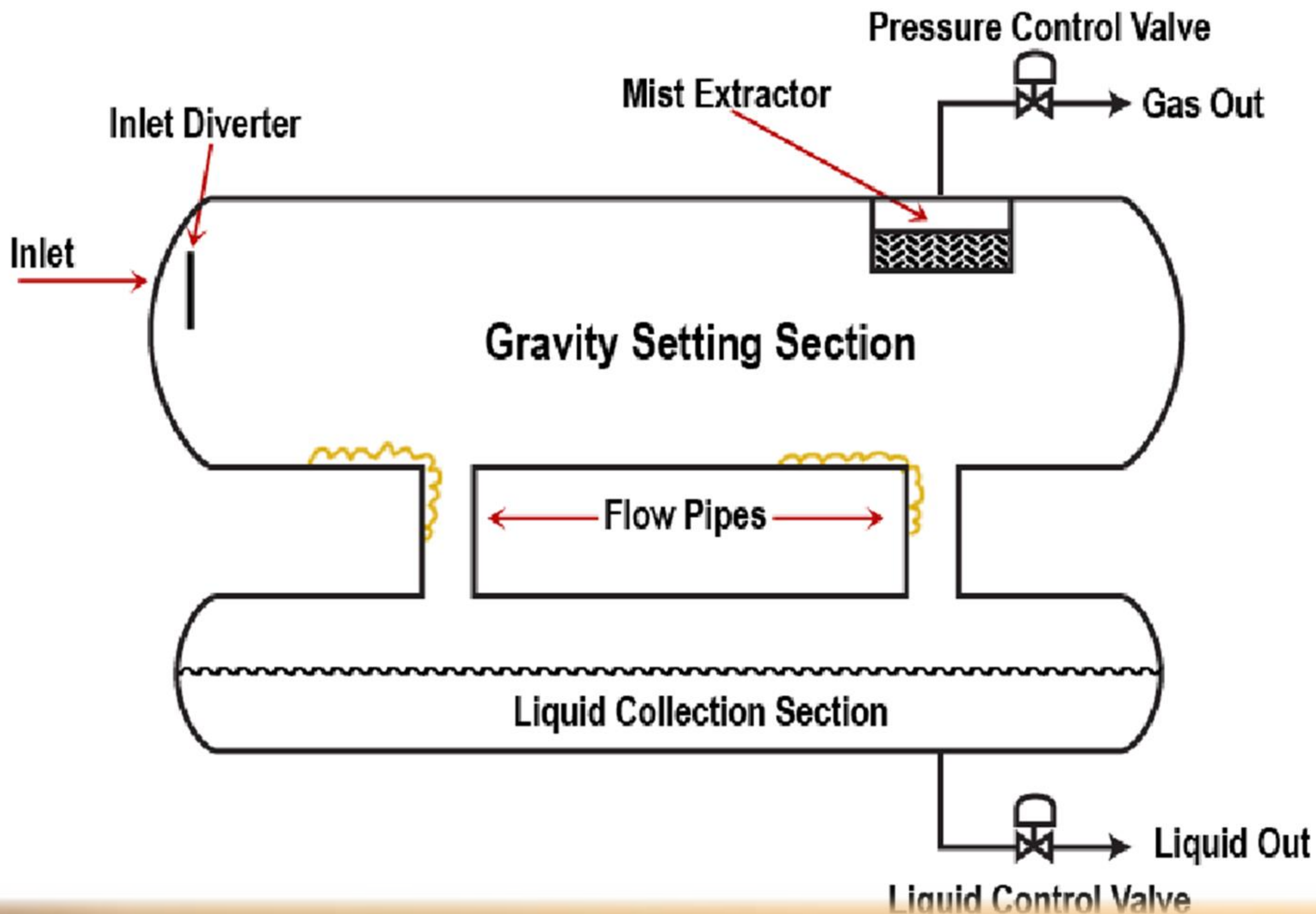
Horizontal Separators

Mono-tube horizontal separator



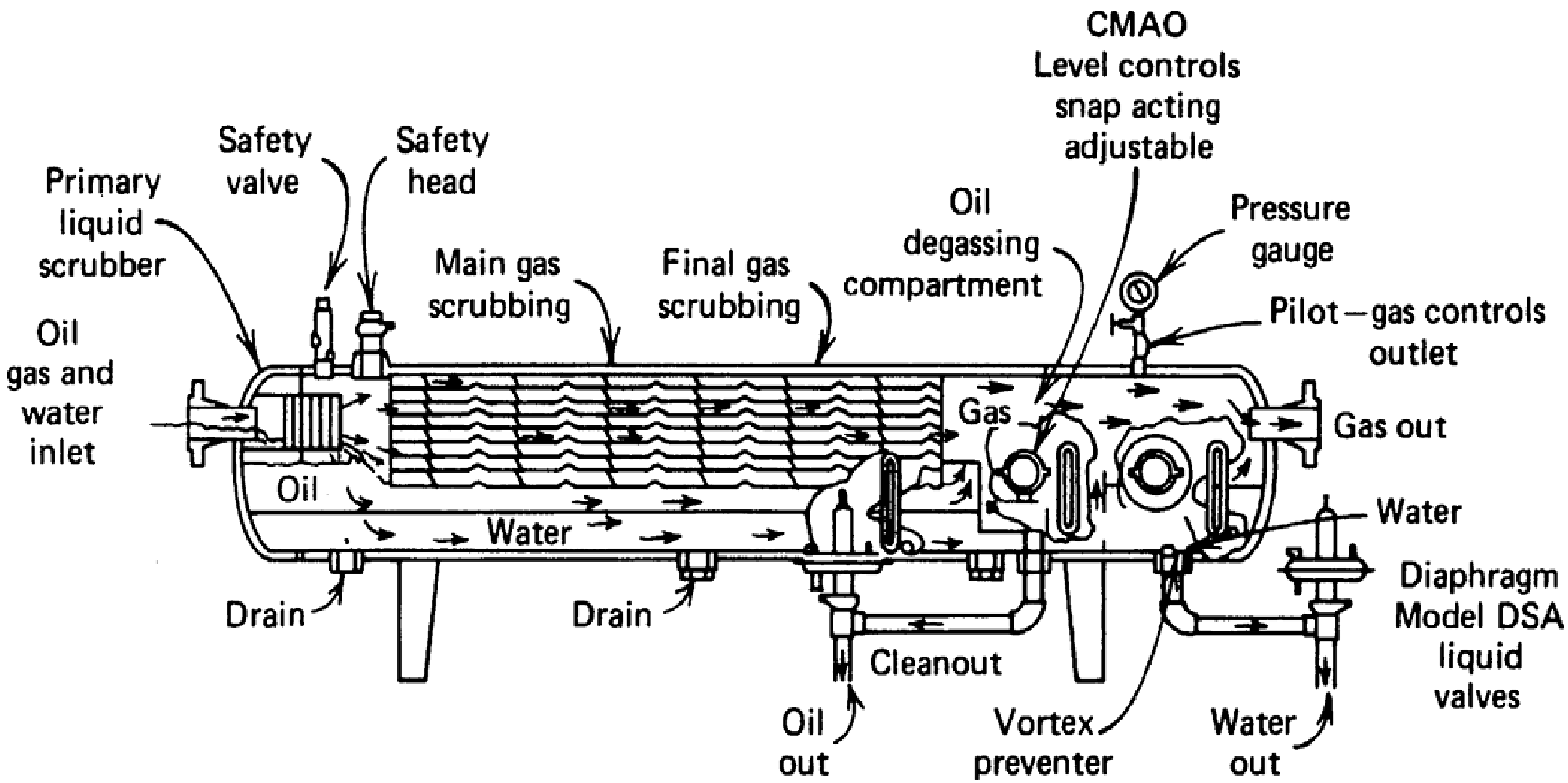
Horizontal Separators

Dual-tube horizontal separator



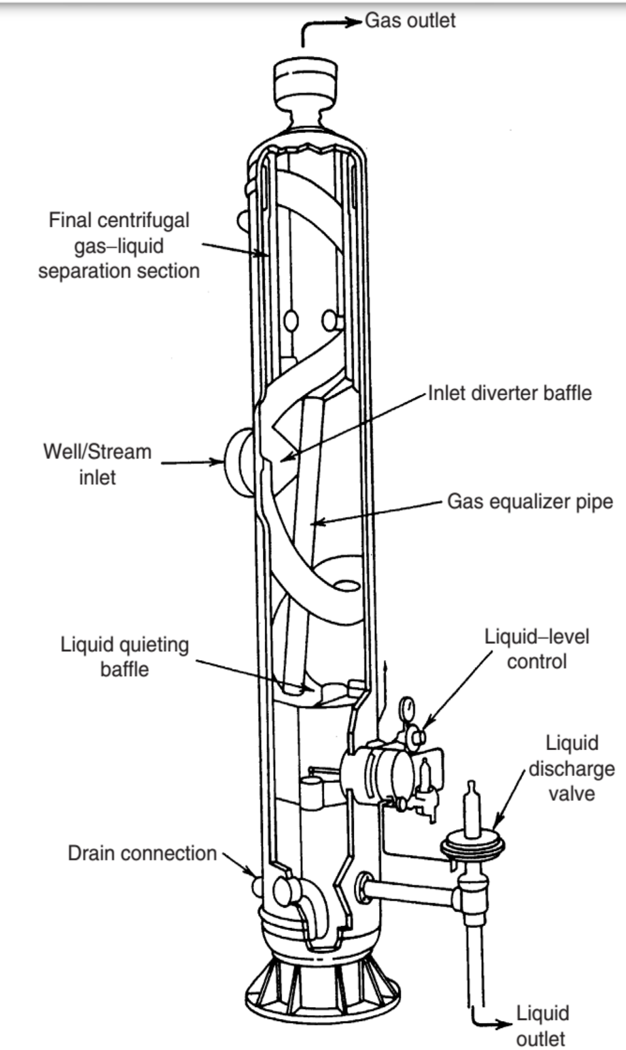
Horizontal Separators

A typical horizontal three-phase separator



Vertical Separators

A typical vertical separator



Vertical Separators

Advantages - Vertical Separators

1.Good bottom drain and easier to clean out.
2.Saves floor space.
3.Good liquids surge capacity and since the liquid level is normally substantially below the main gas flow path, the separator’s efficiency does not vary with the liquid level.
4.Liquid level control not so critical.
5.Handle more liquid per unit of gas (due to good and high surge control and capacity).

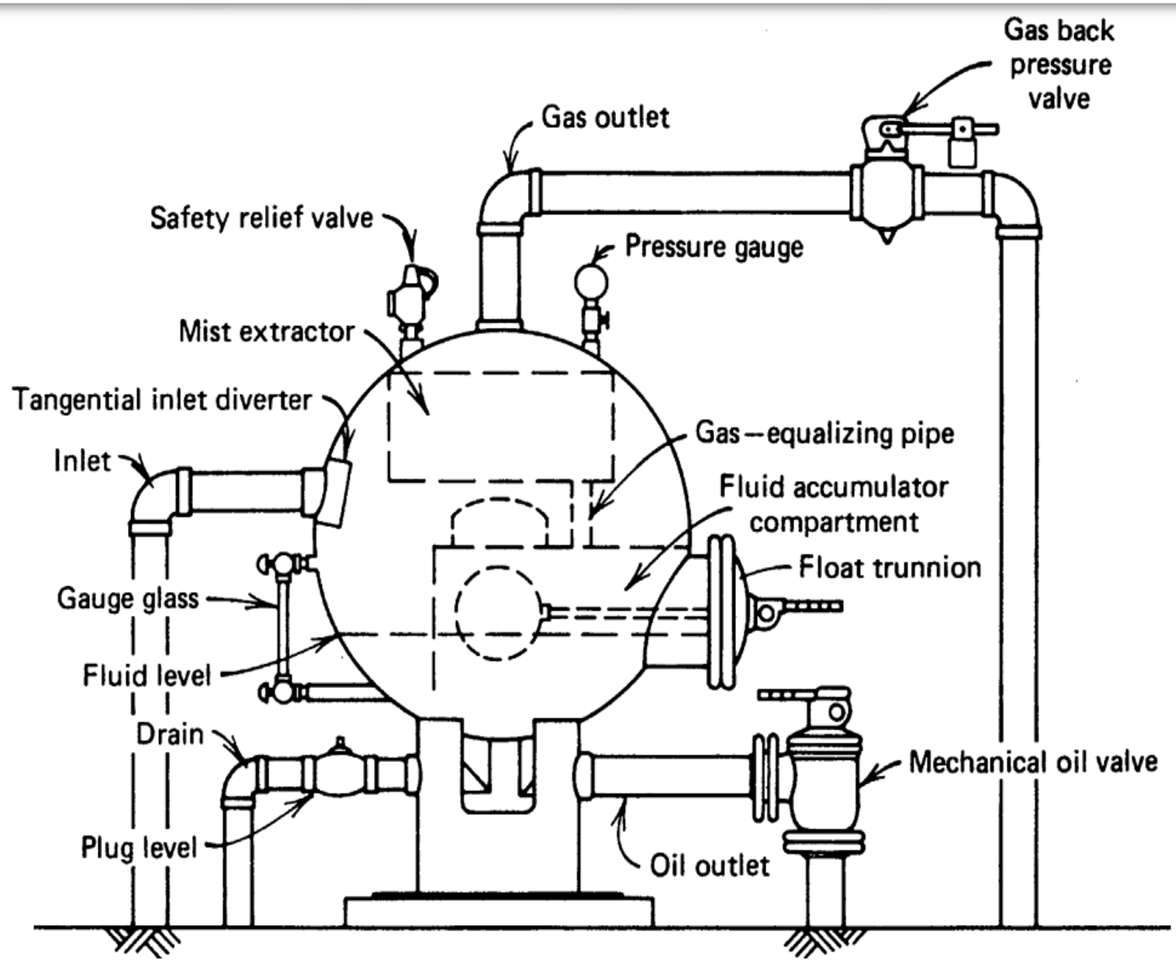
Vertical Separators

Disadvantages- Vertical Separators

1.Limited gas capacity. (gas separation depends on the cross section area)
2.Top-mounted safety device, controls and outlets may be difficult to reach.
3.High load per unit ground area and more height required between platform decks offshore.

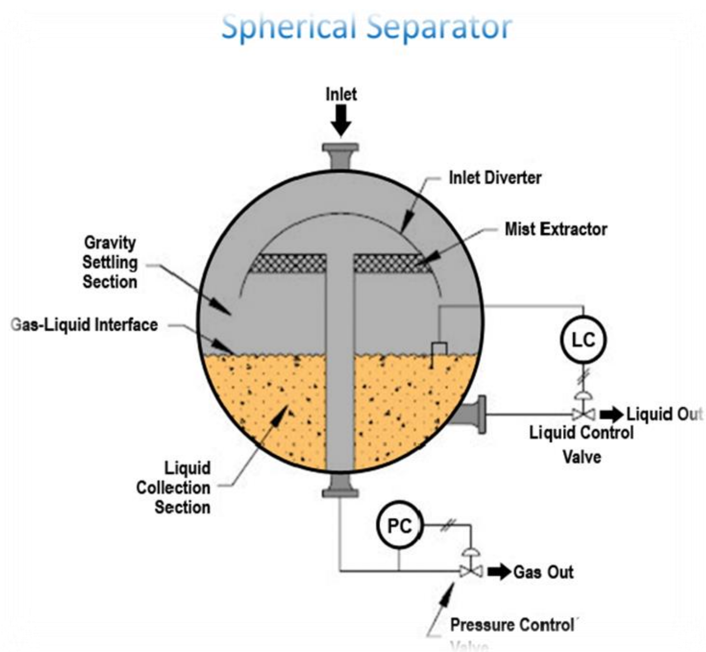
Spherical Separators

A typical spherical low-pressure separator



Spherical Separators

- The same four common elements can be found in this vessel.
- Spherical separators are a special case of a vertical separator where there is no cylindrical shell between the two heads. They may be very efficient from a pressure containment standpoint, but, because they have limited liquid surge capability and they present fabrication difficulties.
- They are not widely used in the oil industry.
- For this reason, we will not be discussing spherical
- separators in further detail.



classification of separators

3-Classification based on function :

Test separator → **Production separator.**

- ❑ Test separator :

A test separator is used to separate and to meter the well fluids and is specifically used as a well tester or well checker .

Test separators can be vertical, horizontal, or spherical, and they can be two-phase or three-phase They can be permanently installed or portable (skid or trailer mounted) Test separators are generally equipped with various types of meters for measuring the oil, gas, and/or water for potential tests, periodic production tests, marginal well tests, etc..

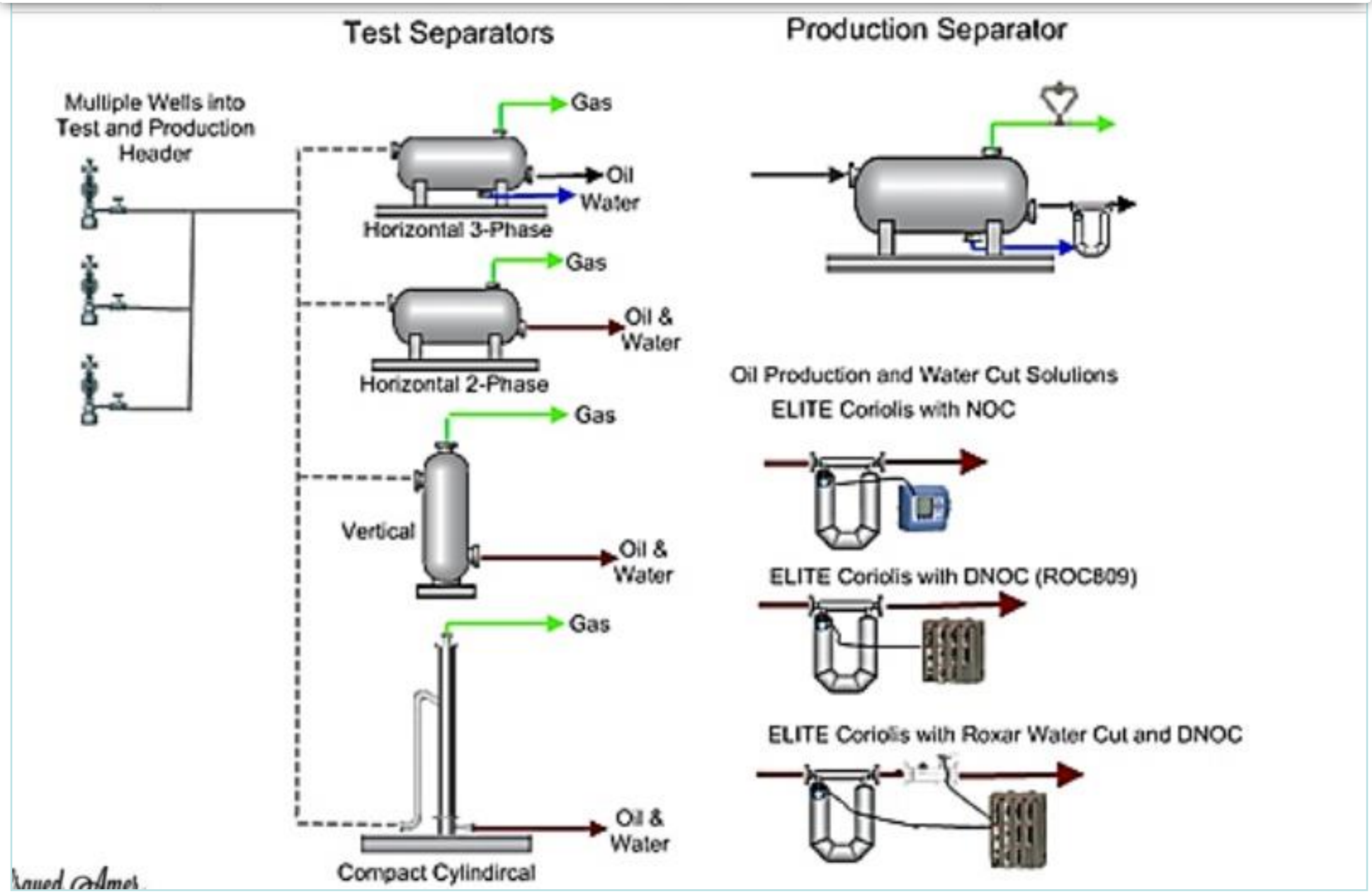
- ❑ Production Separator pressure vessel used for separating well fluids produced from oil and gas wells into gaseous and liquid components

classification of separators

- Test separator :

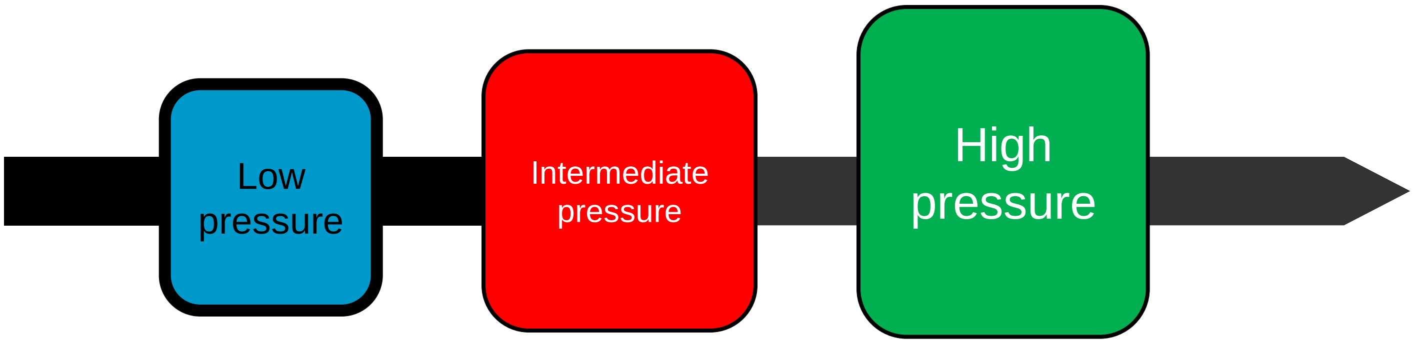
classification of separators

Test separator and production separator



classification of separators

4-Classification Based on operation pressure



01	**Low Pressure**	▪ operate at pressures ranging from 10 to 20 up to 180 to 225 psi.
02	**Intermediate Pressure**	▪ operate at pressures ranging from 230 to 250 up to 600 to 700 psi.
03	**High Pressure**	▪ operate in the wide pressure range from 750 to 1,500 psi.

Separator section

1-Separator Section in vertical separator :

1.Primary separation section
2.Secondary separation section
3.Mist extraction section
4.Liquid accumulation section

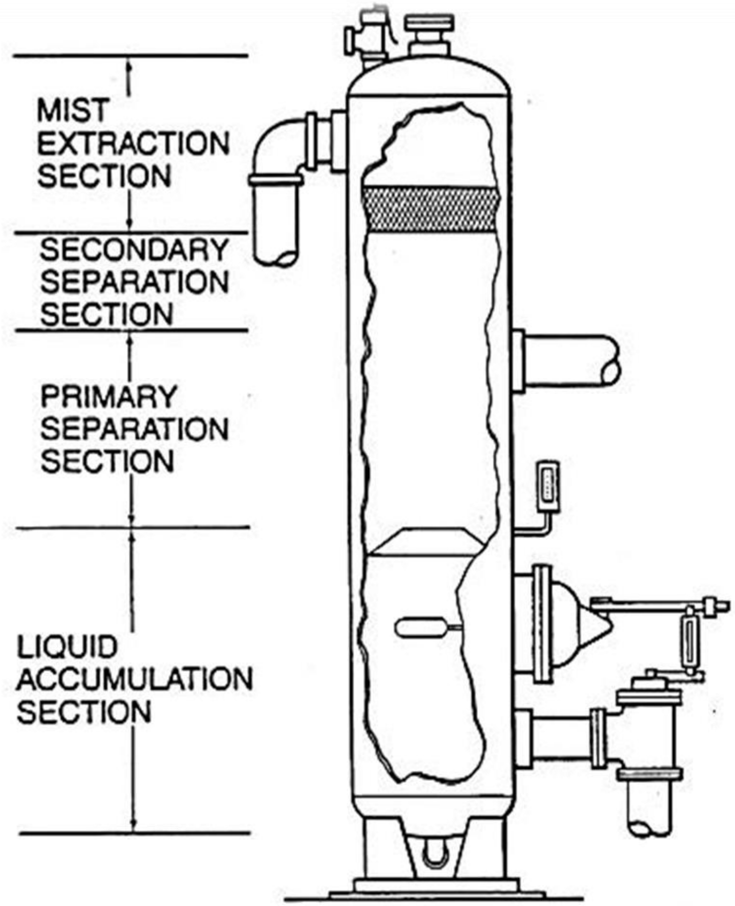


Figure 2

Separator Sections

Separator section

1-Separator Section in vertical separator :

1.Primary separation section

As the fluids enter the vessel an initial separation of gas and liquid takes place. This happens because of: Reduction in velocity Separator internal Reduction in pressure Change in flow direction • Collecting and removing the bulk of the liquid in the inlet stream. • Exploit the momentum of the inlet stream either by creating centrifugal force or change of direction (as in horizontal separators) thus separating most of the incoming liquid.

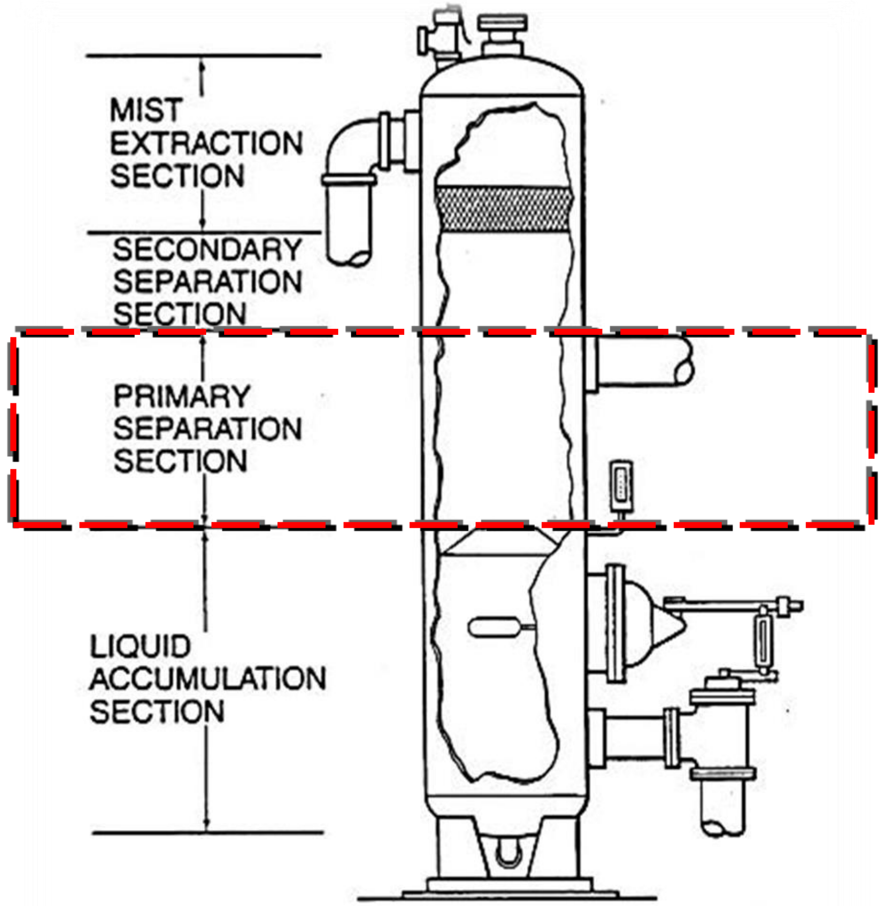


Figure 2

Separator Sections

Separator section

1-Separator Section in vertical separator :

2.Secondary separation section In the secondary separation process these liquid droplets are removed from the gas stream. Liquid droplets which are suspended in the gas stream will tend to fall or 'settle' towards the bottom of the vessel. This is simply due to the force of gravity. • The difference in density between liquid and gas and the droplet size will be determined by the composition of the inlet fluid streams. • The velocity of the gas stream is determined by the size of the separator and its throughput.

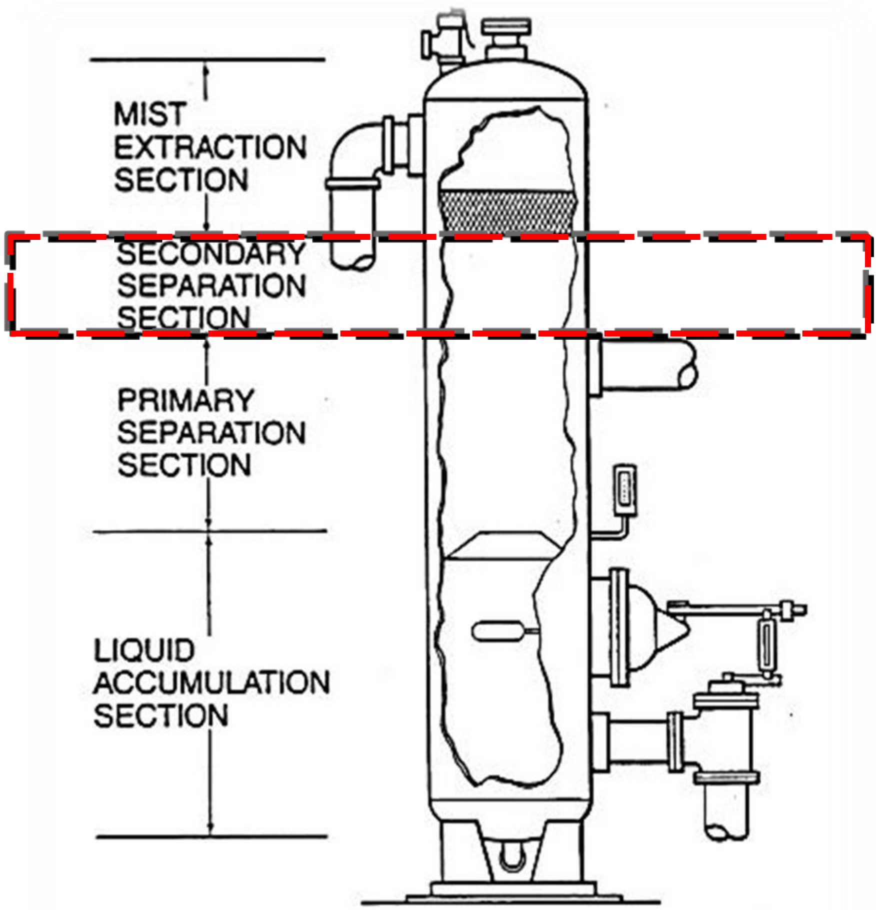


Figure 2

Separator Sections

Separator section

1-Separator Section in vertical separator :

3-Mist Extraction Section

• The secondary separation of liquid droplets from the gas by gravity settling will not usually remove very small particles. • These particles tend to remain in the gas stream in the form of a mist. In order that the gas leaving a separator is as free as possible from liquid, a final mist extraction section is built into the vessel. • Mist extraction is accomplished using either an impingement or a centrifugal force mechanism.

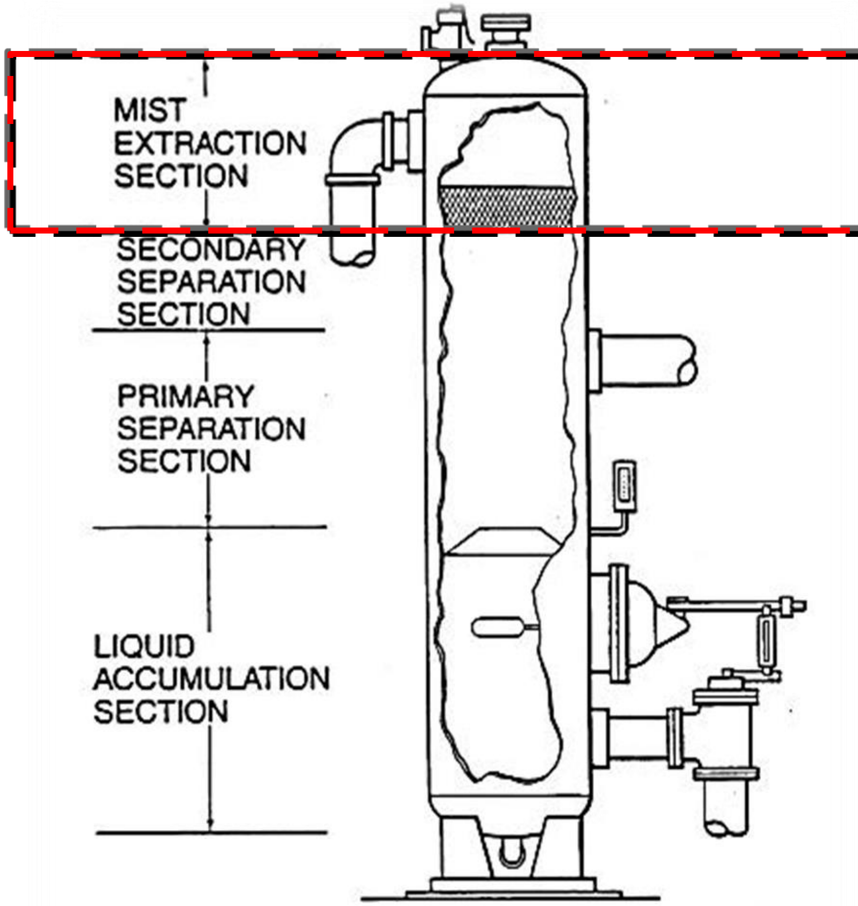


Figure 2

Separator Sections

Separator section

1-Separator Section in vertical separator :

4-Liquid accumulation Section

- The lowermost section of a separator where the liquids from the other three sections accumulate before being discharged from the vessel. Initially, this liquid will have gas bubbles entrained within it which must be removed. Just as liquid droplets tend to fall through a gas stream, gas bubbles tend to rise to the surface of liquids due to density differences. The time required for the bubbles to reach the surface and re-enter the gas stream will vary. However, for most oilfield applications it will occur in one to four minutes. This means that the liquids must stay in the vessel for this period of time, which is known as the retention time.'

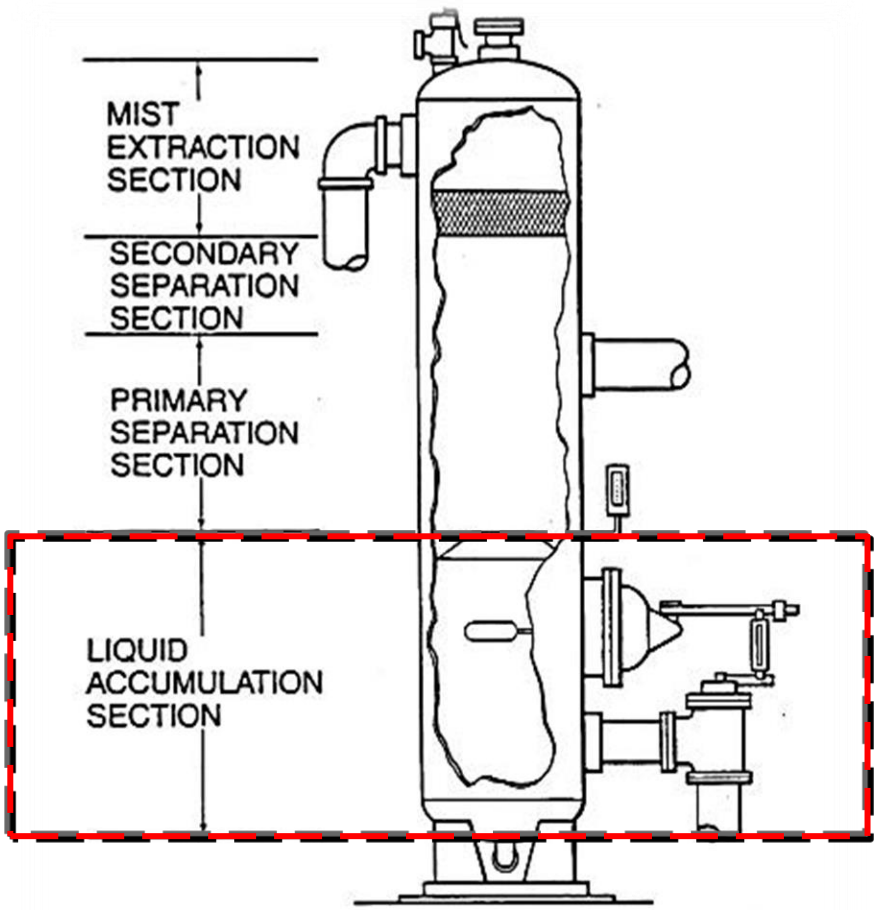
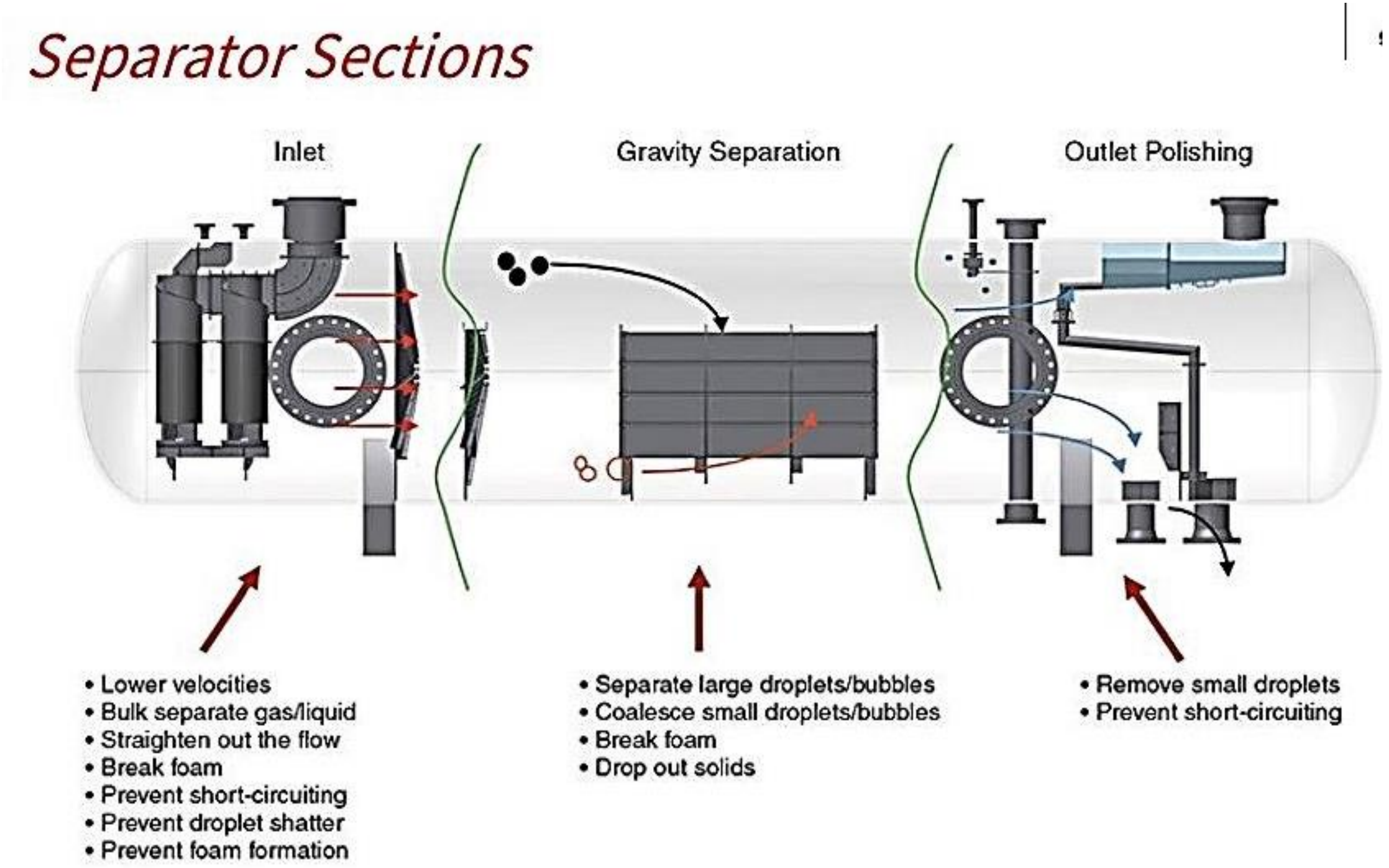


Figure 2

Separator Sections

2-Separator Section in Horizontal separator :



Stage separation

1. Single stage separation
2. Two stage separation
3. Three stage separation
4. Four stage separation
5. Multi-stage separation

The purpose of the stage separation is to reduce the operating pressure on steps or stages with the aim of obtain the maximum quantity of stable stock tank oil.

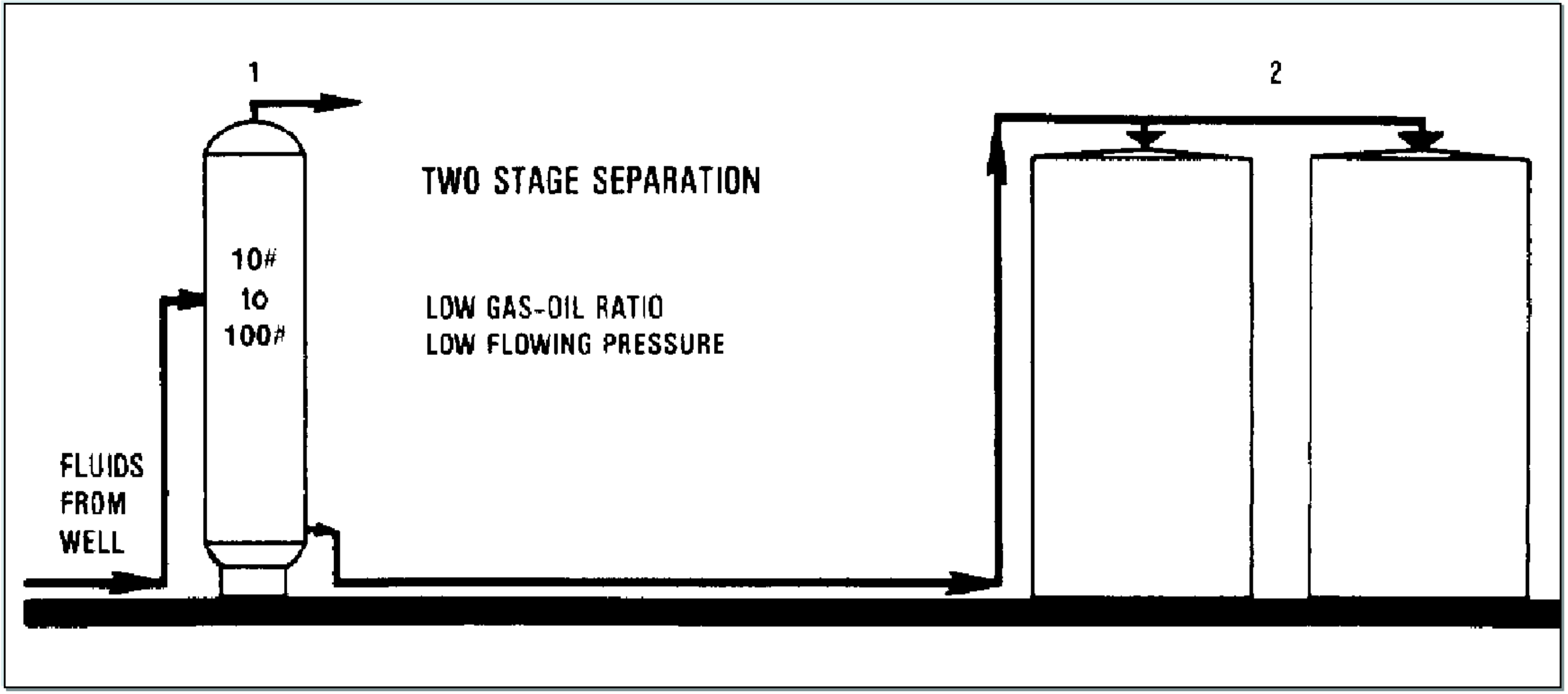
▪separation is single stage:-

▪Single High Pressure Separation: Too many light components will stay in the liquid phase at the separator and be lost to the gas phase at the tank.

▪Single Low Pressure Separation: Less heavy components will be stabilized into the liquid at the separator and they will be lost to the gas phase in the separator.

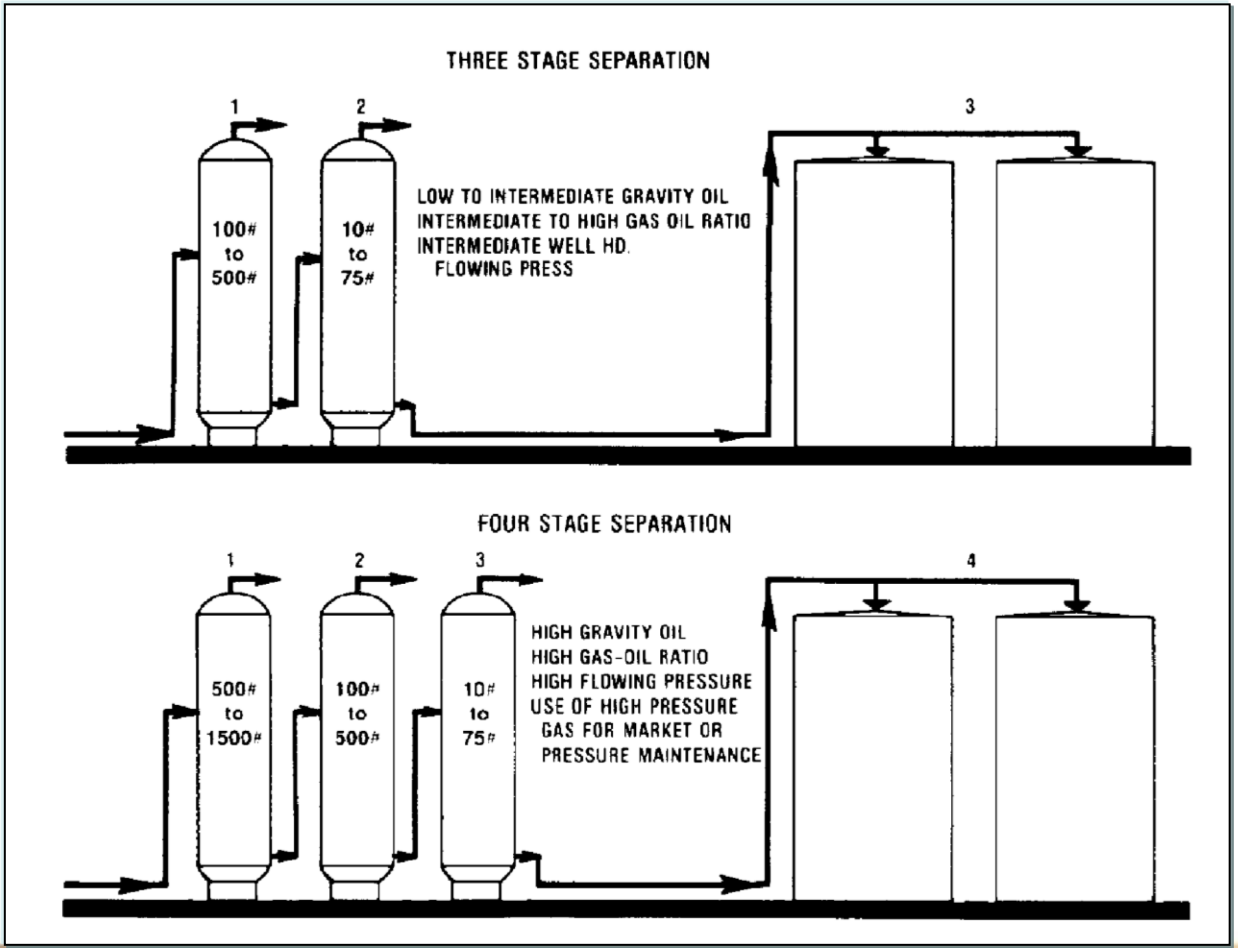
Stage separation

Two stage separation means one separator and storage tank



Stage separation

Three stage separators means two separators and tank.
Four stage separators means Three separators and tank.

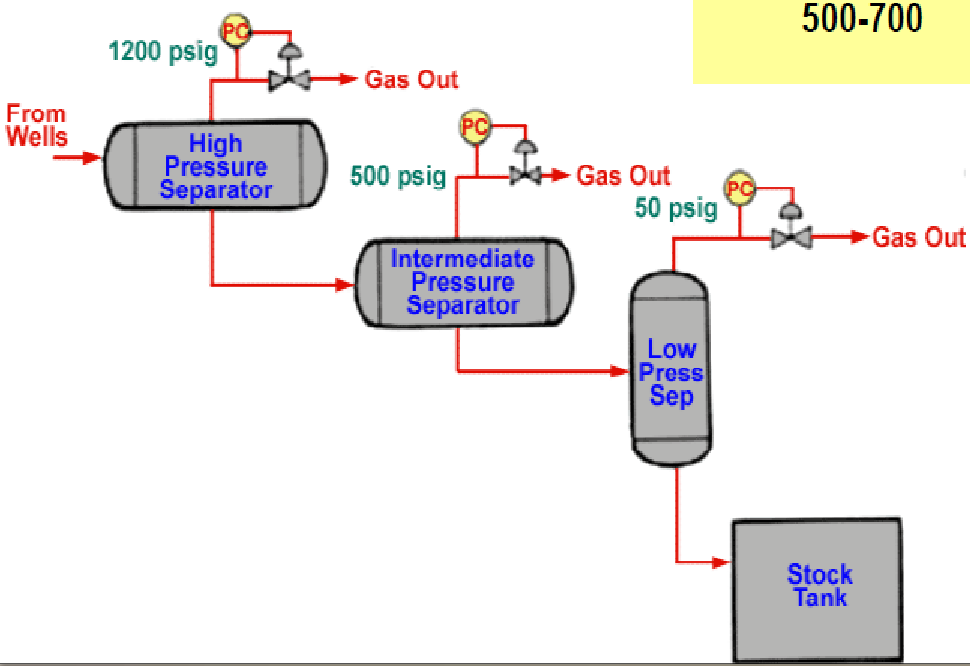


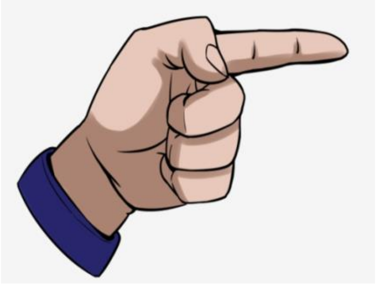
Stage separation

Multi-stage Separation

The <u>more stages</u> of separation after the initial separation, the <u>more of the light components</u> will be <u>stabilized</u> into the liquid phase

Initial Separator Pressure, (PSIG)	Number of stages
25-125	1
125-300	1-2
300-500	2
500-700	2-3





(7) Well Production problems

Introduction

Firstly any Engineer working on diagnose the well problem should have enough knowledge about :

1. well logging (open Hole and cased hole)
2. Well testing

For surveillance should have knowledge about typical cased hole logging and well test because this very important to diagnose the well problem during the production

If diagnose the problem is right will solve the problem for this well easy then will prepare the workover program for this well (Rig or Rig-less) depend on case .

Well logging

Open Hole logging

Conventional log

1. Lithology logs
   - SP
   - GR

2. Porosity logs :
   - Density
   - Neutron
   - Sonic
   - NMR

3. Resistivity logs :
   - in Water base mud (MSFL & DLL)
   - In oil base mud use induction (DIL & AIT)

4. Caliper log

High tech log

1. Nuclear magnetic resonance log (NMR)

2. Modular dynamic formation tester (MDT)

3. Full bore Formation Micro Imager(FMI)

4.Sidewall core (SWC)

5. Vertical seismic profile (VSP)

.

Cased Hole logging

Cased Hole logging

1.Cement evaluation log :
- normal CBL , VDL , GR , CCL
- Image cement evaluation

SBT
URS
RIB
RBT
USI
USIT
SCMT

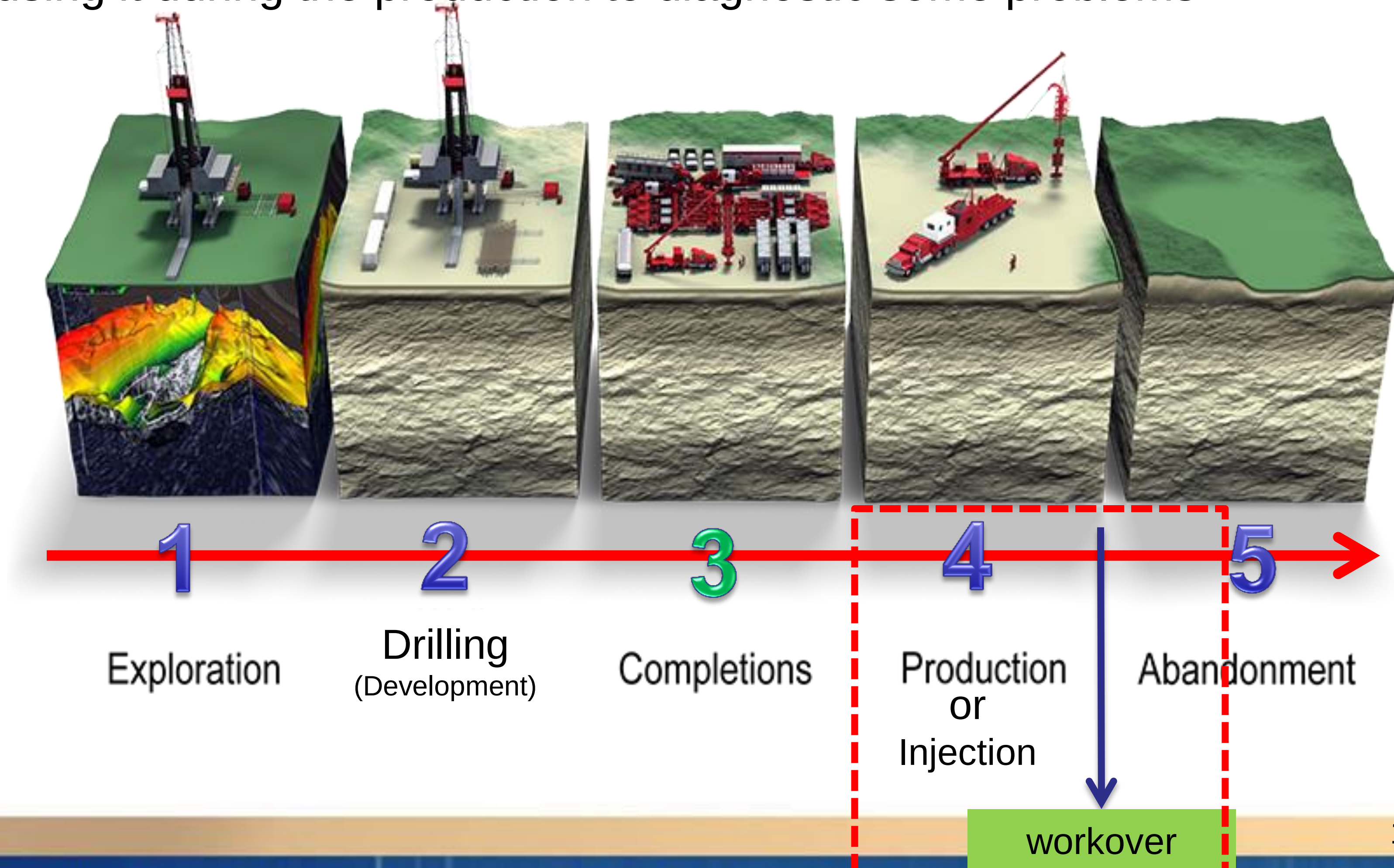
2. production logging tools (PLT)
3. saturation log (RST (sigma , C/O) , PNN , TDT)
4. Casing inspection log (MFC , MIT)
5. SNL (SPECTRAL noise log)

General Application of cased hole logging

- Primary cement evaluation
- Monitoring and evaluation of the remaining oil saturation
- Production profile logging interpretation of single-phase & multi-phase
- Injection profile logging interpretation
- Casing inspection
- Diagnostic well problem (packer leak , cross flow , channeling , water problem … etc)

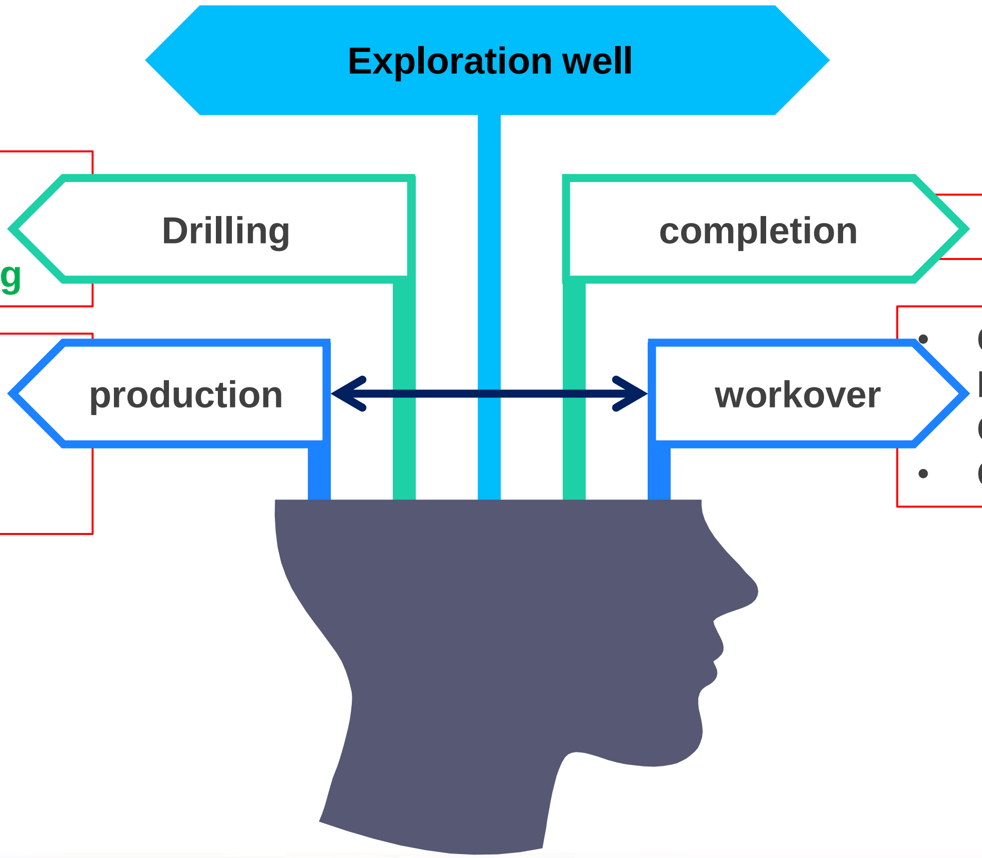
When do cased hole logging ?

We can do the cased hole logging in all stages of well life , but almost using it during the production to diagnostic some problems



When do cased hole logging ?

- GR , CCL ,
- Cement log
- Casing inspection log



- GR , CCL ,
- CEMENT LOG
- Casing inspection log

GR , CCL

- GR , CCL ,
- PLT
- SNL
- RST

- GR , CCL ,
  RST
  Casing inspection log
- Cement log

Choosing cased hole logging

Choosing the cased hole logging depend on Reservoir Surveillance plan or to diagnostic well problem , depend on well status

Well status

Flowing wells

PLT

1. Production rate
2. Injection rate
3. Fluid type
4. Cross flow
5. Casing leak

SNL

1. Channel behind casing
2. fracture
3. Packer leak
4. Casing leak

Shut-in wells

MIT

Check casing damage

CBL , URS

Check cement behind casing

RST

Formation evaluating behind casing

Practical Well Testing

1. Most well tests can be grouped either as productivity testing or as descriptive/reservoir testing.
2. Identify produced fluids and determine their respective volume ratios.
3. Measure reservoir pressure and temperature.
4. Obtain samples suitable for PVT analysis.
5. Determine well deliverability.
6. Evaluate completion efficiency.
7. Characterize well damage.
8. Evaluate workover or stimulation treatment.
9. Evaluate reservoir parameters.
10. Characterize reservoir heterogeneities.
11. Assess reservoir extent and geometry.
12. Determine hydraulic communication between wells.

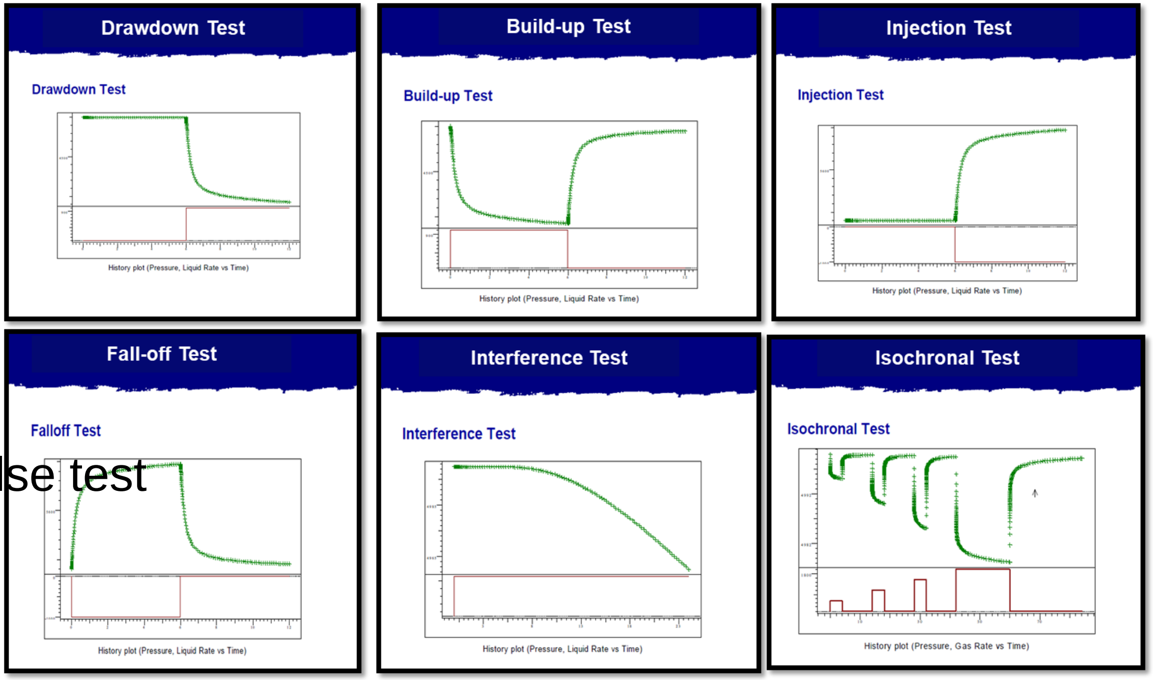
Typical Well testing

Open hole well test :

1. DST (Drill stem test) : we can do it in cased hole
2. MDT (Modular Dynamic Formation Tester)

Cased Hole well test :

1. Static pressure test
2. Drawdown test
3. Build-up test
4. Injection test
5. fall-off test
6. Interference test and pulse test
7. Isochronal test,



Well life cycle

Drilling

Completion

Put in production
Or Injection

Remarks :
To diagnose the problem the first step should know this well produce as a Natural flow or Artificial lift .

- IF Natural flow easy to do test (well logging or well test)
- IF Artificial lift well and no **Y-tools** difficult run any tools to test the wells

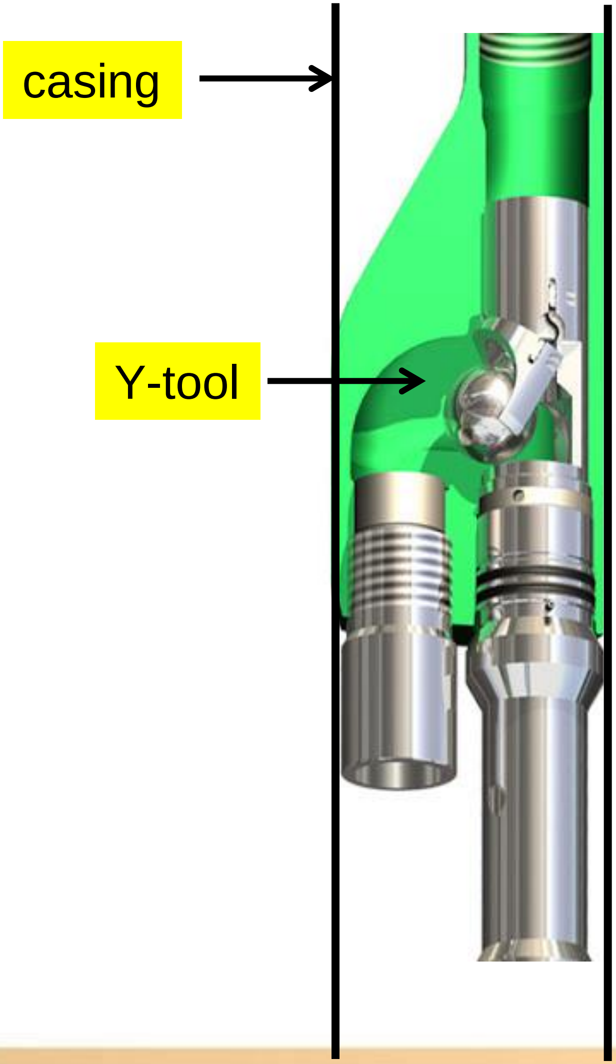
1. Natural Flow

2. Artificial lift

1.Sucker Rods Pumps
2.Hydraulic Pumps
3.Electric Submersible Pump (ESP)
4.Gas Lift
5.Progressing Cavity Pump (PCP)

Y-Tool

The is a solution to enable production-logging and well intervention below a working ESP at any point in time during production without pulling the completion string. The Y-tool is installed on the production tubing, providing two separate conduits. One conduit concentric with the production tubing and enables access to the reservoir below the ESP. The second conduit is offset and used to support the ESP system. Flow rates in different perforation intervals and other valuable geophysical information could be collected for production optimization and enhanced recovery plans.



Well Production problems

Production problem

Hydrocarbon-Related Problems

1. Asphaltenes
2. Waxes
3. Toxic-Materials Production

Water-Related Production Problems

1. Hydrates
2. Water Control
3. Inorganic-Scale Formation
4. Corrosion

Well Production problems

Possible well problem happen during the production :

1. High water cut (about 10 Reasons)
2. Low productivity
3. Low injectivity (for injector well)
4. Sand production (gravel pack or sand screen failed)
5. Cement quality problem
6. Stimulation quality
7. Well fluid level
8. Sustained casing pressure

Analysis Well Production problems

Analysis Well Production problems

1.Possible Reasons

This analysis by :

- Reservoir Engineer
- Petrophysics Engineer
- Production Engineer (sub surface)

2.tools determined the problem

This decided by :

- Reservoir Engineer
- Petrophysics Engineer

3.Remedial plan

The solution suggestion by:

- Reservoir Engineer
- Petrophysics Engineer

Executed the suggestion by:

workover (rig or rig-less)

1- High water cut problem

Problem	Possible Reason	Tools
1-High water cut	1. Casing, tubing or packer leaks 2. Channel flow behind casing 3. Moving oil-water contact 4. Watered-out layer without cross flow 5. Fractures or faults between injector and producer 6. Watered-out layer with crossflow 7. Gravity-segregated layer 8. Fractures or faults from a water layer (vertical well). 9. Fractures or faults from a water layer (horizontal well). 10. Coning	PLT SNL RST

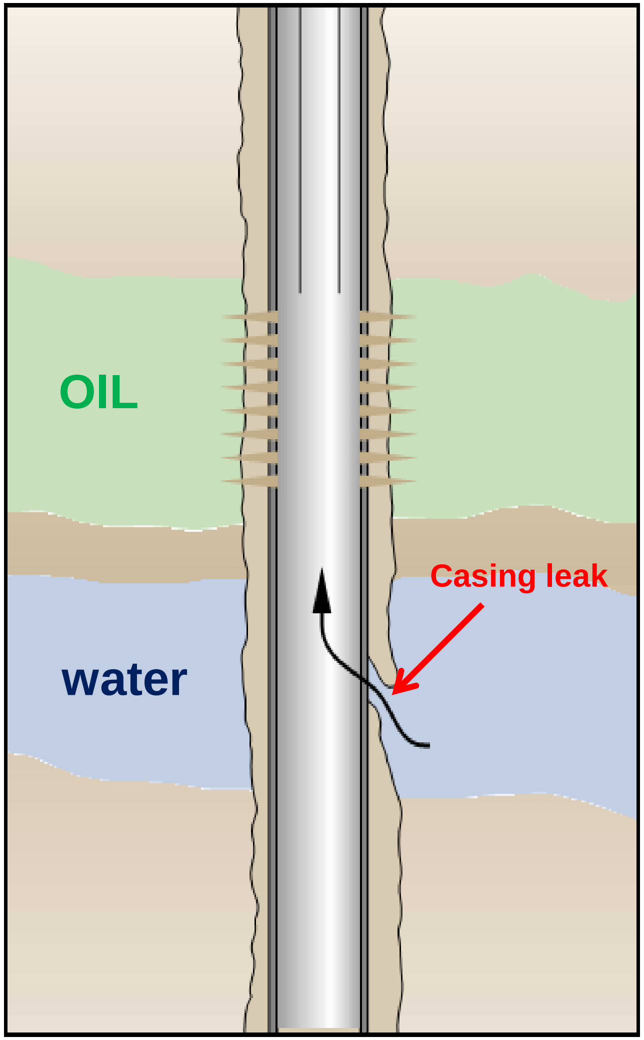
High water cut : 1-Casing, tubing or packer leaks

Casing, tubing or packer leaks

Leaks through casing, tubing or packers allow water from non- oil-productive zones to enter the production string

:Detection of problems

Detection of problems and application of solutions are highly dependent on the well con- figuration. Basic production logs such as fluid Density, temperature and spinner may be sufficient to diagnose these problems. In more complex wells, WFL Water Flow Logs or multiphase fluid logging such as the TPHL three-phase fluid holdup log can be valuable. Tools with electrical probes, such as the Flow View tool, can identify small amounts of water in the production flow.



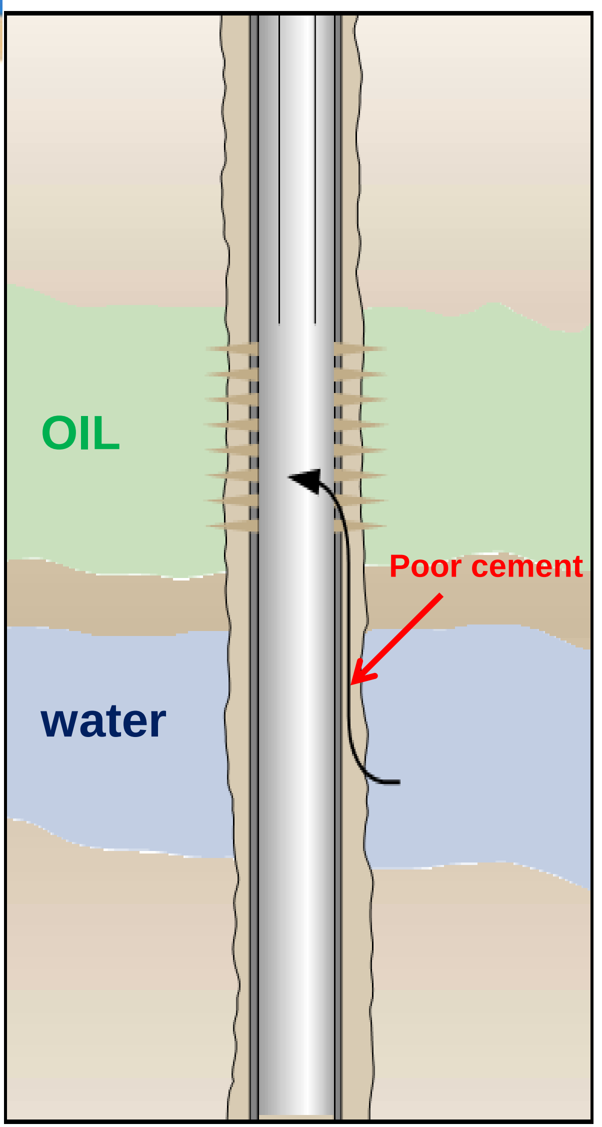
Solutions

Solutions typically include squeezing shutoff fluids and mechanical shutoff using plugs, cement and packers. Patches can also be used. This problem type is a prime candidate for low-cost, inside-casing water shut- off technology

High water cut : 2-Channel flow behind casing

Channel flow behind casing:

Failed primary cementing can connect water-bearing zones to the pay zone (below middle). These channels allow water to flow behind casing in the annulus. A secondary cause is the creation of a 'void' behind the casing as sand is produced.



:Detection of problems

Temperature logs or oxygen-activation-based WFL logs can detect this water flow.

Solutions

The main solution is the use of shutoff fluids, which may be either high-strength squeeze cement, resin-based fluids placed in the annulus, or lower strength gel-based fluids placed in the formation to stop flow into the annulus. Placement is critical and typically is achieved with coiled tubing

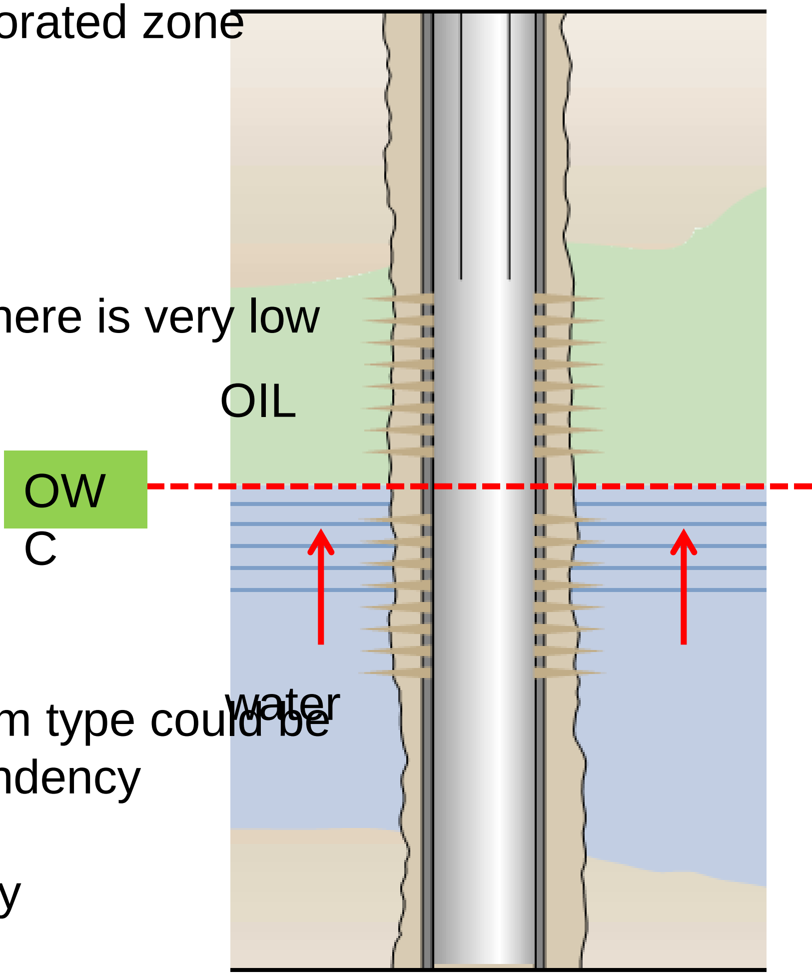
High water cut : 3-Moving oil-water contact

Moving oil-water contact

A uniform oil water contact moving up into a perforated zone in a well during normal water-driven production can lead to unwanted water production .

Why happen this problem ?

vertical permeability : This happens wherever there is very low vertical permeability. Since the flow area is large and the rate at which the contact rises is low, it can even occur at extremely low intrinsic vertical permeabilities (less than 0.01 mD). In wells with higher vertical permeability (*Kv* > 0.01 *Kh*),



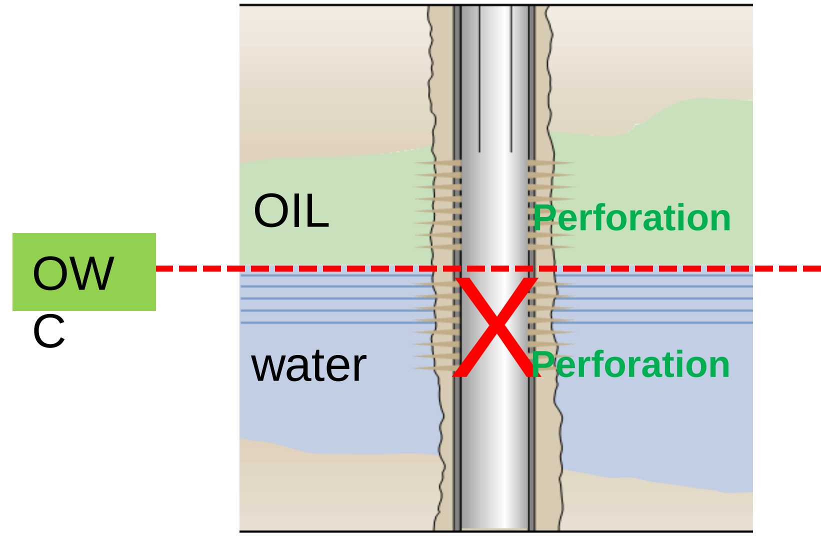
coning and other problems .In fact, this problem type could be considered a subset of coning, but the coning tendency is so low that near-wellbore shutoff is effective. Diagnosis cannot be based solely on known entry of water at the bottom of the well, since other problems also cause this behavior.

High water cut : 3-Moving oil-water contact

Remedial plane

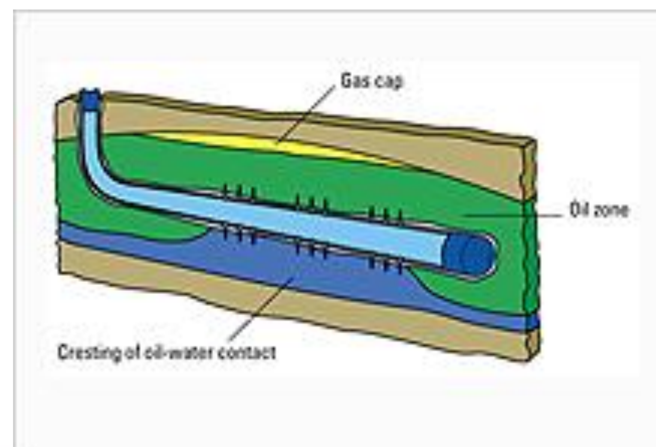
In a vertical well:

this problem can be solved by using a cement plug or bridge plug



In horizontal wells:

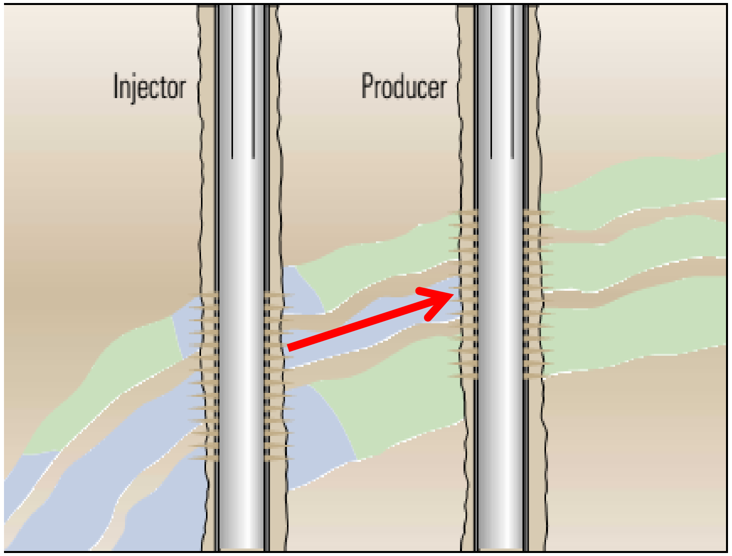
a sidetrack can be solve this problem



High water cut : 4-Watered-out layer without cross flow

Watered-out layer without cross flow:

A common problem with multilayer production occurs when a high-permeability zone with a flow barrier (such as a shale bed) above and below is watered out (above). In this case, the water source may be from an active aquifer or a waterflood injection well. The watered-out layer typically has the highest permeability.



Solutions

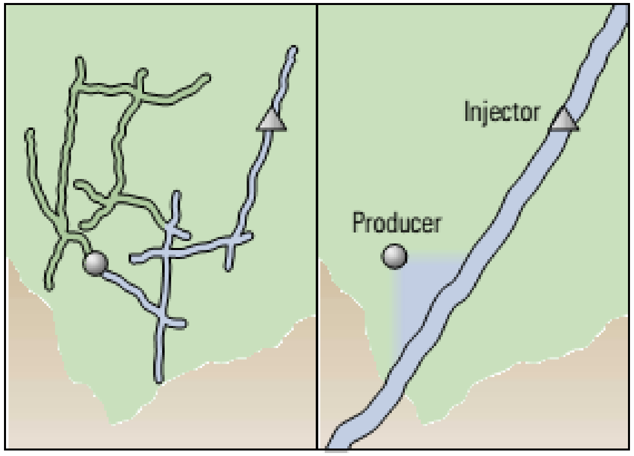
In the absence of reservoir crossflow, this problem is easily solved by the application of rigid, shutoff fluids or mechanical shutoff in either the injector or producer. Choosing between placement of a shutoff fluid—typically using coiled tubing—or a mechanical shutoff system depends on knowing which interval is watered out. Effective selective fluids, discussed later, can be used in this case to avoid the cost of logging and selective place- ment. The absence of crossflow is dependent on the continuity of the permeability barrier.

Fractures or faults between injector and producer

In naturally fractured formations under waterflood, injection water can rapidly break through into producing wells (above). This is especially common when the fracture system is extensive or fissured and can be confirmed with the use of interwell tracers and pressure transient testing.6 Tracer logs also can be used to quantify the fracture volume, which is used for the treatment design. The injection of a flowing gel at the injector can reduce water production without adversely affecting oil production from the formation. When crosslinked flowing gels are used, they can be bullheaded since they have limited penetration in the matrix and so selec- tively flow in the fractures. Water shutoff is usu- ally the best solution for this problem.

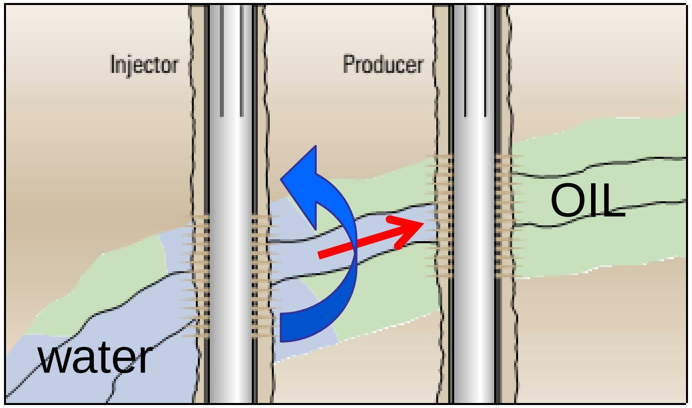
Wells with severe fractures or faults often exhibit extreme loss of drilling fluids. If a conduc- tive fault and associated fractures are expected during drilling, pumping flowing gel into the well may help solve both the drilling problem and the subsequent water production and poor sweep problems—particularly in formations with low matrix permeability.

In horizontal wells, the same problem can exist when the well intersects one or more faults that are conductive or have associated conduc- tive fractures.



High water cut : 6-Watered-out layer with cross-flow

Watered-out layer with crossflow

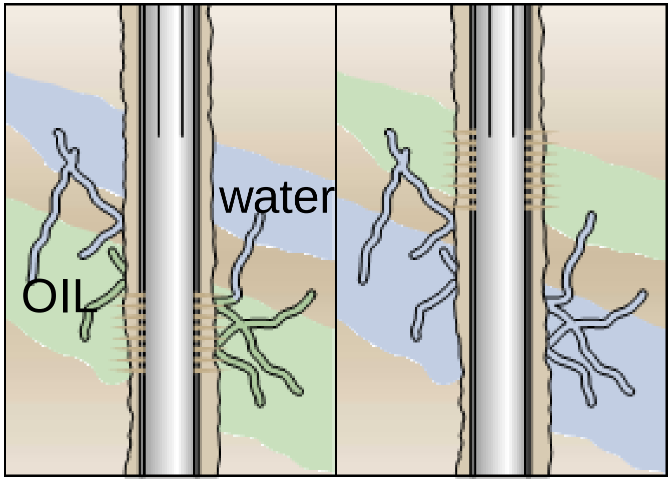


Water crossflow can occur in high-permeability layers
that are not isolated by impermeable barriers (below right). Water production through a highly permeable layer with crossflow is similar to the problem of a watered-out layer without crossflow, but differs in that there is no barrier to stop crossflow in the reservoir. In these cases, attempts to
modify either the production or injection profile near the wellbore are doomed to be short-lived because of crossflow away from the wellbore. It is vital to determine if there is crossflow in the reservoir since this alone distinguishes between the
two problems. When the problem occurs without crossflow, it can be easily treated. With crossflow, successful treatment is less likely. However, in
rare cases, it may be possible to place deep-penetrating gel economically in the permeable thief layer if the thief layer is thin and has high permeability compared with the oil zone. Even under these optimal conditions, careful engineering is required before committing to a treatment. In
many cases, a solution is to drill one or more lateral drainholes to access the undrained layers.

Fractures or faults from a water layer—

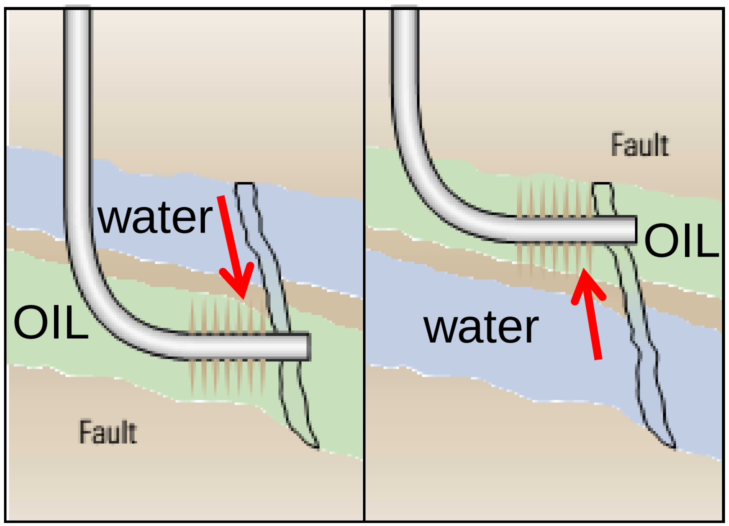
Water can be produced from fractures that intersect a deeper water zone.

These fractures may be treated with a flowing gel; this is particularly successful where the fractures do not contribute to oil production. Treatment volumes must be large enough to shut off the fractures far away from the well. However, the design engineer is faced with three difficulties. First, the treatment volume is difficult to determine because the fracture volume is unknown. Second, the treatment may shut off oil-producing fractures; here, an overflush treatment maintains productivity near the wellbore. Third, if a flowing gel is used, it must be carefully tailored to resist flowback after the treatment. In cases of localized fractures, it may be appropriate to shut them off near the wellbore, especially if the well is cased and cemented. Similarly, a degradation in production is caused when hydraulic fractures penetrate a water layer. However, in such cases the problem and environment are usually better understood and solutions, such as shutoff fluids, are easier to apply.



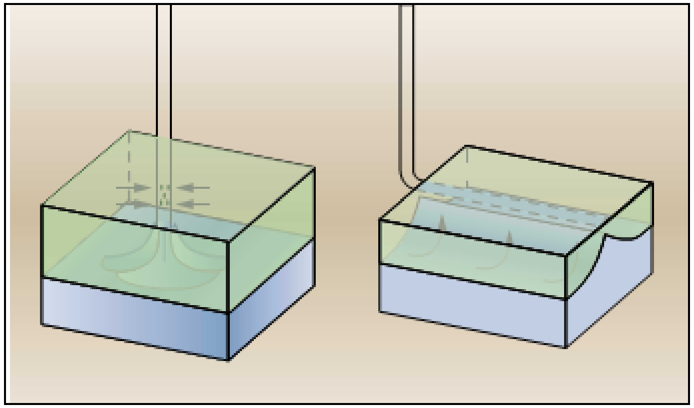
High water cut : 9-Fractures or faults from a water layer (horizontal well).

In many carbonate reservoirs, the fractures are generally steep and tend to occur in clusters
that are spaced at large distances from each other—especially in tight dolomitic zones. Thus, the probability of these fractures intersecting
avertical wellbore is low. However, these fractures



are often observed in horizontal wells where water production is often through conductive faults or fractures that intersect an aquifer
As discussed above, pumping flowing gel may help address this problem.

High water cut : 10-Coning.



Coning

Coning occurs in a vertical well when there is an OWC near perforations
in a formation with a relatively high vertical permeability (below). The maximum rate at which oil
can be produced without producing water through a cone, called the critical coning rate, is often too low to be economic. One approach, which is sometimes inappropriately proposed, is to place a layer of gel above the equilibrium OWC. However, this will rarely stop coning and requires a large volume of gel to significantly reduce the WOR. For example, to double the critical coning rate, an effective gel radius of at least
50 feet [15 m] typically is required.

.

However, economically placing gel this deep into the formation
is difficult. Smaller volume treatments usually result in rapid water re-breakthrough unless the gel fortuitously connects with shale streaks.
A good alternative to gel placement is to drill one or more lateral drain holes near the top of the formation to take advantage of the greater distance from the OWC and decreased drawdown,
both of which reduce the coning effect.
In horizontal wells, this problem may be referred to as duning or cusping. In such wells, it may be possible to at least retard cusping with near-wellbore shutoff that extends sufficiently up- and downhole as in the case of a rising OWC

2-Low productivity problem

Problem	Possible Reasons	Tools
Low productivity	Low permeability Plugged perforations Near-wellbore damage Channeling or cross flow Fill over perforations Scale, paraffin, asphaltene	1. Pressure transient tests 2. Temp and spinner survey 3. Slickline gauge ring runs to tag fill 4. Bailer samples of solids

Remedial plan : depend on case maybe use :

- Acidizing
- Solvent
- Inhibitor
- Acid fracturing
- etc

3-Low injectivity problem

Problem	Possible Reasons	Tools
Low injectivity	Low permeability Plugged perforations Near-wellbore damage Channeling or cross flow Fill over perforations Scale, paraffin, asphaltene	1. Temperature and RA tracer or spinner 2. Caliper log (ID restrictions) 3. Pressure buildup or drawdown tests 4. Injection water quality 5. Sand fill bailers

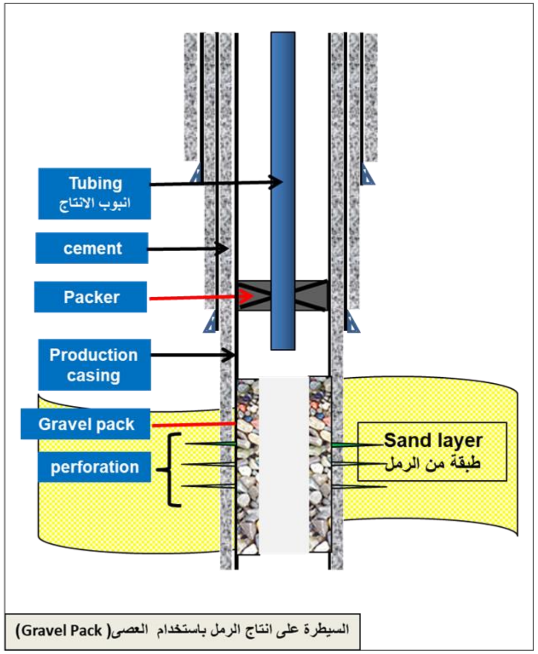
4- sand production problem

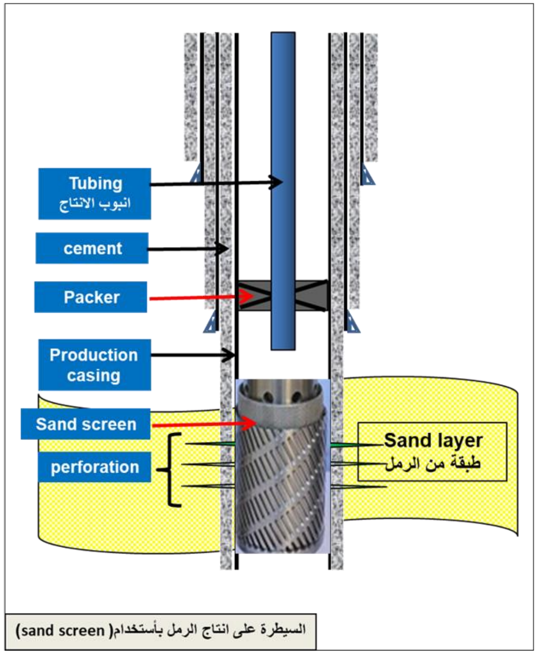
Problem	Possible Reason	Tools
3- sand production problem	1. Perforated sand layers	We can see the sand on surface if not put sand control

Remedial plan :

You can use the sand control methods , for example :

- Sand screen
- Gravel pack





5- cement quality problem

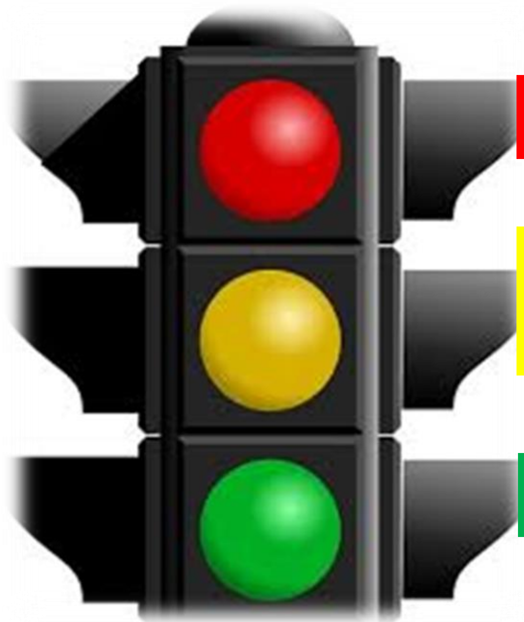
Problem	Possible Reason	Tools
4- cement quality problem	1. Cement job failure or any another reason	Cement bond log

Many types for cement log see bellow table

No	Log	Full name	Company
1	CBL	Cement Bond Log	Many companies
2	SBT	Segmented Bond Tool	Backer Hughes
3	URS	Ultra sonic redial scanner	Weatherford
4	RIB	Radius Incremented Bond	AWALCO
5	RBT	Radial Bond Too	Halliburton
6	USI	Ultrasonic Image	Schlumberger
7	SCMT	Slim Cement Mapping Tool	

4- cement quality problem

After received the cement logging results should do cement evaluation report according to standard

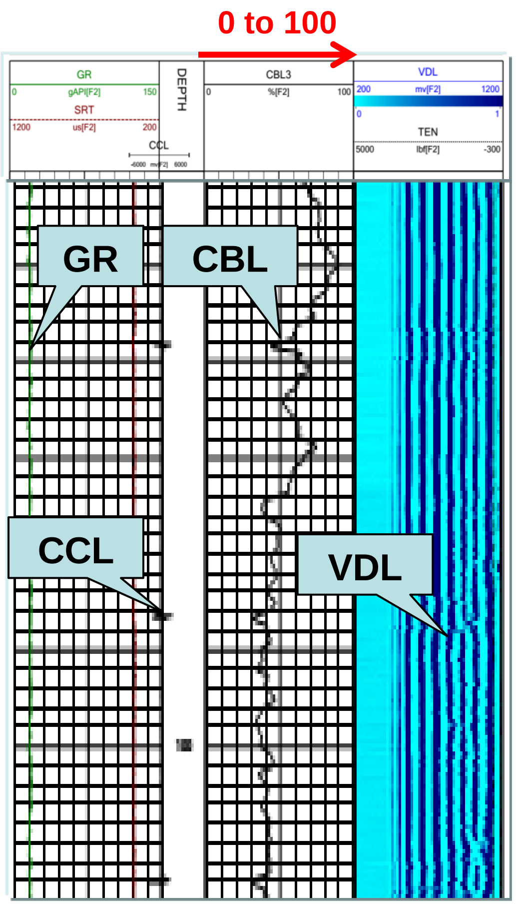


Poor (Bad) : STOP (cant Pass)

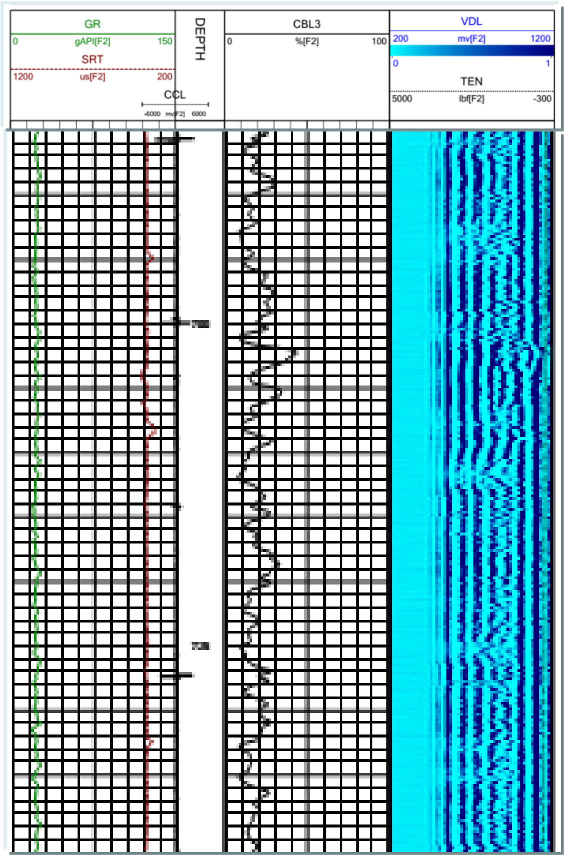
Medium to Good cement with good isolation in pay zone : can pass

Good cement : can pass

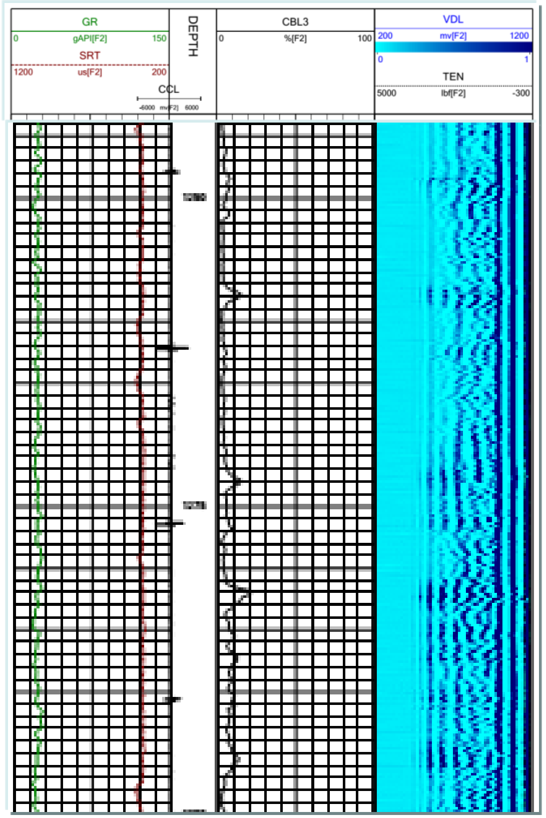
Example for three case cement CBL (poor – medium – good)



Poor cement

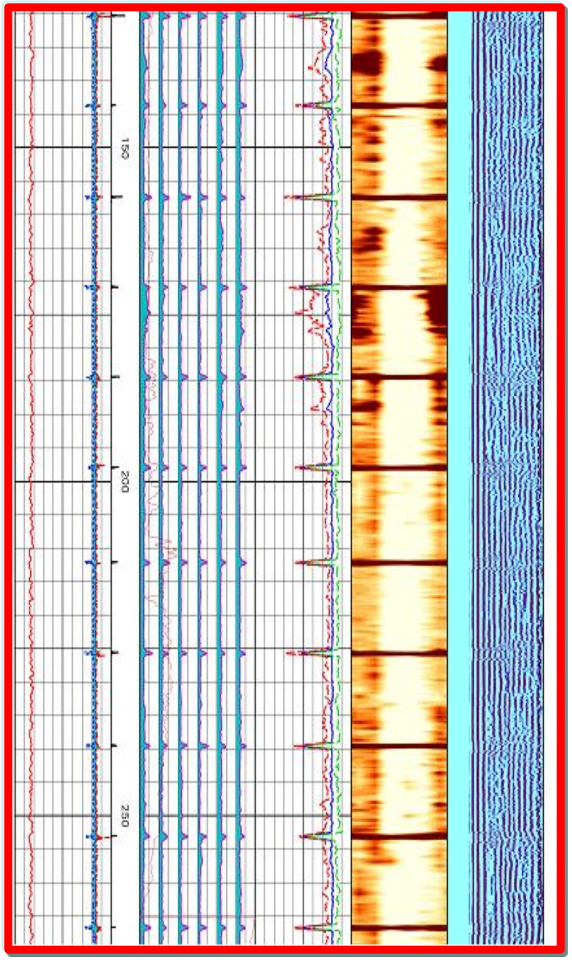


Medium to good cement

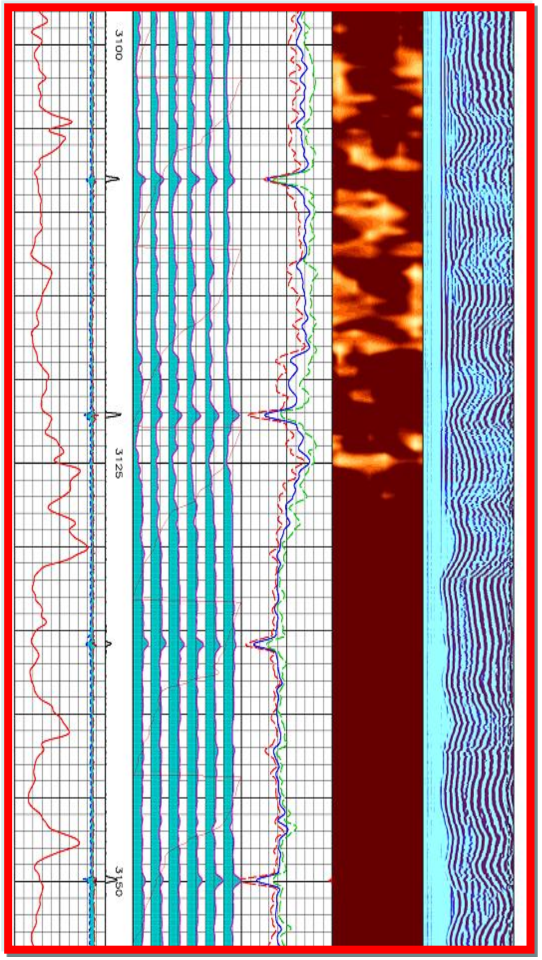


Good cement

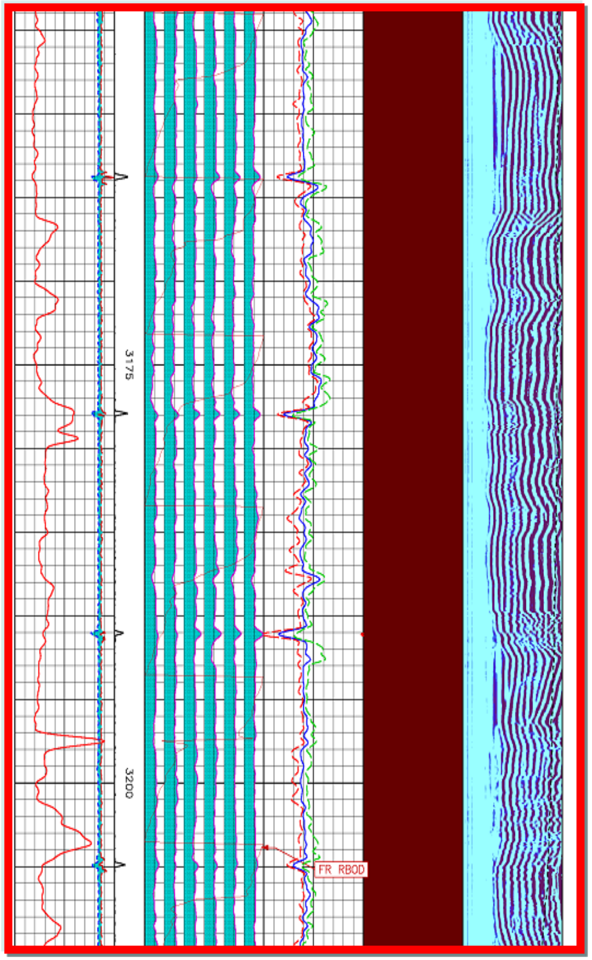
Example for three case cement **SBT** (poor – medium – good)



Poor cement

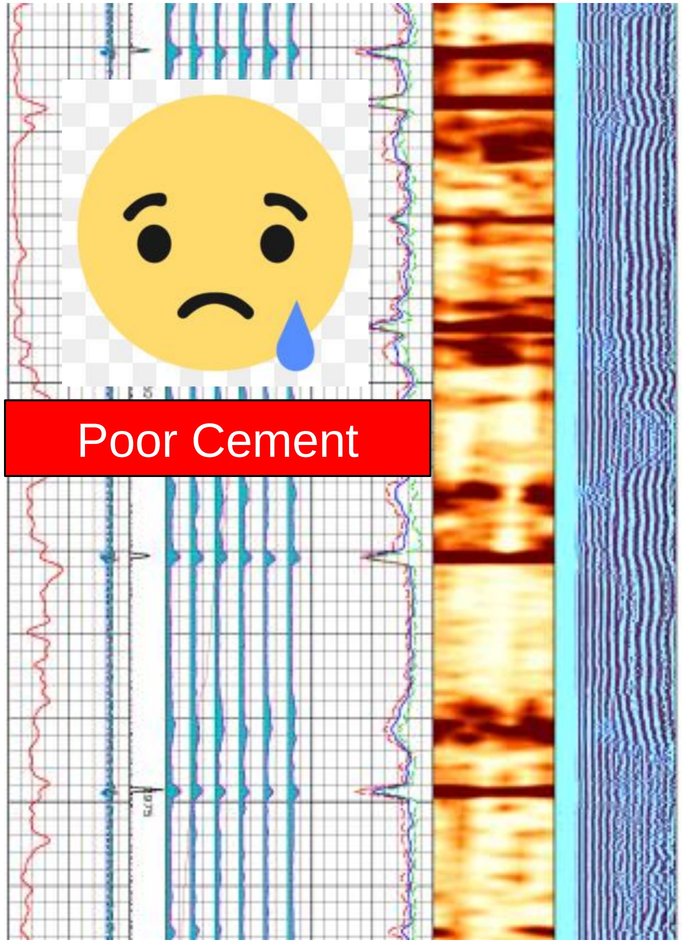


Medium to good cement

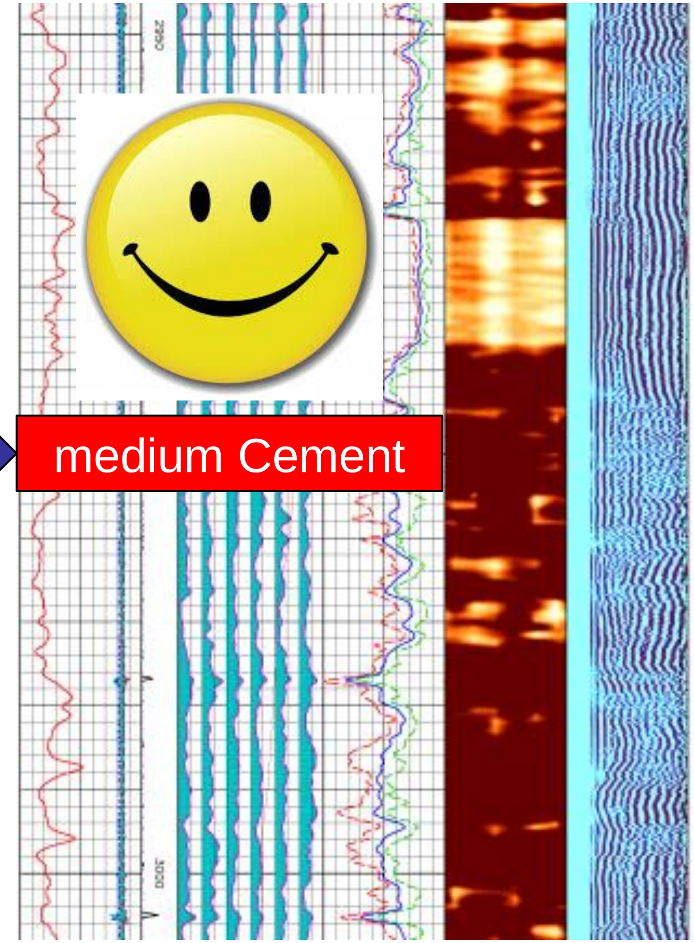


Good cement

Remedial plan : Example (before and after squeeze cement)



Before Squeeze cement



After Squeeze cement

6- Stimulation Quality

Problem	Possible Reason	Tools
4- Stimulation Quality	1. Poor fracture conductivity 2. Well bore damage	1- build up test to see the formation damage and check the fracture analysis 2- PLT to check the production profile

Remedial plan :

You can use suitable stimulation techniques depend on well case

Available stimulation techniques

Technique	Objective
Mechanical Methods • Propped Hydraulic Fracturing • Explosive Fracturing • Under reaming • Re – and Additional perforating	Increase r_w Increase r_w and k Increase r_w Increase h
Chemical Methods • Matrix Acidsing • Tubing Acid Washes • Other Chemical Matrix Treatments (Surfactants, Solvents Mutual Solvent Etc.)	Decrease S Improve well Outflow by Removing Tubing Deposits Increase k
Biological Methods • Microbial Stimulation	Mechanism Uncertain
Combined Mechanical / Chemical Methods • Acid Fracturing Including Propped Acid – Fracturing • Closed Fracture Acidizing	Increase r_e Increase r_e
Thermal Methods • Steam Soak • Heat / Gas Generation From injected chemicals • Electrical Heating	Decrease μ Decrease μ and Improve well Outflow by increasing GOR Decrease μ

7- well fluid level

Problem	Possible Reason
5- well fluid level	1. Reservoir pressure drop , then the fluids cant reach to surface

Remedial plan :

You can use Artificial lift

1.Sucker Rods Pumps

2.Hydraulic Pumps

3.Electric Submersible Pump (ESP)

4.Gas Lift

5.Progressing Cavity Pump (PCP)

8- Substance casing pressure

Problem	Possible Reason	tools
6- Substance casing pressure	1. Packer or tubing leaked 2. Poor cement behind casing	1. SNL 2. Cement Log

Remedial plan :

1. For packer or tubing leak should replacement it by workover
2. For poor cement should do remedial such as squeeze cement

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Name:	**Abbas Radhi Abbas**
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Education Background:	
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15 Certificates of Appreciation from difrent international companies such as (**Schlumberger**- waetherford , CNOOC , COSL , BHDC)	
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during (2011)	drilling and workover engineer
(2011 to 2020)	petrophysics manager in Reservoir department
Language:	
Mother language:	Arabic
Second language/level:	English/Fluent oral and written in English.

Thanks