PRODUCTION I (PP 414)

SUBJECT:

Design of Oil-Gas Separators – From Hydrocarbon Stream

BY:

JAVIER FLAVIO INGA AMPUERO

ANDY JUNIOR CARRANZA CASTRO

PROFESSOR

MSc. LUIS ANTONIO DEL CASTILLO DE RODRIGUEZ

LIMA, PERU

2017

COURSE: PRODUCTION I (PP-414)

Professor: MSc. Luis Del Castillo Rodríguez

Academic Semester: 2016-2

Date: December, 7th 2016

DESIGN OIL AND GAS SEPARATION

INTRODUCTION

Produced wellhead fluids are complex mixtures of different compounds of hydrogen and carbon, all with different densities, vapor pressures, and other physical characteristics. As a well stream flows from the hot, high-pressure petroleum reservoir, it experiences pressure and temperature reductions. Gases evolve from the liquids and the well stream changes in character. 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 from a hydrocarbon stream the liquid and gas components 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 component can "bottleneck" and reduce the capacity of the entire facility.

Separators are classified as "two-phase" if they separate gas from the total liquid stream and "three-phase" if they also separate the liquid stream into its crude oil and water components. This chapter deals with two-phase separators. In addition, it discusses the requirements of good separation design and how various mechanical devices take advantage of the physical forces in the produced stream to achieve good separation.

Separators are sometimes called "gas scrubbers" when the ratio of gas rate to liquid rate is very high. Some operators use the term "traps" to designate separators that handle flow directly from wells. In any case, they all have the same configuration and are sized in accordance with the same procedure.

FACTORS AFFECTING SEPARATION

Characteristics of the flow stream will greatly affect the design and operation of a separator. The following factors must be determined before separator design:

- 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
- 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

EQUIPMENT DESCRIPTION

Horizontal Separators

Separators are designed in either horizontal, vertical, or spherical configurations. Figure 4-1 is a schematic of a horizontal separator. The fluid enters the separator and hits an inlet diverter causing a sudden change in momentum. The initial gross separation of liquid and vapor occurs at the inlet diverter. The force of gravity causes the liquid droplets to fall out of the gas stream to the bottom of the vessel where it is collected. This liquid collection section provides the retention time required to let entrained gas evolve out of the oil and rise to the vapor space. It also provides a surge volume, if necessary, to handle intermittent slugs of liquid. The liquid then leaves the vessel through the liquid dump valve. The liquid dump valve is regulated by a level controller. The level controller senses changes in liquid level and controls the dump valve accordingly.

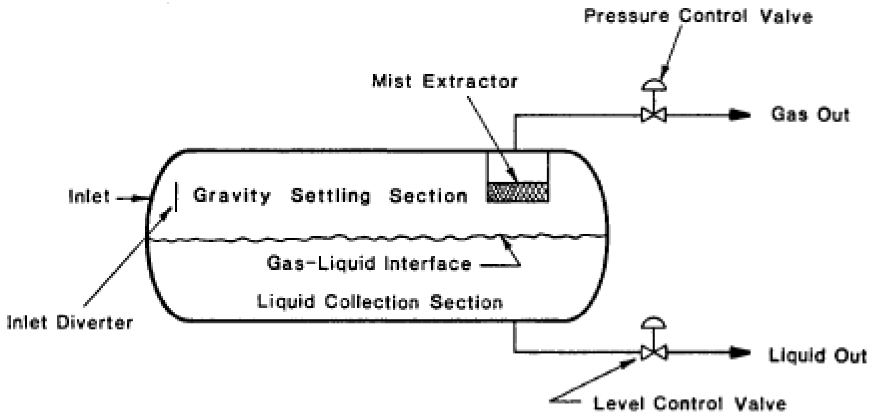


Figure 4-1. Horizontal separator schematic.

The gas flows over the inlet diverter and then horizontally through the gravity settling section above the liquid. As the gas flows through this section, small drops of liquid that were entrained in the gas and not separated by the inlet diverter are separated out by gravity and fall to the gas liquid interface.

Some of the drops are of such a small diameter that they are not easily separated in the gravity settling section. Before the gas leaves the vessel, it passes through a coalescing section or mist extractor. This section uses elements of vanes, wire mesh, or plates to coalesce and remove the very small droplets of liquid in one final separation before the gas leaves the vessel.

The pressure in the separator is maintained by a pressure controller.

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. By controlling the rate at which gas leaves the vapor space of the vessel the pressure in the vessel is maintained. Normally, horizontal separators are operated half full of liquid to maximize the surface area of the gas liquid interface.

Vertical Separators

Figure 4-2 is a schematic of a vertical separator. In this configuration, the inlet flow enters the vessel through the side. As in the horizontal separator, the inlet diverter does the initial gross separation. The liquid flows down to the liquid collection section of the vessel. Liquid continues to flow downward through this section to the liquid outlet. As the liquid reaches equilibrium, gas bubbles flow counter to the direction of the liquid flow and eventually migrate to the vapor space. The level controller and liquid dump valve operate the same as in a horizontal separator.

The gas flows over the inlet diverter and then vertically upward toward the gas outlet. In the gravity settling section the liquid drops fall vertically downward counter to the gas flow. Gas goes through the mist extractor section before it leaves the vessel. Pressure and level are maintained as in a horizontal separator.

Spherical Separators

A typical spherical separator is shown in Figure 4-3. The same four sections can be found in this vessel. Spherical separators are a special

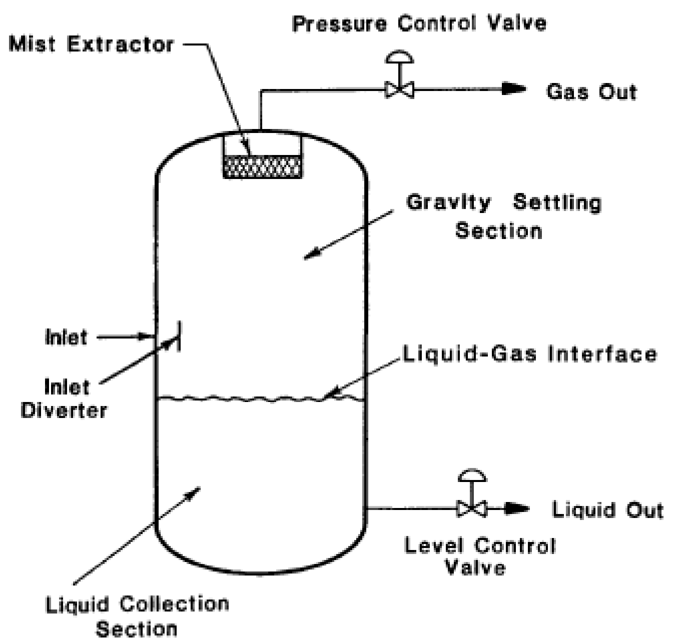


Figure 4-2. Vertical separator schematic

case of a vertical separator where there is no cylindrical shell between the two heads. They may be very efficient from a pressure containment standpoint but because (1) they have limited liquid surge capability and (2) they exhibit fabrication difficulties, they are not usually used in oil field facilities. For this reason, we will not be discussing spherical separators any further.

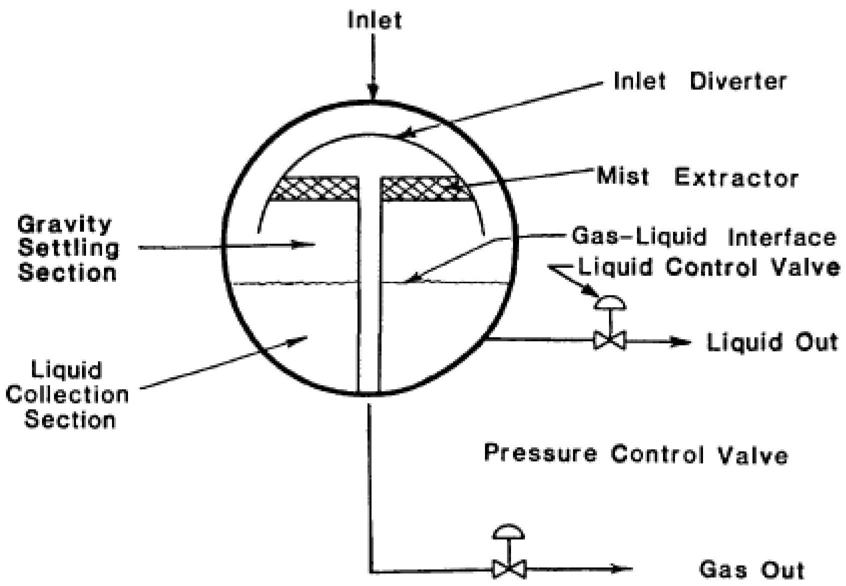


Figure 4-3. Spherical separator schematic.

Other Configurations

Cyclone separators are designed to operate by centrifugal force. These designs are best suited for fairly clean gas streams. The swirling action of the gas stream as it enters the scrubber separates the droplets and dust from the gas stream by centrifugal force. Although such designs can result in significantly smaller sizes, they are not commonly used in production operations because (1) their design is rather sensitive to flow rate and (2) they require greater pressure drop than the standard configurations previously described. Since separation efficiency decreases as velocity decreases, cyclone separators are not suitable for widely varying flow rates. These units are commonly used to recover glycol carryover downstream of a dehydration tower. In recent years, demand for using cyclone separators on floating facilities has increased because space and weight considerations are overriding on such facilities.

Two-barrel separators are common where there is a very low liquid flow rate. In these designs the gas and liquid chambers are separated as shown in Figure 4-4. The flow stream enters the vessel in the upper barrel and strikes the inlet diverter. The free liquids fall to the lower barrel through a flow pipe. The gas flows through the gravity settling section and encounters a mist extractor en route to the gas outlet. The liquids drain through a flow pipe into the lower barrel. Small amounts of gas entrained in the liquid are liberated in the liquid collection barrel and flow up through the flow pipes. In this manner, the liquid accumulation is separated from the gas stream so that there is no chance of high gas velocities re-entraining liquid as it flows over the interface. Because of their additional cost, and the absence of problems with single vessel separators, they are not widely used in oil field systems.

Another type of separator that is frequently used in some high-gas/low-liquid flow applications is a filter separator. These can be either horizontal or vertical in configuration. Figure 4-5 shows a horizontal two-barrel design. Filter tubes in the initial separation section cause coalescence of any liquid mist into larger droplets as the gas passes through the tubes. A secondary section of vanes or other mist extractor elements.

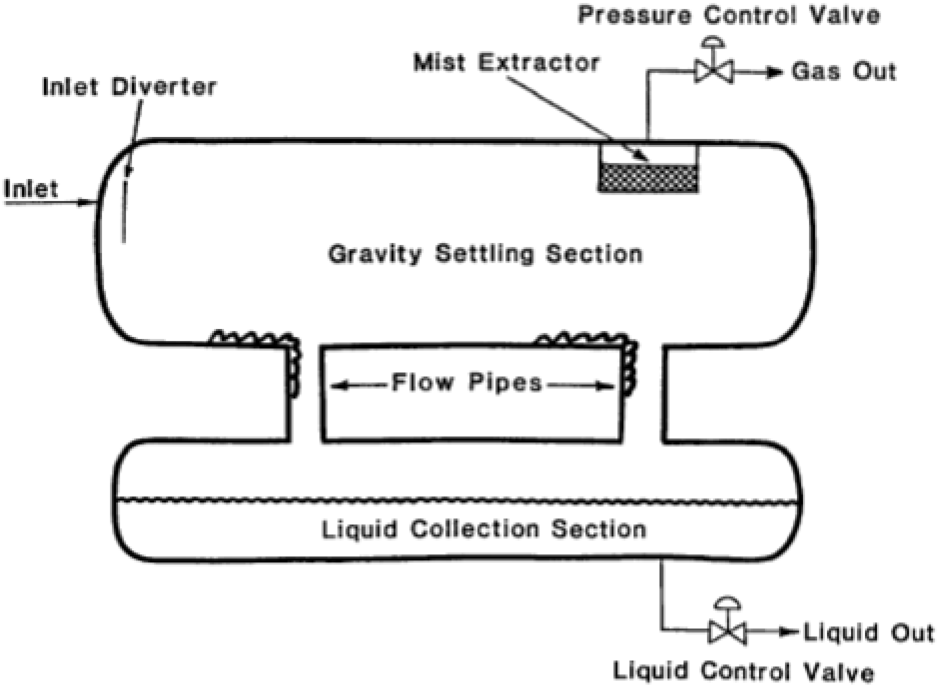


Figure 4-4. Double-barrel separator

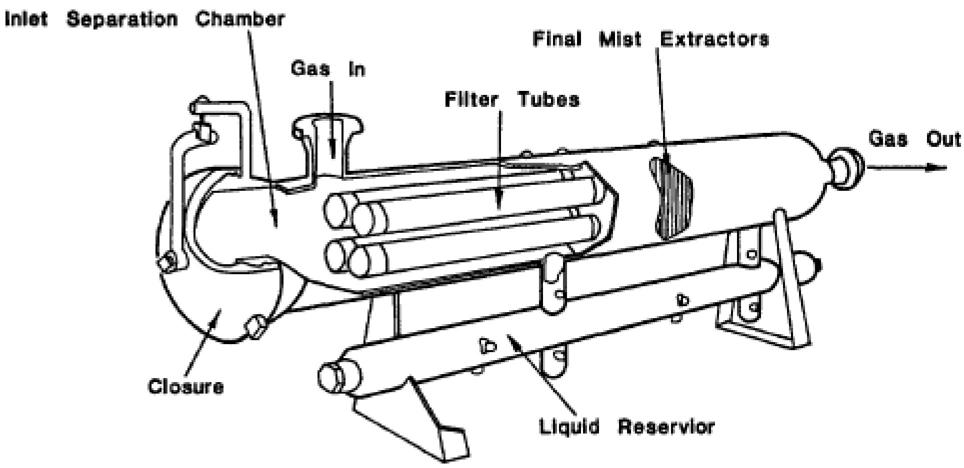


Figure 4·5. Typical filter separator.

removes these coalesced droplets. This vessel can remove 100% of all particles larger than about 2 microns and 99% of those down to about 1/2 micron. Filter separators are commonly used on compressor inlets in field compressor stations, final scrubbers upstream of glycol contact towers, and instrument/fuel gas applications. The design of filter separators is proprietary and dependent upon the type of filter element employed.

In applications where there is very little liquid flow, often a horizontal separator will be designed with a liquid sump on the outlet end to provide the required liquid retention time. This results in an overall smaller diameter for the vessel.

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. Typical applications include: 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.

HORIZONTAL VS. VERTICAL VESSEL SELECTION

Horizontal separators are smaller and less expensive than vertical separators for a given gas capacity. In the gravity settling section of a horizontal vessel, the liquid droplets fall perpendicular to the gas flow and thus are more easily settled out of the gas continuous phase. Also, since the interface area is larger in a horizontal separator than a vertical separator, it is easier for the gas bubbles, which come out of solution as the liquid approaches equilibrium, to reach the vapor space. Horizontal separators offer greater liquid capacity and are best suited for liquid-liquid separation and foaming crudes.

Thus, 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. The liquid dump of a vertical separator can be placed at the center of the bottom head so that solids will not build up in the separator but continue to the next vessel in the process. As an alternative, a drain could be placed at this location so that solids could be disposed of periodically while liquid leaves the vessel at a slightly higher elevation.

In a horizontal vessel, it is necessary to place several drains along the length of the vessel. Since the solids will have an angle of repose of 45° to 60°, the drains must be spaced at very close intervals. Attempts to lengthen the distance between drains, by providing sand jets in the vicinity of each drain to fluidize the solids while the drains are in operation, are expensive and have been only marginally successful in field operations.

2. Horizontal vessels require more plan area to perform the same separation as vertical vessels. While this may not be of importance at a land location, it could be very important offshore.

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. However, the geometry of a horizontal vessel causes any high level shut-down device to be located close to the normal operating level. In a vertical vessel, the shutdown could be placed much higher, allowing the level controller and dump valve more time to react to the surge. In addition, surges in horizontal vessels could create internal waves that could activate a high-level sensor.

It should be pointed out that vertical vessels also have some drawbacks that are not process related and must be considered in making a selection. These are:

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.

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. 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.

THEORY

Settling

In the gravity settling section the liquid drops will settle at a velocity determined by equating the gravity force on the drop with the drag force caused by its motion relative to the gas continuous phase.

The drag force is determined from the equation:

$$F_D = C_D A\rho \left[\frac{V_t^2}{2g}\right] \qquad (4\text{-}1)$$

where F_D = drag force, lb

C_D = drag coefficient

A = cross-sectional area of the droplet, ft^2

p = density of the continuous phase, lb/ft^3

V_t = terminal settling velocity of the droplet, ft/s

g = gravitational constant, 32.2 ft/s^2

If the flow around the drop were laminar, then Stokes Law would govern and:

$$C_D = \frac{24}{Re} \qquad (4\text{-}2)$$

where Re = Reynolds number

It can be shown that in such a gas the droplet settling velocity would be given by:

$$V_t = \frac{1.78 \times 10^{-6} \, (\Delta S.G.) \, d_m^2}{\mu} \qquad (4\text{-}3)$$

where ΔS.G. = difference in specific gravity relative to water of the drop and the gas

d_m = drop diameter, micron

µ = viscosity of the gas, cp

Derivation of Equation 3

For low Reynolds number flows, i.e., Re < 1

$$C_D = \frac{24}{Re}$$

The drag force is then

$$F_D = C_D A \rho_g \frac{V^2}{2g} = \frac{24}{Re}\left(\pi \frac{D^2}{4}\right)\rho_g \frac{V^2}{2g}$$

$$= \frac{24}{\frac{\rho_g}{g}\frac{Dv}{\mu'}}\left(\pi \frac{D^2}{4}\right)\rho_g \frac{V^2}{2g}$$

D = drop diameter, ft

μ' = viscosity, lb-sec/ft^2

F_D = $3\pi\mu'$ Dv (Stokes' Law)

The buoyant force on a sphere from Archimedes' principles is

$$F_B = (\rho_1 - \rho_g)\frac{\pi D^3}{6}$$

When the drag force is equal to the buoyancy force, the droplet's acceleration is zero so that it moves at a constant velocity. This is the terminal velocity.

$$F_D = F_B$$

$$3\pi\mu' VD = (\rho_1 - \rho_g)\frac{\pi D^3}{6}$$

$$V_t = \frac{(\rho_1 - \rho_g) D^2}{18\mu'}$$

$$\mu' = \mu\,(2.088 \times 10^{-5})$$

where μ = viscosity, cp

D = (d_m)(3.281 X 10-^{6})

where d_m = diameter, micron

ρ_1 = 62.4 X S.G.

ρ_g = 62.4 X S.G.

where S.G. = specific gravity relative to water

$$V_t = \frac{62.4\,(\Delta S.G.)\,(3.281 \times 10^{-6} \times d_m)^2}{18\,(\mu)\,(2.088 \times 10^{-5})}$$

$$V_t = \frac{1.78 \times 10^{-6}\,(\Delta S.G.) d_m^2}{\mu}$$

Unfortunately, for production facility design it can be shown that Stokes' Law does *not* govern, and the following more complete formula for drag coefficient must be used:

$$C_D = \frac{24}{Re} + \frac{3}{Re^{1/2}} + 0.34$$

Equating drag and buoyant forces, the terminal settling velocity is given by:

$$V_t = 0.0199\left[\left(\frac{\rho_1 - \rho_g}{\rho_g}\right)\frac{d_m}{C_D}\right]^{1/2}$$

where ρ_1 = density of liquid, *lb/ft3*

ρ_g = density of the gas at the temperature and pressure in the separator, *lb/ft^3*

Derivation of Equation 4-5

C_D = constant

The drag force is then:

$$F_D = C_D A\,\rho_g \frac{V^2}{2g} = C_D\left(\frac{\pi D^2}{4}\right)\rho_g \frac{V^2}{2g}$$

when $F_B = F_D$

$$C_D = \left(\frac{\pi D^2}{4}\right)\rho_g \frac{V^2}{2g} = (\rho_1 - \rho_g)\frac{\pi D^3}{6}$$

$$V_t = 6.55\left[\left(\frac{\rho_1 - \rho_g}{\rho_g}\right)\frac{D}{C_D}\right]^{1/2}$$

$$D = d_m\,(3.281\times 10^{-6})$$

$$V_t = 0.0199\left[\left(\frac{\rho_1 - \rho_g}{\rho_g}\right)\frac{d_m}{C_D}\right]^{1/2}$$

For $C_D = 0.34$

$$V_t = 0.0204\left[\left(\frac{\rho_1 - \rho_g}{\rho_g}\right)d_m\right]^{1/2}$$

Equations 4-4 and 4-5 can be solved by an iterative solution as follows:

1. Start with

$$V_t = 0.0204\left[\frac{(\rho_1 - \rho_g)\,d_m}{\rho_g}\right]^{1/2}$$

2. Calculate

$$Re = 0.0049\,\frac{\rho_g d_m V}{\mu}$$

3. From Re, calculate C_D using

$$C_D = \frac{24}{Re} + \frac{3}{Re^{1/2}} + 0.34$$

4. Recalculate V_t using

$$V_t = 0.0119\left[\left(\frac{\rho_l - \rho_g}{\rho_g}\right)\frac{d_m}{C_D}\right]^{1/2}$$

5. Go to step 2 and iterate

Drop Size

The purpose of the gas separation section of the vessel is to condition the gas for final polishing by the mist extractor. From field experience, it appears that if 100-micron drops are removed in this section, the mist extractor will not become flooded and will be able to perform its job of removing those drops between 10- and 100-micron diameter.

The gas capacity design equations in this section are all based on 100- micron removal. In some cases, this will give an overly conservative solution. The techniques used here can be easily modified for any drop size.

We are addressing separators used in oil field facilities.

These vessels usually require a gas separation section. There are special cases where the separator is designed to remove only very small quantities of liquid that could condense due to temperature or pressure changes in a stream of gas that has already passed through a separator and a mist extractor. These separators, commonly called "gas scrubbers," could be designed for removal of droplets on the order of 500 microns without fear of flooding their mist extractors. Fuel gas scrubbers, compressor suction scrubbers, and contact tower inlet scrubbers are examples of vessels to which this might apply.

Flare or vent scrubbers are designed to keep large slugs of liquid from entering the atmosphere through the vent or relief systems. In vent systems the gas is discharged directly to the atmosphere and it is common to design the scrubbers for removal of 300- to 500-micron droplets in the gravity settling section. A mist extractor is not included because of the possibility that it might plug creating a safety hazard. In flare systems, where the gas is discharged through a flame, there is the possibility that burning liquid droplets could fall to the ground before being consumed. It is still common to size the gravity settling section for 300- to 500- micron removal, which the API guideline for refinery flares indicates is adequate to assure against a falling flame. In critical locations, such as offshore platforms, many operators include a mist extractor as an extra precaution against a falling flame. If a mist extractor is used, it is necessary to provide safety relief protection around the mist extractor in the event that it becomes plugged.

Retention Time

To assure that the liquid and gas reach equilibrium at separator pressure a certain liquid storage is required. This is defined as "retention time" or the average time a molecule of liquid is retained in the vessel assuming plug flow. The retention time is thus the volume of the liquid storage in the vessel divided by the liquid flow rate.

For most applications retention times of between 30 seconds and 3 minutes have been found to be sufficient. Where foaming crude is present retention times up to four times this amount may be needed.

Re-entrainment

Re-entrainment is a phenomenon caused by high gas velocity at the gas-liquid interface of a separator. Momentum transfer from the gas to the liquid causes waves and ripples in the liquid, and then droplets are broken away from the liquid phase.

The general rule of thumb that calls for limiting the slenderness ratio to a maximum of 4 or 5 is applicable for half-full horizontal separators. Re-entrainment should be particularly considered for high-pressure separators sized on gas-capacity constraints. It is more likely at higher operating pressures (> 1,000 psig) and higher oil viscosities <30^0 API). For more specific limits, see Viles [1].

SEPARATOR SIZING

Horizontal Separators

For sizing a horizontal separator, it is necessary to choose a seam-to-seam vessel length and a diameter. This choice must satisfy the conditions for gas capacity that allow the liquid drops to fall from the gas to the liquid volume as the gas traverses the effective length of the vessel. It must also provide sufficient retention time to allow the liquid to reach equilibrium.

For a vessel 50% full of liquid, and separation of 100-micron liquid drops from the gas, the following equations apply:

Gas Capacity

$$d\,L_{eff} = 420\left[\frac{TZQ_g}{P}\right]\left[\left(\frac{\rho_g}{\rho_1 - \rho_g}\right)\frac{C_D}{d_m}\right]^{1/2}$$

where d = vessel internal diameter, in.

L_{eff}= effective length of the vessel where separation occurs, ft

T = operating temperature, OR

Qg = gas flow rate, MMscfd

P= operating pressure, psia

Z = gas compressibility

C_D = drag coefficient

d_m = liquid drop to be separated, micron

ρ_g = density of gas, Ib/ft3

ρ_1 = density of liquid, Ib/ft3

Derivation of Equation 4-6

Assume vessel is one-half full of liquid. Determine gas velocity, V_g. A is in ft^2, D in ft, d in inches, Q in ft^3/s

$$V_g = \frac{Q}{A_g}$$

$$A_g = \frac{1}{2}\left(\frac{\pi}{4}D^2\right) = \frac{1}{2}\left(\frac{\pi}{4}\frac{d^2}{144}\right) = \frac{d^2}{367}$$

Q_g is in MMscfd

$$Q = Q_g \times 10^6 \frac{scf}{MMscf} \times \frac{day}{24\ hr} \times \frac{hr}{3{,}600s} \times \frac{14.7}{P} \times \frac{TZ}{520}$$

$$= 0.327\frac{TZ}{P}Q_g$$

$$V_g = \frac{\left(0.327\frac{TZ}{P}Q_g\right)(367)}{d^2}$$

$$V_g = 120\frac{TZQ_g}{Pd^2}$$

Set the residence time of the gas equal to the time required for the droplet to fall to the gas-liquid interface:

$$t_g = \frac{L_{eff}}{V_g} \qquad t_d = \frac{D}{2V_t} = \frac{d}{24V_t}$$

$$t_g = \frac{L_{eff}}{120\left(\frac{TZQ_g}{Pd^2}\right)}$$

Recalling that

$$V_t = 0.0119\left[\left(\frac{\rho_l - \rho_g}{\rho_g}\right)\frac{d_m}{C_D}\right]^{1/2}$$

Setting $t_g = t_d$,

$$\frac{L_{eff}}{120\left(\frac{TZQ_g}{Pd^2}\right)} = \frac{d\left[\left(\frac{\rho_g}{\rho_l - \rho_g}\right)\frac{C_D}{d_m}\right]^{1/2}}{(24)(0.0119)}$$

$$L_{eff}\, d = 420\,\frac{TZQ_g}{P}\left[\left(\frac{\rho_g}{\rho_l - \rho_g}\right)\frac{C_D}{d_m}\right]^{1/2}$$

Liquid Capacity

$$d^2 L_{eff} = \frac{t_r Q_l}{0.7} \qquad (4\text{-}7)$$

Where t_r = desired retention time for the liquid, min

Q_1 = liquid flow rate, bpd

t is in s, Vol in ft^3, Q in ft^3/s

$$t = \frac{Vol}{Q}$$

$$Vol = \frac{1}{2}\left(\frac{\pi D^2 L_{eff}}{4}\right) = \frac{\pi d^2 L_{eff}}{(2)(4)(144)} = 2.73\times10^{-3}\, d^2 L_{eff}$$

Q_1 is in bpd

$$Q = Q_1 \times 5.61 \frac{ft^3}{barrel} \times \frac{day}{24\ hr} \times \frac{hr}{3,600s} = 6.49 \times 10^{-5} Q_1$$

$$t = 42.0 \frac{d^2 L_{eff}}{Q_1}$$

$$d^2 L_{eff} = \frac{t_r Q_1}{0.7}$$

Seam-to-Seam Length and Slenderness Ratio

The seam-to-seam length of the vessel should be determined from the geometry once an effective length has been determined. Allowance must be made for the inlet diverter and mist extractor. For screening purposes the following approximation has been proven useful:

$$L_{ss} = L_{eff} + \frac{d}{12}$$ for gas capacity

$$L_{ss} = \frac{4}{3} L_{eff}$$ for liquid capacity (4-8)

Equations 4-6 and 4-7 allow for various choices of diameter and length. It can be shown that the smaller the diameter the less the vessel will weigh and thus the lower its cost. There is a point, however, where decreasing the diameter increases the possibility that high velocity in the gas flow will create waves and re-entrain liquids at the gas-liquid interface. Experience has shown that if the gas capacity governs and the length divided by the diameter (slenderness ratio) is greater than 4 or 5, re-entrainment could become a problem. Equation 4-8 indicates that slenderness ratios must be at least 1 or more. Most common separators are designed for slenderness ratios of 3 to 4.

Procedure for Sizing Horizontal Separators

1. Calculate values of d, L_{eff} that satisfy the gas capacity constraint.

$$L_{eff} d = 420 \frac{TZQ_g}{P} \left[\frac{\rho_g}{\rho_l - \rho_g} \frac{\bar{C}_D}{d_m} \right]^{1/2}$$

2. Calculate values of d, L_{eff} that satisfy the retention time constraint.

$$d^2 L_{eff} = \frac{t_r Q_l}{0.7}$$

3. Estimate seam-to-seam length.

$$L_{ss} = L_{eff} + \frac{d}{12}$$ for gas capacity

$$L_{ss} = \frac{4}{3} L_{eff}$$ for liquid capacity

4.Select a size of reasonable diameter and length. Slenderness ratios (12 L_{ss}/d) on the order of 3 to 4 are common. Do not exceed a slenderness ratio of 5 without further study of re-entrainment,

For separators other than 50% full of liquid, equations can be derived similarly, using the actual gas and liquid areas to calculate gas velocity and liquid volume. The equations are derived using the same principles.

Vertical Separators

In vertical separators, a minimum diameter must be maintained to allow liquid drops to separate from the vertically moving gas. The liquid retention time requirement specifies a combination of diameter and liquid volume height. Any diameter greater than the minimum required for gas capacity can be chosen. Figure 4-15 shows the model used for a vertical separator.

Gas Capacity

$$d^2 = 5{,}040 \left[\frac{TZQ_g}{P}\right]\left[\left(\frac{\rho_g}{\rho_l - \rho_g}\right)\frac{C_D}{d_m}\right]^{1/2} \qquad (4\text{-}9)$$

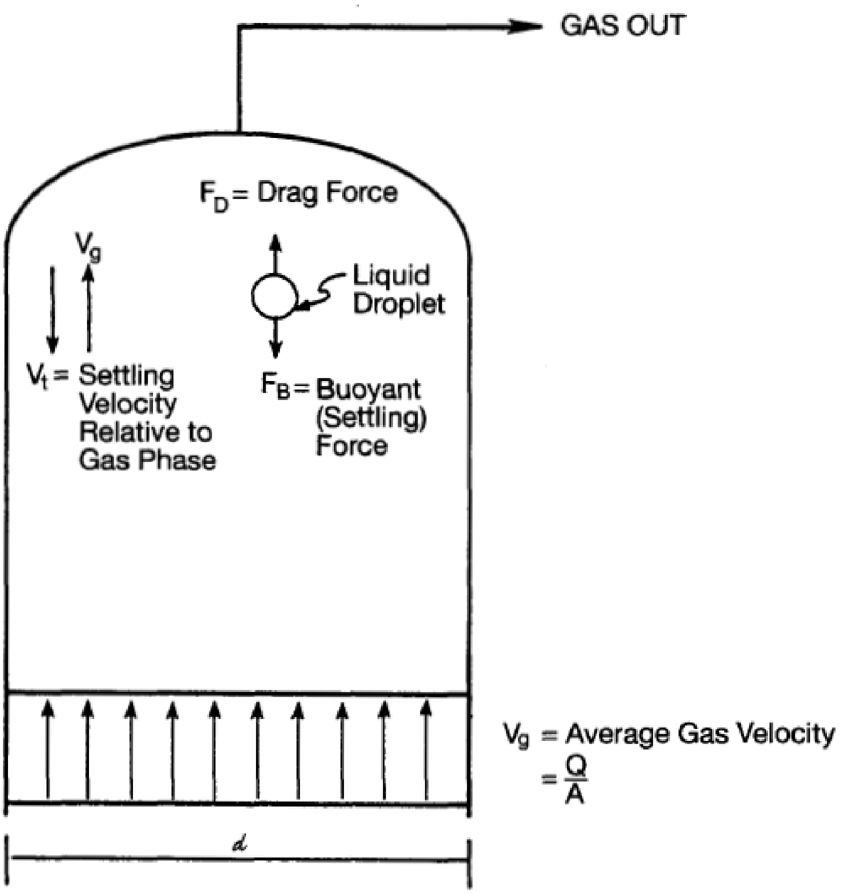


Figure 4-15. Model of a vertical separator.

Derivation of Equation 4-9

For the droplets to fall, the gas velocity must be less than the terminal velocity of the droplet. Recall that:

.

$$V_t = 0.0119\left[\left(\frac{\rho_l - \rho_g}{\rho_g}\right)\frac{d_m}{C_D}\right]^{1/2}$$

Determine gas velocity, V_g. A is in ft^2, D in ft, d in inches, Q in ft^3/s

$$V_g = \frac{Q}{A_g}$$

$$A_g = \left(\frac{\pi}{4}D^2\right) = \left(\frac{\pi}{4}\frac{d^2}{144}\right) = \frac{d^2}{183}$$

Q_g is in MMscfd

$$Q = Q_g \times 10^6 \frac{\text{scf}}{\text{MMscf}} \times \frac{\text{day}}{24\text{ hr}} \times \frac{\text{hr}}{3{,}600\text{s}} \times \frac{14.7}{P} \times \frac{TZ}{520}$$

$$= 0.327 \frac{TZ}{P} Q_g$$

$$V_g = \frac{\left(0.327 \frac{TZ}{P} Q_g\right)(183)}{d^2}$$

$$V_g = 60 \frac{TZQ_g}{Pd^2}$$

$V_t = V_g$

$$0.0119 \left[\left(\frac{\rho_l - \rho_g}{\rho_g}\right)\frac{d_m}{C_D}\right]^{1/2} = \frac{60TZQ_g}{Pd^2}$$

$$d^2 = 5{,}040 \frac{TZQ_g}{P}\left[\left(\frac{\rho_g}{\rho_l - \rho_g}\right)\frac{C_D}{d_m}\right]^{1/2}$$

Liquid Capacity

$$d^2\ h = \frac{t_r\ Q_l}{0.12} \qquad (4\text{-}10)$$

Derivation of Equation 4-10

t is in s, Vol in ft^3, Q in ft^3/s, h in inches

$$t = \frac{Vol}{Q}$$

$$Vol = \frac{\pi D^2\ h}{(4)(12)} = \frac{\pi d^2\ h}{(4)(144)(12)} = 4.55 \times 10^{-4}\ d^2 h$$

Q_l is in bpd

$$Q = Q_l \times 5.61 \frac{\text{ft}^3}{\text{barrel}} \times \frac{\text{day}}{24\text{ hr}} \times \frac{\text{hr}}{3{,}600\text{s}} = 6.49 \times 10^{-5} Q_l$$

$$t = 7.00 \frac{d^2 h}{Q_l}$$

t_r is in min

$$d^2h = \frac{t_r Q_1}{0.12}$$

Seam-to-Seam Length and Slenderness Ratio

The seam-to-seam length of the vessel should be determined from the geometry once a diameter and height of liquid volume are known.

As shown in Figure 4-16, allowance must be made for the gas separation section and mist extractor and for any space below the water outlet. For screening purposes the following approximation has been proven useful. Use the larger of the two values:

$$L_{ss} = \frac{h + 76}{12} \text{ or } L_{ss} = \frac{h + d + 40}{12} \qquad (4\text{-}11)$$

As with horizontal separators, the larger the slenderness ratio, the less expensive the vessel. In vertical separators whose sizing is liquid dominated, it is common to choose slenderness ratios no greater than 4 to keep the height of the liquid collection section to a reasonable level. Choices of between 3 and 4 are common, although height restrictions may force the choice of a lower slenderness ratio.

EXAMPLES

Example 4-1: Sizing a Vertical Separator

Given: Flow Rate: 10 MMscfd at 0.6 specific gravity

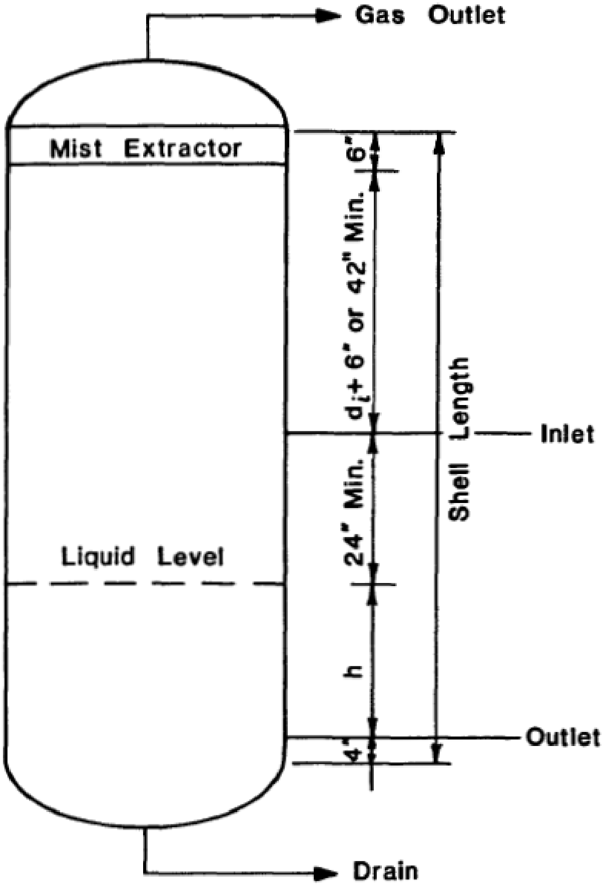
2,000 bopd at 40° API

Operating Pressure: 1,000 psia

Operating Temperature: 60°F

Solution:

1. Calculate C_D



d = minimum diameter for gas separation

Figure 4-16. Approximate shell length from liquid level height.

$$\rho_l = 62.4[141.5/(131.5 + 40)] = 51.5 \text{ lb/ft}^3$$

$$\rho_g = 2.70 \frac{S\,P}{T\,Z}$$

Z = 0.84 (from Chapter 3)

$$\rho_g = 2.70 \frac{(0.6)(1,000)}{(520)(0.84)} = 3.71$$

D_m = 140 micron

μ = 0.013 cp (from Chapter 3)

Assume C_D = 0.34

$$V_t = 0.0119 \left[\left(\frac{51.5 - 3.71}{3.71} \right) \frac{140}{0.34} \right]^{1/2}$$

$$V_t = 0.866$$

$$Re = 0.0049 \left[\frac{(3.71)(140)(0.866)}{0.013} \right] = 169.54$$

$$C_D = \frac{24}{169.54} + \frac{3}{(169.54)^{1/2}} + 0.34$$

$$C_D = 0.711$$

Repeat using C_D = 0.711

V_t =0.597

Re = 118

C_D= 0.820

Repeat:

V_t = 0.556

Re= 110

C_D =0.844

Repeat:

V_t= 0.548

Re= 108

C_D=0.851

Repeat:

V_t= 0.545

Re = 108

C_D=0.851 OK

2. Gas capacity constraint

$$d^2 = 5{,}040\left[\frac{TZQ_g}{P}\right]\left[\left(\frac{\rho_g}{\rho_1-\rho_g}\right)\frac{C_D}{d_m}\right]^{1/2}$$

Z = 0.84 (from Chapter 3)

$$d^2 = 5{,}040\left[\frac{(520)(0.84)(10)}{1{,}000}\right]\left[\left(\frac{3.71}{51.5-3.71}\right)\frac{0.851}{140}\right]^{1/2}$$

$$d = 21.8 \text{ in.}$$

3. Liquid capacity constraint

$$d^2h = \frac{t_r\,Q_1}{0.12}$$

4. Compute combinations of d and h for various tr (Table 4-1).

5. Compute seam-to-seam length (Table 4-1).

$$L_{ss} = \frac{h+76}{12} \text{ or } L_{ss} = \frac{h+d+40}{12}$$

where d is the minimum diameter for gas capacity

6. Compute slenderness ratio (12 L_{ss}/d). Choices in the range of 3 to 4 are most common (Table 4-1).

7. Choose a reasonable size with a diameter greater than that determined by the gas capacity. A 36-in. x 10-ft separator provides slightly more than three minutes retention time with a diameter greater than 21.8 in. and a slenderness ratio of 3.2.

Table 4-1
Vertical Separator Example
Diameter vs. Length for Liquid Capacity Constraint

t_r min	d in.	h in.	L_{ss} ft	$(12)L_{ss}/d$
3	24	86.8	13.6	6.8
	30	55.6	11.0	4.4
	36	38.6	9.6	3.2
	42	28.3	8.7	2.5
	48	21.7	8.1	2.0
2	24	57.9	11.2	5.6
	30	37.0	9.4	3.8
	36	25.7	8.5	2.8
	42	18.9	7.9	2.3
1	24	28.9	8.7	4.4
	30	18.5	7.9	3.2
	36	12.9	7.4	2.5

Example 4-2: Sizing a Horizontal Separator

Given: Flow Rate: 10 MMscfd at 0.6 specific gravity

2,000 bopd at 40° API

Operating Pressure: 1,000 psia

Operating Temperature: 60° F

Solution:

1.Calculate C_D (same as Example 4-1)

C_D=0.851

2.Gas capacity constraint

$$d\,L_{eff} = 420\left[\frac{TZQ_g}{P}\right]\left[\left(\frac{\rho_g}{\rho_l - \rho_g}\right)\frac{C_D}{d_m}\right]^{1/2}$$

Z = 0.84 (from Chapter 3)

$$d\,L_{eff} = 420\left[\frac{(520)\,(0.84)\,(10)}{1{,}000}\right]\left[\left(\frac{3.71}{51.5 - 3.71}\right)\frac{0.851}{140}\right]^{1/2}$$

$$d\,L_{eff} = 55.04$$

3. Liquid capacity constraint

$$d^2 L_{eff} = \frac{t_r Q_1}{0.7}$$

4. Compute combinations of d and L_{ss} for gas and liquid capacity.

5. Compute seam-to-seam length for various d (Table 4-2).

$$L_{ss} = L_{eff} + \frac{d}{12}$$

6. Compute slenderness ratios (12 L_{ss}/d). Choices in the range of 3 to 4 are common.

7. Choose a reasonable size with a diameter and length combination above both the gas capacity and the liquid capacity constraint lines. A 36-in. x 10-ft separator provides about 3 minutes retention time.

Table 4-2 Horizontal Separator Example Diameter vs. Length

d	Gas L_{eff}	Liquid L_{eff}	L_{ss}	$12L_{ss}/d$
16	2.5	33.5	44.7	33.5
20	2.0	21.4	28.5	17.1
24	1.7	14.9	19.9	9.9
30	1.3	9.5	12.7	5.1
36	1.1	6.6	9.1*	3.0
42	0.9	4.9	7.4*	2.1
48	0.8	3.7	6.2*	1.6

*$L_{ss} = L_{eff} + 2.5$ *governs*

1.Viles J. C. "Predicting Liquid Re-entrainment in Horizontal Separators" (SPE 25474). Paper presented at the Production Operations Symposium in Oklahoma City, OK, USA, in March 1993.

Oil and Water Separation

INTRODUCTION

This chapter discusses the concepts, theory, and sizing equations for the separation of two immiscible liquid phases (in this case, normally crude oil and produced water). The separator design concepts that have been presented in Chapter 4 relate to the two-phase separation of liquid and gas and are applicable to the separation of gas that takes place in three-phase separators, gas scrubbers, and any other device in which gas is separated from a liquid phase.

When oil and water are mixed with some intensity and then allowed to settle, a layer of relatively clean free water will appear at the bottom. The growth of this water layer with time will follow a curve as shown in Figure 5-1. After a period of time, ranging anywhere from three minutes to thirty minutes, the change in the water height will be negligible. The water fraction, obtained from gravity settling, is called "free water." It is normally beneficial to separate the free water before attempting to treat the remaining oil and emulsion layers.

"Three-phase separator" and "free-water knockout" are terms that are used to describe pressure vessels that are designed to separate and remove

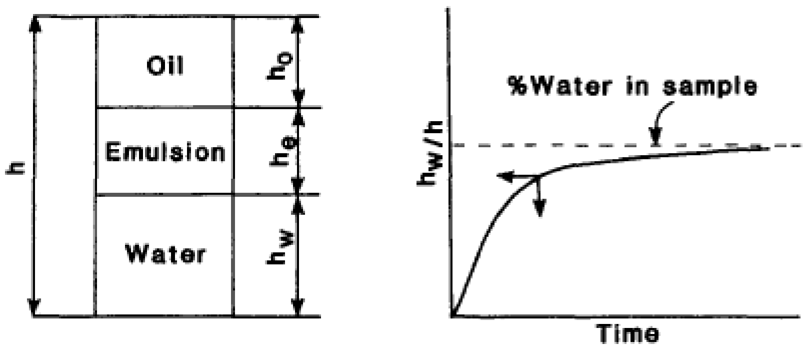


Figure 5· 1. Growth of water layer with time

the free water from a mixture of crude oil and water. Because flow normally enters these vessels either directly from (1) a producing well or (2) a separator operating at a higher pressure, the vessel must be designed to separate the gas that flashes from the liquid as well as separate the oil and water.

The term "three-phase separator" is normally used when there is a large amount of gas to be separated from the liquid, and the dimensions of the vessel are determined by the gas capacity equations discussed in Chapter 4. "Free-water knockout" is generally used when the amount of gas is small relative to the amount of oil and water, and the dimensions of the vessel are determined by the oil/water separation equations discussed in this chapter. No matter what name is given to the vessel, any vessel that is designed to separate two immiscible liquid phases will employ the concepts described in this chapter. For purposes of this chapter, we will call such a vessel a "three-phase separator."

The basic design aspects of three-phase separation are identical to those discussed in Chapter 4. The only additions are that more concern is placed on liquid-liquid settling rates; and that some means of removing the free water must be added. Liquid-liquid settling rates will be discussed later in this chapter. Water removal is a function of the control methods used to maintain separation and removal from the oil. Several control methods are applicable to three-phase separators. The shape and diameter of the vessel will, to a degree, determine the types of control used.

EQUIPMENT DESCRIPTION

Horizontal Separators

Three-phase separators are designed as either horizontal or vertical pressure vessels. Figure 5-2 is a schematic of a horizontal separator. The

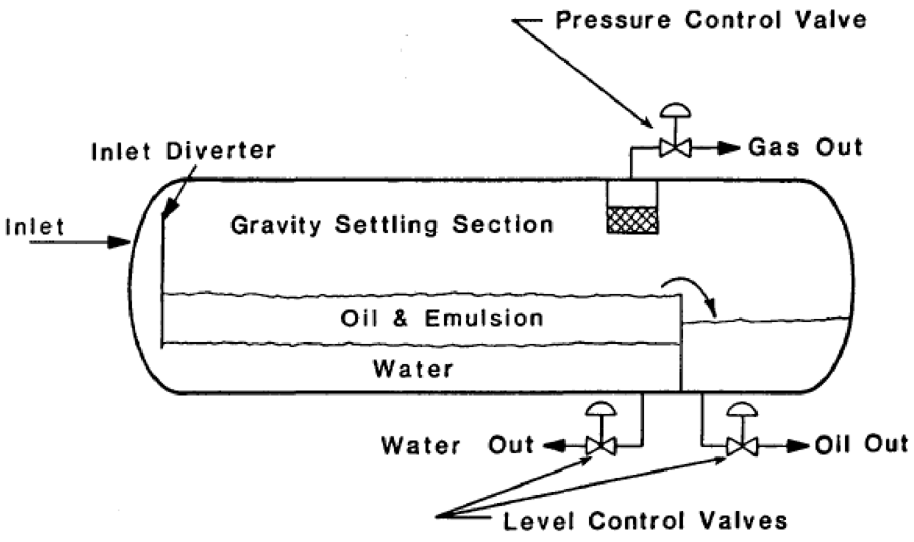


Figure 5-2. **Horizontal three-phase separator schematic.**

fluid enters the separator and hits an inlet diverter. This sudden change in momentum does the initial gross separation of liquid and vapor as discussed in Chapter 4. In most designs, the inlet diverter contains a downcomer that directs the liquid flow below the oil/water interface.

This forces the inlet mixture of oil and water to mix with the water continuous phase in the bottom of the vessel and rise through the oil/water interface. This process is called "water-washing," and it promotes the coalescence of water droplets which are entrained in the oil continuous phase. The inlet diverter assures that little gas is carried with the liquid, and the water wash assures that the liquid does not fall on top of the gas/oil or oil/water interface, mixing the liquid retained in the vessel and making control of the oil/water interface difficult.

The liquid collecting section of the vessel provides sufficient time so that the oil and emulsion form a layer or "oil pad" at the top. The free water settles to the bottom. Figure 5-2 illustrates a typical horizontal separator with an interface controller and weir. The weir maintains the oil level and the level controller maintains the water level. The oil is skimmed over the weir. The level of the oil downstream of the weir is controlled by a level controller that operates the oil dump valve.

The produced water flows from a nozzle in the vessel located upstream of the oil weir. An interface level controller senses the height of the oil/water interface. The controller sends a signal to the water dump valve thus allowing the correct amount of water to leave the vessel so that the oil/water interface is maintained at the design height.

The gas flows horizontally and out through a mist extractor to a pressure control valve that maintains constant vessel pressure. The level of the gas/oil interface can vary from half the diameter to 75% of the diameter depending on the relative importance of liquid/gas separation. The most common configuration is half full, and this is used for the design equations in this section. Similar equations can be developed for other interface levels.

Figure 5-3 shows an alternate configuration known as a "bucket and weir" design. This design eliminates the need for a liquid interface controller. Both the oil and water flow over weirs where level control is accomplished by a simple displacer float. The oil overflows the oil weir into an oil bucket where its level is controlled by a level controller that operates the oil dump valve. The water flows under the oil bucket and then over a water weir. The level downstream of this weir is controlled by a level controller that operates the water dump valve.

The height of the oil weir controls the liquid level in the vessel. The difference in height of the oil and water weirs controls the thickness of the oil pad due to specific gravity differences. It is critical to the operation of the vessel that the water weir height be sufficiently below the oil weir height so that the oil pad thickness provides sufficient oil retention time. If

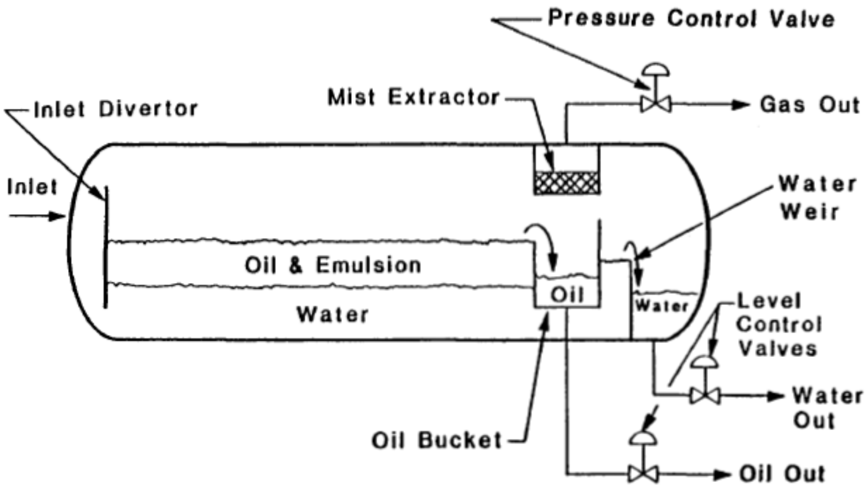


Figure 5-3. **Bucket and weir design.**

the water weir is too low and the difference in specific gravity is not as great as anticipated, then the oil pad could grow in thickness to a point where oil will be swept under the oil box and out the water outlet. Normally, either the oil or the water weir is made adjustable so that changes in oil/water specific gravities or flow rates can be accommodated.

To obtain a desired oil pad height, the water weir should be set a distance below the oil weir, which is calculated by:

$$\Delta h = h_o \left[1 - \left(\frac{\rho_o}{\rho_w}\right)\right] \tag{5-1}$$

where Δh = distance below the oil weir, in.

h_0 = desired oil pad height, in.

ρ_o = oil density, lb/ft^3

ρ_w = water density, lb/ft^3

This equation neglects the height of the oil and water flowing over the weir and presents a view of the levels when there is no inflow. A large inflow of oil will cause the top of the oil pad to rise; the oil pad will thus get thicker, and the oil bucket must be deep enough so that oil does not flow under it. Similarly, a large inflow of water will cause the level of water flowing over the water weir to rise, and there will be a large flow of oil from the oil pad over the oil weir until a new h_w is established. These dynamic effects can be minimized by making the weirs as long as possible.

Derivation of Equation 5-1

ρ is in lb/ft^3, h is in inches. Setting the pressures at Point "A" in Figure 5-4 equal,

$$\rho_o h_o + \rho_w h_w = \rho_w h_w'$$

$$h_w = \frac{\rho_w h_w' - \rho_o h_o}{\rho_w} = h_w' - \frac{\rho_o}{\rho_w} h_o$$

$$\Delta h = h_o + h_w - h_w'$$

$$\Delta h = h_o - \frac{\rho_o}{\rho_w} h_o = h_o \left[1 - \frac{\rho_o}{\rho_w}\right]$$

Interface control has the advantage of being easily adjustable to handle unexpected changes in oil or water specific gravity or flow rates. However, in heavy oil applications or where large amounts of emulsion or paraffin are anticipated it may be difficult to sense interface level. In such a case bucket and weir control is recommended.

In some areas of the world, the term "free-water knockout" is reserved for a vessel which processes an inlet liquid stream with little entrained gas and makes no attempt to separate the gas from the oil. Such a vessel has only an oil outlet and a water outlet (no separate gas outlet), as shown in Figure 5-5. It should be clear that the principles of operation of such a vessel are the same as those described above.

Vertical Separators

Figure 5-6 shows a typical configuration for a vertical three-phase separator. Flow enters the vessel through the side as in the horizontal separator, the inlet diverter separates the bulk of the gas. A downcomer is

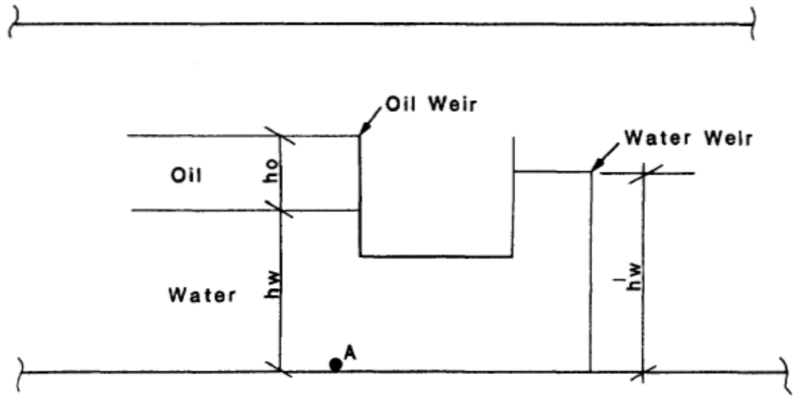


Figure 5-4. Determination of oil pad height

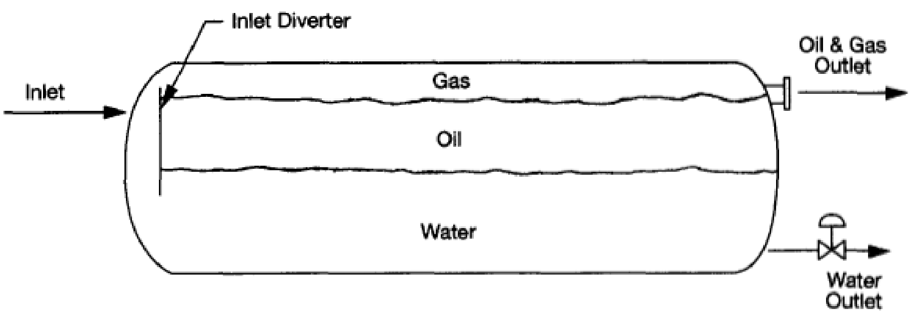


Figure 5-5. Free-water knockout (FWKO).

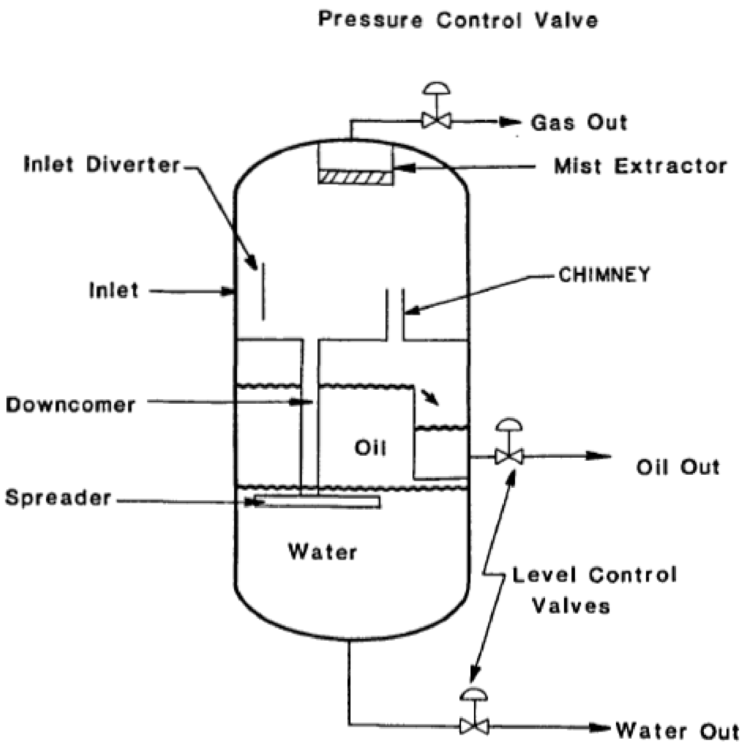


Figure 5-6. Vertical three-phase separator schematic.

required to transmit the liquid through the oil-gas interface so as not to disturb the oil skimming action taking place. A chimney is needed to equalize gas pressure between the lower section and the gas section.

The spreader or downcomer outlet is located at the oil-water interface.

From this point as the oil rises any free water trapped within the oil phase separates out. The water droplets flow countercurrent to the oil. Similarly, the water flows downward and oil droplets trapped in the water phase tend to rise countercurrent to the water flow.

Sometimes a cone bottom three-phase separator is used. This is a design that would be used if sand production was anticipated to be a major problem. The cone is normally at an angle to the horizontal of between 45° and 60°. Produced sand may have a tendency to stick to steel at 45°. If a cone is installed it could be part of the pressure containing walls of the vessel, or for structural reasons, it could be installed internal to the vessel cylinder. In such a case, a gas equalizing line must be installed to assure that the vapor behind the cone is always in pressure equilibrium with the vapor space.

Figure 5-7 shows the three different methods of control that are often used on vertical separators.

The first is strictly level control. A regular displacer float is used to control the gas-oil interface and regulate a control valve dumping oil from the oil section. An interface float is used to control the oil-water interface and regulate a water outlet control valve. Because no internal baffling or weirs are used, this system is the easiest to fabricate and handles sand and solids production best.

The second method shown uses a weir to control the gas-oil interface level at a constant position. This results in a better separation of water from the oil as all the oil must rise to the height of the oil weir before exiting the vessel. Its disadvantages are that the oil box takes up vessel volume and costs money to fabricate. In addition, sediment and solids could collect in the oil box and be difficult to drain, and a separate low level shut-down may be required to guard against the oil dump valve failing to open.

The third method uses two weirs, which eliminates the need for an interface float. Interface level is controlled by the height of the external water weir relative to the oil weir or outlet height. This is similar to the bucket and weir design of horizontal separators. The advantage of this system is that it eliminates the interface level control. The disadvantage is that it requires additional external piping and space.

Horizontal VS. Vertical Selection

The benefits of each type of design were described earlier. As in two phase separation, it is also true for three-phase separation that the flow

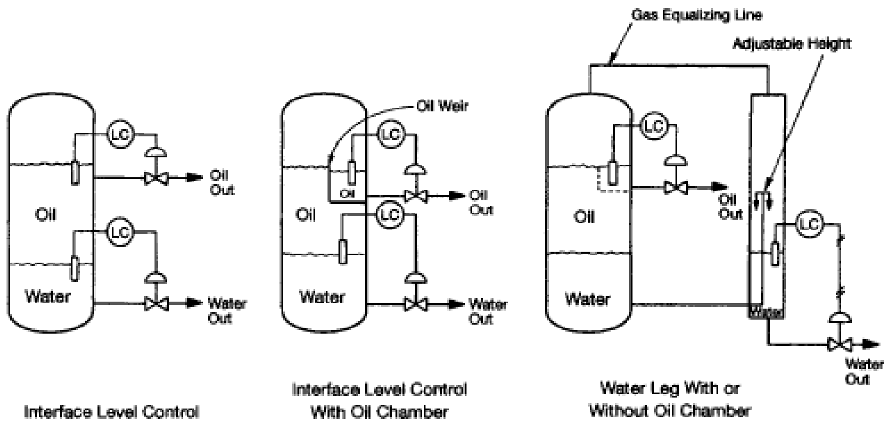


Figure 5-7. **Liquid level control** schemes.

geometry in a horizontal vessel is more favorable from a process standpoint. However, there may be non-process reasons to select a vertical vessel for a specific application.

VESSEL INTERNALS

Most of the vessel internals are discussed in Chapter 4. Two common internals not discussed are coalescing plates and sand jets. It is possible to use various plate or pipe coalescer designs to aid in the coalescing of oil droplets in the water and water droplets in the oil.

Coalescing Plates

The installation of coalescing plates in the liquid section will cause the size of the water droplets entrained in the oil phase to increase, making gravity settling of these drops to the oil-water interface easier. Thus, the use of coalescing plates or the use of free-flow turbulent coalescers (SP Packs), which are both described in Chapter 7, will often lead to the ability to handle a given flow rate in a smaller vessel. However, because of the potential for plugging with sand, paraffin, or corrosion products, the use of coalescing plates should be discouraged, except for instances where the savings in vessel size and weight are large enough to justify the potential increase in operating costs and decrease in availability.

Sand Jets and Drains

In horizontal three-phase separators, one worry is the accumulation of sand and solids at the bottom of the vessel. If allowed to build up, these solids upset the separator operations by taking up vessel volume. Generally, the solids settle to the bottom and become well packed.

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. The sand jets are normally designed with a 20 *ft/s* jet tip velocity and aimed in such a manner to give good coverage of the vessel bottom.

To prevent the settled sand from clogging the sand drains, sand pans or sand troughs are used to cover the outlets. These are inverted troughs with slotted side openings.

EMULSIONS

Emulsions can be particularly troublesome in the operation of three-phase separators. Over a period of time an accumulation of emulsified materials and/or other impurities usually will form at the interface of the water and oil phases. In addition to adverse effects on the liquid level control, this accumulation will also decrease the effective oil or water retention time in the separator, with a resultant decrease in water-oil separation efficiency. Addition of chemicals and/or heat often minimizes this difficulty.

Frequently, it is possible to appreciably lower the settling time necessary for water-oil separation by either the application of heat in the liquid section of the separator or the addition of de-emulsifying chemicals. The treating of emulsions is discussed in more detail in Chapter 6.

THEORY

Gas Separation

The concepts and equations pertaining to two-phase separation described in Chapter 4 are equally valid for three-phase separation.

Oil/Water Settling

It can be shown that flow around settling oil drops in water or water drops in oil is laminar and thus Stokes' Law governs. The terminal drop velocity is:

$$V_t = \frac{1.78 \times 10^{-6} (\Delta S.G.)\, d_m^2}{\mu} \qquad (5\text{-}2)$$

Where:

V_t = terminal settling velocity, ft/s

$\Delta S.G.$ = difference in specific gravity relative to water between the oil and the water phases

d_m = drop size, micron

μ = viscosity of continuous phase, cp

Water Droplet Size in Oil

It is difficult to predict the water droplet size that must be settled out of the oil phase to coincide with the rather loose definition of "free oil." Unless laboratory or nearby field data are available, good results have been obtained by sizing the oil pad such that water droplets 500 microns and larger settle out. If this criteria is met, the emulsion to be treated by downstream equipment should contain less than 5% to 10% water without an excessive chemical treatment program.

Oil Droplet Size in Water

From Equation 5-2 it can be seen that the separation of oil droplets from the water is easier than the separation of water droplets from the oil. The oil's viscosity is on the order of 50 to 20

times that of water. The primary purpose of three-phase separation is to prepare the oil for further treating. Field experience indicates that oil content in the produced water from a three-phase separator, sized for water removal from oil, can be expected to be between a few hundred and 2,000 mg/l. This water will require further treating and is discussed later. Sizing for oil droplet removal from the water phase does not appear to be a meaningful criterion.

Retention Time

A certain amount of oil storage is required to assure that the oil reaches equilibrium and flashed gas is liberated. An additional amount of storage is required to assure that the free water has time to coalesce into droplet sizes sufficient to fall in accordance with Equation 5-2. It is common to use retention times ranging from three minutes to thirty minutes depending upon laboratory or field data. If this information is not available, an oil retention time of ten minutes is suggested for design.

Similarly, a certain amount of water storage is required to assure that most of the large droplets of oil entrained in the water have sufficient time to coalesce and rise to the oil-water interface. It is common to use retention times for the water phase ranging from three minutes to thirty minutes depending upon laboratory or field data. If this information is not available, a water retention time of ten minutes is recommended for design.

The retention time for both the maximum oil rate and the maximum water rate should be calculated, unless laboratory data indicate that it is unnecessary to take this conservative design approach.

SEPARATOR SIZING

The guidelines presented here can be used for initial sizing determinations. They are meant to complement and not replace operating experiences. Determination of the type and size separator must be made on an individual basis. All the functions and requirements should be considered including the likely uncertainties in design flow rates and properties. For this reason, there is no substitute for good engineering evaluations of each separator by the design engineer. The "trade off' between design size and details and uncertainties in design parameters should not be left to manufacturer recommendations or rules of thumb.

Horizontal Separators

For sizing a horizontal three-phase separator it is necessary to specify a vessel diameter and a seam-to-seam vessel length. The gas capacity and retention time considerations establish certain acceptable combinations of diameter and length. The need to settle 500-micron water droplets from the oil establishes a maximum diameter.

Gas Capacity

The gas capacity constraints provide the following formula, discussed in Chapter 4:

$$d^2 L_{eff} = 420\left[\frac{TZQ_g}{P}\right]\left[\left(\frac{\rho_g}{\rho_l - \rho_g}\right)\frac{C_D}{d_m}\right]^{1/2} \qquad (5\text{-}3)$$

where d = vessel inside diameter, in.

L_{eff} = vessel effective length, ft

T = operating temperature, °R

Z = gas compressibility

Q_g = gas flow rate, MMscfd

ρ = operating pressure, psia

ρ_g = density of gas, Ib/ft^3

ρ_1 = density of liquid, Ib/ft^3

C_D = drag coefficient

d_m = liquid drop to be separated, microns

Retention Time

Retention time constraints give another equation that provides acceptable combinations of d and L_{eff}

$$d^2 L_{eff} = 1.42\ [(Q_w)(t_r)_w + (Q_o)(t_r)_o] \qquad (5\text{-}4)$$

where Q_w = water flow rate, bpd

$(t_r)_w$ = water retention time, min

Q_o = oil flow rate, bpd

$(t_r)_o$ = oil retention time, min

Derivation of Equation 5-4

t is in S, Vol in ft^3, Q in ft^3/s, D in ft, d in inches, L_{eff} in ft

$$t = \frac{Vol}{Q}$$

$$Vol = \frac{1}{2}\left(\frac{\pi D^2 L_{eff}}{4}\right) = \frac{\pi d^2 L_{eff}}{(2)(4)(144)} = 2.73 \times 10^{-3}\ d^2 L_{eff}$$

$$(Vol)_o = 2.73 \times 10^{-3}\ d^2 L_{eff}\left(\frac{A_o}{A_1}\right)$$

$$(Vol)_w = 2.73 \times 10^{-3}\ d^2 L_{eff}\left(\frac{A_w}{A_1}\right)$$

Q_0 and Q_w are in bpd

$$Q = Q_o \times 5.61 \frac{ft^3}{barrel} \times \frac{day}{24\ hr} \times \frac{hr}{3,600s} = 6.49 \times 10^{-5} Q_o$$

$$Q = 6.49 \times 10^{-5}\ Q_w$$

A_o , A_w, and A_1 are cross - sectional areas of oil, water, and liquid.

$$42\left(\frac{A_o}{A_1}\right) = \frac{t_o\ Q_o}{d^2\ L_{eff}} \quad 42\left(\frac{A_w}{A_1}\right) = \frac{t_w\ Q_w}{d^2\ L_{eff}}$$

$(t_r)_o$ and $(t_r)_w$ are in minutes

$$0.7\left(\frac{A_o}{A_1}\right) = \frac{(t_r)_o\ Q_o}{d^2\ L_{eff}} \quad 0.7\left(\frac{A_w}{A_1}\right) = \frac{(t_r)_w\ Q_w}{d^2\ L_{eff}}$$

$$0.7\left(\frac{A_o + A_w}{A_1}\right) = \frac{(t_r)_o\ Q_o + (t_r)_w\ Q_w}{d^2\ L_{eff}}$$

$$d^2\ L_{eff} = 1.42\ [(t_r)_o\ Q_o + (t_r)_w\ Q_w]$$

Settling Equation

The requirement that 500-micron water droplets be capable of settling out of the oil pad establishes a maximum oil pad thickness given by the following formula:

$$h_o = \frac{0.00128\ (t_r)_o\ (\Delta S.G.)\ d_m^2}{\mu} \qquad (5\text{-}5)$$

Derivation of Equation 5-5

t_w, t_o are in s, V in *ft/s,* h_o in inches, d_m in micron, μ in cp

$t_w = t_o$

$$t_w = \frac{h_o/12}{V_t},\ V_t = \frac{1.78 \times 10^{-6}\ (\Delta S.G.)\ d_m^2}{\mu}$$

$$t_w = 46,800\ \frac{\mu\ h_o}{(\Delta S.G.)\ d_m^2}$$

t_r is in minutes

$$t_o = 60\,(t_r)_o$$

$$46{,}800\,\frac{\mu\, h_o}{(\Delta S.G.)\, d_m^2} = 60\,(t_r)_o$$

$$h_o = \frac{0.00128\,(t_r)_o\,(\Delta S.G.)\, d_m^2}{\mu}$$

This is the maximum thickness the oil pad can be and still allow the water droplets to settle out in time $(t_r)_o$.

For d_m = 500 micron

$$(h_o)_{max} = 320\,\frac{(t_r)_o\,(\Delta S.G.)}{\mu} \qquad (5\text{-}6)$$

For a given oil retention time and a given water retention time the maximum oil pad thickness constraint establishes a maximum diameter in accordance with the following procedure:

1.Compute $(h_o)_{max}$.

Calculate the fraction of the vessel cross-sectional area occupied by the water phase. This is given by:

$$\frac{A_w}{A} = 0.5\,\frac{Q_w\,(t_r)_w}{(t_r)_o Q_o + (t_r)_w Q_w} \qquad (5\text{-}7)$$

Derivation of Equation 5-7

A_o and A_w are in ft^2, Q in ft^3/s, t in s, L_{eff} in ft.

$$A = \frac{Q\,t}{L_{eff}}$$

$$Q = 6.49 \times 10^{-5}\, Q_o,\ Q = 6.49 \times 10^{-5}\, Q_w$$

$$t_o = 60(t_r)_o,\ t = 60(t_r)_w$$

$$A_o = 3.89 \times 10^{-3}\,\frac{Q_o\,(t_r)_o}{L_{eff}},\quad A_w = 3.89 \times 10^{-3}\,\frac{Q_w\,(t_r)_w}{L_{eff}}$$

$$A = 2\,(A_o + A_w)$$

$$\frac{A_w}{A} = 0.5\,\frac{Q_w\,(t_r)_w}{(t_r)_o Q_o + (t_r)_w Q_w}$$

3.From Figure 5-8 determine the coefficient □ .

4.Calculate d_{max} from:

$$d_{max} = \frac{(h_o)_{max}}{\beta}, \text{ where } \beta = h(o)/d \quad (5\text{-}8)$$

Any combination of d and L_{eff} that satisfies all three of Equations 5-3, 5-4, and 5-5 will meet the necessary criteria

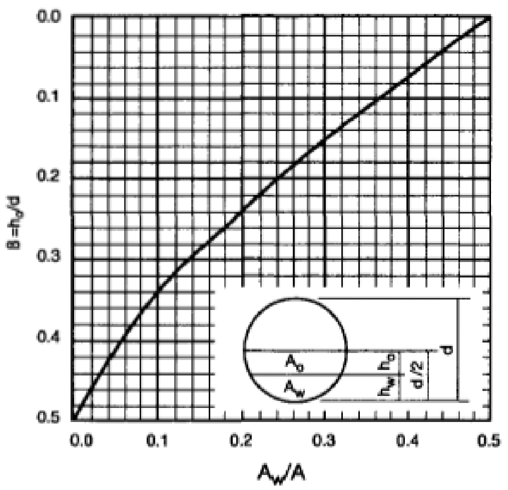


Figure 5-8. **Coefficient "□' for a cylinder half filled with liquid.**

Seam-to-Seam Length and Slenderness Ratios

The seam-to-seam length can be estimated from the effective length using the same formulas as for two-phase separators. Where the gas capacity governs, the slenderness ratio should be limited to less than 4 or 5 to prevent re-entrainment of liquid at the gas-liquid interface. If the separator sizing is based on liquid capacity a higher slenderness ratio is acceptable. There is the possibility of generating internal waves at the oil-water interface. Unless a more elaborate study is performed, it is recommended that slenderness ratios of less than 4 be chosen. Most common horizontal three-phase separators have slenderness ratios between 3 and 5.

Procedure for Sizing Three-Phase Horizontal Separators

1. Select a $(t_r)_o$ and a $(t_r)_w$
2. Calculate $(h_o)_{max}$. Use 500-micron droplet if no other information is available.

$$(h_o)_{max} = 1.28 \times 10^{-3} \frac{(t_r)_o \, (\Delta S.G.) \, d_m^2}{\mu}$$

For 500 microns,

$$(h_o)_{max} = 320 \frac{(t_r)_o \, (\Delta S.G.)}{\mu}$$

3.Calculate A_W/A

$$\frac{A_w}{A} = 0.5 \frac{Q_w (t_r)_w}{(t_r)_o Q_o + (t_r)_w Q_w}$$

4.Determine h_0/d from curve.

5.Calculate d_{max}.

$$d_{max} = \frac{(h_o)_{max}}{h_o / d}$$

Note: d_{max} depends on Q_0, Q_W, $(t_r)_0$ and a $(t_r)_W$

Calculate combinations of d, L_{eff} for d less than d_{max} that satisfy the gas capacity constraint. Use 100-micron droplet if no other information is available.

$$d\, L_{eff} = 420 \left(\frac{TZQ_g}{P}\right) \left[\left(\frac{\rho_g}{\rho_l - \rho_g}\right) \frac{C_D}{d_m}\right]^{1/2}$$

7.Calculate combinations of d, L_{eff} for d less than d_{max} that satisfy the oil and water retention time constraints.

$$d^2 L_{eff} = 1.42 \left[(t_r)_o Q_o + (t_r)_w Q_w\right]$$

8.Estimate seam-to-seam length:

$$L_{ss} = L_{eff} + \frac{d}{12}$$ for gas capacity

$$L_{ss} = \frac{4}{3} L_{eff}$$ for liquid capacity

9.Select reasonable diameter and length. Slenderness ratios (12 L_{ss}/d) on the order of 3 to 5 are common.

For separators other than 50% full of liquid, equations can be derived similarly, using the actual oil and water areas. The equations are derived using the same principles.

Vertical Separators

As with vertical two-phase separators, a minimum diameter must be maintained to assure adequate gas capacity. In addition, vertical three-phase separators must maintain a minimum diameter to allow the 500-micron water droplets to settle. The height of the three-phase separator is determined from retention time considerations.

Gas Capacity

The gas capacity constraints provide the following formula discussed in Chapter 4:

$$d_{min}^2 = 5{,}040\left[\frac{TZQ_g}{P}\right]\left[\left(\frac{\rho_g}{\rho_1 - \rho_g}\right)\frac{C_D}{d_m}\right]^{1/2} \qquad (5\text{-}9)$$

Settling

The requirement for settling water droplets from the oil requires that the following equation must be satisfied:

$$d_2 = 6{,}690\,\frac{Q_o\mu}{(\Delta S.G.)\,d_m^2} \qquad (5\text{-}10)$$

Derivation of Equation 5-10

V_t is in ft/s, V_0 in ft/s, d_m in micron, µ in cp

$V_t = V_o$

$$V_t = \frac{1.78\times10^{-6}\,(\Delta S.G.)\,d_m^2}{\mu}$$

Q is in ft^3/s, A in ft^2

$$V_o = \frac{Q}{A}$$

Q_0 is in bpd

$$Q = Q_o \times 5.61\,\frac{ft^3}{barrel}\times\frac{day}{24\ hr}\times\frac{hr}{3{,}600s} = 6.49\times10^{-5}Q_o$$

D is in ft, d in inches

$$A = \frac{\pi D^2}{4} = \frac{\pi d^2}{(4)(144)}$$

$$V_o = 0.0119 \frac{Q_o}{d^2}$$

$$\frac{1.78 \times 10^{-6} (\Delta S.G.) d_m^2}{\mu} = 0.0119 \frac{Q_o}{d^2}$$

$$d^2 = 6,690 \frac{Q_o \mu}{(\Delta S.G.) d_m^2}$$

For 500-micron droplets Equation 5-10 becomes

$$d^2 = 0.0267 \frac{Q_o \mu}{\Delta S.G.} \qquad (5\text{-}11)$$

Retention Time

$$h_o + h_w = \frac{(t_r)_o Q_o + (t_r)_w Q_w}{0.12 d^2} \qquad (5\text{-}12)$$

Where:

h_0 = height of oil pad, in.

h_w = height from water outlet to interface, in.

(Note that this height must be adjusted for cone bottom vessels.)

Derivation of Equation 5-12

From two-phase separator design:

$$d^2 h = \frac{t_r Q_l}{0.12}$$

Thus,

$$d^2 h_o = \frac{(t_r)_o Q_o}{0.12}$$

$$d^2 h_w = \frac{(t_r)_w Q_w}{0.12}$$

$$h_o + h_w = \frac{(t_r)_o Q_o + (t_r)_w Q_w}{0.12 d^2}$$

Seam-to-Seam Length and Slenderness Ratios

As in the case of a vertical two-phase separator, the seam-to-seam length (L_{ss}) can be approximated from the geometry once h_0 and h_w are chosen. For screening purposes, it can be assumed that L_{ss} is the larger of the two values in the following equations:

$$L_{ss} = \frac{h_o + h_w + 76}{12} \text{ or } \frac{h_o + h_w + d + 40}{12} \qquad (5\text{-}13)$$

where d is the minimum diameter for gas capacity.

Any d larger than that calculated by Equation 5-9 and 5-10 and that satisfies Equation 5-12 is acceptable. Diameter should be chosen with slenderness ratios less than 4. Most vertical three-phase separators have slenderness ratios on the order of 1.5 to 3 to keep within reasonable height restrictions.

Procedure for Sizing Three-Phase, Vertical Separators

1.Calculate minimum diameter from requirement for water droplets to fall through oil layer. Use 500-micron droplets if no other information is available.

$$d^2 = 6{,}690 \frac{Q_o \mu}{(\Delta S.G.)\, d_m^2}$$

For 500 - micron

$$d^2 = \frac{Q_o \mu}{\Delta S.G.}$$

2.Calculate minimum diameter from requirement for oil droplets to fall through gas. Use 100-micron droplets if no other information is available.

$$d^2 = 5{,}040 \frac{TZQ_g}{P} \left[\left(\frac{\rho_g}{\rho_1 - \rho_g} \right) \frac{C_D}{d_m} \right]^{1/2}$$

3.Choose the larger of the two as d_{min}.

4.Select $(t_r)_0$ and $(t_r)_w$, and solve for $h_0 + h_w$ for various d.

$$h_o + h_w = \frac{[(t_r)_o Q_o + (t_r)_w Q_w]}{0.12\, d^2}$$

5. Estimate seam-to-seam length using the larger value.

$$L_{ss} = \frac{h_o + h_w + 76}{12} \text{ or } \frac{h_o + h_w + d + 40}{12}$$

6.Select a size of reasonable diameter and length. Slenderness ratios ($12\, L_{ss}/d$) on the order of 1.5 to 3 are common.

EXAMPLES

Example 5-1: Sizing a Vertical Three-Phase Separator

Given:

Q_o= 5,000 bopd

Q_w= 3,000 bwpd

Q_g=5 MMscfd

P_o= 100 psia

T_o= 90°F

Oil = 30^0 API

$(S.G.)_w$ = 1.07

S_g = 0.6

$(t_r)_0 = (t_r)_w$,= 10 min.

Oil viscosity = 10 cp

Solution:

1.Calculate difference in specific gravities.

$$°API = \frac{141.5}{(S.G.)_o} - 131.5$$

$$(S.G.)_o = \frac{141.5}{30 + 131.5}$$

$$= 0.876$$

$$\Delta S.G. = 1.07 - 0.876 = 0.194$$

2.Calculate minimum diameter to satisfy gas capacity constraint. (See two-phase separator chapter for procedure.)

d_{min} = 34.9 in.

3.Calculate minimum diameter for water droplet settling.

$$d^2_{min} = 6{,}690\left(\frac{Q_o\,\mu}{\Delta S.G.\ d^2_m}\right)$$

$$= 6{,}690\left[\frac{(5{,}000)\,(10)}{0.194\,(500)^2}\right]$$

$$d_{min} = 83.0 \text{ in.}$$

4.Liquid retention constraint.

$$h_o = \frac{(t_r)_o\,(Q_o)}{0.12\,d^2}$$

$$h_w = \frac{(t_r)_w\,(Q_w)}{0.12\,d^2}$$

$$h_o + h_w = \frac{(10)\,(5{,}000 + 3{,}000)}{0.12\,d^2} = \frac{667{,}000}{d^2}$$

5.Compute combinations of d, and $h_0 + h_w$ for diameters greater than d_{min} (Table 5-1).

Table 5-1

Vertical Three-Phase Separator Capacity Diameter vs. Length for Retention Time Constraint $(t_r)_o = (t_r)_w$ = 10 minutes

d in.	$h_o + h_w$ in.	L_{ss} ft	(12) L_{ss}/d
84	94.5	18.2	2.6
90	82.3	17.7	2.4
96	72.3	17.4	2.2
102	64.1	17.2	2.0

6.Compute seam-to-seam length (Table 5-1) as the larger of:

$$L_{ss} = \frac{h_o + h_w + 76}{12} \text{ or } \frac{h_o + h_w + d + 40}{12}$$

7.Compute slenderness ratio (12 L_{ss}/d). Choices in the range of 1.5 to 3 are common (Table 5-1).

8.If necessary, repeat steps 6 through 10 for various retention times and graph as was done two-phase separators.

9.Choose a reasonable size. A 90-in. X 15-ft or a 96-in. X 12-ft 6-in. size would be a reasonable choice.

Example 5-2: Sizing a Horizontal Three-Phase Separator

Given: Q_o = 5,000 bopd

Q_w = 3,000 bwpd

Q_g=5MMscfd

P= 100 psia

T=90°F

Oil = 30° API

$(S.G.)_w$= 1.07 Sg= 0.6

$(t_r)_o = (t_r)_w$,= 10 min

Oil viscosity = 10 cp

Solution:

1. Calculate difference in specific gravities.

$$°API = \frac{141.5}{(S.G.)_o} - 131.5$$

$$(S.G.)_o = \frac{141.5}{30 + 131.5}$$

$$\Delta S.G. = 1.07 - 0.876 = 0.194$$

2.Check for gas separation. See Chapter 4 procedure.

dL_{eff} = 102

Table 5-2

Horizontal Three-Phase Separator Diameter vs. Length for Gas Capacity Restraint

d in.	L_{eff} ft
60	1.7
72	1.4
84	1.2
96	1.1

3.Calculate combinations of d and L_{eff} for gas separation (Table 5-2).

Because of the low values for L_{eff}, gas capacity will not govern.

4.Calculate maximum oil pad thickness

$$(h_o)_{max} = 0.00128 \frac{(t_r)_o\,(\Delta S.G.)\,d_m^2}{\mu}$$

$$= 0.00128 \frac{(10)(0.194)(500)^2}{10}$$

$$= 62.1$$

5.Calculate maximum diameter for oil pad thickness constraint.

$$(h_o)_{max} = 0.00128 \frac{(t_r)_o\,(\Delta S.G.)\,d_m^2}{\mu}$$

$$= 0.00128 \frac{(10)(0.194)(500)^2}{10}$$

$$= 0.1875$$

From Figure 5-8:

$$\beta = 0.257$$

$$d_{max} = \frac{(h_o)_{max}}{\beta}$$

$$= \frac{62.1}{0.257}$$

$$d_{max} = 24.16 \text{ in.}$$

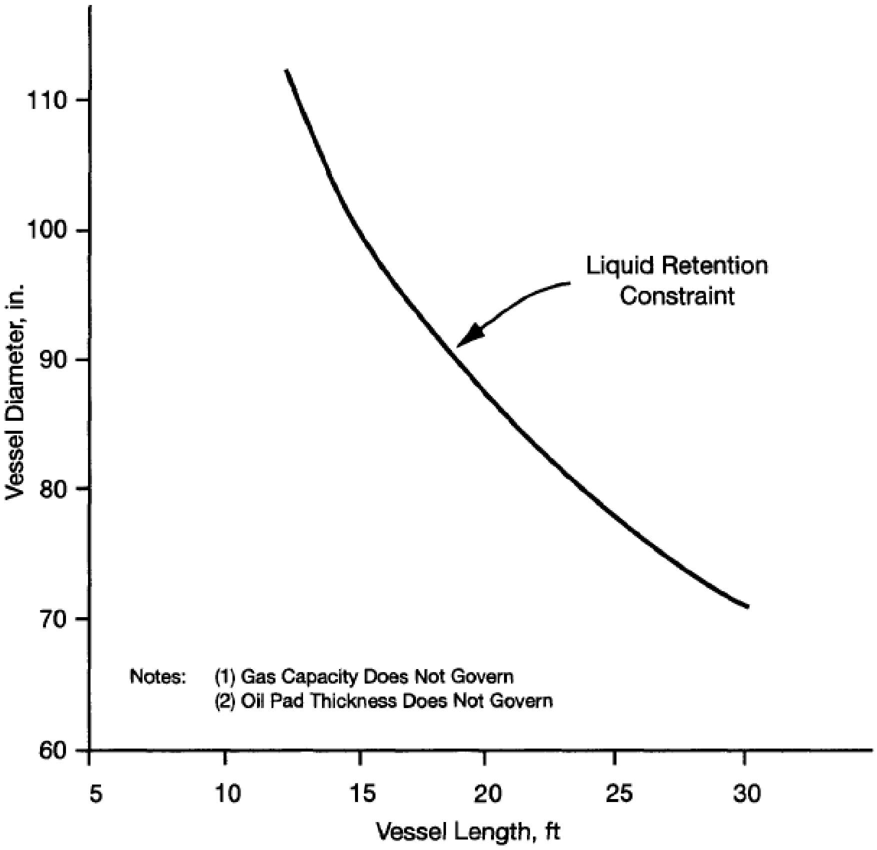


Figure 5-9. Horizontal three-phase separator example.

Table 5-3

Horizontal Three-Phase Separator Capacity Diameter vs. Length for Liquid Retention Time Constraint $(t_r)_o = (t_r)_w = 10$ minutes

d in.	L_{eff} ft	L_{ss} ft	(12) L_{ss}/d
60	31.6	42.1	8.4
72	21.9	29.2	4.9
84	16.1	21.5	3.1
96	12.3	16.4	2.1
108	9.7	13.0	1.4

6.Liquid retention constraint:

$$\begin{aligned} d^2 L_{eff} &= 1.42\,[Q_w\,(t_r)_w + Q_o\,(t_r)_o] \\ &= (1.42)(10)(8{,}000) \\ &= 113{,}600 \end{aligned}$$

7.Compute combinations of d and L_{eff} (Table 5-3).

8.Compute seam-to-seam length (Table 5-3).

$$L_{ss} = \frac{L_{eff}}{0.75} \text{ or } L_{ss} = L_{eff} + \frac{d}{12}$$

9.Compute slenderness ratio (12 L_{ss}/d). Choices in the range of 3 to 5 are common.

10.Graph results and choose a reasonable size that does not violate gas capacity restraint or oil pad thickness restraint. Possible choices from Figure 5-9 are 90 in. x 20 ft, 96 in. x 17 ft 6 in., and 102 in. X 15 ft.

References

1. Ken Arnold and Maurice Stewart et al.: “Surface Production Operations”, Volume 1, Design of Oil-Handling Systems and Facilities, Gulf Publishing Company, Houston, TX, 1989,1999, 101-108, 117-159