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Offshore Equipment

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Two-phase oil and gas separation

Introduction

- The velocity of the gas carries liquid droplets, and the liquid carries gas bubbles. The physical separation of these phases is one of the basic operations in the production, processing, and treatment of oil and gas.
- In oil and gas separator design, we mechanically separate the liquid and gas components from a hydrocarbon stream that exist at a specific temperature and pressure. Proper separator design is important because a separation vessel is normally the initial processing vessel in any facility, and improper design of this process can “bottleneck” and reduce the capacity of the entire facility.
- Downstream equipment cannot handle gas-liquid mixtures. For example, pumps require gas-free liquid, to avoid cavitation, while compressors and dehydration equipment require liquid-free gas.
- In addition, measurement devices for gases or liquids are highly inaccurate when another phase is present.
- Two phase: Separate gas from the total liquid stream
- Three phase: also separate the liquid stream into crude oil and water
- Gas scrubber: the ratio of gas rate to liquid rate is very high (mostly gas)
- Slug catcher: two-phase separator to handle intermittent large liquid slug

Phase equilibrium

- Equilibrium: a “steady-state” condition whereby the vapor is condensing to a liquid at exactly the same rate at which liquid is boiling to vapor.
- Flash calculation: determine the vapor liquid ratio, which is used to size a separator.

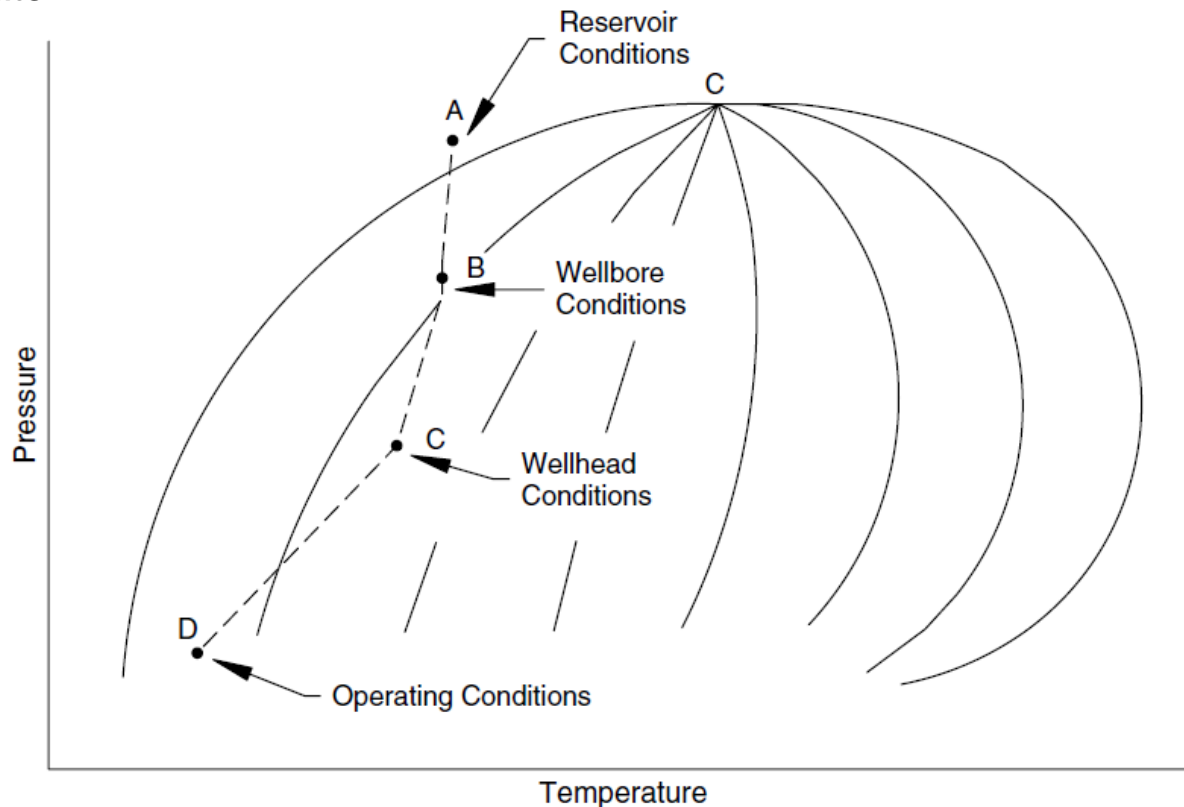


Figure 4-1. Phase equilibrium phase diagram for a typical production system.

Factors affecting separation

- Gas and liquid flow rates (minimum, average, and peak),
- Operating and design pressures and temperatures,
- Surging or slugging tendencies of the feed streams,
- Physical properties of the fluids such as density and compressibility factor,
- Designed degree of separation (e.g., removing 100% of particles greater than 10 microns),
- Presence of impurities (paraffin, sand, scale, etc.),
- Foaming tendencies of the crude oil,
- Corrosive tendencies of the liquids or gas.

Functional section of a Gas-Liquid separator

- Inlet Diverter Section

- : abruptly changes the direction of flow by absorbing the momentum of the liquid and allowing the liquid and gas to separate.

- Liquid Collection Section

- : provides the required retention time necessary for any entrained gas in the liquid to escape to the gravity settling section. Also, provides surge volume.

- : The degree of separation is dependent on the retention time provided. Retention time is affected by the amount of liquid the separator can hold, the rate at which the fluids enter the vessel, and the differential density of the fluids.

- Gravity Settling Section

- : Gas velocity drops and small liquid droplets entrained in the gas stream and not separated by the inlet diverter are separated out by gravity and fall to the gas-liquid interface. (remove liquid droplets greater than 100~140 micron)

- Mist Extractor Section

- : Coalescing section to gather small droplets less than 100~140 microns.

- : As the gas flows through the coalescing elements, it must make numerous directional changes.

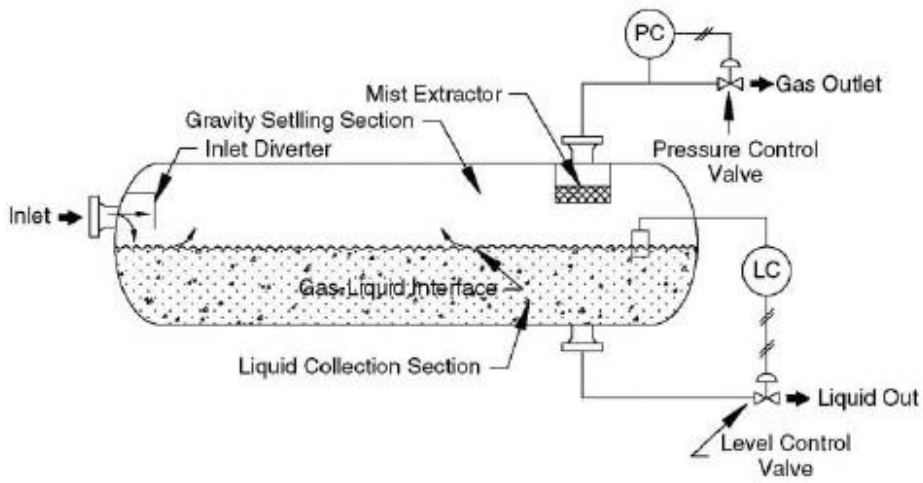


Figure 4-2. Horizontal separator schematic.

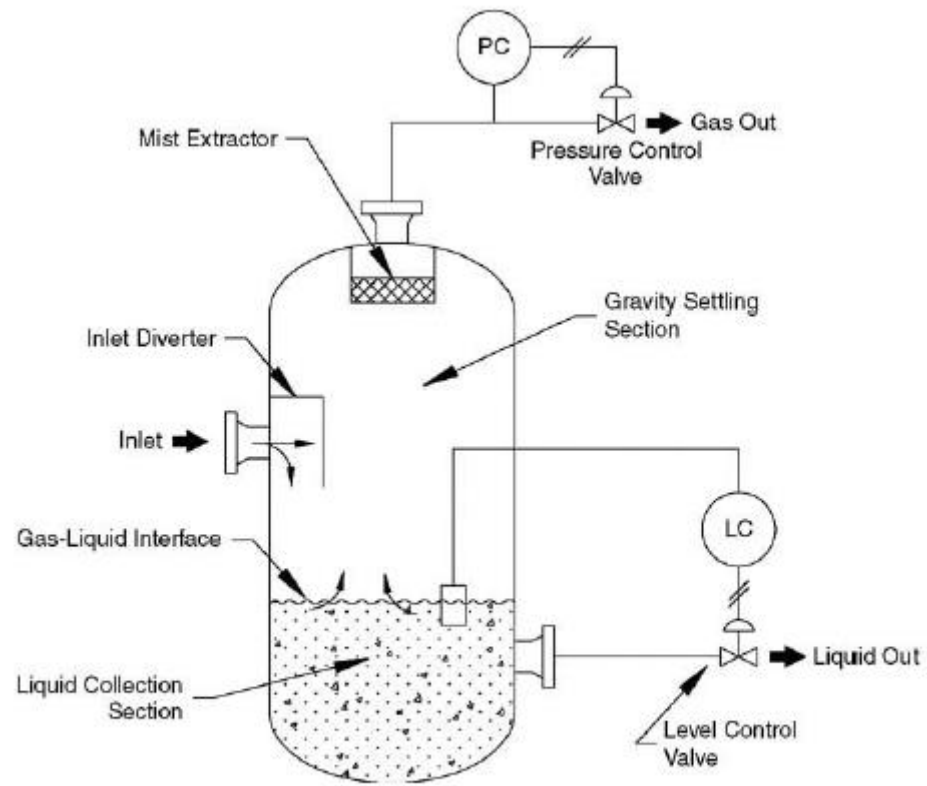


Figure 4-3. Vertical separator schematic.

Equipment description

- Horizontal, vertical, spherical, and a variety of other configurations

Horizontal separators

- : The liquid collection section provides the retention time required to let entrained gas evolve out of the oil and rise to the vapor space and reach a state of “equilibrium.”
- : It also provides a surge volume, if necessary, to handle intermittent slugs of liquid.
- : The liquid dump valve is regulated by a level controller. The level controller senses changes in liquid level and controls the dump valve accordingly.
- : The pressure in the separator is maintained by a pressure controller mounted on the gas outlet. The pressure controller senses changes in the pressure in the separator and sends a signal to either open or close the pressure control valve accordingly.

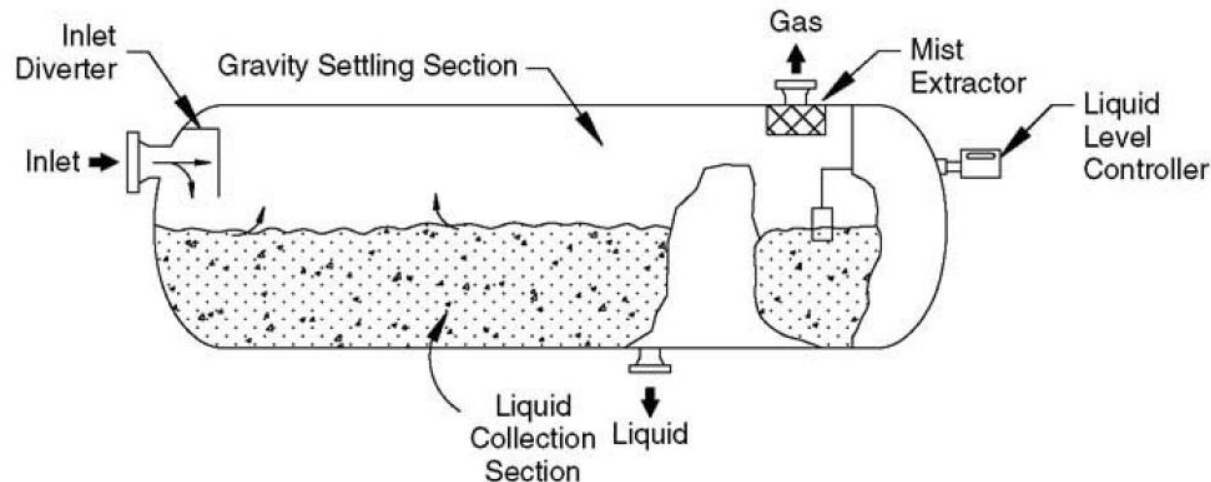


Figure 4-4. Cutaway view of a horizontal two-phase separator.

- Normally, horizontal separators are operated half full of liquid to maximize the surface area of the gas-liquid interface.
- Horizontal separators are smaller and thus less expensive than a vertical separator for a given gas and liquid flow rate. Horizontal separators are commonly used in flow streams with high gas-liquid ratios and foaming crude.

Vertical separators

- The liquid flows down to the liquid collection section of the vessel. The level controller and liquid dump valve operate the same as in a horizontal separator.
- Secondary separation occurs in the upper gravity settling section. In the gravity settling section the liquid droplets fall vertically downward counter-current to the upward gas flow.
- A mist extractor section is added to capture small liquid droplets.
- Pressure and level are maintained as in a horizontal separator.
- Vertical separators are commonly used in flow streams with low to intermediate gas-liquid ratios.
- Suited for sand production

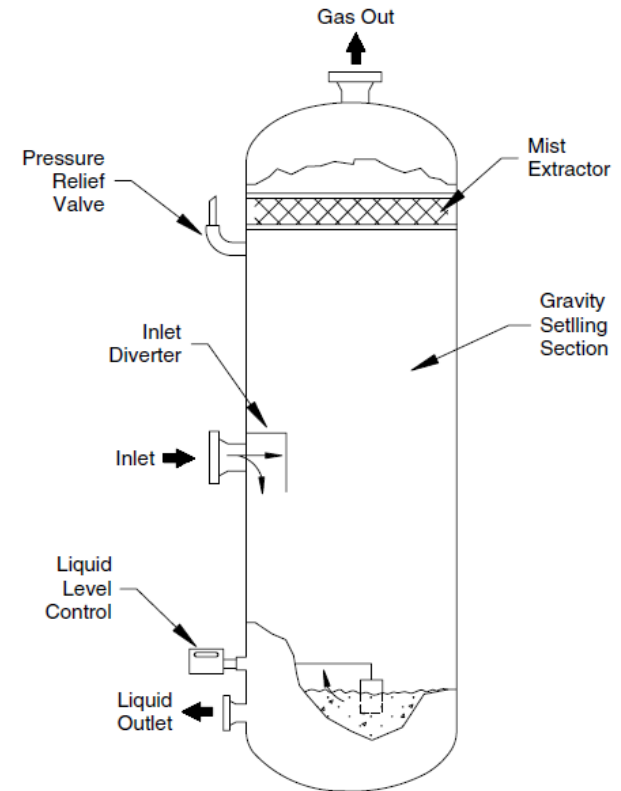


Figure 4-5. Cutaway view of a vertical two-phase separator.

Spherical separators

- They have limited liquid surge capability and exhibit fabrication difficulties, thus they are seldom used in oil field facilities.

Centrifugal separators

- The basic flow pattern involves a double vortex, with the gas spiraling downward along the wall, and then upward in the center.
- no moving parts; low maintenance; compact; insensitive to motion; low cost.
- But, rather sensitive to flow rate; require large pressure drop; not suitable for widely varying flow rates

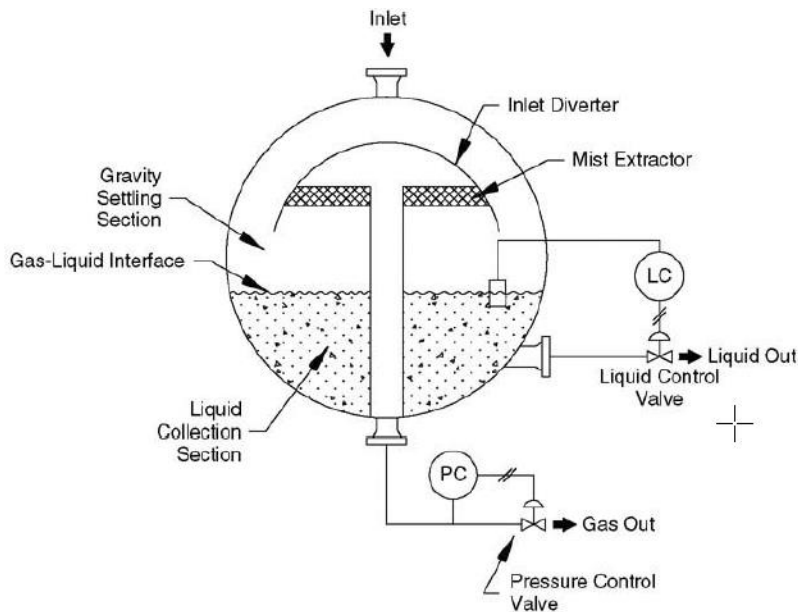


Figure 4-6. Spherical separator schematic.

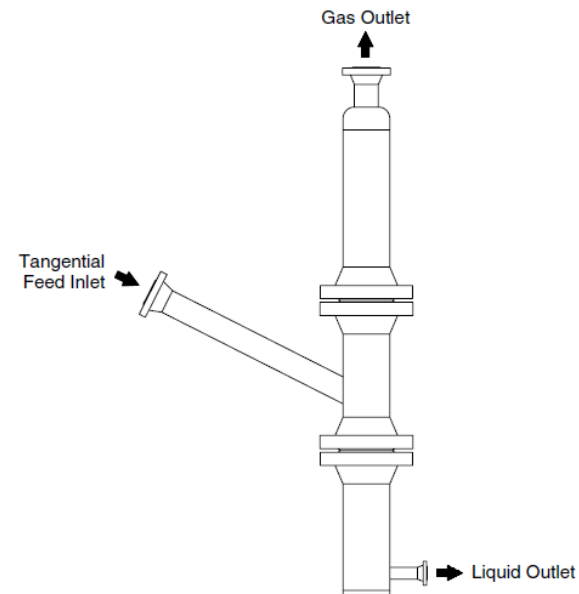


Figure 4-7. Cylindrical cyclone separator.

Venturi separator

- Like the centrifugal, the venturi separator increases droplet coalescence by introducing additional forces into the system.
- Not cost effective, high pressure drop

Double-barrel horizontal separator

- For high gas flow rates and there is a possibility of large liquid slugs.
- The baffles help the free liquids to fall to the lower barrel
- Due to additional cost not widely used in oil field, but used as gas scrubber.

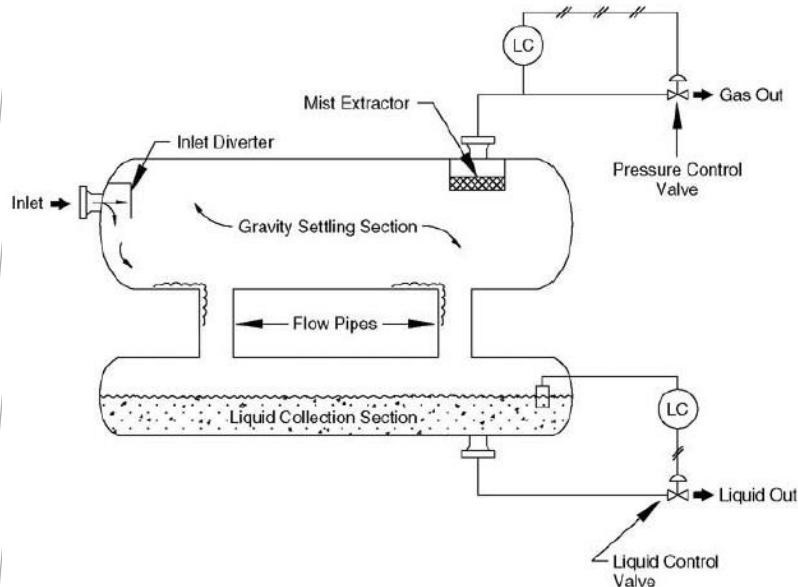


Figure 4-8. Double-barrel horizontal separator.

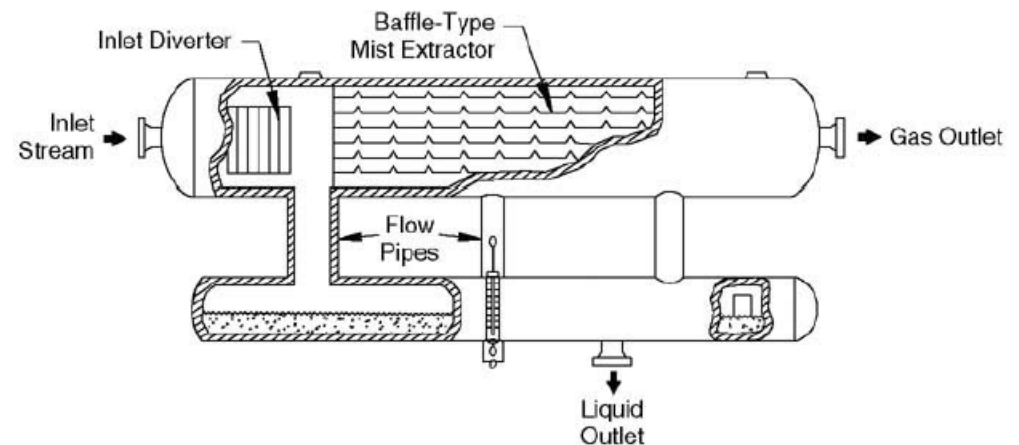


Figure 4-9. Cutaway view of a horizontal double-barrel separator fitted with a baffle-type mist extractor in the gravity settling section.

Horizontal separator with a boot or water pot

- It is used when there are very low liquid flow rates, especially where the flow rates are low enough that the “boot” can serve as a liquid-liquid separator.

Filter separators

- designed to remove small liquid and solid particles from the gas stream.
- Filter tubes in the initial separation section cause coalescence, while a secondary section of vanes removes these coalesced droplets
- Used on compressor inlet, upstream of glycol contact tower, and fuel gas application

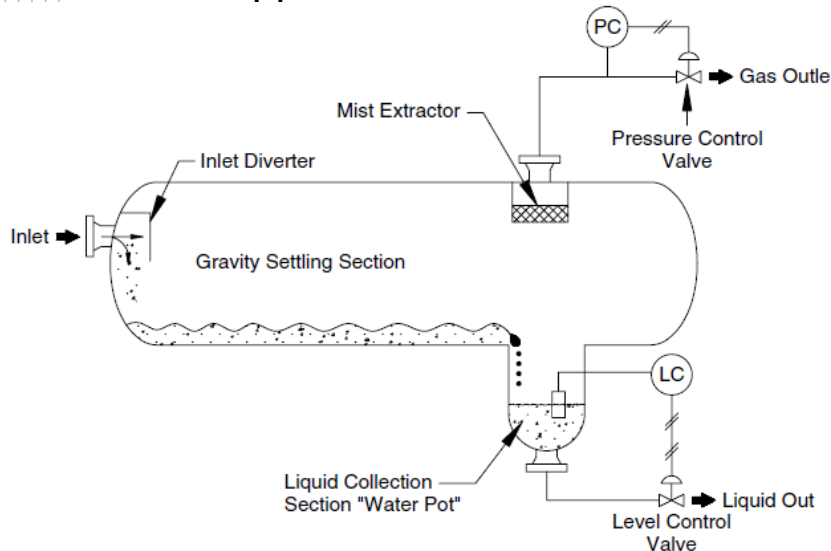


Figure 4-10. Single-barrel horizontal separator with a liquid “boot.”

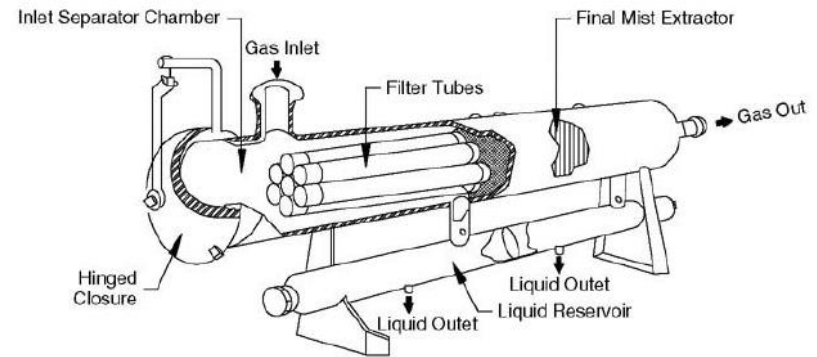


Figure 4-11. Typical horizontal two-barrel filter separator.

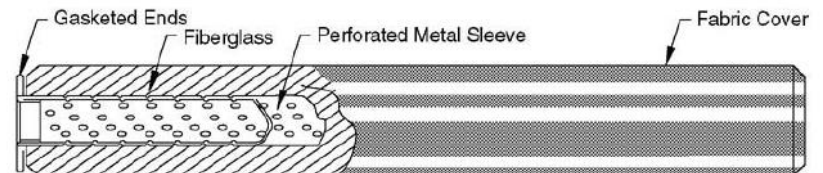


Figure 4-12. Typical filter element.

Scrubbers

- : 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.
- : Liquid loading in a scrubber is much lower than that in a separator.
- : used for upstream of mechanical equipment such as compressors that could be damaged, destroyed or rendered ineffective by free liquid;
- : Downstream of equipment that can cause liquids to condense from a gas stream (such as coolers);
- : upstream of gas dehydration equipment that would lose efficiency, be damaged, or be destroyed if contaminated with liquid hydrocarbons;
- : and upstream of a vent or flare outlet.
- : Vertical scrubbers are most commonly used. Horizontal scrubbers can be used, but space limitations usually dictate the use of a vertical configuration.

Slug catcher

: 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.

: When the pigs sweep the liquids out of the gathering lines, large volumes of liquids must be handled by the downstream separation equipment.

: Gas and liquid slug from the gathering system enters the horizontal portion of the two-phase vessel, where primary gas-liquid separation is accomplished.

: Gas exits the top of the separator through the mist extractor while the liquid exits the bottom of the vessel through a series of large-diameter tubes or “fingers.”

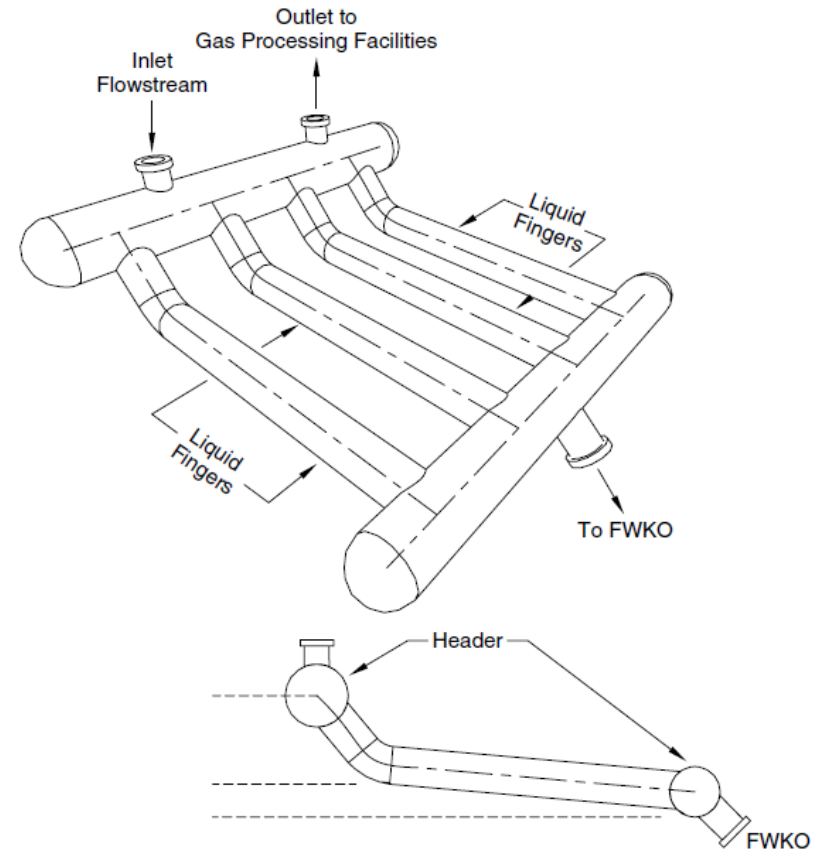


Figure 4-13. Schematic of a two-phase horizontal slug catcher with liquid “fingers.”

Selection considerations

- Horizontal separators are smaller, more efficient at handling large volumes of gas, and less expensive than vertical separators for a given gas capacity.
 - : Gravity settling section - the liquid droplets fall perpendicular to the gas flow and thus are more easily settled out of the gas continuous phase.
 - : Since the interface area is larger in a horizontal separator than a vertical separator, it is easier for the gas bubbles to reach the vapor space.
 - : Horizontal separators offer greater liquid capacity and are best suited for liquid-liquid separation and foaming crude.
- From a pure gas/liquid separation process, horizontal separators would be preferred.

- However, they do have the following drawbacks, which could lead to a preference for a vertical separator in certain situations;
 1. Horizontal separators are not as good as vertical separators in handling solids.
 - : For a vertical separator, the liquid dump line can be placed at the center of the bottom so that solids will not build up but continue to the next vessel.
 2. In a horizontal vessel, it is necessary to place several drains along the length of the vessel.
 - : to remove solids at the bottom. Need to provide sand jets.
 3. Horizontal vessels require more plan area to perform the same separation as vertical vessels.
 - : may be overcome by stacking.
 4. Smaller, horizontal vessels can have less liquid surge capacity than vertical vessels sized for the same steady-state flow rate.
 - : For a given change in liquid surface elevation, there is typically a larger increase in liquid volume for a horizontal separator than for a vertical separator sized for the same flow rate.
 - : Surges in horizontal vessels could create internal waves, which could activate a high-level sensor prematurely.

- Vertical vessels also have some drawbacks that are not process related and must be considered in making a selection.
 1. The relief valve and some of the controls may be difficult to service without special ladders and platforms.
 2. The vessel may have to be removed from a skid for trucking due to height restrictions.
- Generally, horizontal separators are less expensive than equally sized vertical separators.
- Since vertical separators are supported only by the bottom skirt, the walls of vertical separators must be somewhat thicker than a similarly sized and rated horizontal separator, which may be supported by saddles.

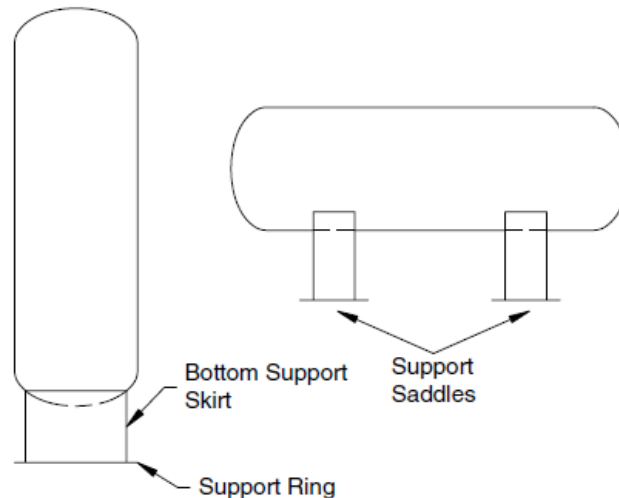


Figure 4-14. Comparison of vertical and horizontal support structures.

- Furthermore, large vertical separators, when exposed to high winds, can be subjected to large lateral (wind) loads. When this is the case, the vertical separator's wall thickness must be increased, which in turn increases the cost of the overall vessel.
- Overall, horizontal vessels are the most economical for normal oil-gas separation, particularly where there may be problems with emulsions, foam, or high gas-oil ratios (GOR).
- Vertical vessels work most effectively in low-GOR applications.
- They are also used in some very high GOR applications, such as scrubbers where only fluid mists are being removed from the gas and where extra surge capacity is needed to allow shutdown to activate before liquid is carried out the gas outlet (e.g., compressor suction scrubber).

Vessel internals

Inlet diverters

- A baffle plate can be a spherical dish, flat plate, angle iron, cone, elbow, or just about anything that will accomplish a rapid change in direction and velocity of the fluids and thus disengage the gas and liquid.
- The advantage of using devices such as a half-sphere elbow or cone is that they create less disturbance than plates or angle iron, cutting down on re-entrainment or emulsifying problems.
- Centrifugal inlet diverters use centrifugal force, but the design is rate sensitive. At low velocities it will not work properly

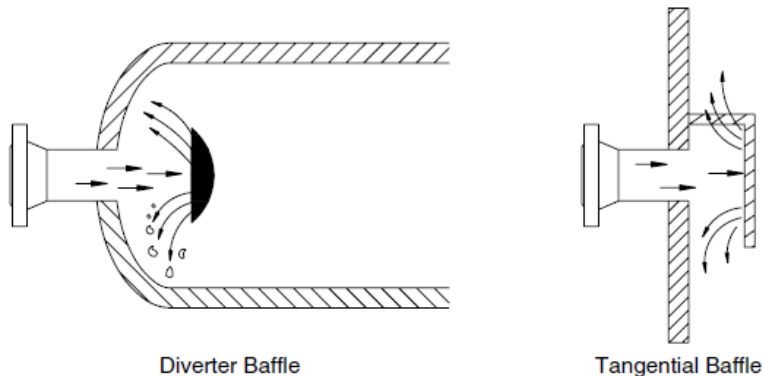


Figure 4-15. Baffle plates.

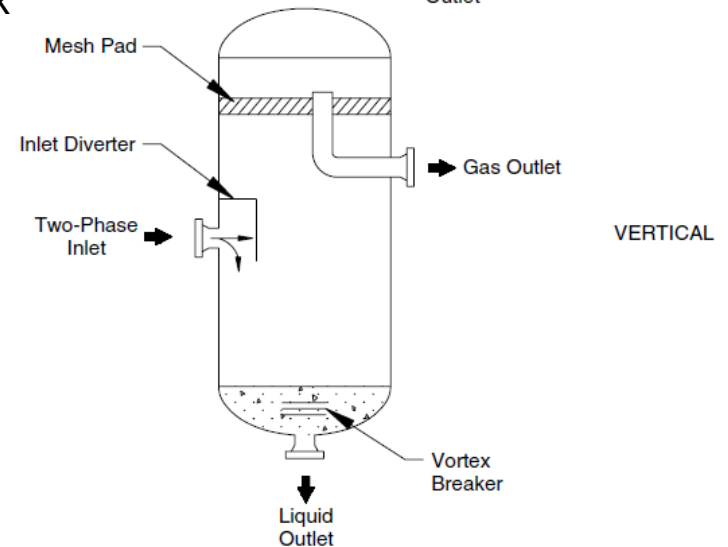
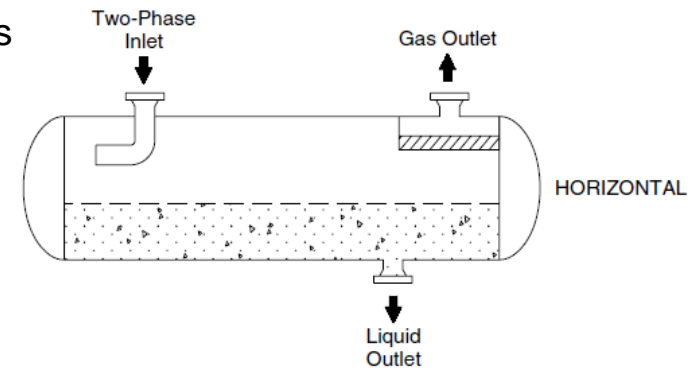


Figure 4-17. Elbow inlet diverter.

Wave breakers

- Wave breakers are nothing more than perforated baffles or plates that are placed perpendicular to the flow located in the liquid collection section of the separator.
- On floating or compliant structures where internal waves may be set up by the motion of the foundation, wave breakers may also be required perpendicular to the flow direction.

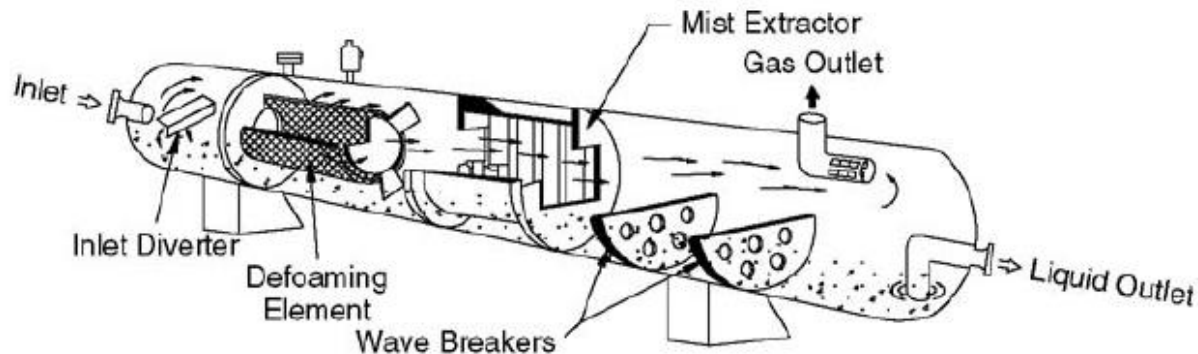


Figure 4-19. Three-dimensional view of a horizontal separator fitted with an inlet diverter, defoaming element, mist extractor, and wave breaker.

Defoaming plates

- Foam at the interface may occur when gas bubbles are liberated from the liquid. This can be stabilized with the addition of chemicals.
- Or force the foam to pass through a series of inclined parallel plates or tubes. These plates or tubes provide additional surface area, which allows the foam to collapse into liquid layer.

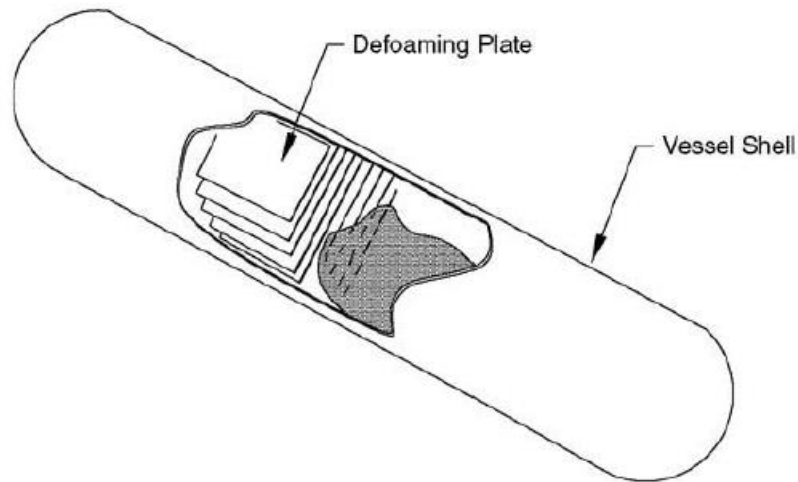


Figure 4-20. Defoaming plates.

Vortex breaker

- Horizontal separators are often equipped with vortex breakers, which prevent a vortex from developing when the liquid control valve is open.
- A vortex could suck some gas out of the vapor space and re-entrain it in the liquid outlet. Any circular motion is prevented by the flat plates.

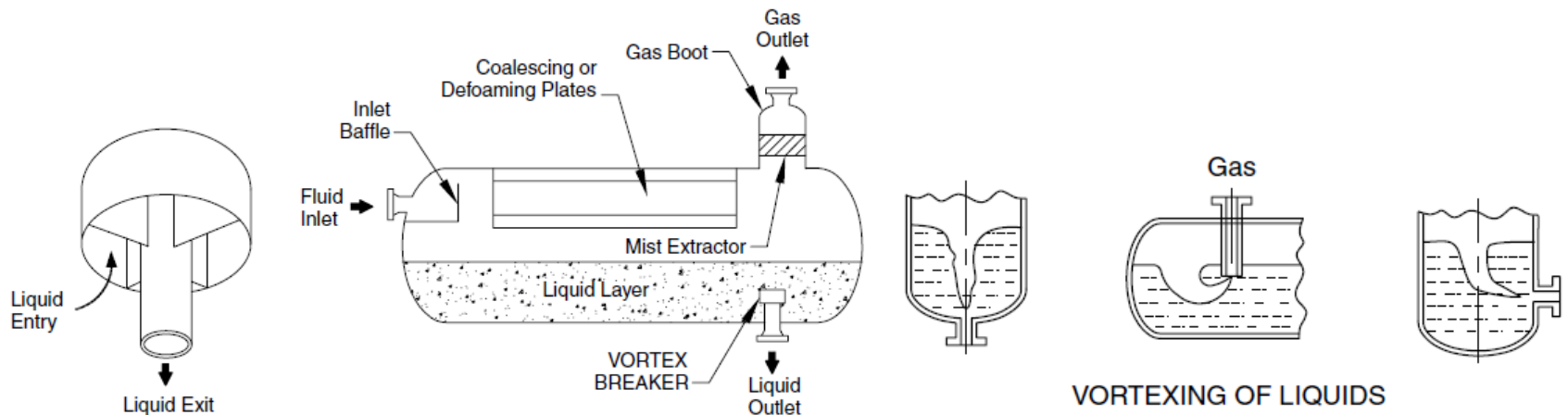


Figure 4-21. Vortex breaker.

Stilling well

- simply a slotted pipe fitting surrounding an internal level control displacer, protects the displacer from currents, waves, and other disturbances

Sand jets and drains

- To remove the solids, sand drains are opened in a controlled manner, and then high-pressure fluid, usually produced water, is pumped through the jets to agitate the solids and flush them down the drains. (jet tip velocity: 6 m/s)
- To assure proper solids removal without upsetting the separation process, an integrated system, consisting of a drain and its associated jets, should be installed at intervals not exceeding 5 ft (1.5 m).

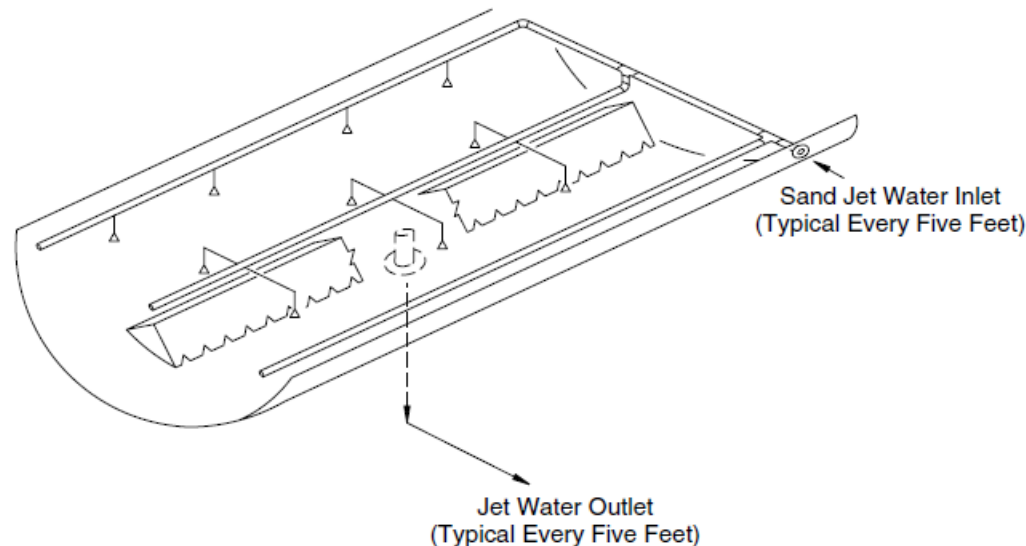


Figure 4-23. Schematic of a horizontal separator fitted with sand jets and inverted trough.

Mist extractors

- 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
- All mist extractor types are based on the some kind of intervention in the natural balance between gravitational and drag forces
 - : Overcoming drag force by reducing the gas velocity (gravity separators or settling chambers)
 - : Introducing additional forces (venturi scrubbers, cyclones, electrostatic precipitators)
 - : Increasing gravitational force by boosting the droplet size (impingement-type)

- Baffles

- : consists of a series of baffles, vanes, or plates between which the gas must flow.

- : The surface of the plates serves as a target for droplet impingement and collection. The space between the baffles ranges from 5 to 75 mm, with a total depth in the flow direction of 150 to 300 mm.

- : As gas flows through the plates, droplets impinge on the plate surface. The droplets coalesce, fall, and are routed to the liquid collection section of the vessel.

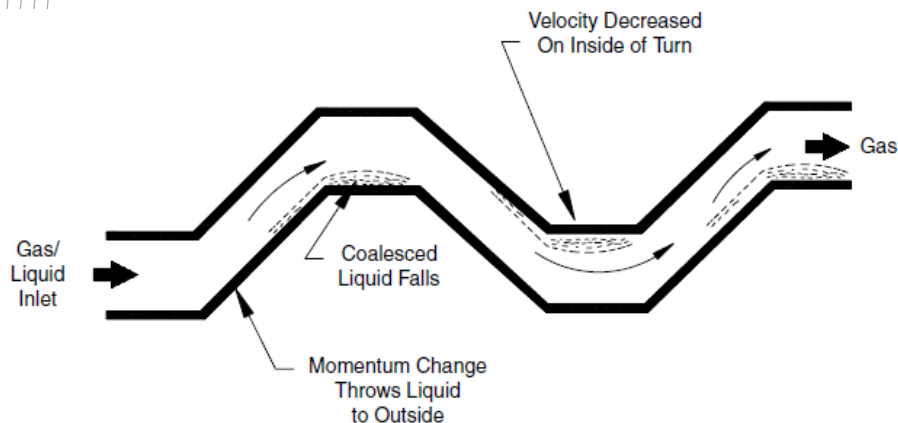


Figure 4-25. Typical vane-type mist extractor/eliminator.

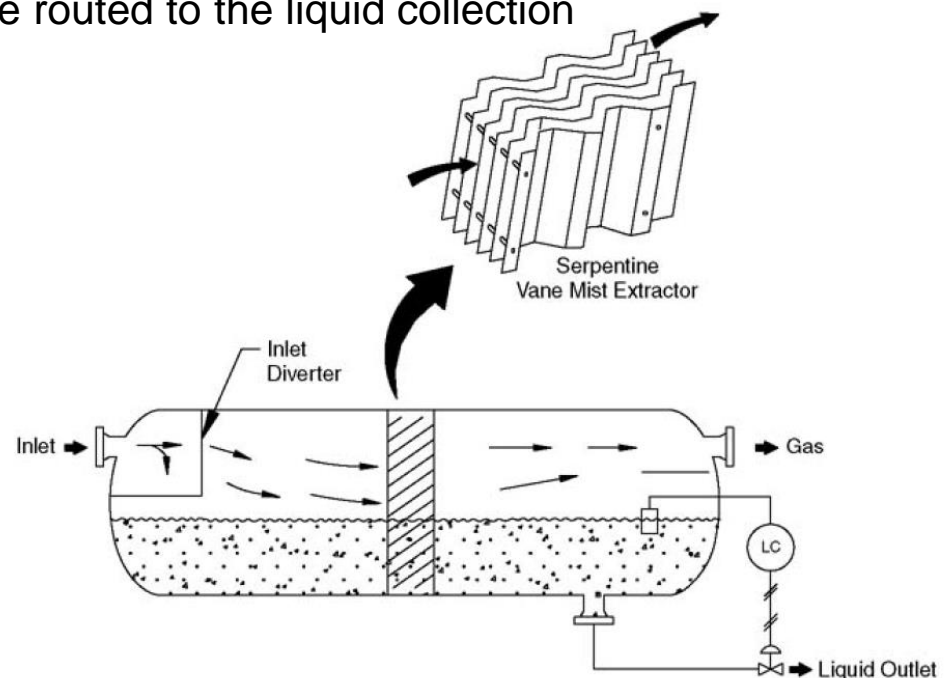


Figure 4-28. Cutaway view of a horizontal separator fitted with a vane-type mist extractor.

- Wire-mesh

- : The most common type of mist extractor found in production operations is the knitted-wire-mesh type

- : have high surface area and void volume.

- : The wire pad is placed between top and bottom support grids to complete the assembly.

- : The effectiveness of wire-mesh depends largely on the gas being in the proper velocity range



Figure 4-31. Example wire-mesh mist extractor. (Photo courtesy of ACS Industries, LP, Houston, Texas.)

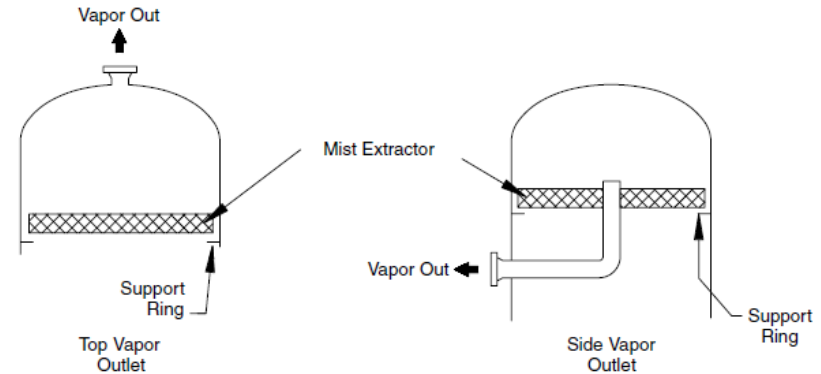


Figure 4-32. Vertical separators fitted with wire-mesh pads supported by support rings.

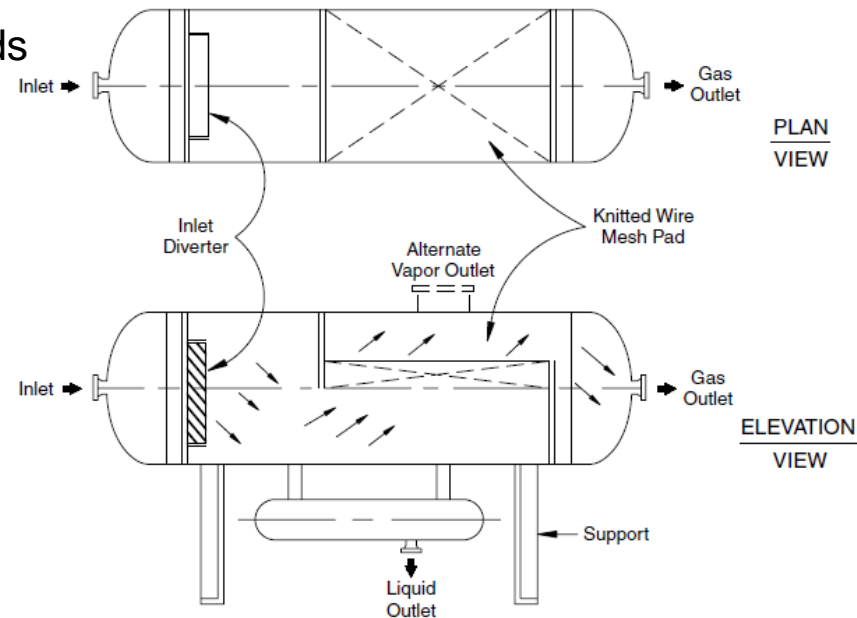


Figure 4-33. Horizontal separator fitted with wire-mesh pads supported by a frame.

- A properly sized wire-mesh unit can remove 100% of liquid droplets larger than 3 to 10 microns in diameter. Although wire-mesh eliminators are inexpensive, they are more easily plugged than the other types. Wire-mesh pads are not the best choice if solids can accumulate and plug the pad.

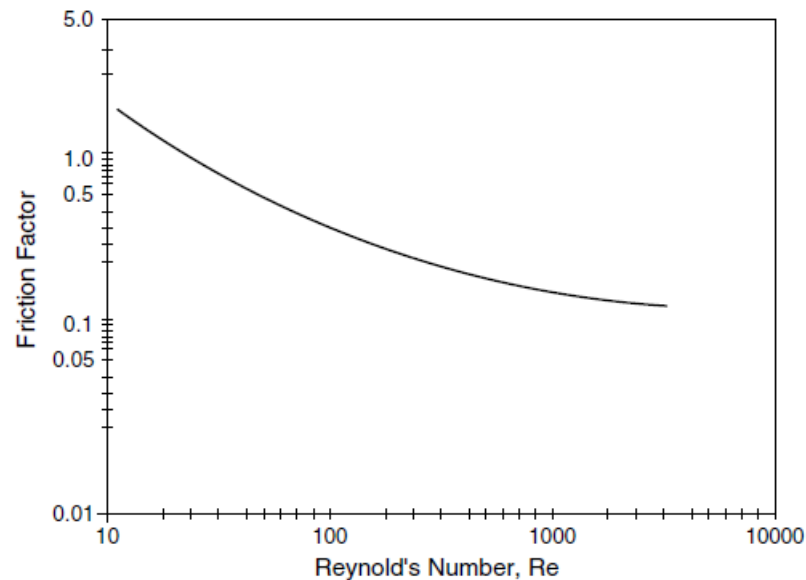


Figure 4-34. Friction factor versus Reynolds number for a dry knitted wire-mesh extractor.

- **Micro-fiber**

- : Use very small diameter fibers, usually less than 0.02 mm, to capture very small droplets.

- : Much of the liquid is eventually pushed through the micro-fiber and drains on the downstream face. The surface area of a micro-fiber mist extractor can be 3 to 150 times that of a wire-mesh unit of equal volume.

- : There are two categories of these units, depending on whether droplet capture is via inertial impaction (interception), or Brownian diffusion. Only the diffusion type can remove droplets less than 2 microns.

Table 4-1
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 ₂ O	< 15 mm H ₂ O	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

- Final selection

- : Wire-mesh pads are the cheapest, but mesh pads are the most susceptible to plugging with paraffins, gas hydrates, etc. With age, mesh pads also tend to deteriorate and release wires and/or chunks of the pad into the gas stream.

- : Vane units are more expensive. Typically, vane units are less susceptible to plugging and deterioration than mesh pads.

- : Micro-fiber units are the most expensive and are capable of capturing very small droplets but, like wire mesh pads, are susceptible to plugging.

- : The selection of a type of mist extractor is affected by the fluid characteristics, the system requirements, and the cost.

* It is recommended that the sizing of mist extractors should be left to the manufacturer.

Potential operating problems

- Foamy crude

Foaming in a separating vessel is a threefold problem:

1. Mechanical control of liquid level is aggravated because any control device must deal with essentially three liquid phases instead of two.
2. Foam has a large volume-to-weight ratio. Therefore, it can occupy much of the vessel space that would otherwise be available in the liquid collecting or gravity settling sections.
3. In an uncontrolled foam bank, it becomes impossible to remove separated gas or degassed oil from the vessel without entraining some of the foamy material in either the liquid or gas outlets.

- Laboratory test

- : Bubbling air through oil (ASTM D 892)

- : Saturation oil with its associated gas then expanded in a gas container

- Foaming can be expected where CO₂ is present in small quantities (1–2%).

- The effects of temperature

- : Viscosity change: An increase in temperature will decrease the oil viscosity, making it easier for the gas to escape from the oil.

- : VLE change: A temperature increase will increase the amount of gas, which evolves from the oil.

- For low API gravity crude (heavy oils) with low GORs, increasing the operating temperature decreases the oils' foaming tendencies.
- For high API crude (light oils) with high GORs, increasing the operating temperature decreases the oils' foaming tendencies.
- For high API crude with low GORs, increasing the operating temperature may increase the foaming tendencies.
- Foam depressant chemicals often will do a good job in increasing the capacity of a given separator. However, in sizing a separator to handle a specific crude, the use of an effective depressant should not be assumed because characteristics of the crude and of the foam may change during the life of the field.

- Paraffin

- : Coalescing plates in the liquid section and mesh pad mist extractors in the gas section are particularly prone to plugging by accumulations of paraffin.

- : Manways, handholes, and nozzles should be provided to allow steam, solvent, or other types of cleaning of the separator internals.

- : The bulk temperature of the liquid should always be kept above the cloud point of the crude oil.

- Sand

- : causing cutout of valve trim, plugging of separator internals, and accumulation in the bottom of the separator.

- : removed by periodically injecting water or steam in the bottom of the vessel so as to suspend the sand during draining.

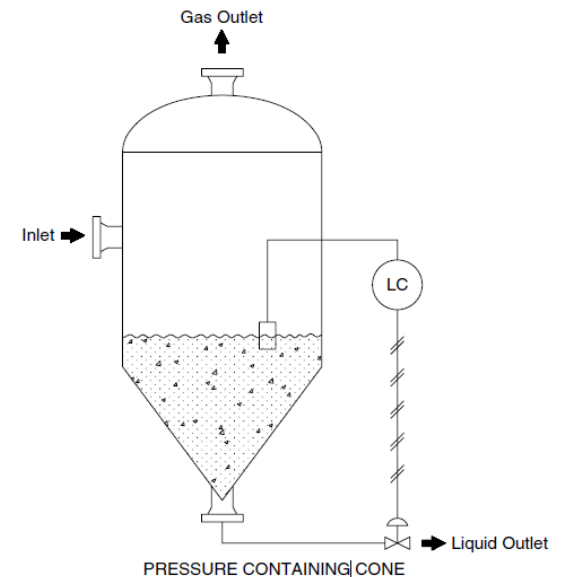


Figure 4-39. Vertical separator with a pressure containing cone bottom used to collect solids.

- Liquid carryover

- : Liquid carryover occurs when free liquid escapes with the gas phase and can indicate high liquid level, damage to vessel internals, foam, improper design, plugged liquid outlets, or a flow rate that exceeds the vessel's design rate.

- : installing a level safety high (LSH) sensor that shuts in the inlet flow to the separator when the liquid level exceeds the normal maximum liquid level by some percentage, usually 10–15%.

- Gas blowby

- : Gas blowby occurs when free gas escapes with the liquid phase and can be an indication of low liquid level, vortexing, or level control failure.

- : Unless the downstream vessel is designed for the gas blowby condition, it can be over-pressured.

- : installing a level safety low sensor (LSL) that shuts in the inflow and/or outflow to the vessel when the liquid level drops to 10–15% below the lowest operating level.

- : Down stream process equipped with a pressure safety high (PSH) sensor and a pressure safety valve (PSV) sized for gas blowby

- Liquid slugs

: Situations in which liquid slugs may occur should be identified prior to the design of a separator. The normal operating level and the high-level shutdown on the vessel must be spaced far enough apart to accommodate the anticipated slug volume. If sufficient vessel volume is not provided, then the liquid slugs will trip the high-level shutdown.

: Design process

- 1) The separator may be sized for liquid flow-rate capacity using the normal operating level. The location of the high-level set point may be established to provide the slug volume between the normal level and the high level.
- 2) The separator size must then be checked to ensure that sufficient gas capacity is provided even when the liquid is at the high-level set point.



Thank you, Question?