8. Phase separation

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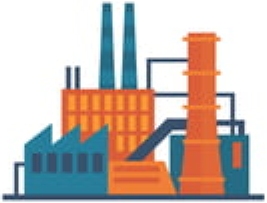
SEPARATOR

a pressure vessel used for separating well fluids produced from oil and gas wells into gaseous and liquid components.

FUNCTIONS



01 Removal of Oil from Gas

02 Removal of Gas from Oil

03 Separation of Water and solid

SEPARATOR

- Downstream equipment cannot handle gas–liquid mixture:

01 Pumps require gas-free liquid

02 Compressor and dehydration equipment require liquid-free gas

03 Product specification set limits on impurities

04 Oil generally cannot contain more than 1% BS&W

05 Gas sales contracts generally require that the gas contain no free liquids

06 Measurement devices for gases or liquids are highly inaccurate when another phase is present.

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Characteristics of Flow Stream

Fluid from a well can include

01. *gas*
02. *condensable liquid*
    condensable vapors
03. *Liquid water*
    water vapor
04. *crude oil*
05. solid debris (sand, Scale, ...)

Well production

Wells are classified according to the type of fluid they produce in the greatest quantity.

A

1. Crude oil well

contains mostly crude oil, but can contain

- solid debris
- water
- gas.

B

2. Dry gas well

- contains mostly gas
- can contain some water
- does not contain crude or Liquid hydrocarbons

C

3. Gas condensate well

- contains both liquid and gaseous hydrocarbons
- contains some water
- does not contain crude oil

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Well fluids

exist as either

A emulsion

B layered

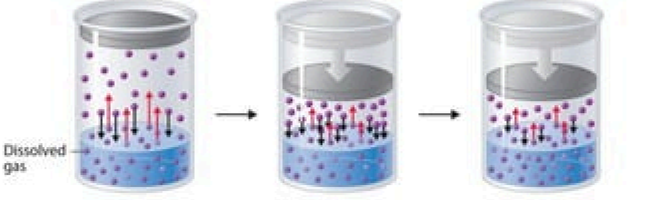
Natural gas solubility

01

Gas Solubility

The solubility of natural gas in oil is a function of pressure & temperature at reservoir conditions.

The gas solubility is defined as the number of cubic feet of gas measured at std. conditions which are in solutions in one barrel of S. T .O. at reservoir temp. & pressure.



(a) Dynamic equilibrium (b) P_{gas} increased (c) Dynamic equilibrium

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Separation terminology

Flash & Differential liberation of gas:

There are two basic types of gas liberation: Flash & Differential.

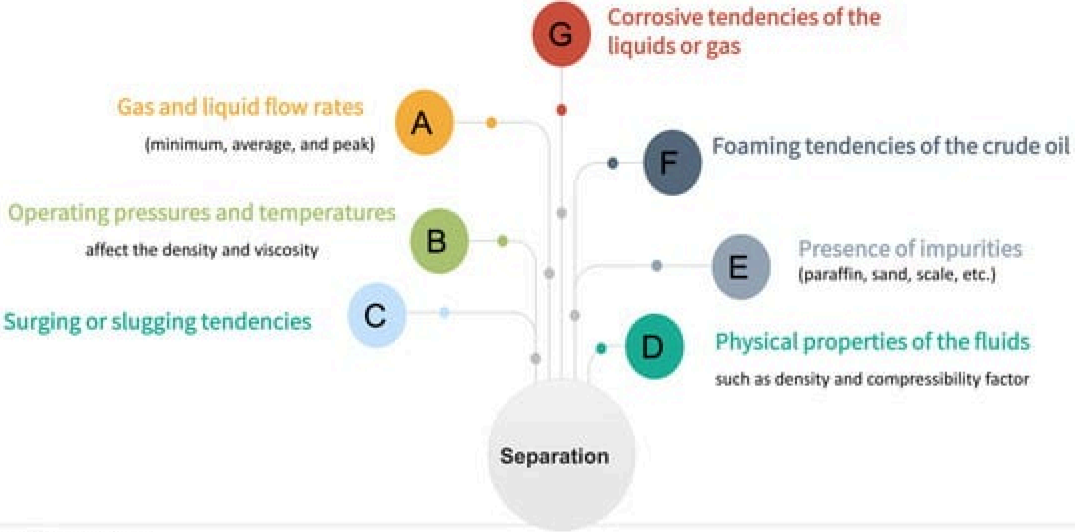
01 flash liberation

pressure is reduced by a finite amount and after equilibrium is established the gas is bled off, keeping the pressure constant.

02 differential liberation

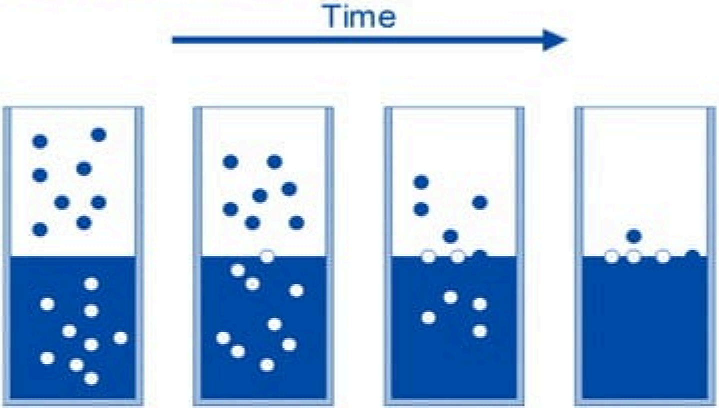
gas evolved is removed continuously from contact with the oil.

Factors Affecting Separation



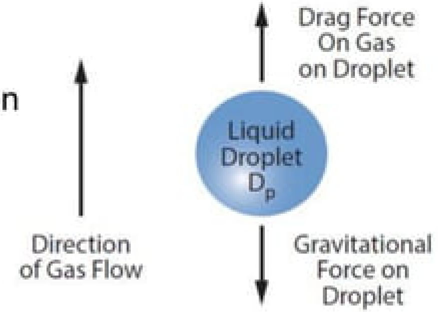
Gas-Liquid Separation Principles

Density difference provides the least effort



SEPARATION MECHANISMS

- Separation works on specific temperature & pressure
- Employs one or more mechanisms:
  - Gravity Settling
  - Centrifugal Force
  - Baffling / Impingement
  - Electrostatic / Sonic Precipitation
  - Filtration
  - Adhesive Separation
  - Adsorption
  - Heat / Thermal
  - Chemical



Separator Classification

Process point of view

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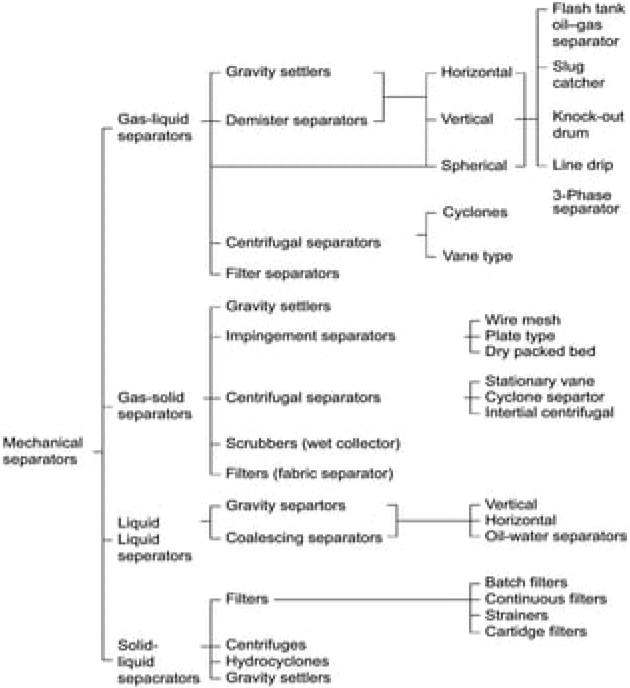
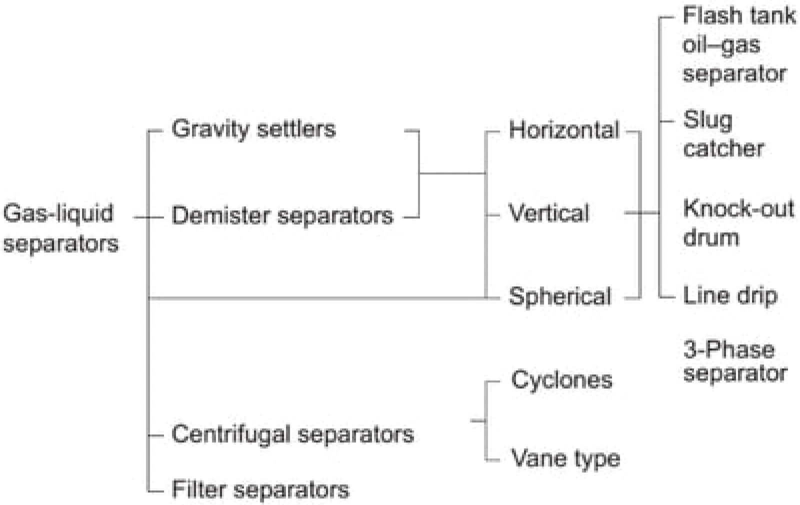
Separators

- **Configuration (Shape)**
  - Vertical
  - Horizontal
  - Spherical
- **Function**
  - Separator
  - Scrubber
  - K.O.D
  - Flash Drum
- **No of phase separation**
  - Two phase
  - Three phase
- **Operating pressure**
  - Low (20 – 200 Psi)
  - Medium (200-750 Psi)
  - High (750 - 1500 Psi
- **Application**
  - LTS
  - Test Separator
  - Production separator



Mechanical separators
Gas-liquid separators
Gravity settlers
Demister separators
Horizontal
Vertical
Spherical
Flash tank oil–gas separator
Slug catcher
Knock-out drum
Line drip
3-Phase separator
Centrifugal separators
Cyclones
Vane type
Filter separators
Gas-solid separators
Gravity settlers
Impingement separators
Wire mesh
Plate type
Dry packed bed
Centrifugal separators
Stationary vane
Cyclone separtor
Intertial centrifugal
Scrubbers (wet collector)
Filters (fabric separator)
Liquid Liquid seperators
Gravity separtors
Coalescing separators
Vertical
Horizontal
Oil-water separators
Solid-liquid sepacrators
Filters
Batch filters
Continuous filters
Strainers
Cartidge filters
Centrifuges
Hydrocyclones
Gravity settlers


Gas-liquid separators
Gravity settlers
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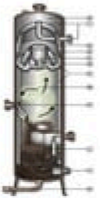
Filter separators
Horizontal
Vertical
Spherical
Cyclones
Vane type
Flash tank oil–gas separator
Slug catcher
Knock-out drum
Line drip
3-Phase separator

Classification of separators

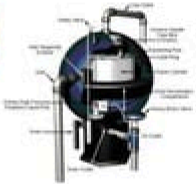
1. Based on Geometry

01 Vertical Separator

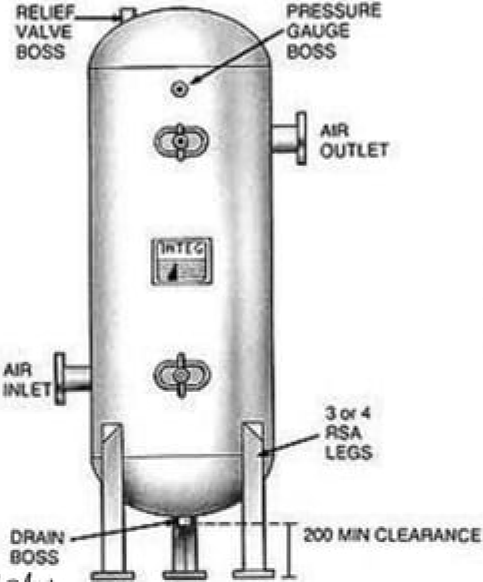


02 Horizontal Separator

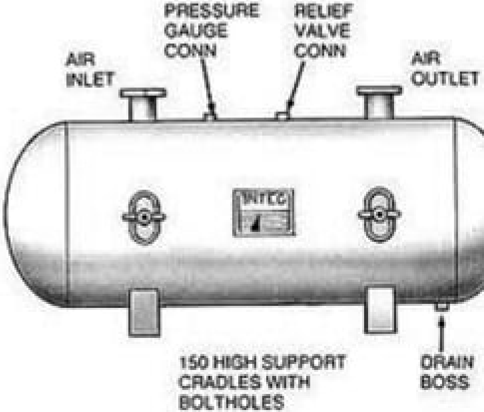
03 Spherical Separator



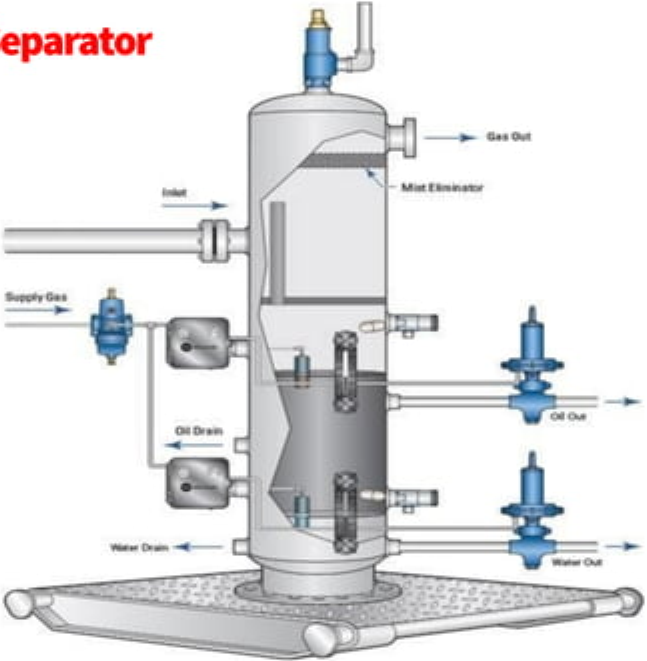
VERTICAL MODEL



HORIZONTAL MODEL



1. Vertical Separator



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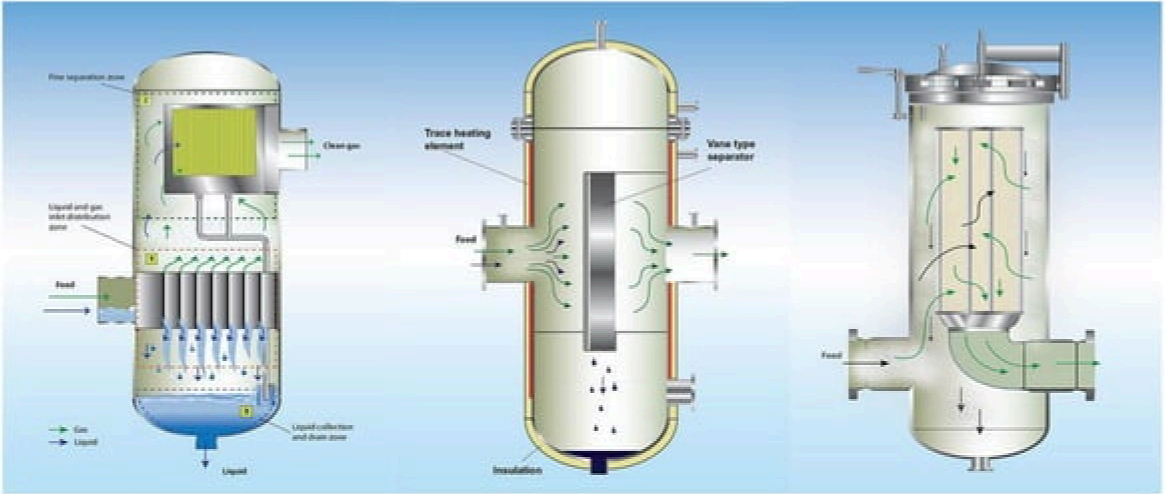
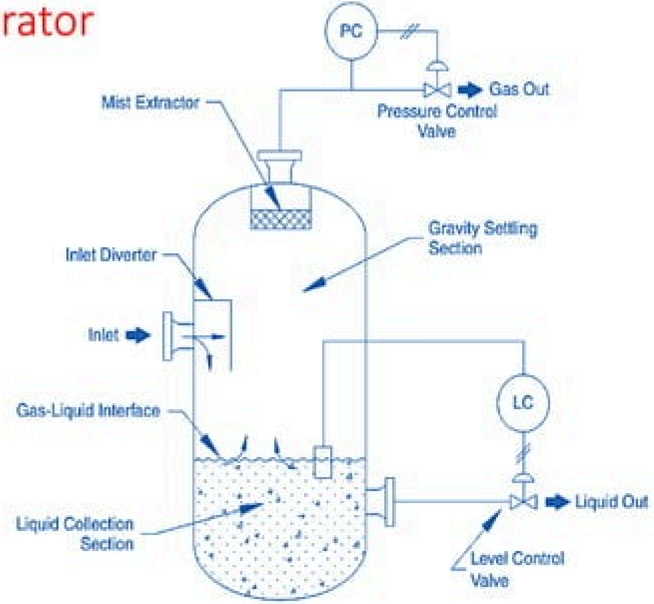
Vertical Separator



Vertical Separator



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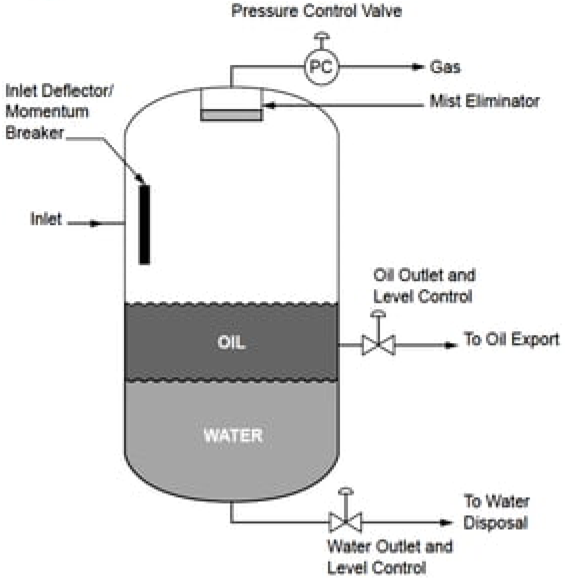
Vertical Separator



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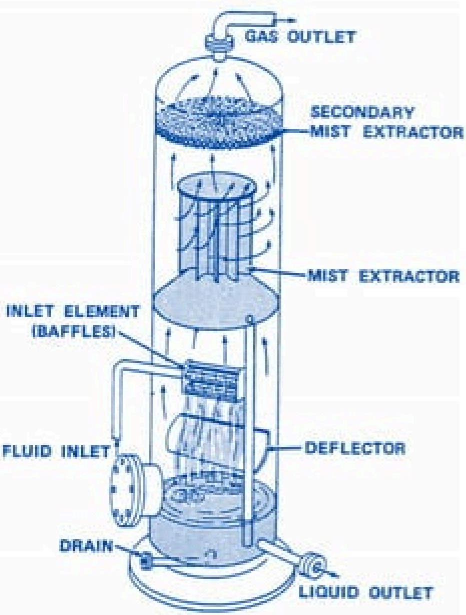

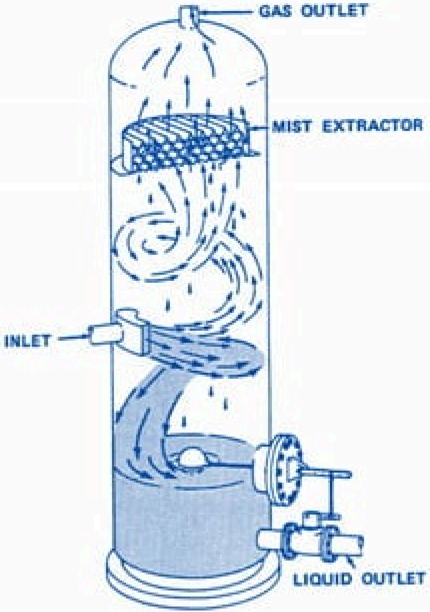

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1. Vertical Separators

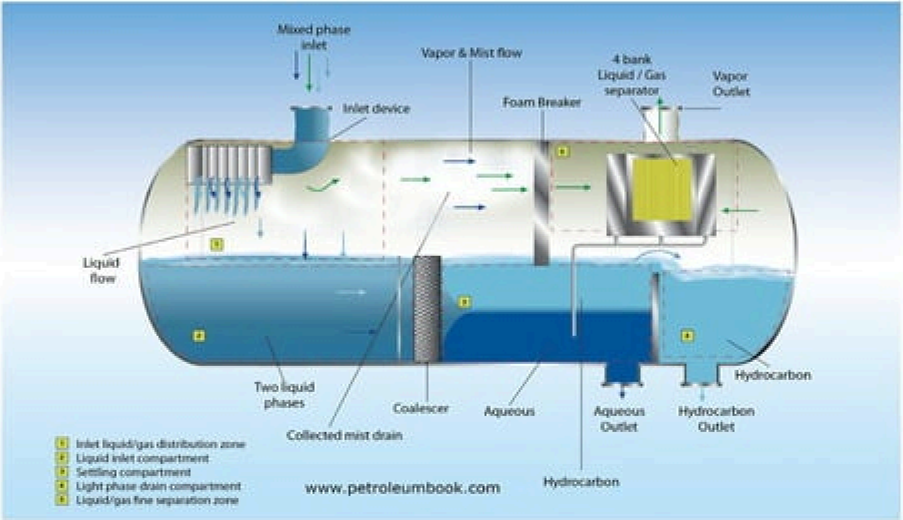
Advantages

- ideal for high flow rate
- Good for surging flows
- Work well for high GOR applications
- can handle foaming liquids with ease
- much more economical as compared to use of horizontal separators.
- Takes up less space than a horizontal separator with the same capacity
- Can handle more sand, mud, paraffin, wax without plugging.
- can be skid-mounted for quick and easy installation

Disadvantages

- Difficult for modular systems - transport & installation.
- Some of the instruments and safety devices may be difficult to access without ladders or access platforms
- Low efficient in high liquid rate

2. Horizontal Separator

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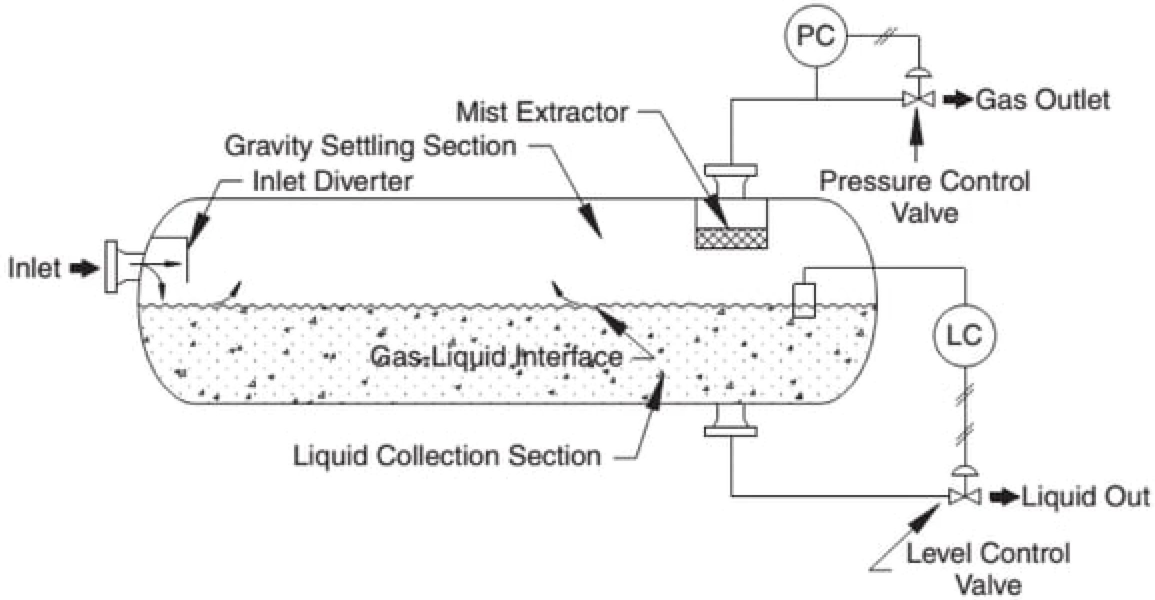

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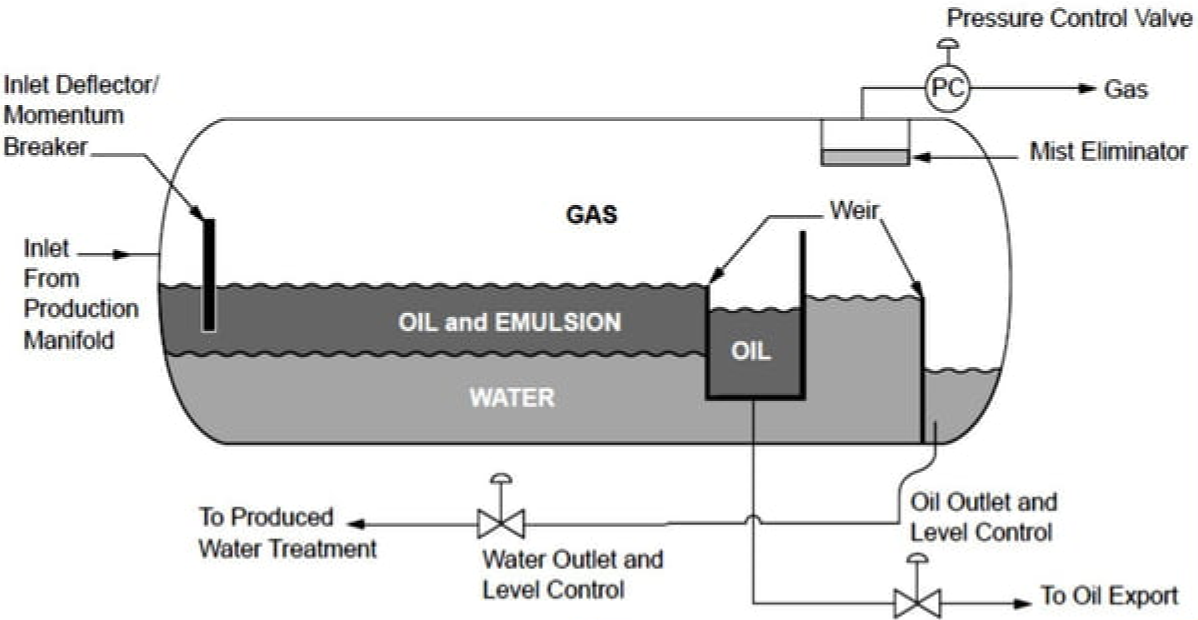
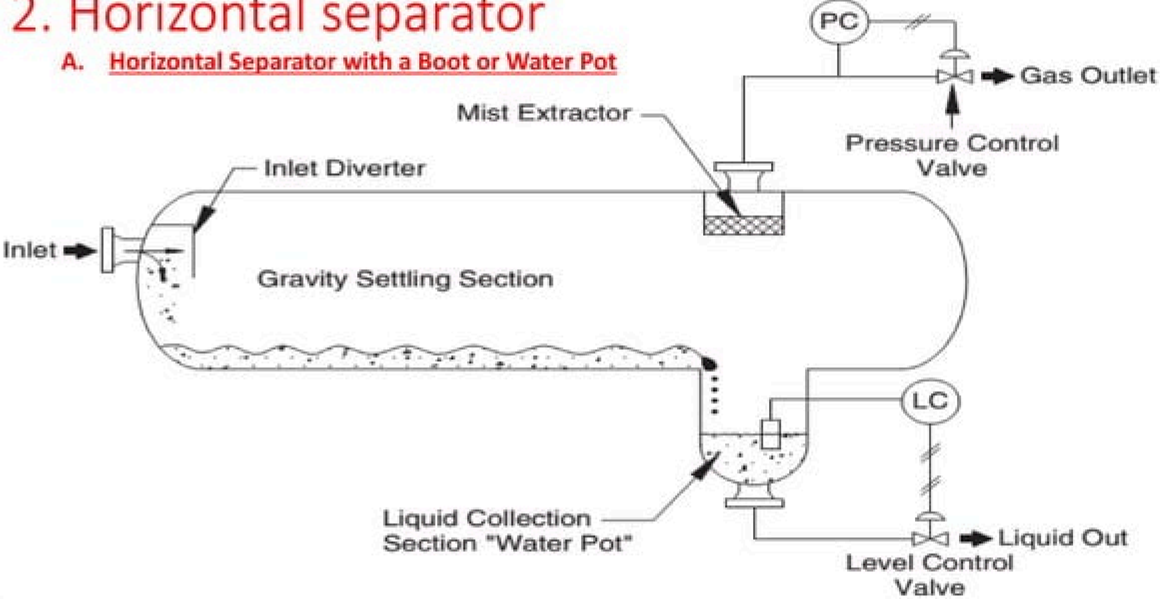


Pressure Control Valve
PC
Gas
Inlet Deflector/ Momentum Breaker
Mist Eliminator
GAS
Weir
Inlet
Inlet From Production Manifold
OIL and EMULSION
OIL
WATER
Oil Outlet and Level Control
To Produced Water Treatment
Water Outlet and Level Control
To Oil Export

2. Horizontal separator

A. Horizontal Separator with a Boot or Water Pot



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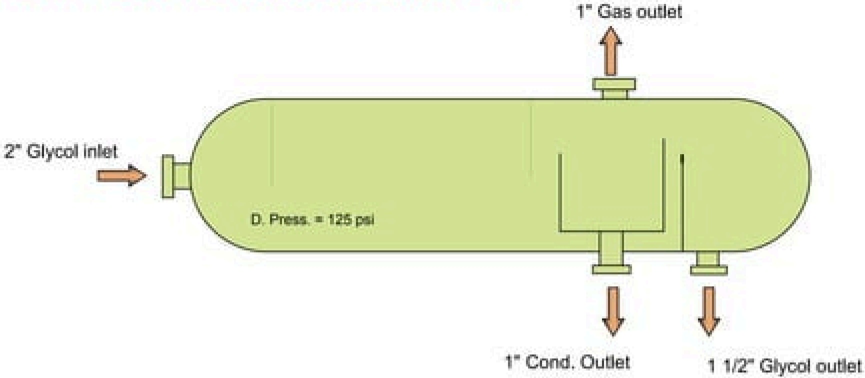
2. Horizontal separator

A. Horizontal Separator with a Boot or Water Pot



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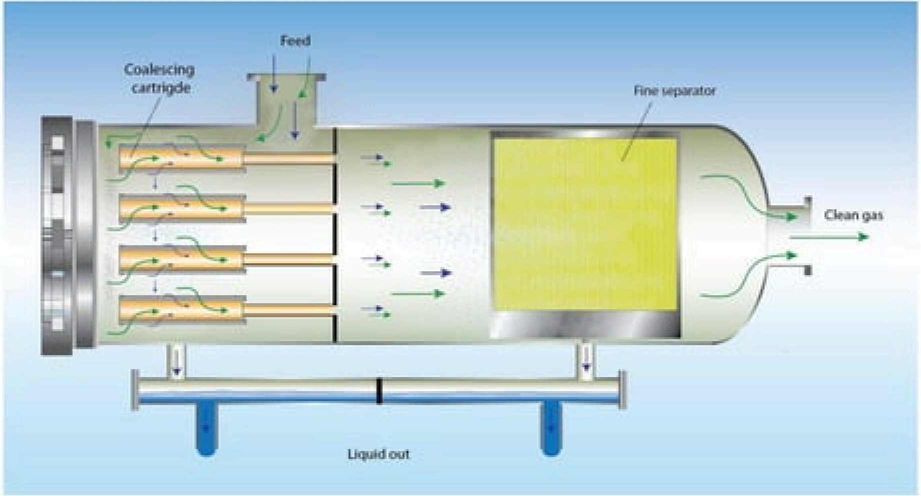
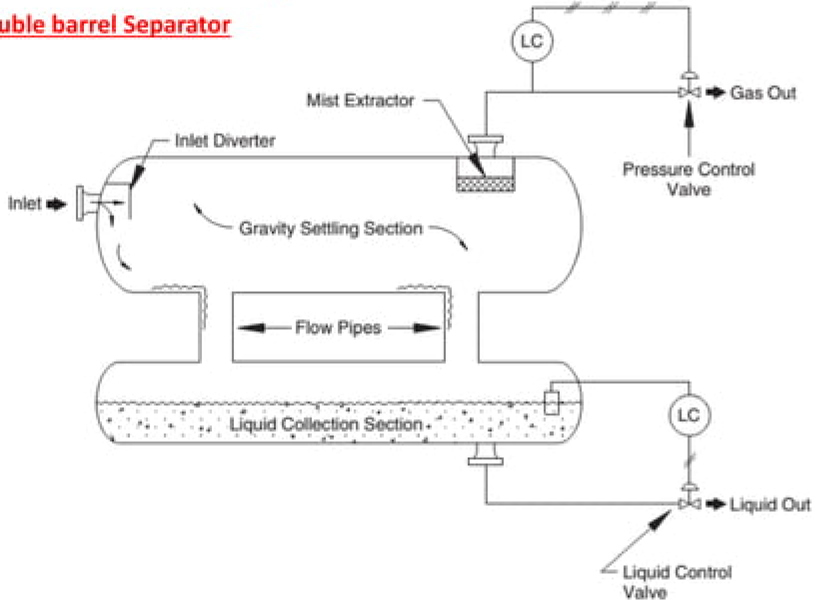
2. Horizontal separator

B. Double barrel Separator



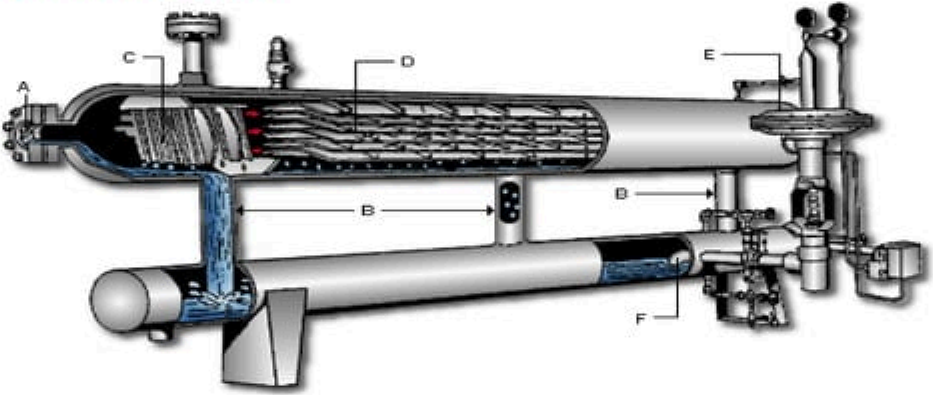
2. Horizontal separator

c. **Double barrel Separator**



2. Horizontal separator

Double barrel Separator



A - INLET
B - LIQUID DRAIN
C - MIST EXTRACTOR
(LARGE PARTICLES)

D - MIST EXTRACTOR
(SMALL PARTICLES)
E - GAS OUTLET
F - OIL DRAIN

Advantage and disadvantage of

- **Horizontal separator**

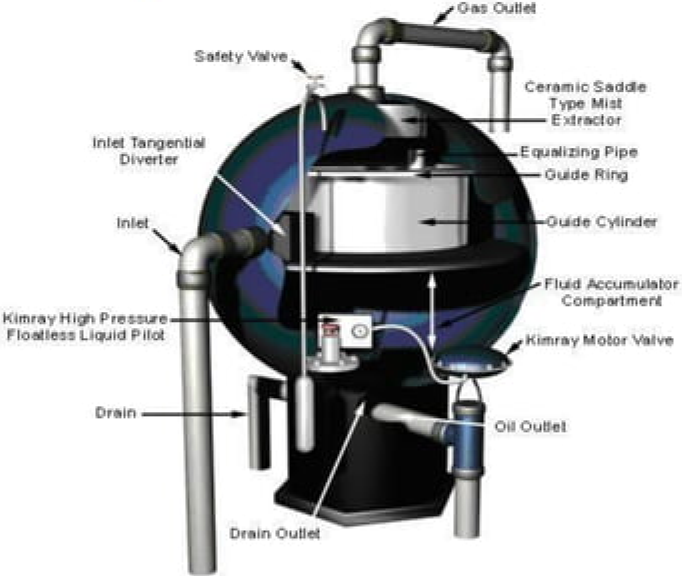
Advantages

- Normally more efficient at handling large amounts of liquid and gas
- Cheaper than Vertical separator for same capacity.
- Large liquid surface area for foam dispersion generally reduces turbulence

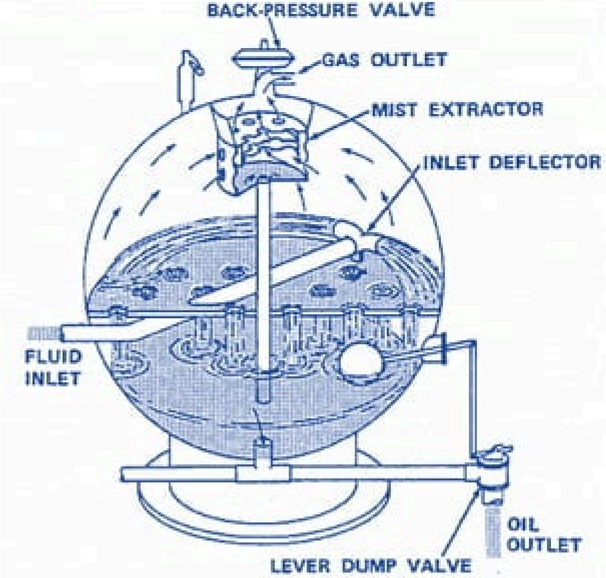
Disadvantages

- More difficult to clean produced sand, mud, wax, paraffin, etc.
- Larger mounting area
- Poor solids removal
- Lower surge capacity

3. Spherical Separator



3. Spherical Separator



3. Spherical Separator

Advantages and disadvantages

- They are not widely used
- They are difficult to fabricate

Separator Types Comparing

Parameters	Vertical	Horizontal	Spherical
Advantages	1. *Easier to clean* 2. *Saves space* 3. *Provides better surge control* 4. *Liquid level control is not critical*	1. *Can handle much higher gas-oil ratio well streams because the design permits much higher gas velocities* 2. *Cheaper than the vertical separator* 3. *Easier and cheaper to ship and assemble* 4. *Requires less piping for field connections* 5. *Reduces turbulence and reduces foaming (thus, it can handle foaming crude)*	1. *Very inexpensive* 2. *Good for low or intermediate gas-oil ratio* 3. *Very compact and easy to ship and install*

Separator Types Comparing

Parameters	Vertical	Horizontal	Spherical
Disadvantages	1.It takes a longer diameter separator for a given gas capacity as compared to horizontal separator 2.More expensive to fabricate 3.Difficult and more expensive to ship (transport)	1.Greater space requirements generally 2.Liquid level control more critical 3.Surge space is somewhat limited Much harder to clean (hence a bad choice in any sand-producing area)	1. Very inexpensive 2. Good for low or intermediate gas-oil ratio 3. Very compact and easy to ship and install

Separator Types Comparing

Parameters	Vertical	Horizontal	Spherical
Ideal Usage	*Low to intermediate gas-oil ratio, and where relatively large slugs of liquid are expected*	*High gas-oil ratio crudes, foaming crudes, or for liquid- liquid separation. Good for a diverse range of situations*	*Intermediate or low gas-oil ratio, preferably two-phase separation*

Separator Types Comparing

Vertical Separator	Horizontal Separator
Gas flows vertically upwards against liquid settling. Therefore, gas velocity must be less than the liquid droplet terminal velocity for effective separation.	Gas flows horizontally and hence perpendicular to droplet setting. Therefore, the gas velocity can be larger than the liquid droplet velocity
For the same application, vertical separator is generally less efficient than horizontal separator.	Horizontal separator is generally more effective in separating vapour and liquid due to a larger surface area for vapour to be released from liquid.
Vapor flow area is constant therefore performance of separator is not sensitive to changing liquid level.	Vapour flow area depends on liquid level therefore the performance of horizontal separator can deteriorate as liquid level rises.
Vertical separator is generally used when gas is the dominant phase.	Horizontal separator is generally used when gas and liquids are of equal proportions or liquid is the dominant phase.
Vertical separator generally takes less plot space.	generally takes more plot space but less height.

Separator Types and Selection Guide

- How much solid (sand) is produced:

  Buildup of solid material can lead to corrosion, reduction in performance. Regular cleaning by jet-wash system or manual removal.
- How steady the flow is

  Slugging and surges cause increases in feed rates causing levels to increase. Control system needs constant adjusting.
- How much water is produced
- Is any emulsion (dispersion) formed

  Long residence time unsuited for primary separators. May need to add chemical de-emulsifier or reduce water quality.
- Is foaming a problem

Classification of separators

2. Based on application

1. Test Separator

A vessel used to separate and meter relatively small quantities of oil and gas. Test separators can be two-phase or three-phase, or horizontal, vertical or spherical. They can also be permanent or portable.

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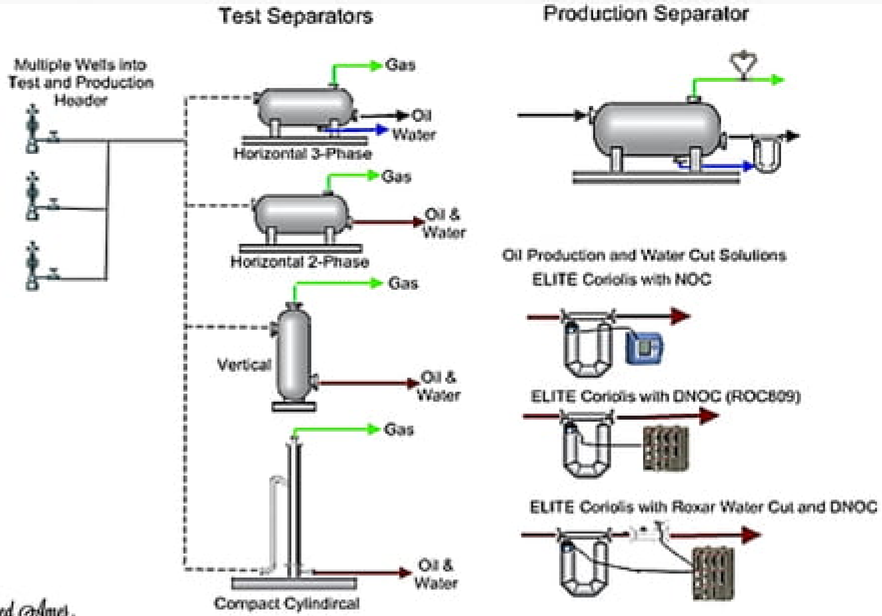
1. Test Separator



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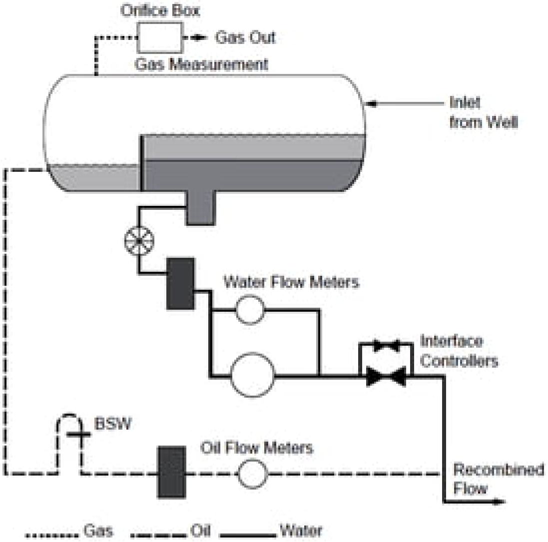
1. Test Separator

- A test separator is used to separate and to meter the well fluids.
- They can be permanently installed or portable (skid or trailer mounted).

1. Test Separator



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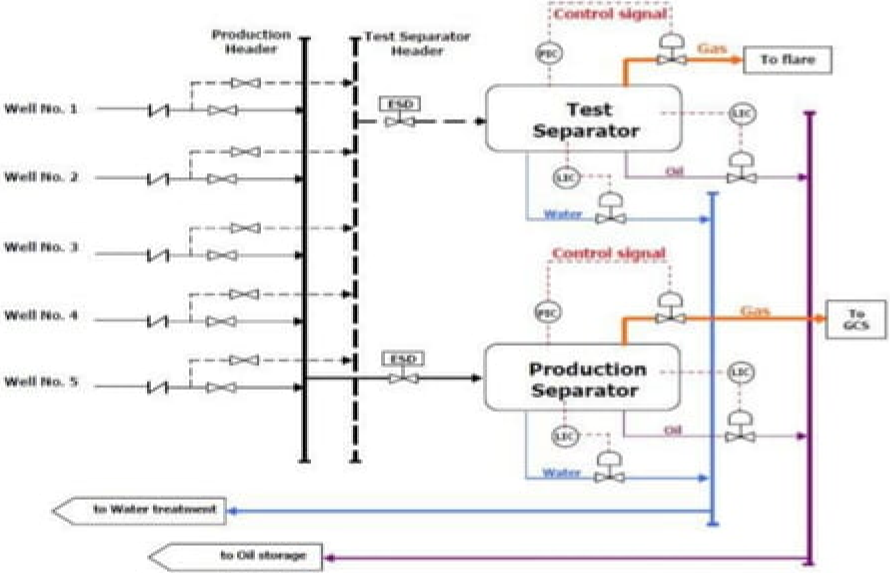
Well manifold



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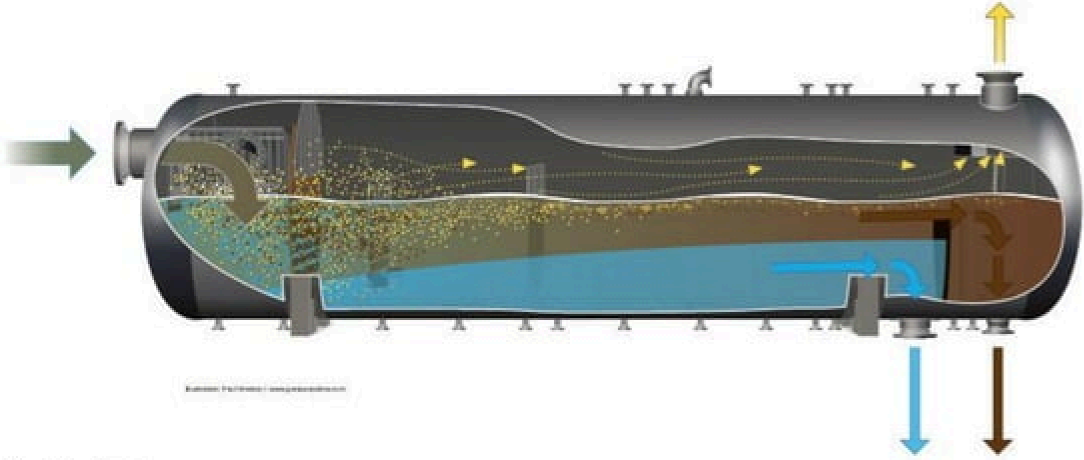
2. Production Separator

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



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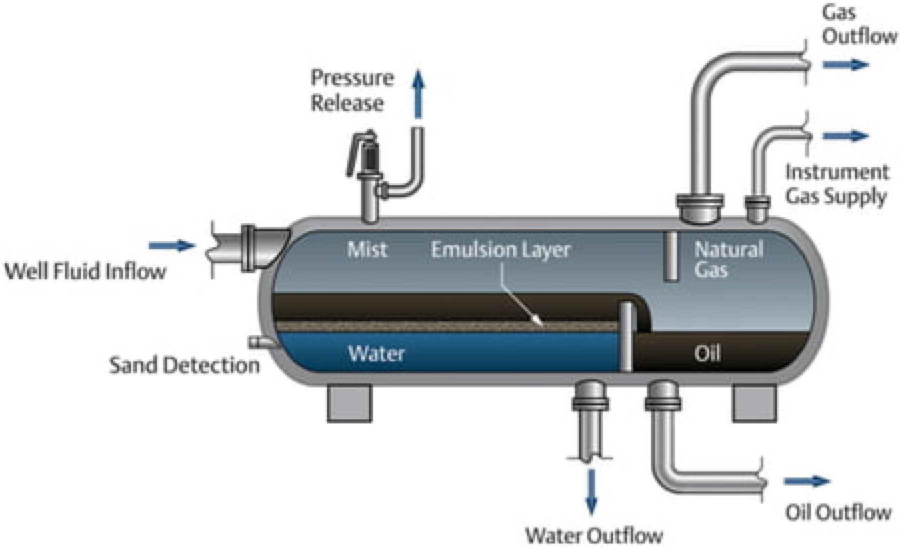
2. Production Separator



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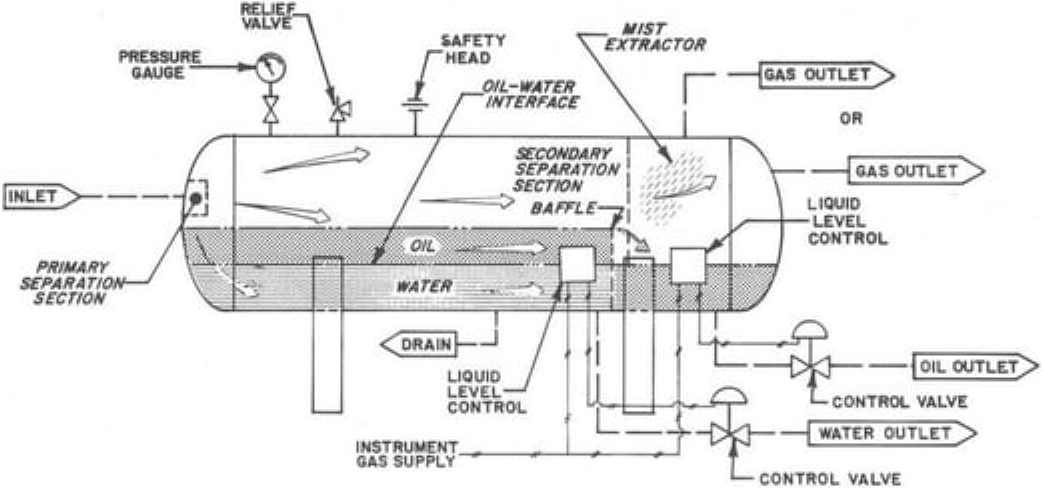
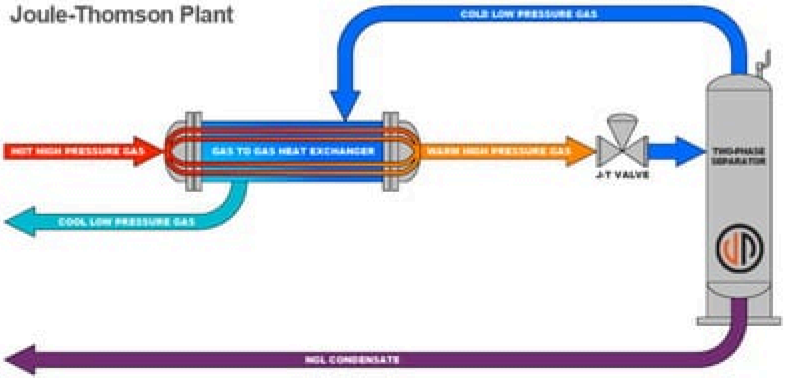


Fig. 2 — Horizontal three-phase separator.

3. Low temperature separator

is an on-site natural gas treatment process aimed at gas condensate recovery. it allows presence of non-hydrocarbon components in gas, ensures compliance of the water dew point and the hydrocarbon dew point of gas with the Industry Standards and the condensate recovery level ($C5H12$ + higher) up to 97 per cent (hydrocarbon dew point corresponds to separation temperature).



3. Low temperature separator

3. Low temperature separator

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3. Low temperature separator

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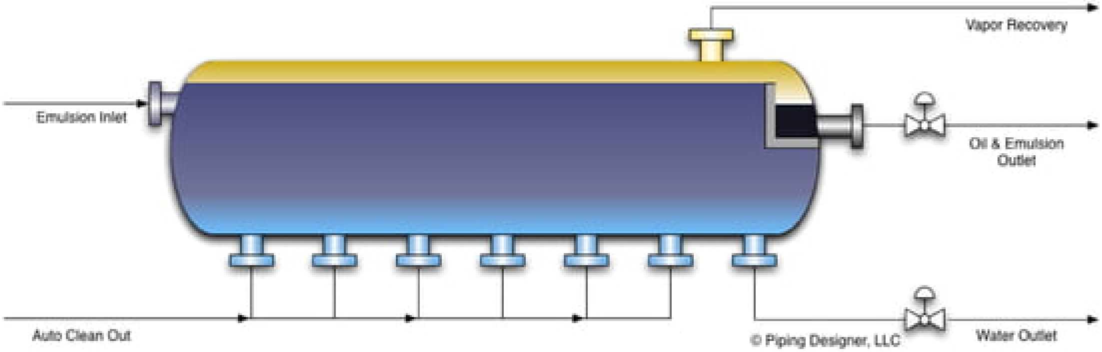
4. Free water Knock out drum

Knockouts are also are separators & fall in two categories:
- free water &
- total liquid knockouts



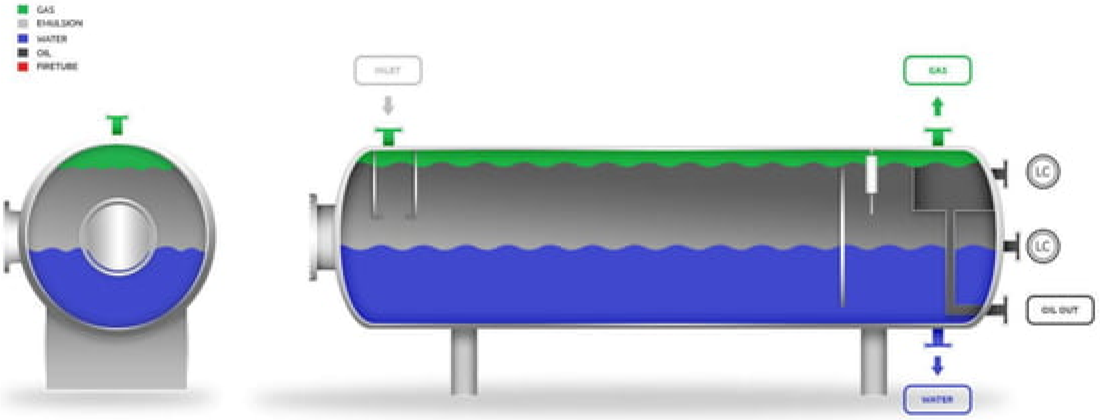
4. Free water Knock out drum

1. **Free water knockout**

is a vessel used to separate free water from a combined gas, hydrocarbon liquid and water stream. The gas & hydrocarbon liquid usually are allowed to leave the vessel together through the same outlet to be processed by other equipment.
The water is removed for disposal. A free water knockout can be utilized at either high or low pressure

4. Free water Knock out drum

No Emulsion Treatment



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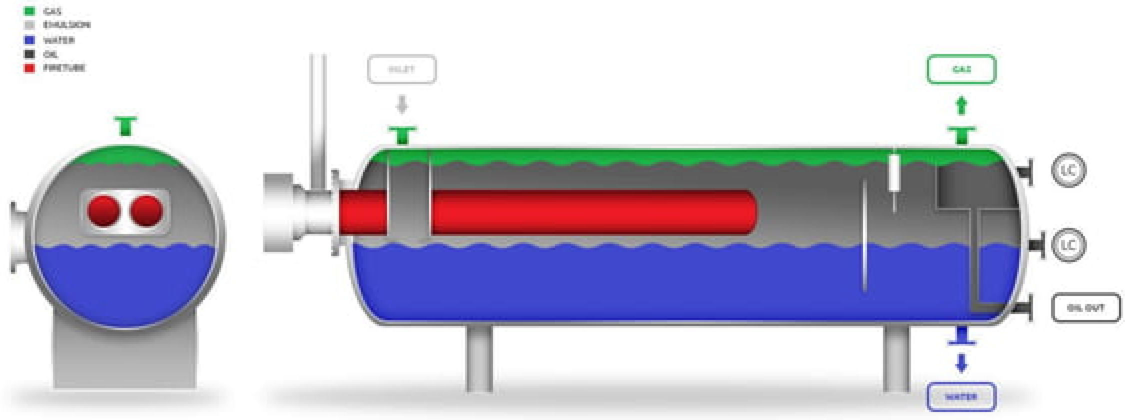
4. Free water Knock out drum

Emulsion Treatment by heating



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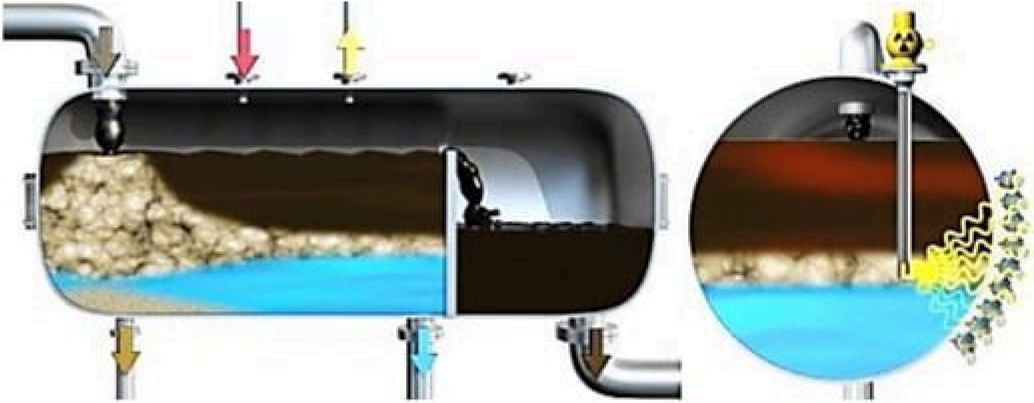
4. Free water Knock out drum

1. **Total liquid knockout**

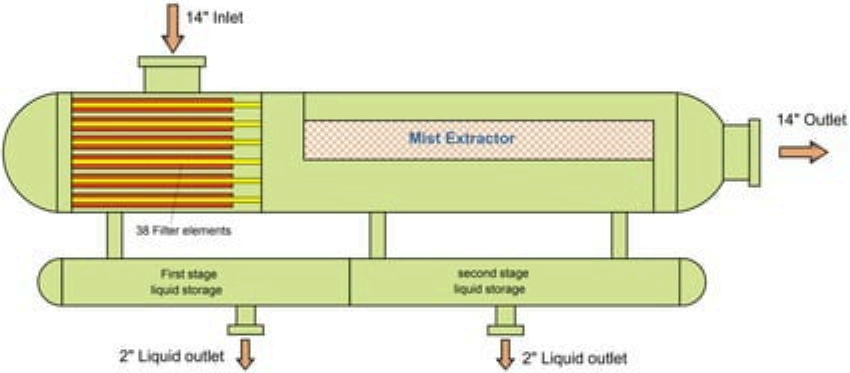
is normally used to remove liquids from a high pressure gas stream (3,000 psig & above). This vessel usually is used with a cold separation unit.

5. Foam separator

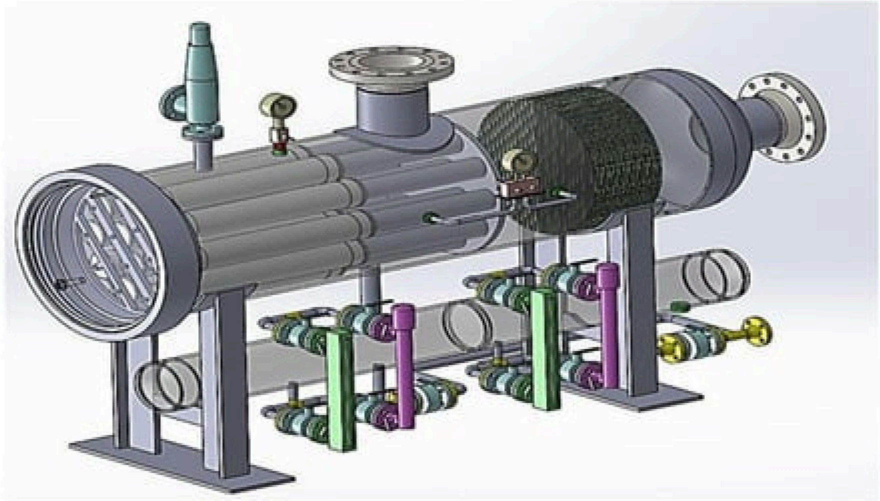


6. Filter separator

The filter separator is frequently used in some high-gas/low-liquid flow applications. It is designed to remove small liquid and solid particles from the gas stream.



6. Filter separator



7. Cyclone sand separator

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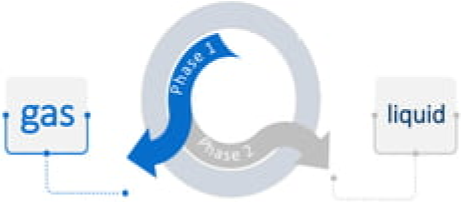
Classification of separators

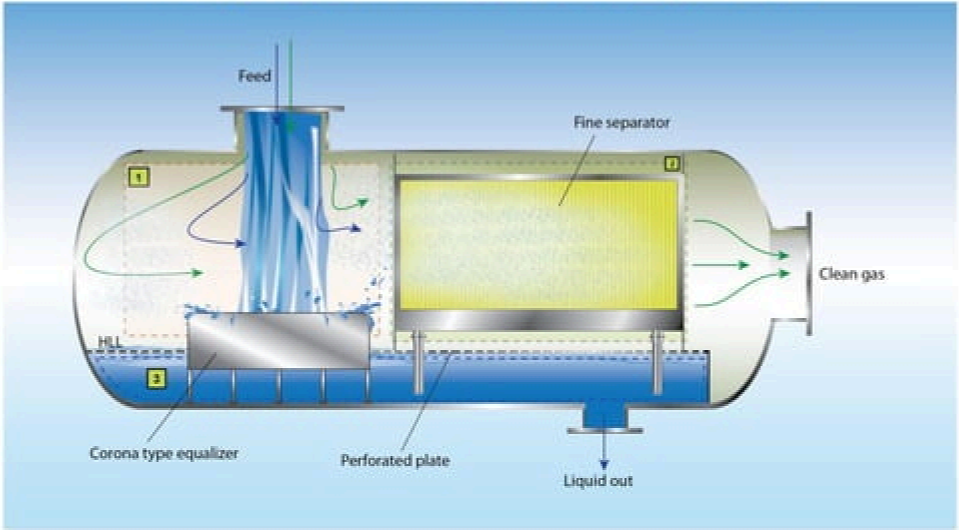
3. Based on Function

Two Phase separator



Three phase separator

Two phase Horizontal separator



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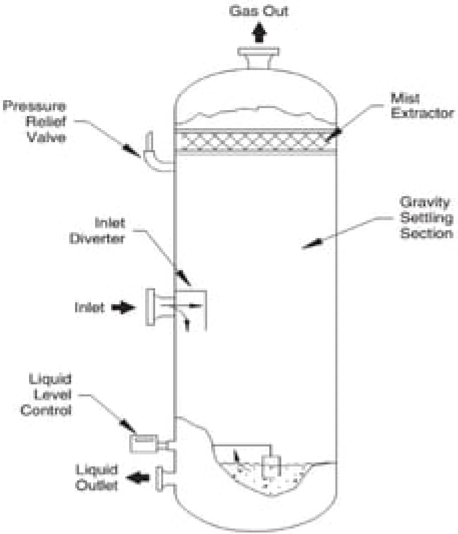
Two phase Vertical separator



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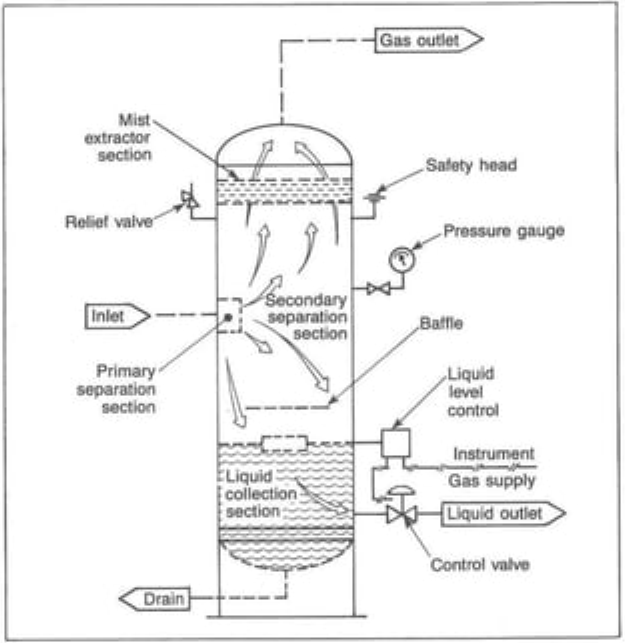
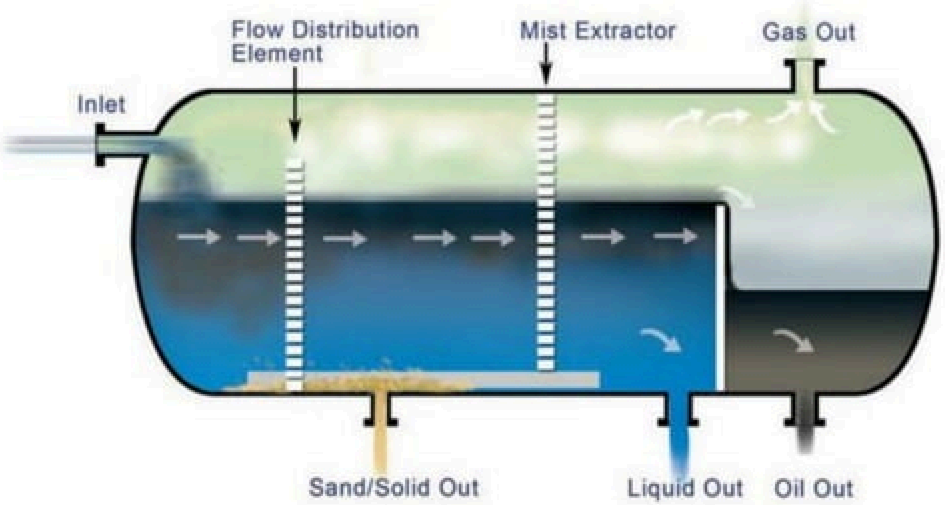


Fig. 11–3 Vertical two-phase separator

Three phase separator



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Classification of separators

4. Operating 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.
04	general	▪ Most oil and gas separators operate in the pressure range of 20 to 1 ,500 psi.

SEPARATOR

- ***A separating vessel may be referred to in the following ways:***

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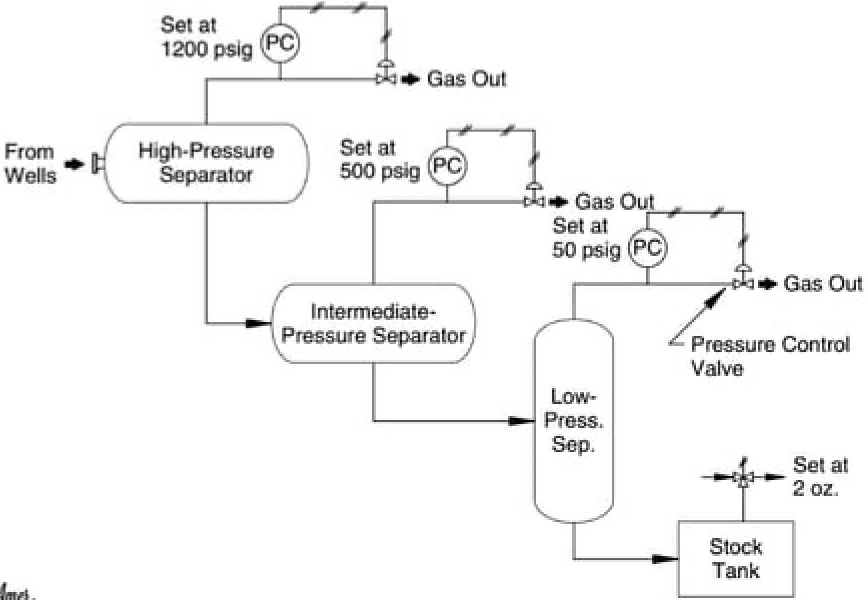
1. Multi Stage Separator



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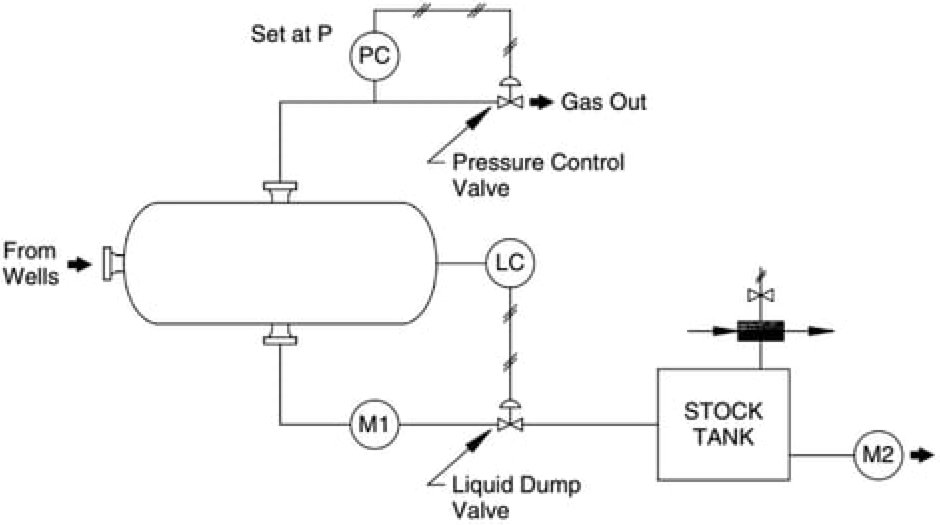
2. Single Stage Separator



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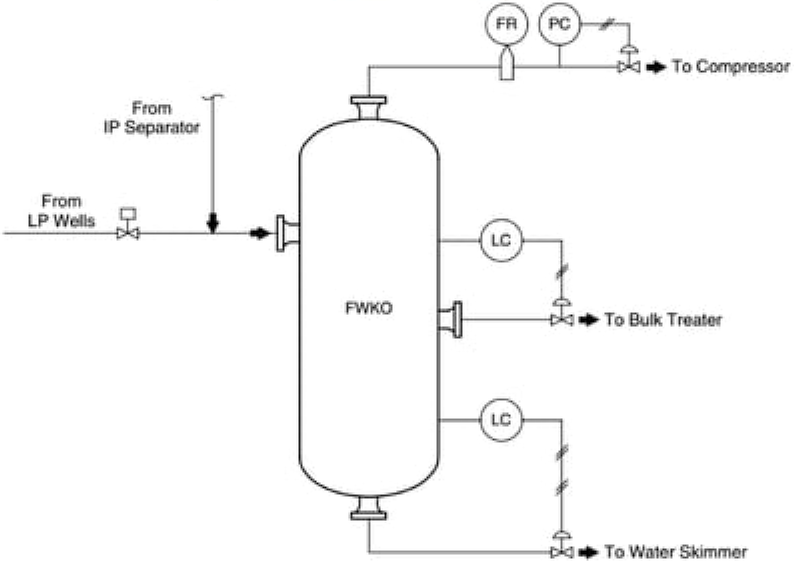
3. knockout drum

A separator used for a bulk separation of gas and liquid.



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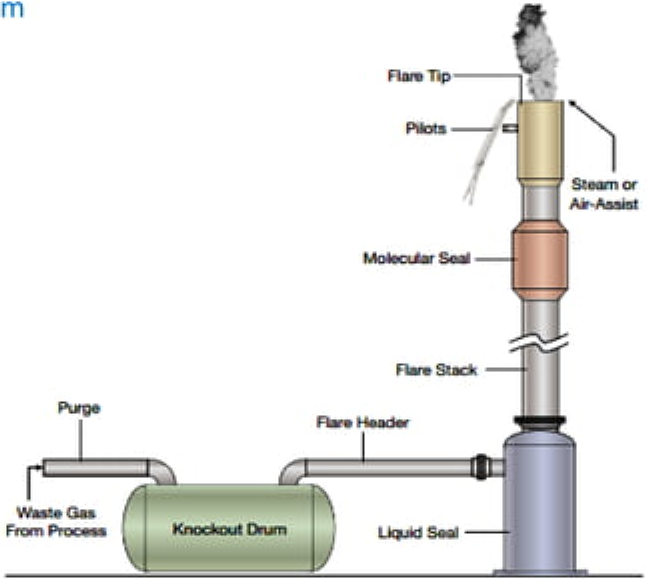
3. knockout drum

Flare Knockout drum



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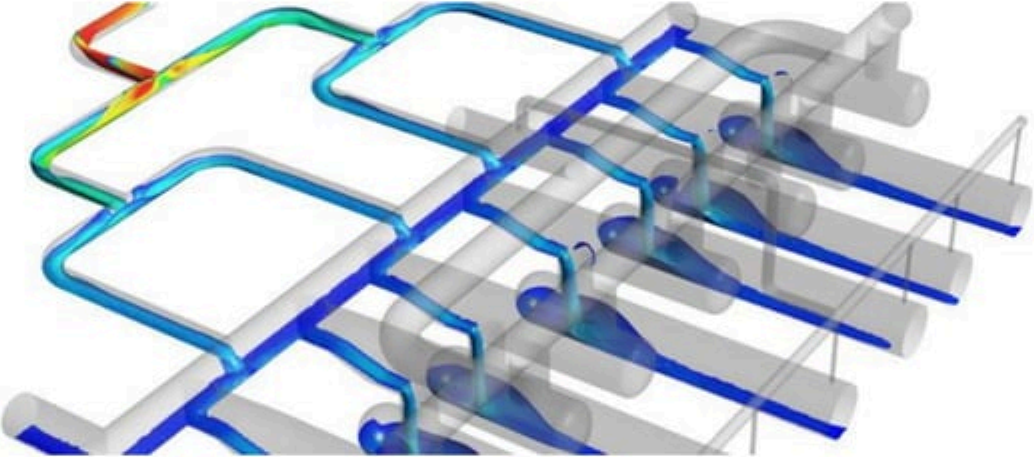
4. Flash drum

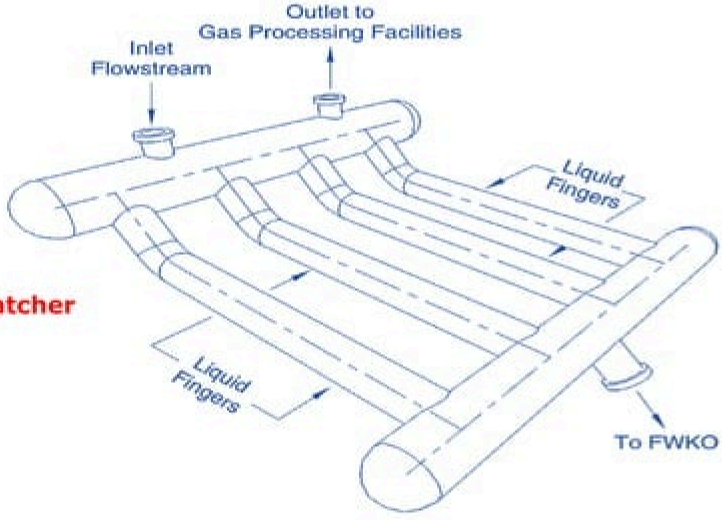
5. Slug catcher (Finger Type)

A particular separator design able to absorb sustained in-flow of large liquid volumes at irregular intervals



5. Slug catcher (Finger Type)

commonly used in gas gathering pipelines, is a special case of a two-phase gas–liquid separator that is designed to handle large gas capacities and liquid slugs on a regular basis



Finger type Slug catcher

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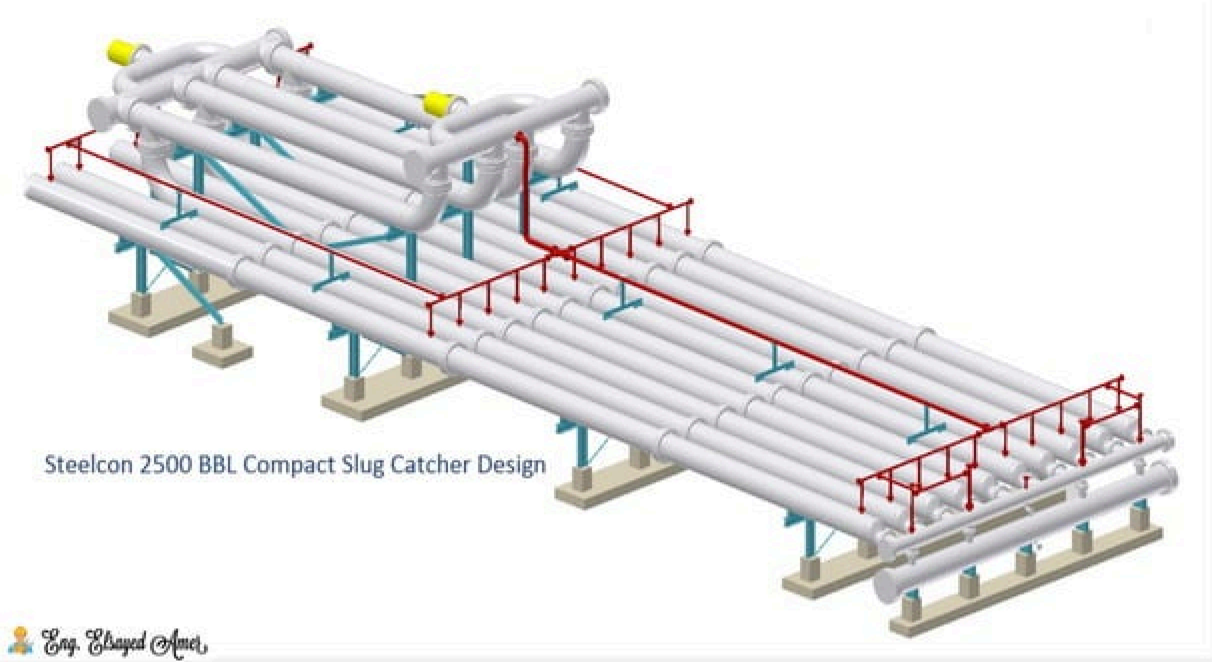

Steelcon 2500 BBL Compact Slug Catcher Design
Eng. Elsayed Amer

5. Slug catcher (Vessel type)

Vessel type Slug catcher

Eng. Elsayed Amer

5. Slug catcher (Vessel type)

6. Scrubber

A scrubber is a two-phase separator that is designed to recover liquids carried over from the gas outlets of production separators or to catch liquids condensed due to cooling or pressure drops.

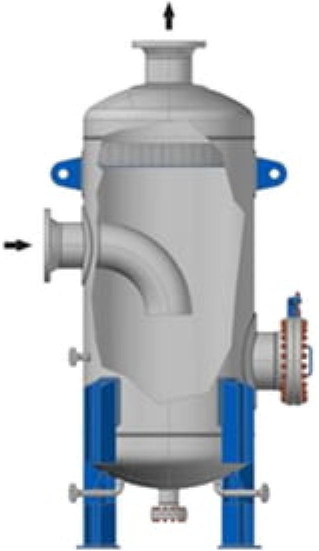
Applications:

1. upstream of mechanical equipment such as compressors that could be damaged, destroyed, or rendered ineffective by free liquid;
2. downstream of equipment that can cause liquids to condense from a gas stream (such as coolers);
3. upstream of gas dehydration equipment that would lose efficiency, be damaged, or destroyed if contaminated with liquid hydrocarbons;

Vertical scrubbers are most commonly used. Horizontal scrubbers can be used, but space limitations usually dictate the use of a vertical configuration.

6. Scrubber

A type of separator which has been designed to handle flow streams with unusually high gas-to liquid ratios.



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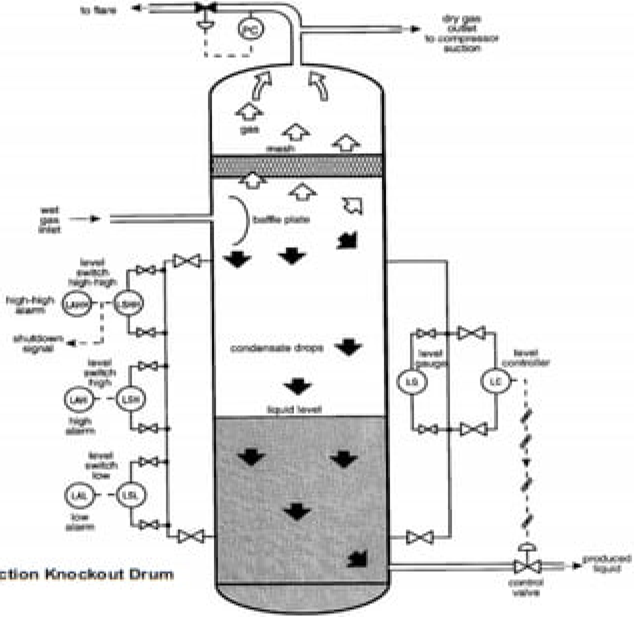
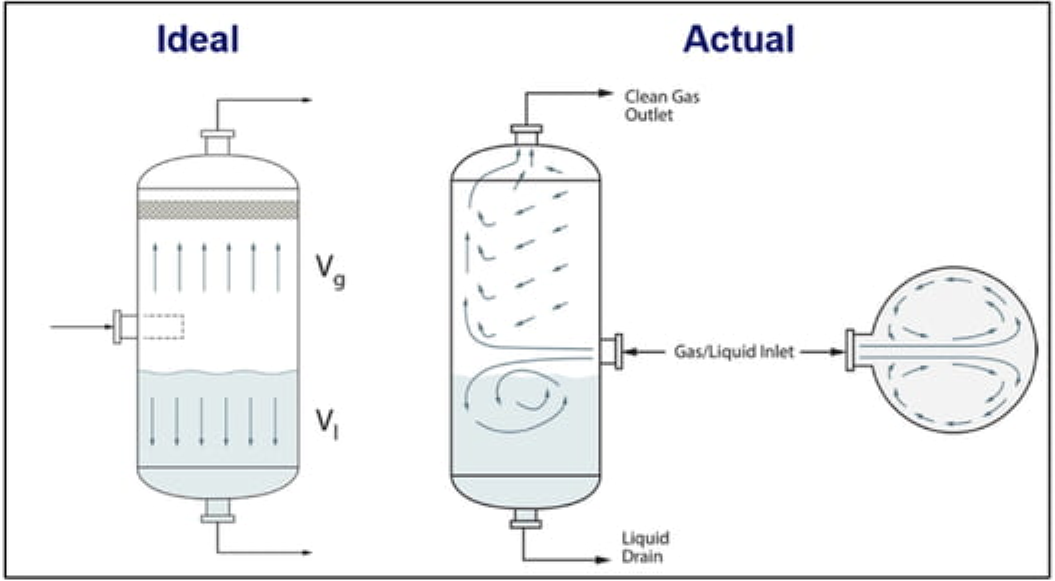
6. Scrubber

Compressor suction scrubber

Designed to recover liquids carried over from production separators or condenses after initial separation
Liquid loading level much lower than separator
Applications
- Upstream of compressors
- Downstream of coolers (liquids can condense)
- Upstream of dehydration equipment
- Upstream of a vent of flare outlet



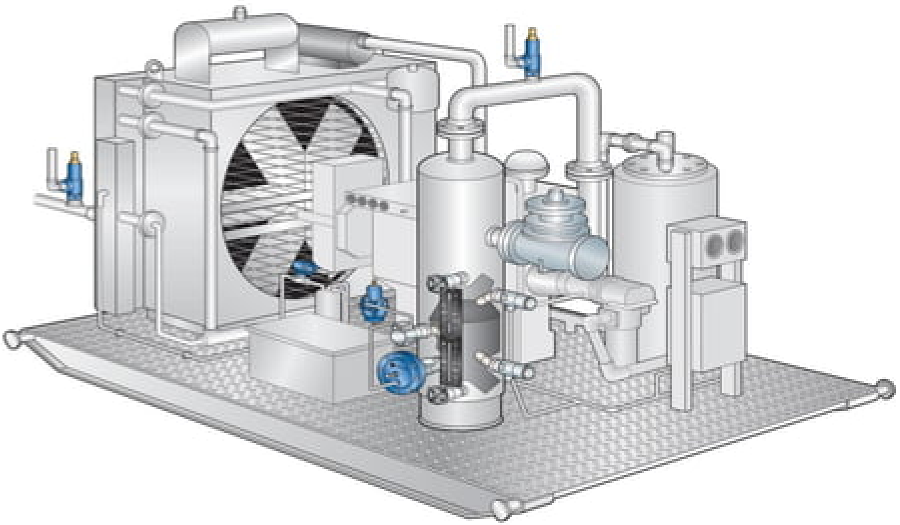
Suction Knockout Drum



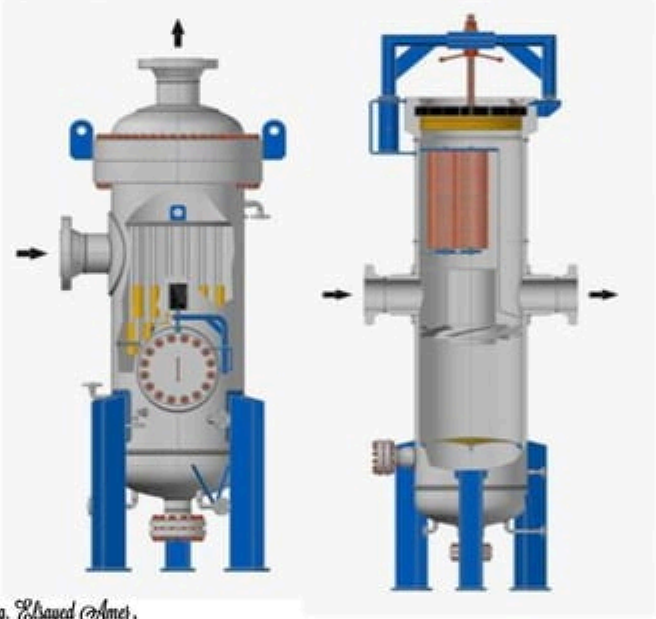
Ideal
Actual
V_g
V_l
Clean Gas Outlet
Gas/Liquid Inlet
Liquid Drain

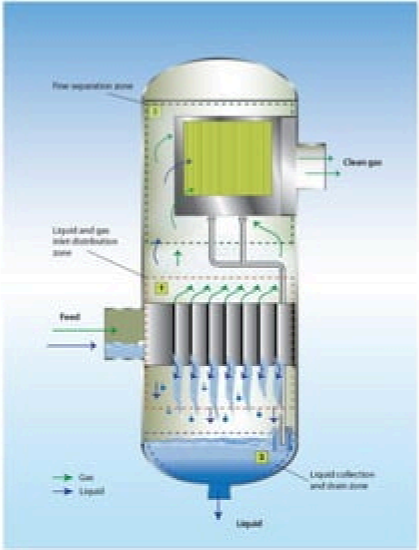
6. Scrubber

Compressor suction scrubber



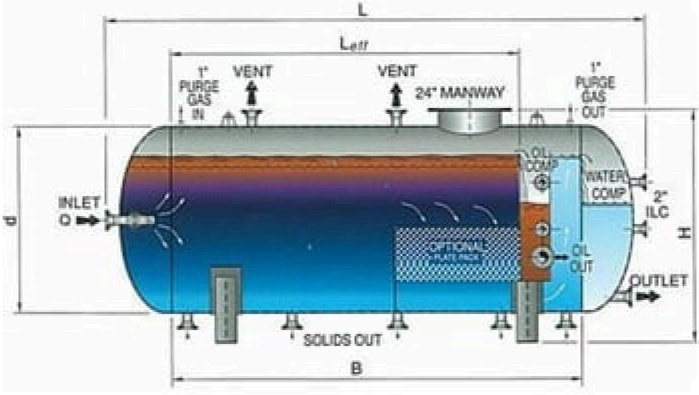
7. Filter

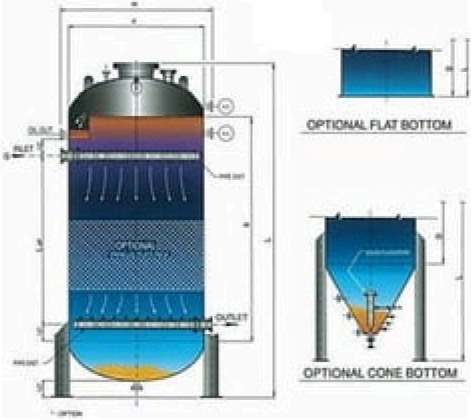




7. Skimmer

An oil skimmer is a device that is designed to remove oil floating on a liquid surface. Depending on the specific design they are used for a variety of applications such as oil spill response, as a part of oily water treatment systems, removing oil from machine tool coolant and aqueous parts washers, and collecting fats oils and greases in wastewater treatment in food manufacturing industries.





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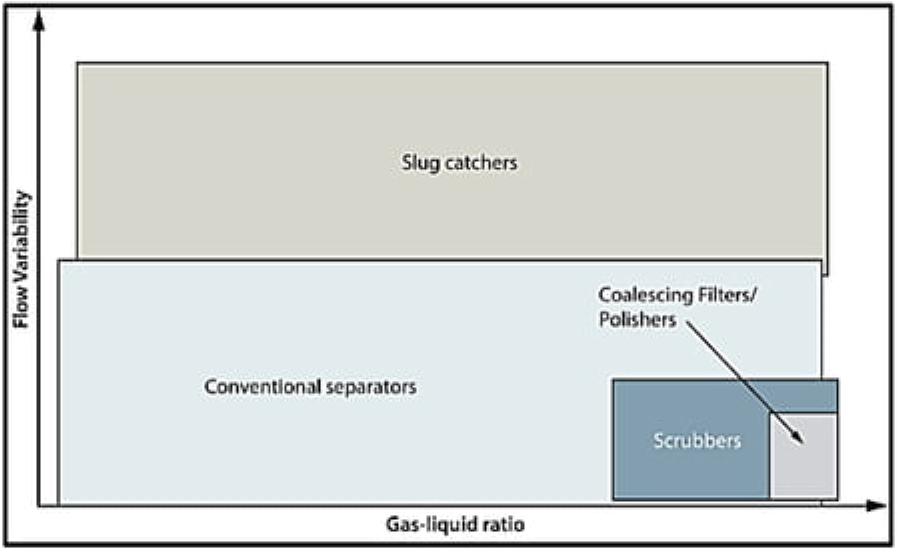

Slug catchers
Coalescing Filters/
Polishers
Conventional separators
Scrubbers
Flow Variability
Gas-liquid ratio

Separator internals

Process point of view

Primary Separation Section

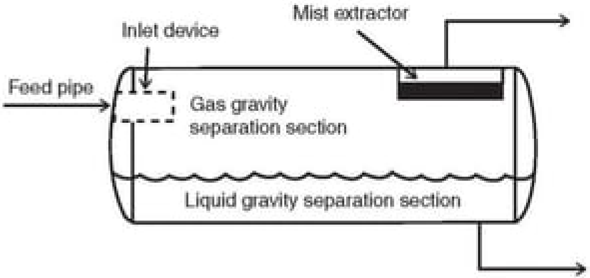
secondary separation Section

Sections of Separator

Mist Extraction Section

Liquid Accumulation Section

Sections of Separators



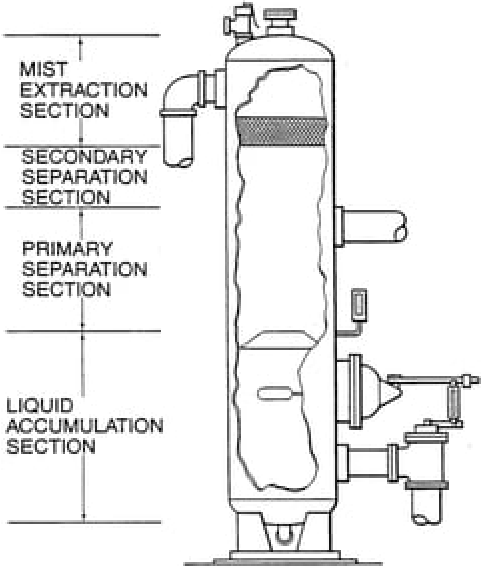
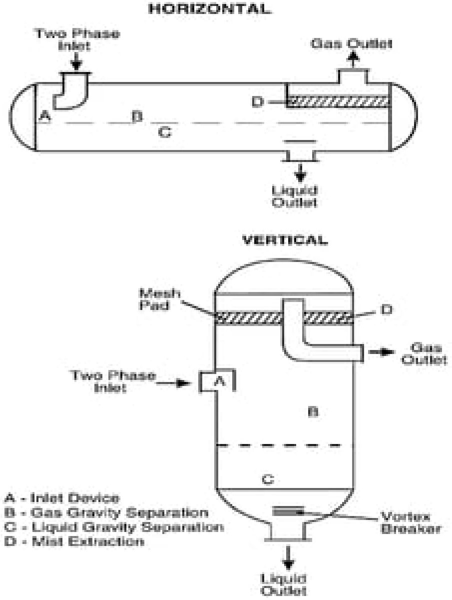


Figure 2

Separator Sections

Separator Sections

- Primary Separation (A)
- Gravity Settling (B)
- Liquid Collecting (C)
- Coalescing/Demister (D)



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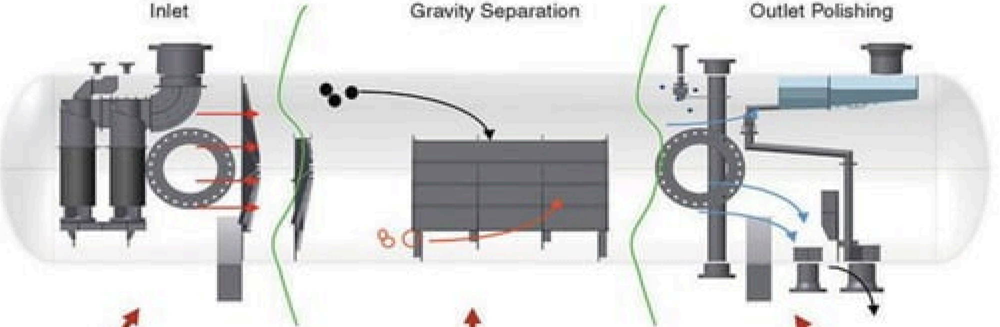
Separator Sections



- Lower velocities
- Bulk separate gas/liquid
- Straighten out the flow
- Break foam
- Prevent short-circuiting
- Prevent droplet shatter
- Prevent foam formation

- Separate large droplets/bubbles
- Coalesce small droplets/bubbles
- Break foam
- Drop out solids

- Remove small droplets
- Prevent short-circuiting

1. Primary Separation section

- 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.

- As the fluids enter the vessel an initial separation of gas and liquid takes place. This happens because of:

Reduction in velocity

Reduction in pressure

Change in flow direction

1. *Primary Separation section*

The velocity of the inlet stream is reduced as the fluids flow from a relatively small diameter pipeline into the large volume separator.

The pressure is reduced by maintaining a controlled pressure on the vessel lower than that of the inlet stream.

The change *in flow direction* is accomplished by placing some form of deflector at the inlet to the 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.

Retention Time

Defined as : the average time a molecule of liquid is retained in the vessel assuming plug flow .

- ❑ It is thus the volume of liquid storage in the vessel divided by the liquid flow rate.
- ❑ It is affected by composition, foaming tendency, presence of solids & emulsions etc.

For most applications retention times between 30 sec. & 3 minutes have been found to be sufficient.
For foaming crudes, retention times up to four times this amount may be needed. For chemical reactors like ‘Water Deoxygenating Towers’ it is kept about 3 to 5 minutes.

Retention Time

Type of Separation	Retention Time (Minutes)
Natural gas condensate separation	2 – 4
Fractionator feed tank	10 – 15
Reflux accumulator	5 – 10
Fractionation column sump	2[a]
Amine flash tank	5 – 10
Refrigeration surge tank	5
Refrigeration economizer	3
Heat medium oil surge tank	5 – 10[b]

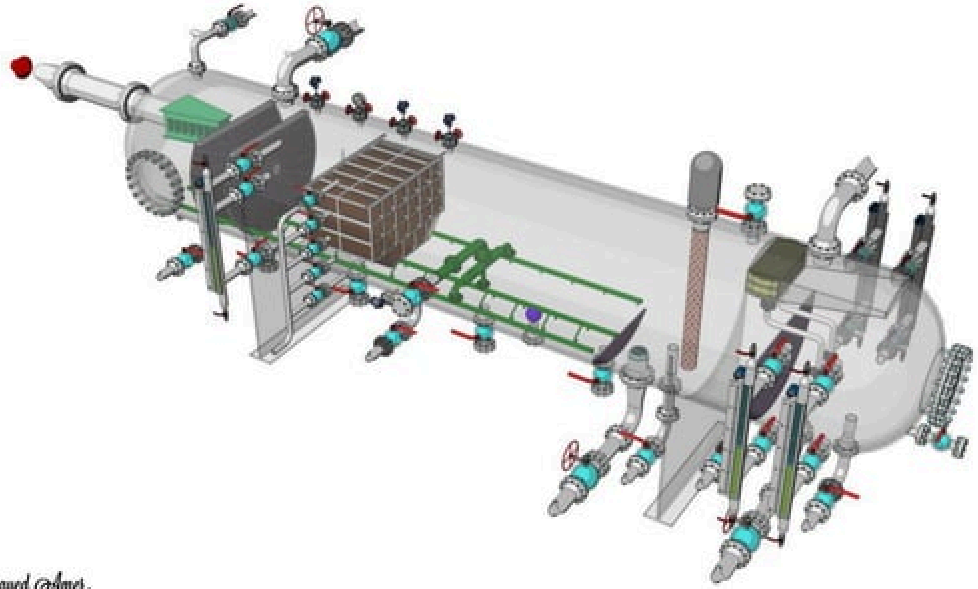
3. *Mist Extraction Section*

- 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.

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.'

Mechanical Devices



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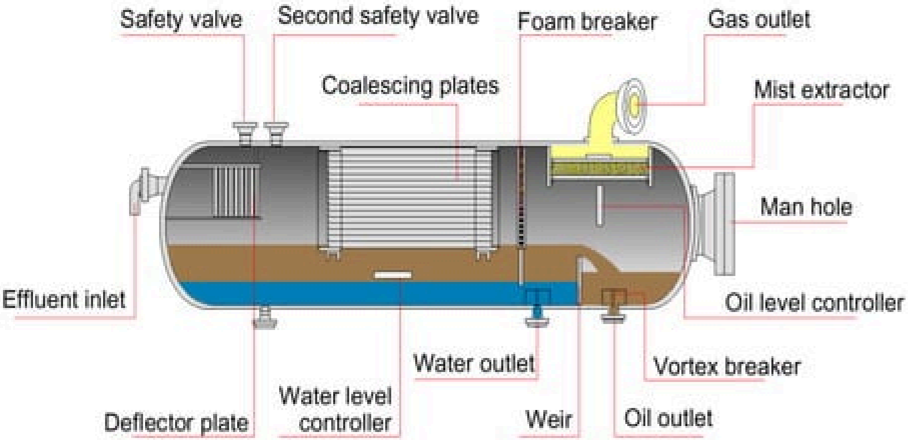
Mechanical Devices



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Components of Separator

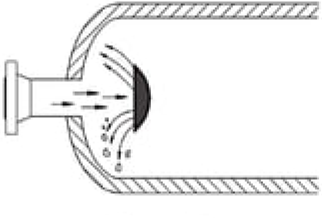
1. Inlet Diverters

- Also Known as Inlet Deflectors & Deflector Plate
  - *Locate in front of the flow inlet*
  - *Cause a rapid change in direction & velocity of fluid.*
  - *Forcing the liquids to fall to the bottom of the vessel.*
  - *Responsible for the initial gross separation of liquid and gas.*

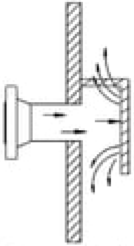
Components of Separator

1. Inlet Diverters

- There are several different types of separator inlet devices
- that are commonly used:
  - no inlet device
  - diverter plate
  - half-pipe
  - vane-type
  - cyclonic



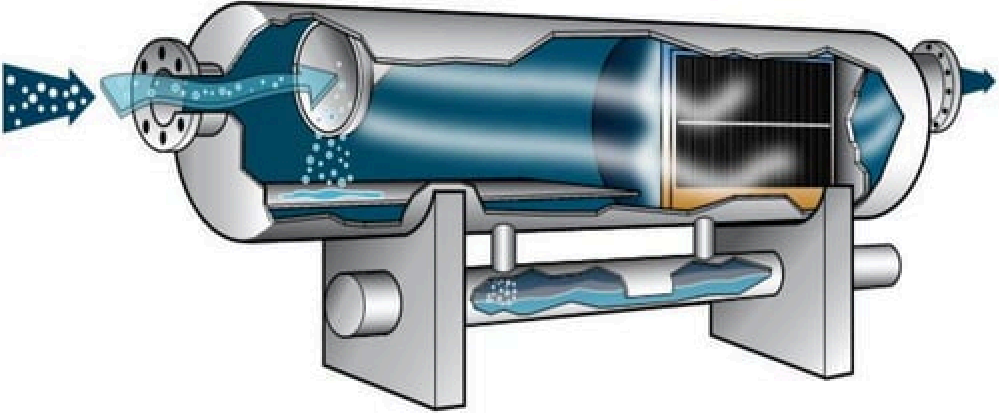
Diverter Baffle



Tangential Baffle

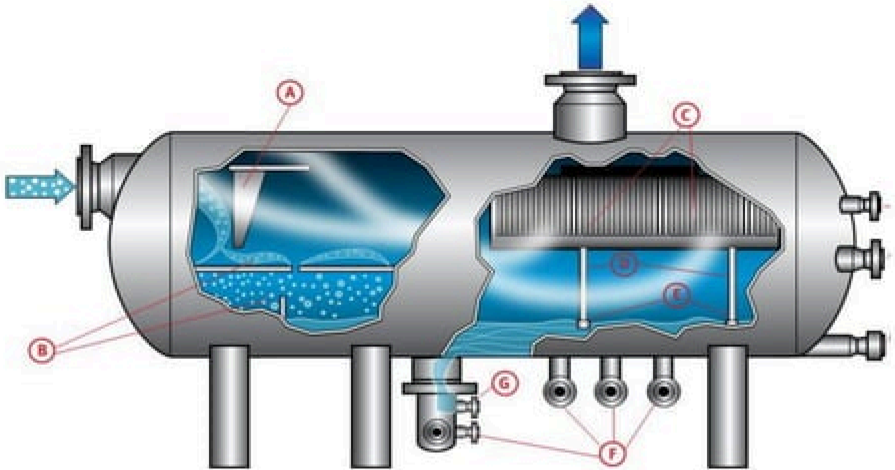
Components of Separator

1. Inlet Diverters



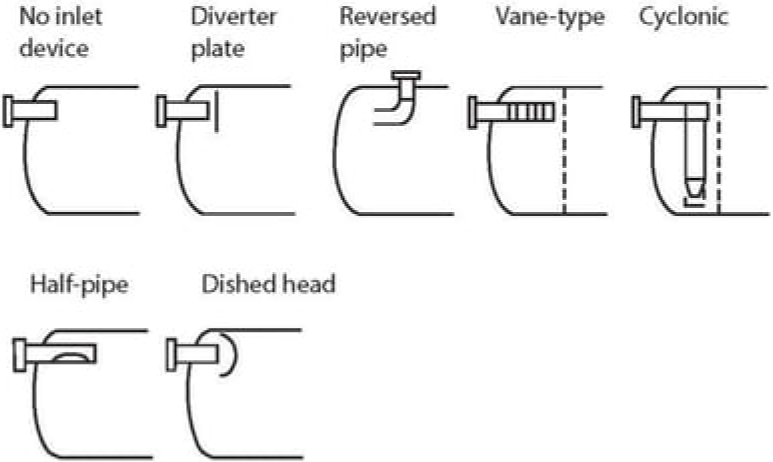
Components of Separator

1. Inlet Diverters



Components of Separator

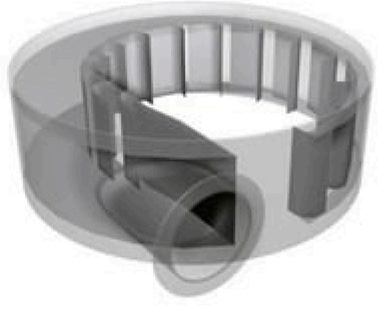
1. Inlet Diverters



Components of Separator

1. Inlet Diverters

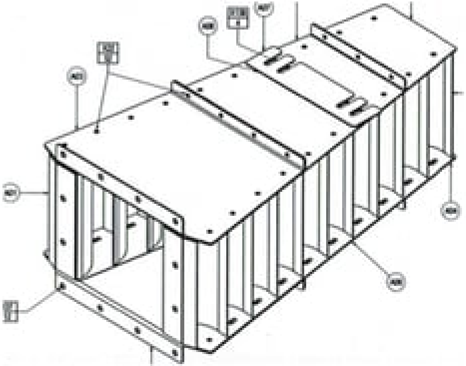
- Cyclonic Inlet Diverters

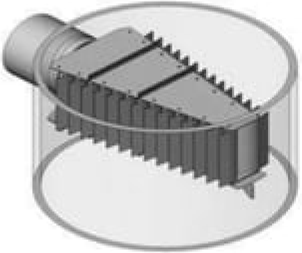


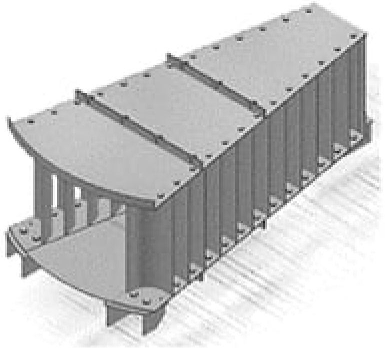
Components of Separator

1. Inlet Diverters

- *Half pipe Inlet Diverters*







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Components of Separator

1. Inlet Diverters

- *Efficiency*

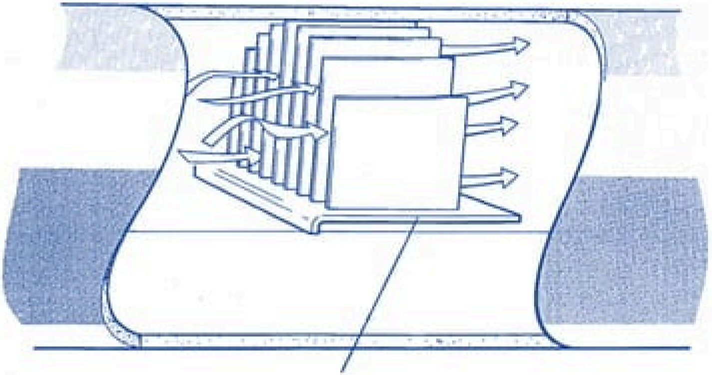
TABLE 3—INLET DEVICE PERFORMANCE MEASURES

Function	No inlet device	Diverter plate	Half-pipe	Van-type	Cyclonic
Momentum reduction	Poor	Average	Good	Good	Good
Bulk liquid separation	Poor	Poor	Average	Good	Good
Prevent re-entrain-ment	Poor	Poor	Average	Good	Average-Good
Minimize droplet shattering	Poor	Poor	Average	Good	Good
Defoam	Poor	Poor	Poor	Aver-age	Good
Low pres-sure drop	Good	Good	Good	Good	Average
Ensure good gas distri-bution	Poor	Poor	Poor	Good	Average

Components of Separator

2. Straightening Vanes

turbulence in the flowing gas stream can be reduced by incorporating straightening vanes



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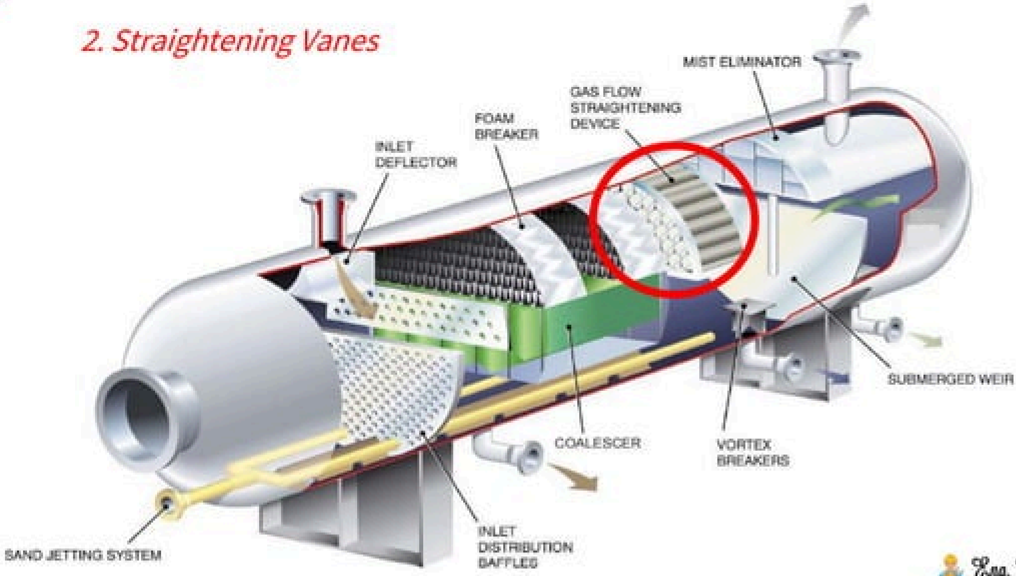
Components of Separator

2. Straightening Vanes



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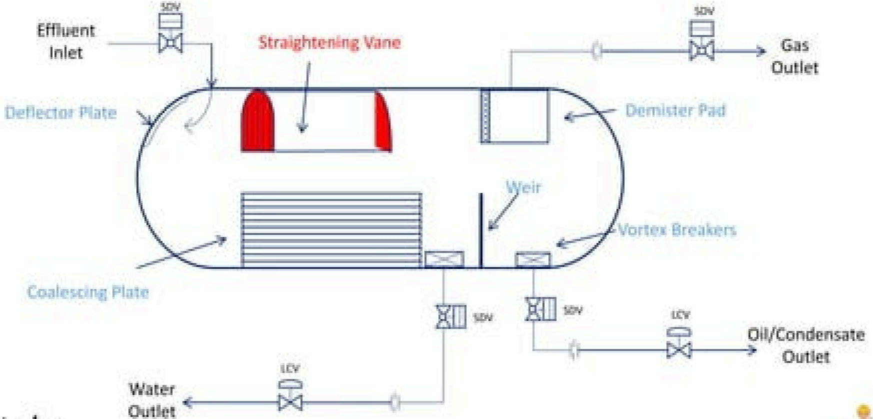
Components of Separator

2. Straightening Vanes

Turbulence in the flowing gas stream can be reduced by incorporating straightening vanes



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Components of Separator

3. Mist extractor

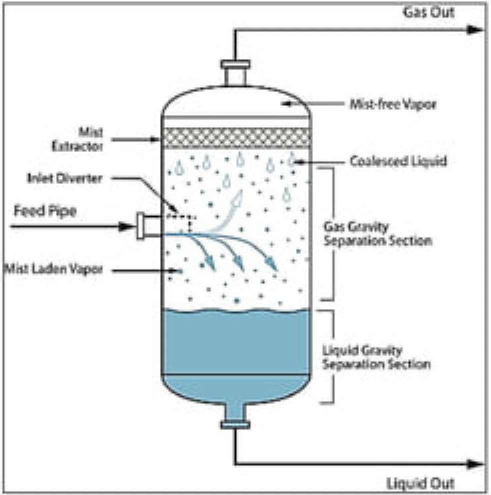
mist extractors or mist eliminators, designed to remove the liquid droplets and solid particles from the gas stream.
Before a selection can be made, one must evaluate the following factors:
Size of droplets the separator must remove

- *Pressure drop that can be tolerated in achieving the required level of removal*
- *Susceptibility of the separator to plugging by solids, if solids are present*
- *Liquid handling capability of the separator*
- *Whether the mist extractor/eliminator can be installed inside existing equipment, or if it requires a standalone vessel instead*
- *Availability of the materials of construction that are comparable with the process*
- *Cost of the mist extractor/eliminator itself and required vessels, piping, instrumentation, and utilities*

Components of Separator

3. Mist extractor

Small liquid droplets present in the gas stream can be carried along with the gas stream and contaminate the gas processing system. Mechanical devices to capture droplets are used close to gas outlet.
Droplets are removed by impingement on solid surface when liquid collects and eventually drips off from unit.

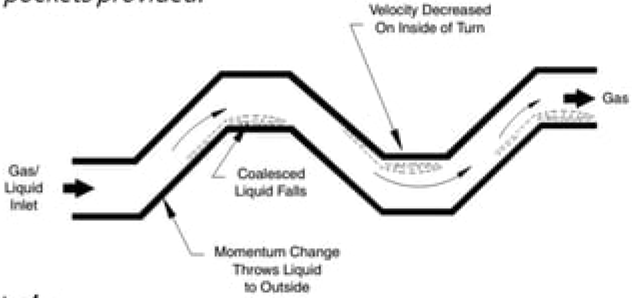


Components of Separator

3. Mist extractor

vane type Mist extractor

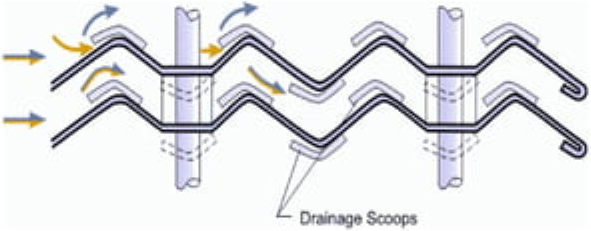
parallel metal sheets with suitable liquid collection "pockets," The gas, in passing between plates, is agitated and has to change direction a number of times. Obviously, some degree of centrifugation is introduced, for as the gas changes direction the heavier particles tend to be thrown to the outside and are caught in the pockets provided.

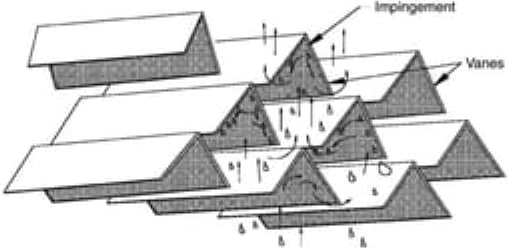


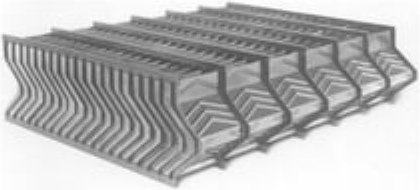
Components of Separator

3. Mist extractor

vane type or knitted wire Mist extractor







Components of Separator

3. Mist extractor

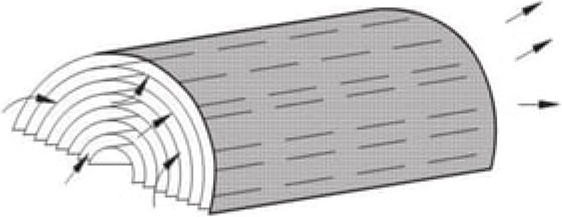
knitted wire type Mist extractor

The most common type of mist extractor found in production operations
a knitted wire mesh supported on a lightweight support. This material has given generally favorable results and has a low installed cost
The element consists of wire knitted into a pad having a number of unaligned, asymmetrical openings. Although similar in appearance to filter media, its action is somewhat different. The latter are rather dense and have small openings. This knitted wire, on the other hand, has about 97 to 98% free voids and collects the particles.

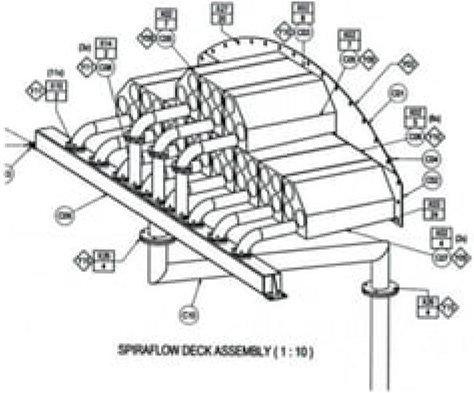
Components of Separator

3. Mist extractor

Special types



An arch plate-type mist extractor

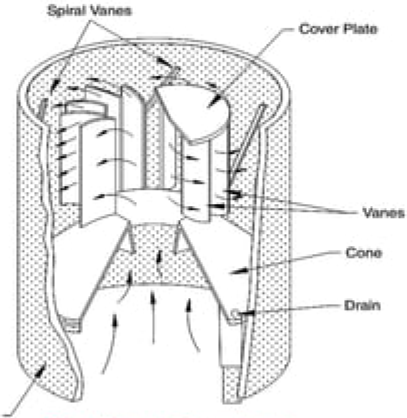


SPIRAFLOW DECK ASSEMBLY (1 : 10)

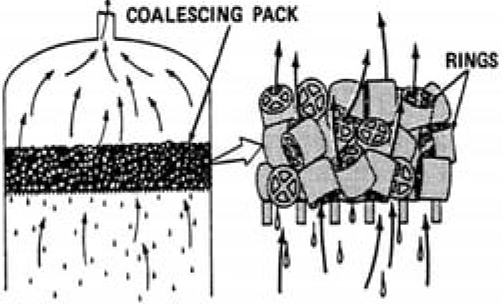
Components of Separator

3. Mist extractor

Special types



Centrifugal mist extractor.



A coalescing pack mist extractor.

Components of Separator

3. Mist extractor

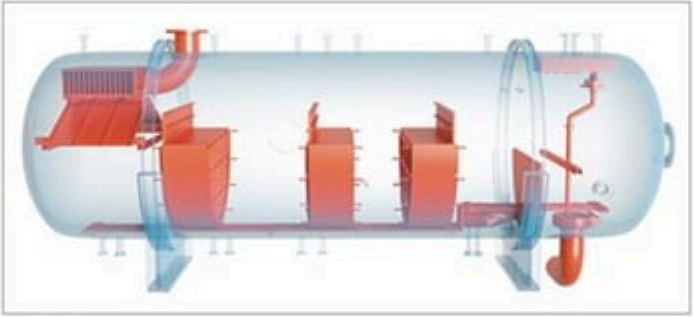
Features of Impingement-Type Mist Extractors

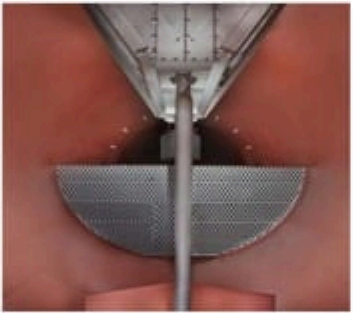
Consideration	Wire-Mesh	Vane	Micro-fiber
Cost	Lowest	2–3 times wire-mesh unit	Highest
Efficiency	100% (for droplets larger than 3–10 µ	100% (for mists > 20–40 µ)	Up to 99.9% (for mists < 3 µ)
Pressure drop	< 25 mm H_2O	< 15 mm H_2O	100–300 mm
Gas capacity	Very good	Up to twice that of a wire-mesh unit	Lowest
Liquid capacity	Good	Best	Lowest
Solids	Good	Best	Soluble particles with sprays only

Components of Separator

4. Foam Breaker

These are flat plates located in the separator just above the liquid accumulation section. They help to prevent waves in the liquid which might result in liquid re-entrainment in the gas stream.

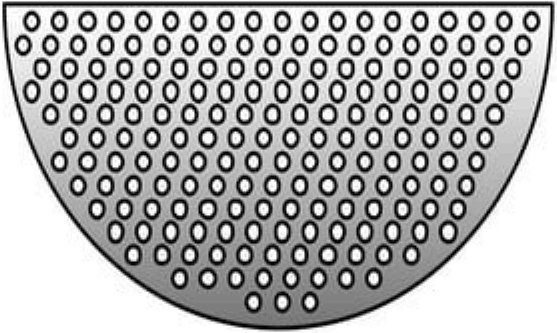


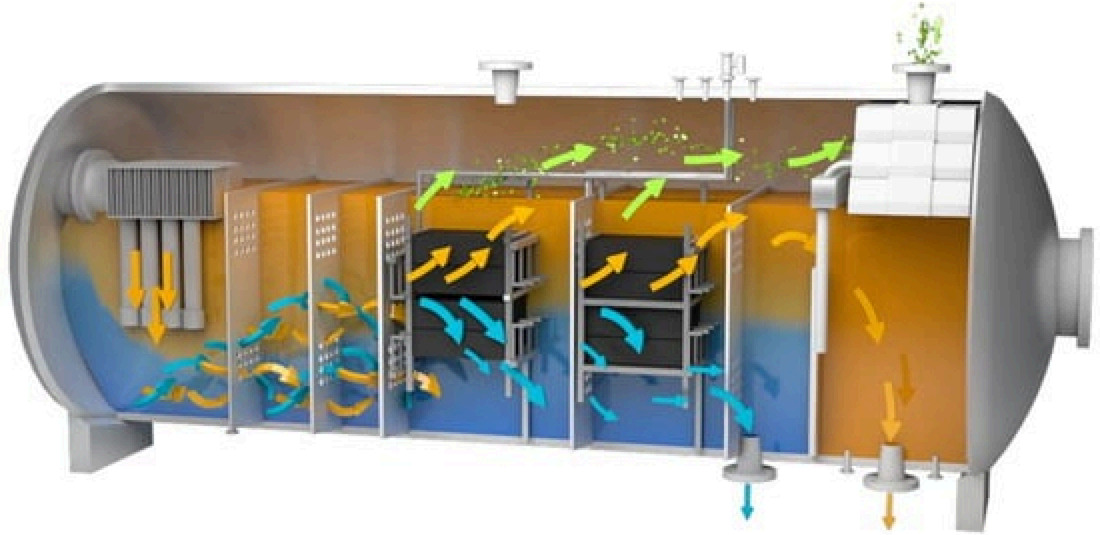



Vane Pack
3
Defoaming Pack
Cyclonic Inlet Device
1
Weir
2
Coalescing
Plate Pack
Calming Baffle
(for FSPO's)
FACID

Components of Separator

4. Foam Breaker





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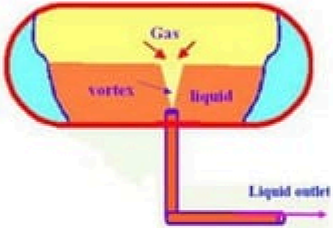
Components of Separator

Vortex in vessels

VORTEX is a region in fluid in which the flow is rotating around an axis line, which is influenced by the Earth's rotation. The formation of vortices can entrain vapor in the liquid stream, leading to;

- *Poor separation in process steps such as distillation*
- *Excessive pressure drop*
- *Erosion of nozzle and connecting pipe due to two phase flow*
- *Causing cavitation of downstream pumps.*

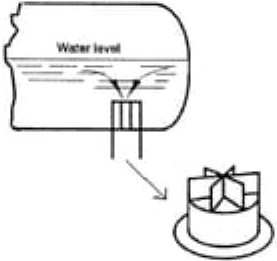


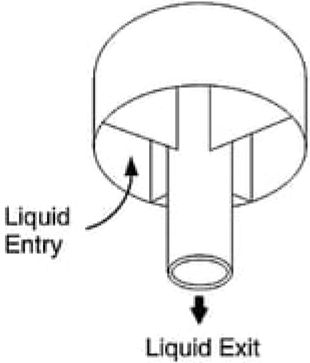
Components of Separator

5. Vortex Breaker

VORTEX BREAKER is a device used to stop formation of a vortex when a liquid is drained from vessel.

- Installed at bottom outlet/drain nozzle of vessel.
- Many type of vortex breaker are available, e.g.
  - Cross Type
  - Disc Type (Baffle Plate)
  - Cross & Disc Type



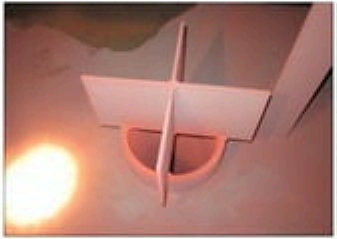


Components of Separator

5. Vortex Breaker

The formation of vortices can entrain vapor in the liquid stream, leading to poor separation in process steps such as distillation or excessive pressure drop, or causing cavitation of downstream pumps. Vortices can also re-entrain solid particles previously separated from a gas stream in a solid-gas separation device such as a cyclone

A Cross Type Vortex Breaker



Disc Type Vortex Breakers in a Tower

Components of Separator

5. Vortex Breaker

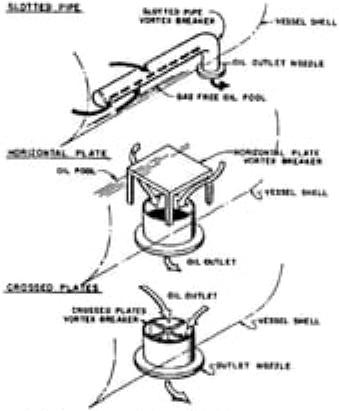
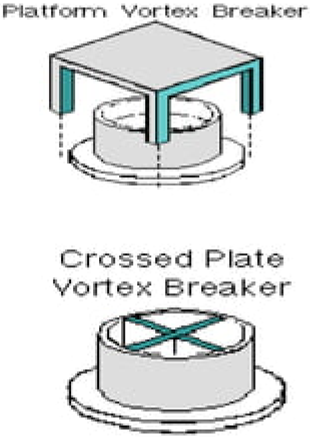


Figure 11.10 Campbells 7th Edition Volume 2.



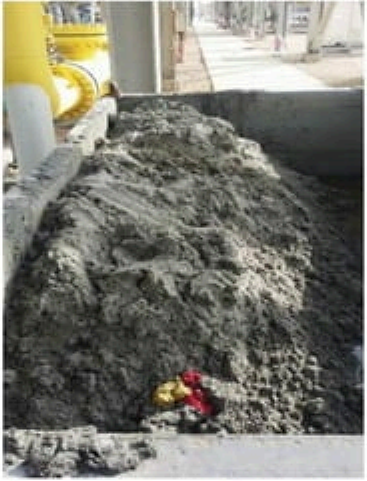
Components of Separator

6. Sand Jets and Drains

- The Sand Jetting system is commonly used in the upstream separator to remove solids that settles in gravity separators.
- It fluidizes the solids with pressurized water introduced through specially designed nozzles.
- The solids are then discharged through sand drains located down the length of the vessel

Components of Separator

6. Sand Jets and Drains



Components of Separator

6. Sand Jets and Drains

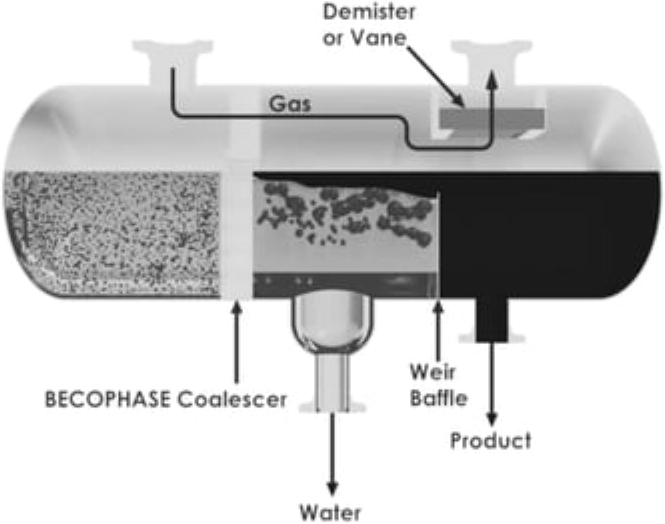
Components of Separator

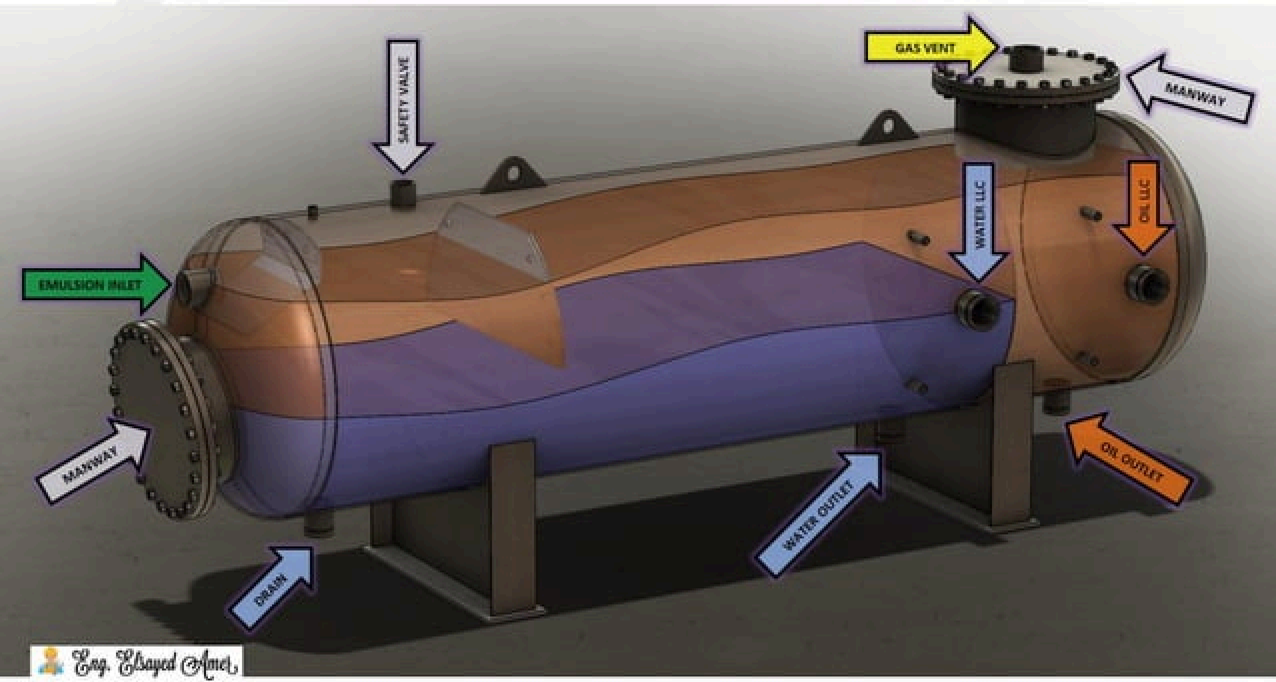
7. Weir

- ***vertical baffles placed in the liquid accumulation section of the separator. In a 3 phase vessel they separate the oil accumulation area from the water accumulation part.***
- ***They may also be used to isolate a section of the oil accumulation part of the separator. This will then provide a calm area for level control equipment to operate in.***
    - Locate at the bottom of the vessel
    - Divide the separator into two compartments
    - Control the water level
    - Permits oil to overflow into the oil compartment

Components of Separator

7. Weir





SAFETY VALVE
GAS VENT
MANWAY
EMULSION INLET
WATER LLC
OIL LLC
MANWAY
OIL OUTLET
WATER OUTLET
DRAIN
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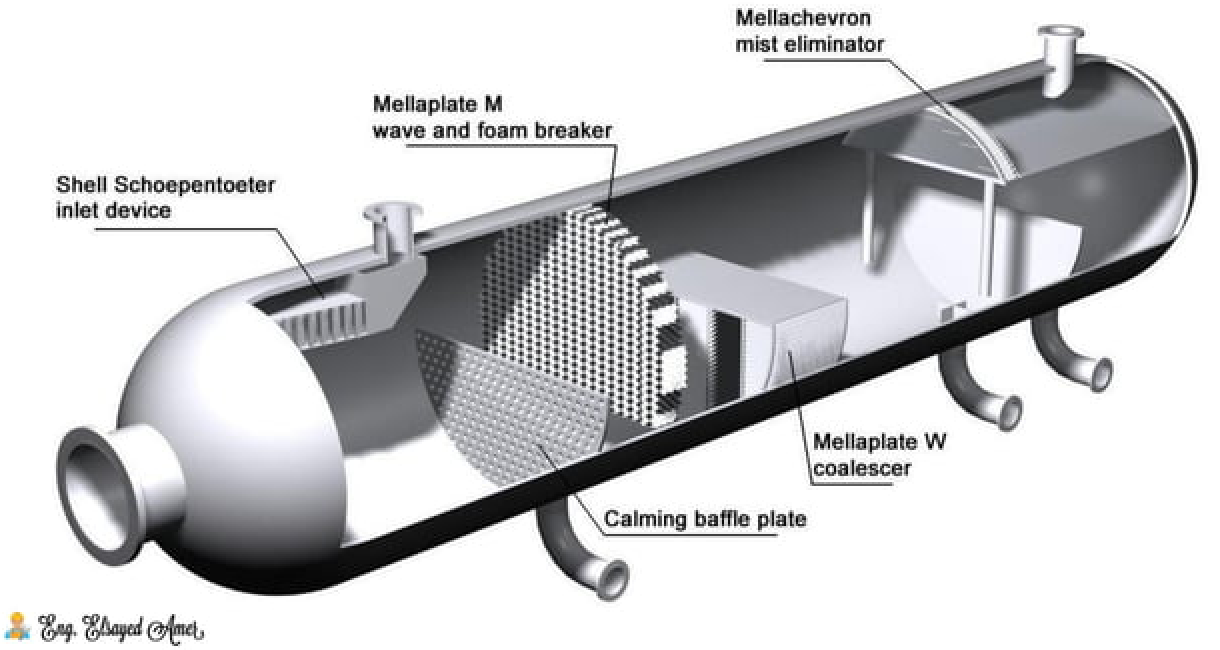

Mellachevron
mist eliminator
Mellaplate M
wave and foam breaker
Shell Schoepentoeter
inlet device
Mellaplate W
coalescer
Calming baffle plate
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Separation troubleshooting

Process point of view

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Operation problems

Gas Blow-by : Blowby occurs when free gas escapes with liquid phase and indicates

- ❑ low liquid level
- ❑ Vortexing
- ❑ Level control failure

Carryover: occurs when free liquid escapes gas phase

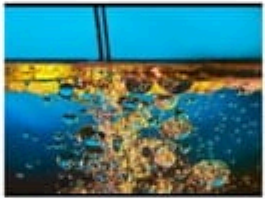
- ❑ Can indicate high liquid level
- ❑ Damage to vessel internals
- ❑ Plugged liquid outlets or exceeding the design rate of vessel (e.g. foam, improper design).

Amount of liquid carry over coming from droplets larger in size than 10 micron is generally less than 0.1 gallon / MSCFlow liquid level

Operation problems

Emulsions – Water Carry Through: troublesome in operations

- ❑ Over a period of time emulsified materials with other impurities accumulate & foam at inter-phase of W&O which affect the separation efficiency
- ❑ Addition of heat & chemicals often minimizes this difficulty
- ❑ To overcome the problem:
  - ➢ add de-emulsifier upstream of separator
  - ➢ provide coalescing devices
  - ➢ when necessary, provide heating coil to improve water settling & break of emulsion of waxy crudes (e.g. Mumbai High Crude)low liquid level



Operation problems

Solid Deposits : troublesome in operations

- Sand carryover from reservoirs
- Salt deposits from formation water

Troublesome;

- ❑ *Can cause cut-out of valve trims*
- ❑ *Plugging of internals*
- ❑ *Accumulations at bottom whereby reducing capacity of LAS & causing corrosion*

To overcome:

- ❑ *provide water-jets to fluidize & prevent accumulation*
- ❑ *Design outlet circuits considering accumulations and corrosion*
- ❑ *Provide anti-deposit additive injection after lab. tests*
- ❑ *Provide soft water injection facilities for water soluble salt deposit*

Operation problems

FOAMING : troublesome in operations, Can increase dramatically amount of liquid carry-over with gas.

Effects of foaming

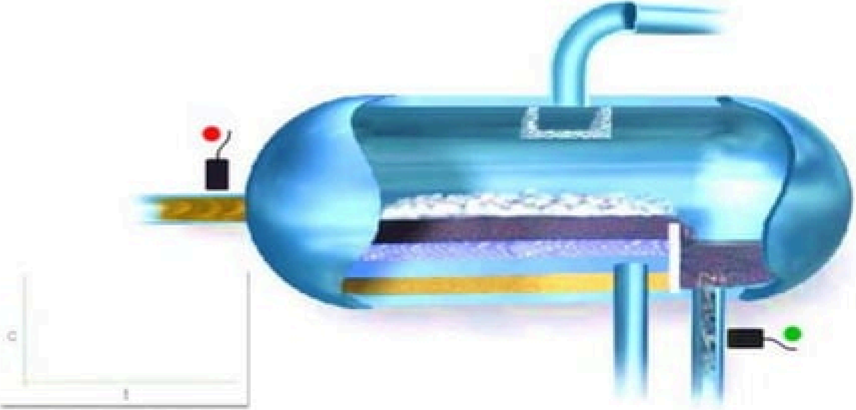
- Reduces the capacities of oil and gas separators
- Carry over of oil in gas
- Control of liquid levels

When foaming is 'potential problem:

- Antifoam additives injection be provided upstream of separator (lab. tests)
- Increase retention time within reasonable limits
- Install cyclonic device as fluid inlet distributor
- Provide vane type of mist extractor upstream of gas outlet nozzle

Operation problems

FOAMING : troublesome in operations, Can increase dramatically amount of liquid carry-over with gas.



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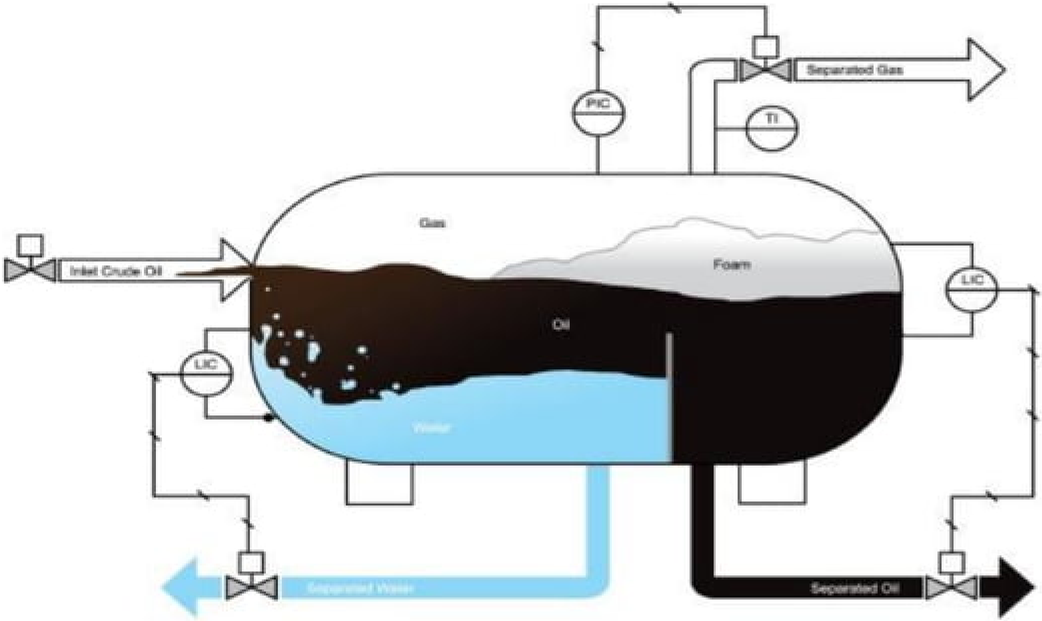

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Retention Time

Defined as : the average time a molecule of liquid is retained in the vessel assuming plug flow .

- ❑ It is thus the volume of liquid storage in the vessel divided by the liquid flow rate.
- ❑ It is affected by composition, foaming tendency, presence of solids & emulsions etc.

For most applications retention times between 30 sec. & 3 minutes have been found to be sufficient.

For foaming crudes, retention times up to four times this amount may be needed. For chemical reactors like 'Water Deoxygenating Towers' it is kept about 3 to 5 minutes.

Retention Time

Typical retention time Mins.

- *Natural gas-oil 2 – 3*
- *Lean oil - surge tank 10 – 15*
- *Fractionation feed tanks 8 – 15*
- *Refrigerant surge tanks 4 – 7*
- *Refrigerant economizers 2 – 3*

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Retention Time

Table 5-1
Oil Retention Time

°API Gravity	Minutes
Condensate	2–5
Light crude oil (30°–40°)	5–7.5
Intermediate crude oil (20°–30°)	7.5–10
Heavy crude oil (less than 20°)	10+

Note: If an emulsion exists in inlet stream, increase above retention times by a factor of 2 to 4.

Recommended retention time

Sizes and Capacities :

- Recommended retention time:

	Oil gravity ° API	Retention time (min.)
2-Phase Separators	> 35	1
	20-30	1-2
	10-20	2-4
3-Phase separators	>35	3-5
	Below35	
	100+° F	5-10
	80+° F	10-20
	60+° F	20-30

Type of Separation	Retention Time (Minutes)
Natural gas condensate separation	2 – 4
Fractionator feed tank	10 – 15
Reflux accumulator	5 – 10
Fractionation column sump	2[a]
Amine flash tank	5 – 10
Refrigeration surge tank	5
Refrigeration economizer	3
Heat medium oil surge tank	5 – 10[b]

Instrumentation and control system

Process point of view

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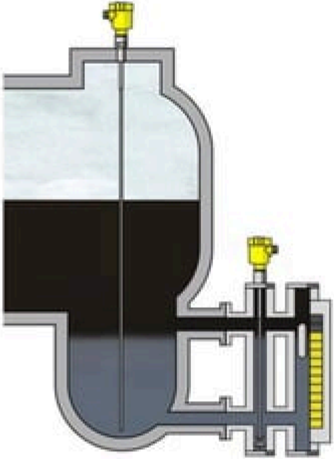
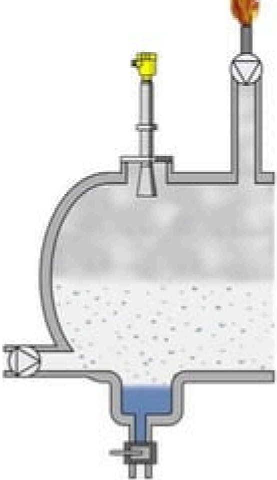
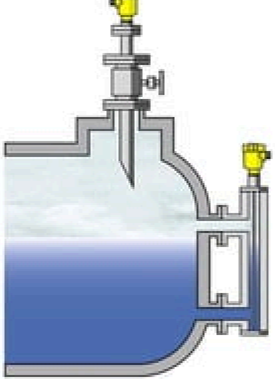
Vessel instrumentation



Level controller



Radar Level Transmitter



Radar Level Transmitter

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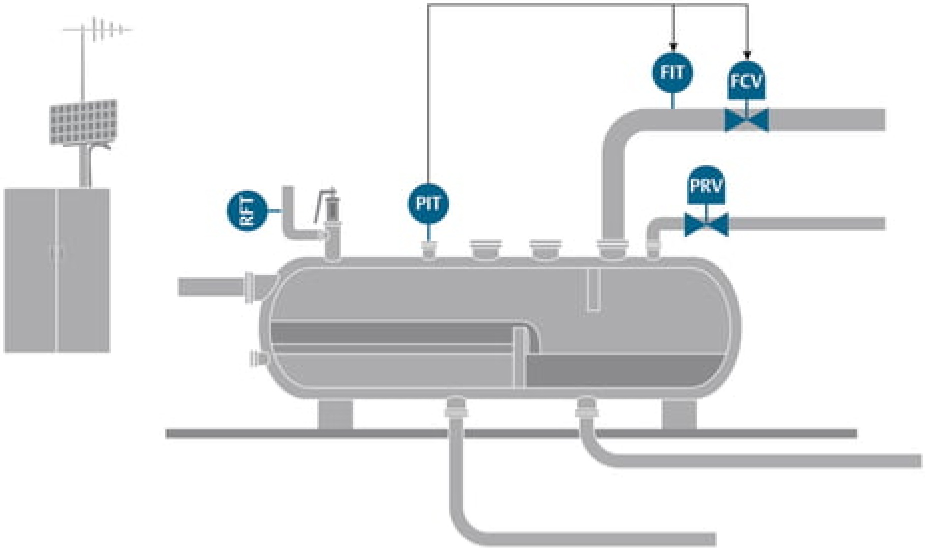
Pressure control



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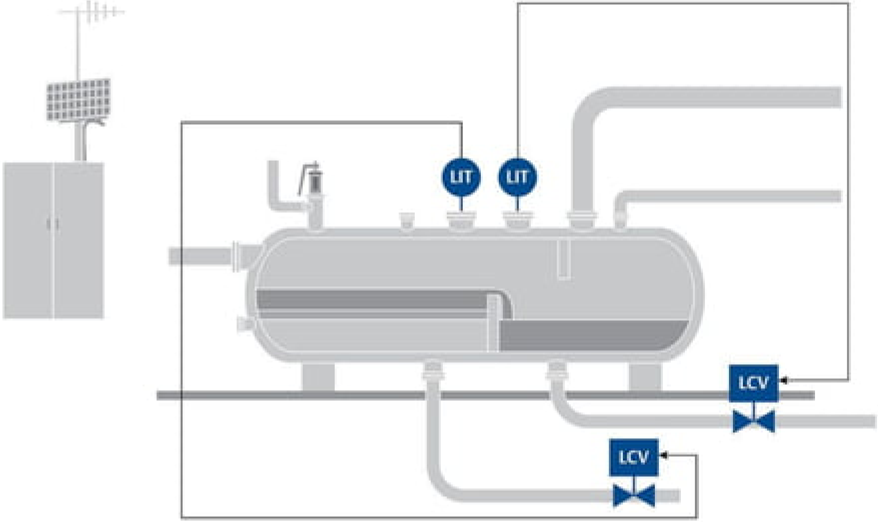
Level control



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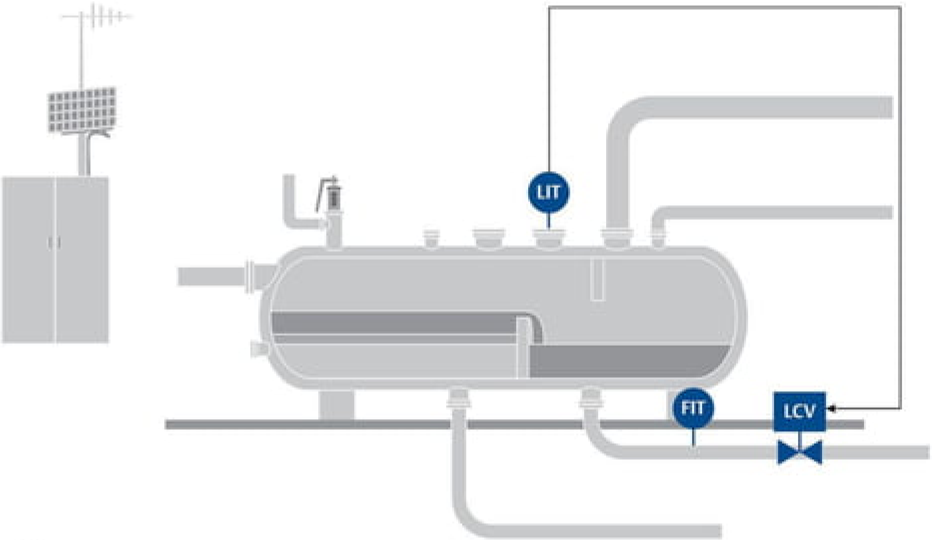
Oil Level control



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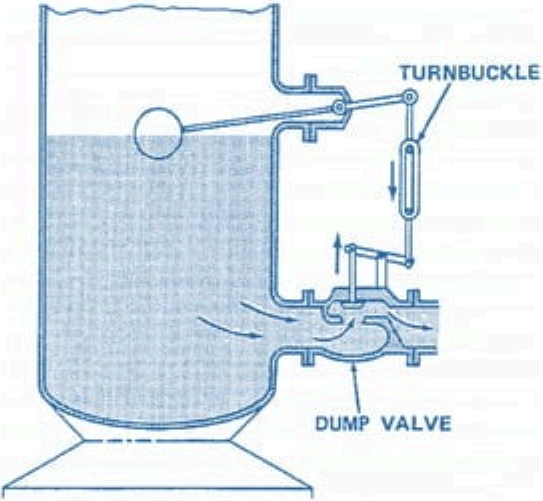
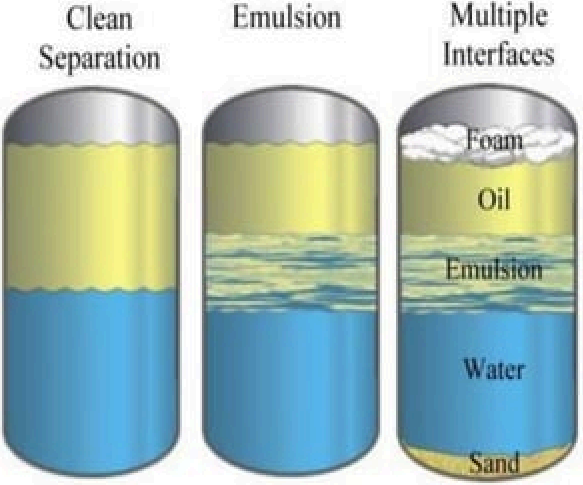
Level control





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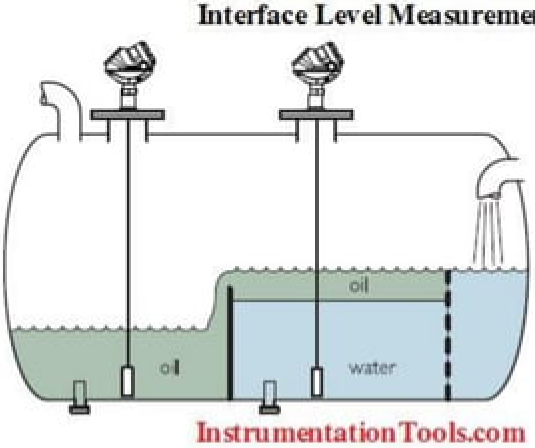
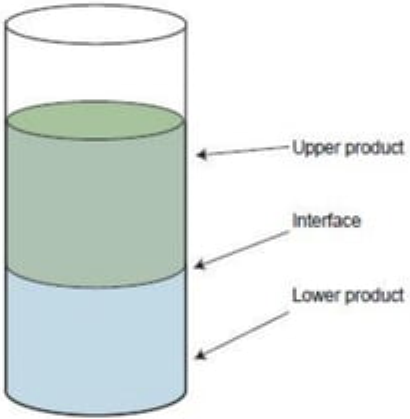
Level Measurement





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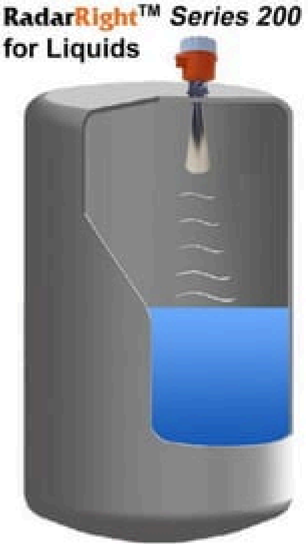
Level Measurement



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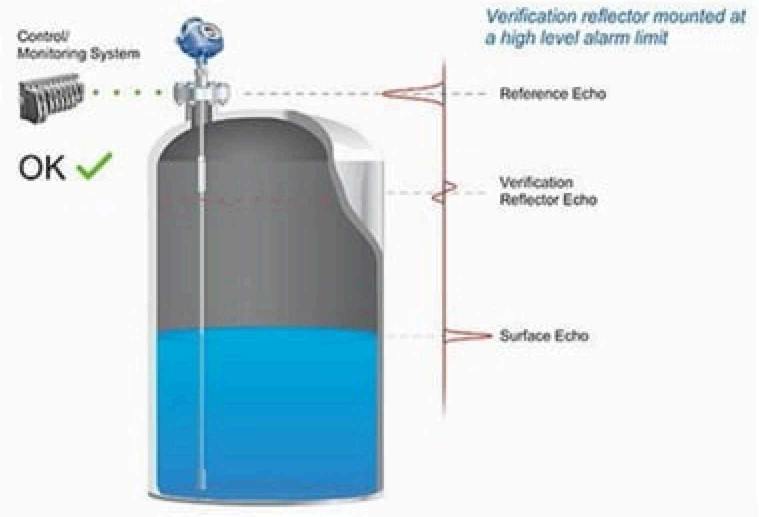
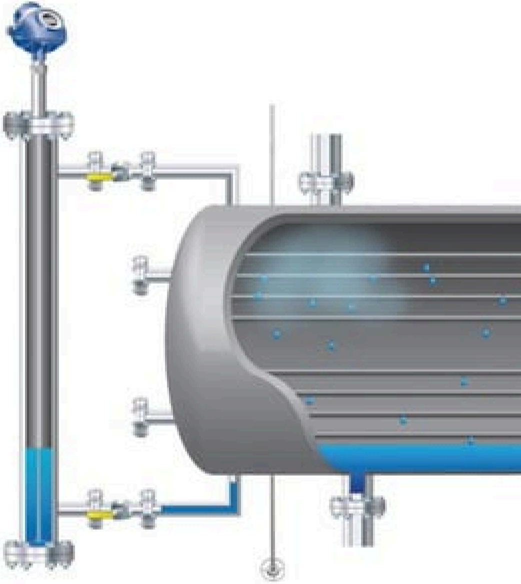
Level Measurement



Level transmitter



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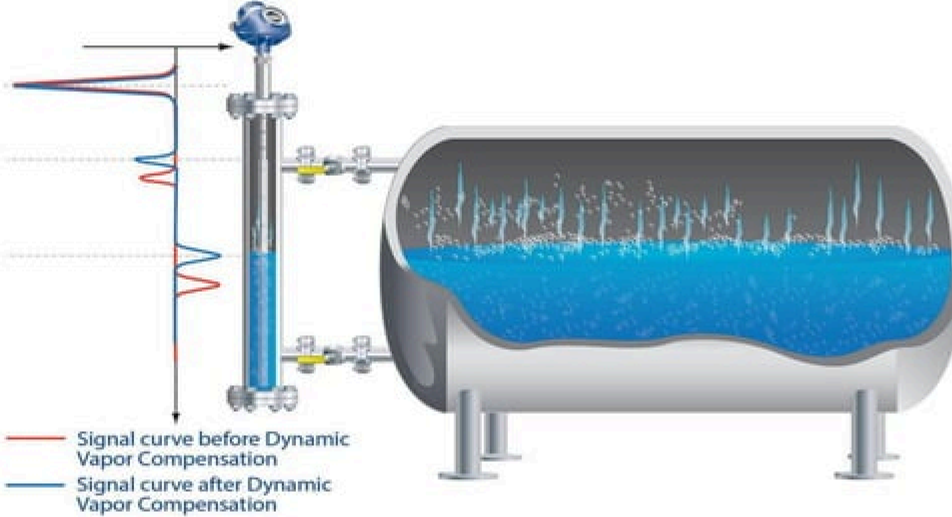
Level Indication



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Level switches

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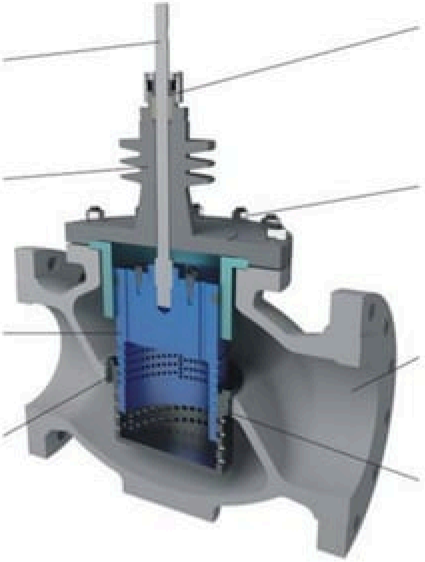
Level control



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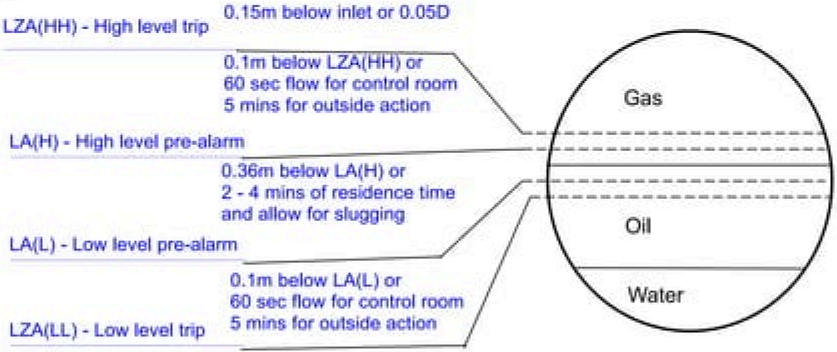
Level Control Settings

- Level control positions give a degree of flexibility to separator design
  - Response times from control room or outside operation
  - Slugging volumes
  - Residence times



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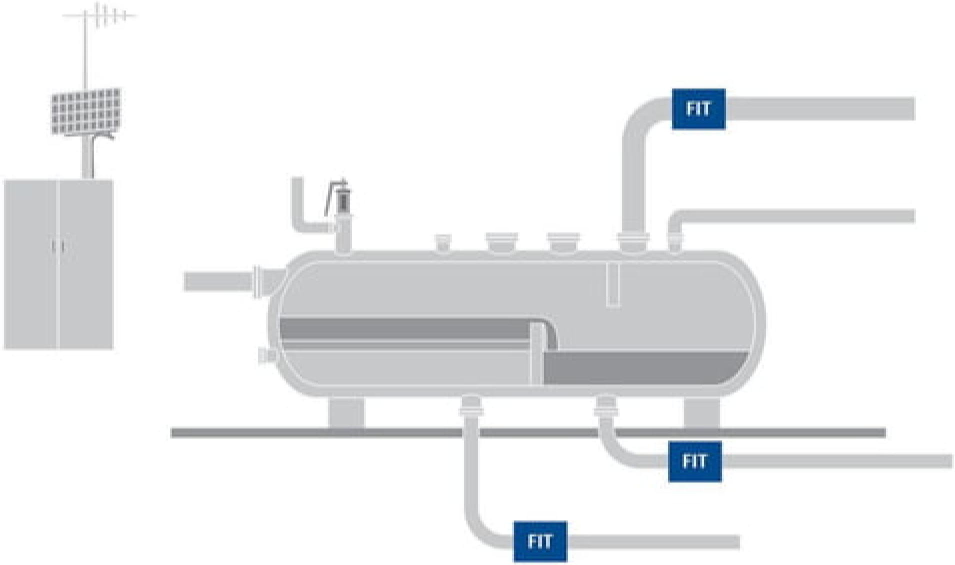
Flow control



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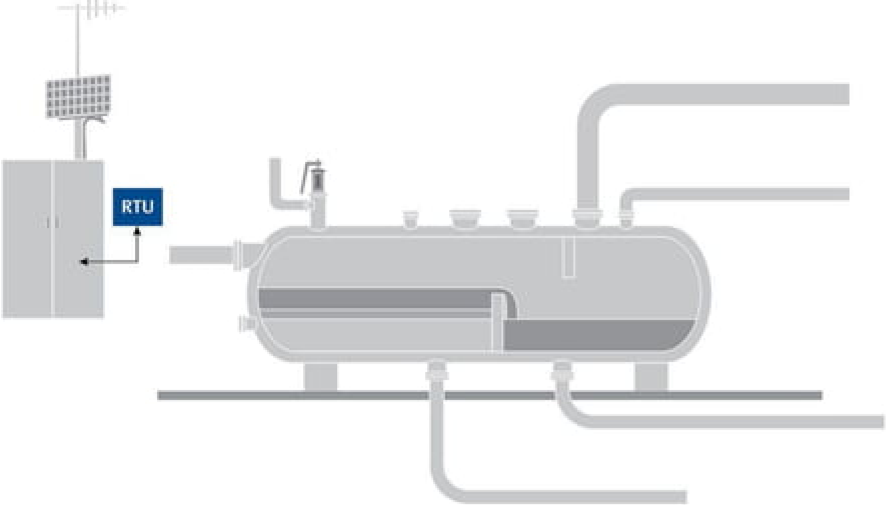
Process Monitoring



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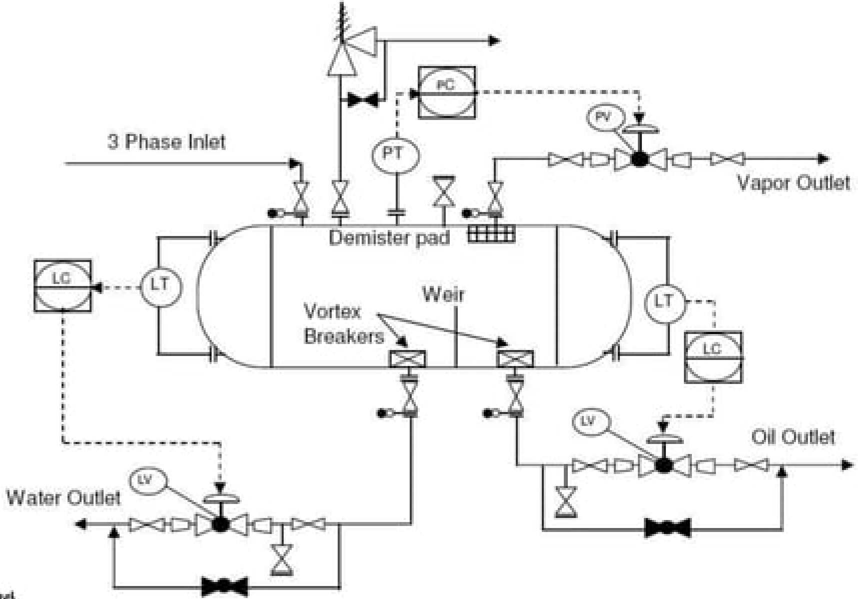

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Control valve standard

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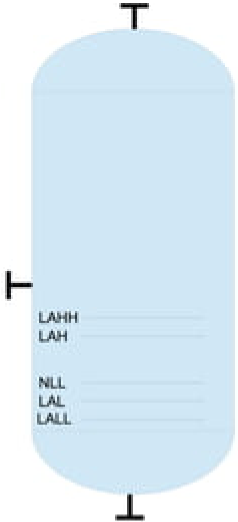
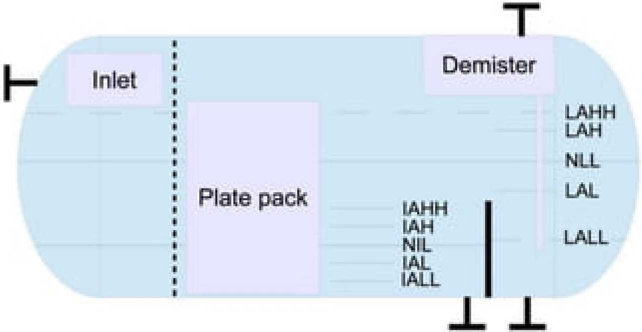
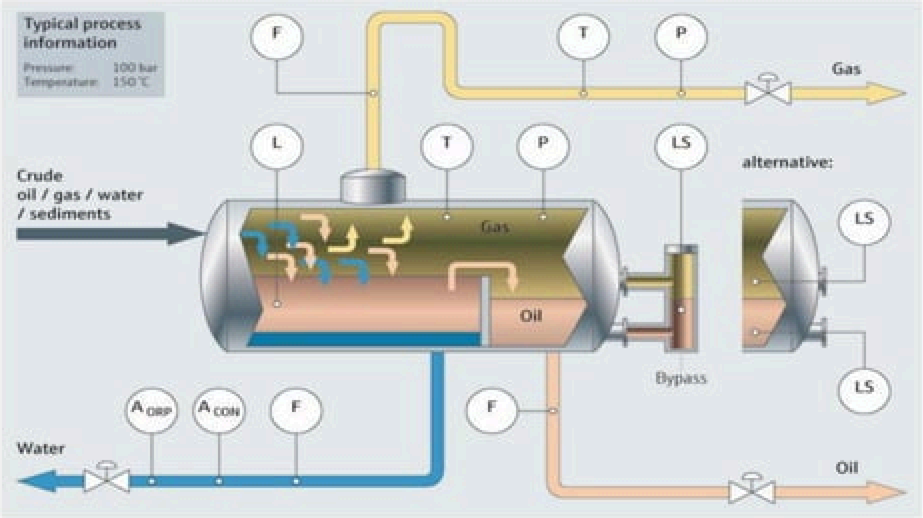
Liquid Levels Definition

NLL	Normal Liquid Level Liquid level maintained by controls during operation
HLL	High Liquid Level First liquid level above NLL to trigger an alarm
HHLL	High High Liquid Level Second liquid level above NLL to trigger a shutdown
LLL	Low Liquid Level First liquid level below NLL to trigger an alarm
LLLL	Low Low Liquid Level Second liquid level below NLL to trigger a shutdown
Hold-up time (Residence Time)	Time to fill separator from empty to NLL at design liquid feed rate.
Surge Time	Time to fill separator from NLL to HLL at design liquid feed rate.


LAHH
LAH
NLL
LAL
LALL


Inlet
Demister
Plate pack
LAHH
LAH
NLL
LAL
LALL
IAHH
IAH
NIL
IAL
IALL



Typical process information
Pressure: 100 bar
Temperature: 150 °C
F
T
P
Gas
L
T
P
LS
alternative:
Crude oil / gas / water / sediments
Gas
Oil
LS
Bypass
LS
A ORP
A CON
F
F
Water
Oil

Safety Devices in Separator

- PSHH (Pressure Swich High High)
- PSLL (Pressure Swich Low Low)
- LSHH (Level Swich High High)
- LSLL (Level Swich Low Low)
- BDV (Blowdown Valve)
- PSV (Pressure Safety Valve)
- SDV (Shut Down Valve)

Comparison of vertical and horizontal support structures

Since vertical separators are supported only by the bottom skirt (Figure 3.16), the walls of vertical separators must be somewhat thicker than a similarly sized and rated horizontal separator, which may be supported by saddles.

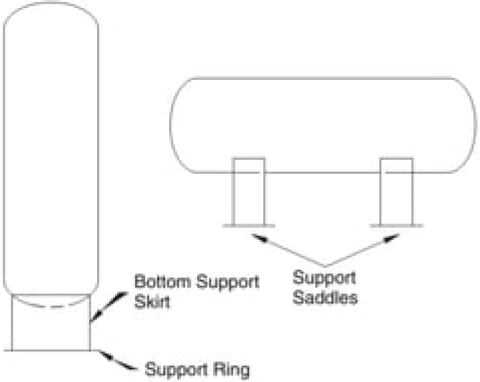
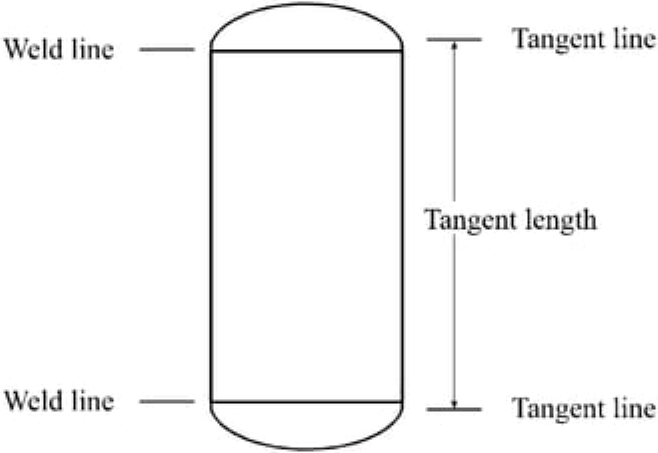
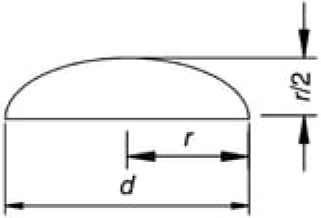


FIGURE 3.16. Comparison of vertical and horizontal support structures.

Geometry





Ellipsoidal head

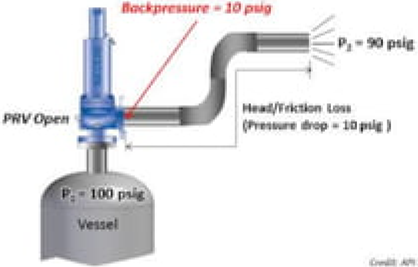
Hemispherical head

PRV – Built-up Backpressure

MHH

Additional Pressure** generated on the outlet side **when the valve is discharging.

- ***Due to Pressure Drop*** in the discharge system as a result of flow from the PRV (head/friction loss)
- Built-up backpressure ***> 10% set pressure*** → Balanced bellow



Pressure Nomenclature

1. **Normal Operating**
   - Pressure at which equipment operates

1. **Maximum operating**
   - Highest operating pressure foreseen for all applicable cases (normal, turndown, startup shutdown).

1. **Design Pressure**
   - Maximum operating pressure plus a safety margin

Process Design Conditions

Determine Design Pressure

Maximum Operating Pressure, psig	Design Pressure, psig
Less than 25	50
25 to 250	Oper P + 25
250 to 1000	(Oper P) * (1.1)
More than 1000	(Oper P) * (1.05) (*)
(*) Applicable only if pilot operated relief valves are used, otherwise use a 10 percent margin	

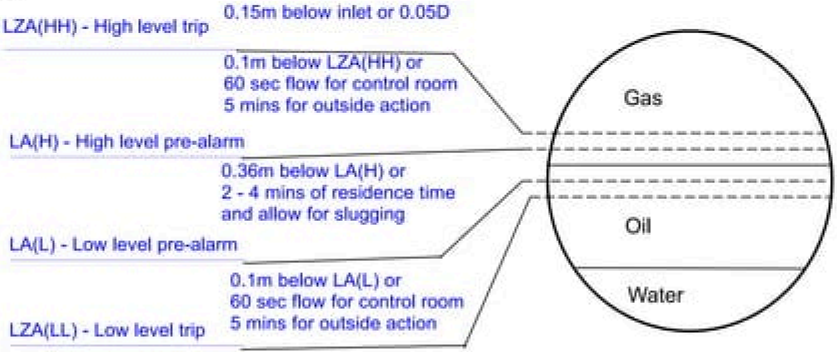
Sizes and Capacities :

Sizes and Capacities :

- **Liquid levels**
  - **Maximum oil level : < 0.65 I.D.**
  - **Normal oil level : 0.5 I.D. or 1 min. retention time between max. and normal liq. Level**
  - **Low oil level : 0.1 I.D. or 12" from bottom**
  - **Water/ inter face level : Water retention time of 1-2 min. or 12" which ever is greater**

Level Control Settings

- Level control positions give a degree of flexibility to separator design
  - Response times from control room or outside operation
  - Slugging volumes
  - Residence times



D.P. 1250 PSIG   O.T. 77 °F