SECTION 7

Separation Equipment

PRINCIPLES OF SEPARATION

Three principles used to achieve physical separation of gas and liquids or solids are momentum, gravity settling, and coalescing. Any separator may employ one or more of these principles, but the fluid phases must be "immiscible" and have different densities for separation to occur.

FIG. 7-1

Nomenclature

- A = Area, m^2
- A_{mesh} = Mesh pad area, m^2
- A_p = Particle or droplet cross sectional area, m^2
- C' = Drag coefficient of particle, dimensionless
- D = Vessel diameter, mm
- D_c = Characteristic diameter in the Stoke Number, St
- D_H = Liquids hydraulic diameter, m
- D_p = Droplet diameter, m
- d_2 = Nozzle diameter, m
- d_{95} = Droplet size (micron) for 95% removal
- g = Acceleration due to gravity, 9.81 m/s^2
- GOR = Gas–oil ratio
- H = Height, mm
- H_{SET} = Settling height, mm
- HILL = High interphase liquid level
- HHILL = High-high interphase liquid level
- HLL = High liquid level
- HHLL = High-high liquid level
- J = Gas velocity head, $kg/(m \cdot s^2)$
- K = Souders-Brown Coefficient, m/s
- K_{CR} = Proportionality constant from Fig. 7-7 for use in Equation 7-6
- L = Seam to seam length of vessel, mm
- L_{SET} = Effective gravity droplet settling length for a horizontal separator, mm
- LILL = Low interphase liquid level
- LLILL = Low-low interphase liquid level
- LLL = Low liquid level
- LLLL = Low-low liquid level
- M_p = Mass of droplet or particle, kg
- MW = Molecular weight, kg/kmole
- NILL = Normal interphase liquid level
- NLL = Normal liquid level
- N_{ref} = Reynolds film number
- N_μ = Interfacial viscosity number
- OD = Outside diameter, mm
- P = System pressure, kPa (abs)
- Q_A = Actual gas flow rate, m^3/s
- Q_l = Liquid volumetric flow rate, m^3/day
- $Q_{l,max}$ = Maximum liquid volumetric flow rate, m^3/s
- R = Gas constant, 8.31 [kPa (abs) $\cdot$ m^3]/(K $\cdot$ kmole)
- Re = Reynolds number, dimensionless
- Stk = Dimensionless Stokes Number: $\dfrac{g \cdot \rho_c \cdot V_c \cdot D_p^2}{18\mu_c \cdot D_c}$
- T = System temperature, K
- t = Retention time, min
- V = Velocity, m/s
- V_c = Velocity of continuous phase, m/s
- V_h = Flow vapor velocity between gas-liquid interphase and the top of a horizontal separator, m/s
- V_l = Liquid velocity, m/s
- V_r = Gas velocity relative to liquid, m/s
- $V_{r,\,max}$ = Maximum velocity of the gas relative to liquid to resist substantial re-entrainment
- V_t = Critical or terminal velocity necessary for particles of size D_p to drop or settle out of a continuous phase, m/s
- W_g = Flow rate of gas, kg/day
- W_l = Flow rate of liquid, kg/day
- Z = Compressibility factor, dimensionless

Greek:

- β = Ratio of the number of influent particles of a given size to the number of effluent particles of the same size
- ρ_c = Continuous phase density, kg/m^3
- ρ_g = Gas phase density, kg/m^3
- ρ_l = Liquid phase density, kg/m^3
- ρ_{hl} = Heavy liquid phase density, kg/m^3
- ρ_{ll} = Light liquid phase density, kg/m^3
- ρ_m = Mixed fluid density, kg/m^3
- ρ_p = Droplet or particle phase density, kg/m^3
- μ_c = Viscosity of continuous phase, mPa $\cdot$ s (cP)
- μ_g = Gas viscosity, mPa $\cdot$ s (cP)
- μ_{hl} = Heavy liquid phase viscosity, mPa $\cdot$ s (cP)
- μ_{ll} = Light liquid phase viscosity, mPa $\cdot$ s (cP)
- μ_l = Liquid viscosity, mPa $\cdot$ s (cP)
- σ = Liquid surface tension, N/m
- Φ = Flow parameter

DEFINITIONS OF WORDS AND PHRASES USED IN SEPARATION EQUIPMENT

Coalescing: To come together to form a larger whole. The process or mechanism of bringing small droplets or aerosols and creating larger droplets that can more easily be removed by gravity. Also refers to the joining of liquid droplets dispersed in another immiscible liquid, as with water drops in oil.

Gas coalescing filter: A separator containing changeable elements that is capable of the removal of sub-micron aerosols and solids. This coalescing and filtering occurs as the gas flows from the inside of the filter/coalescing element to the outside of this element in the vertical filter-coalescer. Properly designed, this coalescing stage will remove solids and fine aerosols down to 0.3 micron and larger.

Electrostatic coalescer: A device used to remove dispersed water from oil by using a high voltage field to polarize and/or charge dispersed water droplets.

Emulsion: A stable dispersion of one immiscible liquid in another liquid.

Entrainment: Fluid in the form of a mist, fog, droplets, or bubbles carried along with the continuous phase.

Filter: A device used to separate solids from liquid or gas flow. Most filters utilize removable elements. Designs offering in-line cleaning by back-flushing are also available.

Filter separators: A device to remove solids and entrained liquids from a gas stream. A filter separator usually has two compartments. The first compartment contains filter-coalescing elements. As the gas flows through the elements, the liquid particles coalesce into larger droplets and when the droplets reach sufficient size, the gas flow causes them to flow out of the filter elements into the center core. The particles are then carried into the second compartment of the vessel (containing a vane-type or knitted wire mesh mist extractor) where the larger droplets are removed. A lower barrel or boot may be used for surge or storage of the removed liquid.

Flash drum: A vessel which separates liquid, generated due to pressure reduction and/or increase in temperature of a liquid stream, from the gas phase or two phase fluid.

Gas-oil ratio (GOR): The ratio of gas to hydrocarbon at a defined condition, typically expressed as Sm^3/m^3.

Heater-treater: A device used to process hydrocarbon, by warming and coalescence, in order to remove small quantities of residual water so as to meet transportation or product specifications.

Line drop: A boot or underground vessel, used on a pipeline, to provide a place for free liquids to separate and accumulate. It is used in pipelines with very high gas-to-liquid ratios to remove only free liquid from a gas stream. It will remove bulk liquid, but not necessarily all the liquid.

Knock out drum: Generic term used to describe vessels for gas-liquid separation. Separation can be either for high, or low, gas-to-liquid ratio streams.

Liquid coalescer vessel: A vessel, with internals designed for the separation of immiscible liquids.

Liquid coalescer: A vessel internal used for increasing the droplet size of immiscible liquids, so that they can be removed by gravity separation. Typical coalescing elements are stacked plates, vanes, wire or plastic mesh, or cartridge type elements.

Liquid-liquid separators: A vessel where two liquid phases are separated.

Mist eliminator: A fixed device used to enhance removal of smaller liquid droplets from a gas above which is not normally possible by gravity separation. Typical mist eliminator designs include knitted wire mesh, vane type, and cyclonic.

Production separator: A vessel typically used as the first separation device that the fluid encounters in the wellhead to processing plant production network (sometimes is called Wellhead Separator, when physically located at the well site).

Retention time: For gas-liquid separation, the average time a flowing fluid remains within the liquid section of a separator at the design feed rate. For three phase separation, the retention time can be the time the total fluid remains in the separation section at the design feed rate, or if defined as phase retention time, the time the phase remains in the separation section.

Scrubber: A category of separator used for high gas-to-liquid ratios. Scrubbers are used as the primary separator in systems where small amounts of liquid are produced, to 'polish' an already-separated gas stream by removing residual contaminants more completely, or as a backup in case of an operational upset upstream.

Separator: A generic term for a device which separates gas-liquid, gas-liquid-liquid, gas–solids, liquid-solids or gas-liquid- solids.

Slug catcher: A particular separator design which is able to absorb sustained in-flow of large liquid volumes at irregular intervals. Usually found on gas gathering systems or other two-phase pipeline systems at the terminus of the pipeline. A slug catcher may be a single large vessel or a manifolded system of pipes.

Surge drum: A vessel used to provide appropriate time for flow control and dampening during process variations and upsets. The capacity of the surge drum provides the ability to accept liquids from the upstream process, or provide liquids to down stream equipment without upsets.

Surge time: The time it takes to fill a specified fraction of a vessel, defined as the volume between a specified level range in a vessel divided by the design feed flow rate. 'Control' surge time is between the low liquid level alarm (LLL) and the high liquid level alarm (HLL). 'Total' surge time is between the lowest level (low-low liquid level, LLLL) and the highest level (high-high level, HHLL).

Test separator: A separator vessel used near the wellhead, which separates the phases for well test metering.

Three phase separator: A vessel used to separate gas and two liquids of different densities (e.g. gas, water, and oil) into three distinct streams.

INTRODUCTION

Scope

The Separation Chapter describes the types, function, application, design criteria, selection, and troubleshooting of separator vessels and devices, used from wellhead to treated product pipeline in the natural gas processing industry. Gas-liquid, liquid-liquid, gas-liquid-liquid, gas-solid, gas-solid-liquid, and liquid-solid devices are covered. The section addresses the primary separator at the well site for gas plants as well as common separation equipment in a gas treating facility. It does not provide substantial guidance on equipment used for water clean-up for re-injection or discharge, or for final treatment of liquid products. The scope does not include any discussion of the design of crude production separators and Gas-Oil Separation Process (GOSP) units for separation and treatment of crude oil, gas, and produced water. Note that some of the terms and design guidelines presented here may not be appropriate for crude oil service.

Separation Devices Used in Gas Processing

A wide variety of separation vessel styles and devices are used in the natural gas processing industry. These include vertical and horizontal vessels, two and three phase, many types of internals, as well as cyclonic devices, filter separators, gas coalescing filters, and gas and liquid filters. Fig. 7-2 shows a typical sour gas treating plant from wellhead to treated product pipeline. The common types of separators that are used within each process system are identified.

PRINCIPLES OF SEPARATION

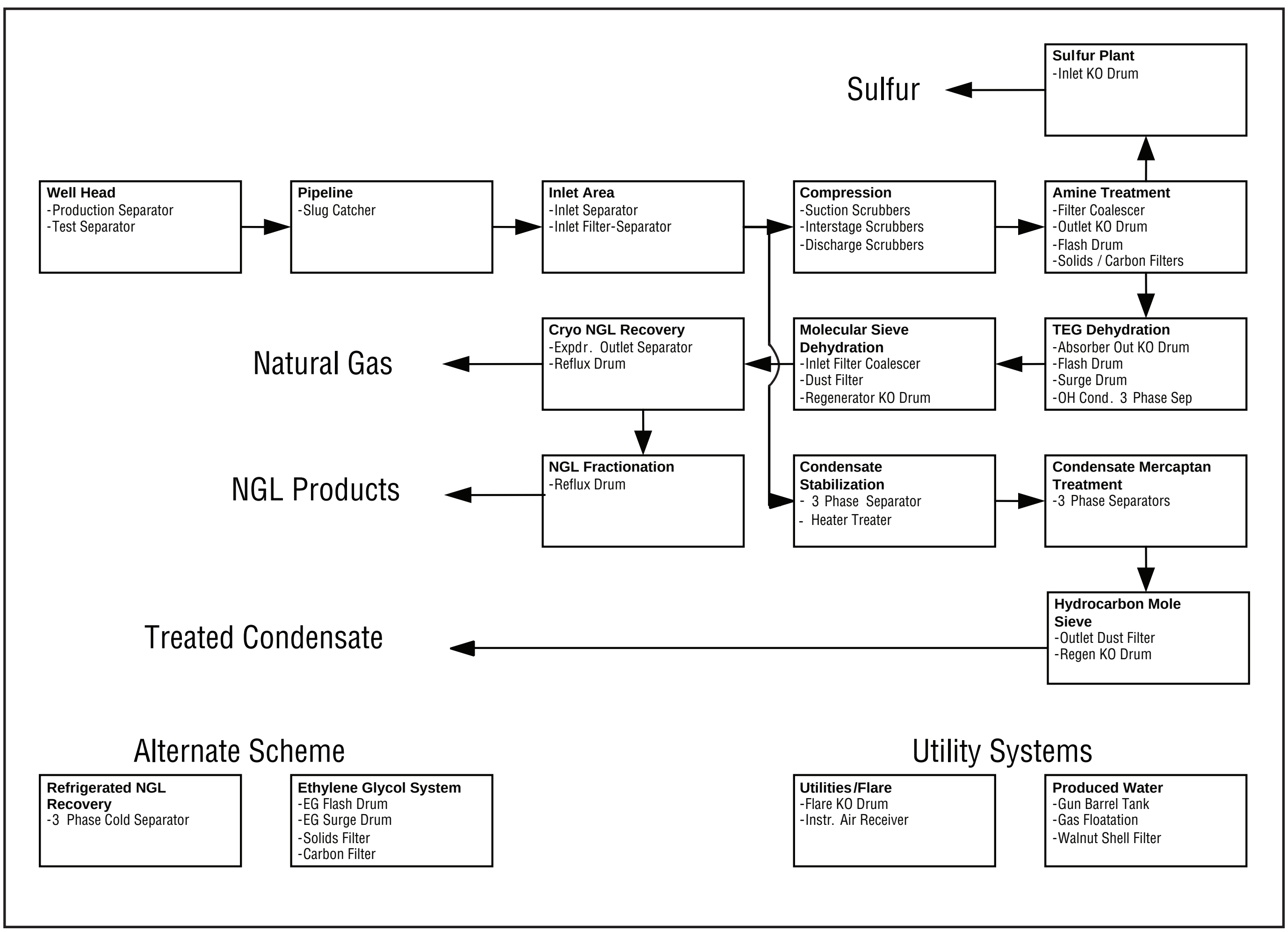
Defining the Separator Feed

Fluids to Be Separated — Many types of fluids are separated in natural gas production and processing. While streams in downstream NGL recovery and processing may be well defined, the primary production stream can vary in composition, pressure, temperature, and impurities.

There are a number of terms used in the industry to characterize production and processing fluids. One such term is gas/oil ratio (GOR). The GOR is the ratio of the volume of gas that comes out of solution to the volume of oil, or condensate at either atmospheric pressure or at any specific process conditions. It is typically expressed as Sm^3/m^3. In most production systems, produced water (production brackish water) will accompany the hydrocarbons. The amount of produced water is

FIG. 7-2

Separators Used in Gas Processing Industry



typically expressed as m^3/Sm^3 gas. The hydrocarbon portion of production in the natural gas industry (both vapor and liquid phases) is typically characterized by component to C_6 or C_8, and then as pseudo components, using MW and density, for heavier hydrocarbons. Water solubility, water entrainment, and trace components in the fluid should also be considered.

These characteristics, typically defined in the project or facility material balance, determine the gas, liquid, and solid phase flows and the properties for the fluids to be separated. The physical properties of the fluids are normally defined using equation of state models, and are supplemented by field physical property data where available. Special care should be used when utilizing simulator generated transport properties in the critical region of the phase envelope, or for cryogenic conditions.

Field Composition and Flow Considerations

A separator must be designed to perform over the full range of flow rate and composition that may be present during the life of the facility. These might include changes in the CO_2 or H_2S content, and how rich the gas is in natural gas liquids, or the production water cut. The vessel must also be designed considering changes in production flow due to reservoir depletion or gas break through. Adequate sizing and sufficient flexibility are required to handle anticipated conditions during the plant life. The possibility of flow variations due to slugs, flow surges, and compressor recycles should be considered. Frequently a design factor is added to the steady state flow rate to account for these variances in separator design. The magnitude of the factor depends on the location of the separator in the process. Also of concern is the presence of solids, either sand and/or iron sulfide in the production fluids.

Dispersed Droplet Size Distribution

Because a primary driver in separation processes is acceleration (e.g., gravity), which is opposed by frictional forces (see Fig. 7-4), an understanding of the likely droplet size of the dispersed phase is important for proper selection and sizing of the separator and internals. The average droplet size and distribution is a function of the upstream processing and the effect of the inlet piping on the fluid to the separator. Typical droplet generation mechanisms for gas-liquid systems include: mechanical action like bubbling and frothing from tower trays, packing and distributors, surface condensation in a heat exchanger tube, condensation due to cooling which does not occur on a surface, and shearing due to pressure drop through a valve or choke. Some typical liquid droplet sizes for liquid in a gas continuous phase are shown in Fig. 7-3. Also, as the liquid surface tension decreases (typical for light hydrocarbon systems at high pressure) the average droplet size formed by these processes will be smaller. The inlet piping flow characteristic is of interest since droplets can either coalesce into larger droplets, or be sheared by the gas phase in the piping. The velocity in the piping, elbows and bends, control valves, and hard "T"s all create shear that can result in fracturing larger droplets into smaller droplets. The higher the inlet velocity, higher the gas density, and the lower the liquid surface tension, the smaller the droplets. Use of inlet devices which shear the fluid (impact baffle plates/diverters) will also result in smaller inlet droplets.

Several correlations, which use the flow regime of the feed in the inlet pipe, and physical properties of the phases, are available to estimate this.[1] Oftentimes, however, past experience is used to set the target particle size expected, and in turn to be removed based on the specific unit operation in the plant, upstream processes, and the fluid to be separated.

For liquid-liquid separation, the effect of static mixers, mechanical agitators, centrifugal pumps, and high pressure drop control valves is also important in establishing the size distribution of droplets. Fine solids and certain chemicals (i.e., well treating chemicals) can stabilize fine droplets.

Flow Regimes Upstream of a Separator

As a mixture of gas, hydrocarbon liquid, and water flows to a separator, the mixture can exhibit various behaviors, or flow patterns, depending on factors such as the relative flow rates of each phase, phase densities, elevation changes, and velocity. A number of empirical models have been developed for predicting flow pattern in a pipe. Possible flow patterns include mist flow, bubble flow, stratified flow, wavy flow, slugging flow, and annular flow. Stratified flow is an ideal flow regime entering a separator since the bulk phases are already segregated. Slugging and foaming flow are of particular concern to separator

FIG. 7-3

Typical Partical Size Distribution Ranges from Entrainment Caused by Various Mechanisms

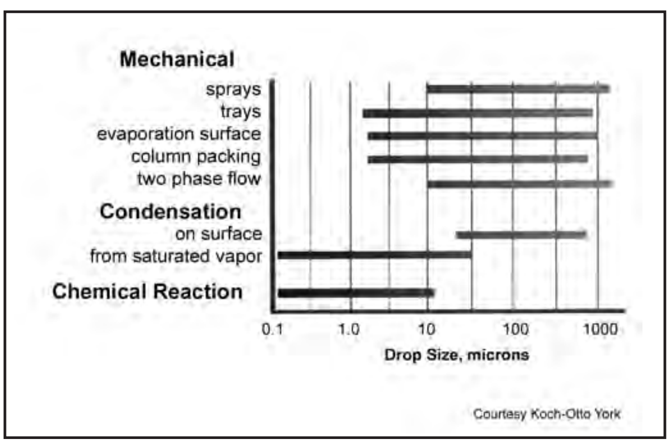
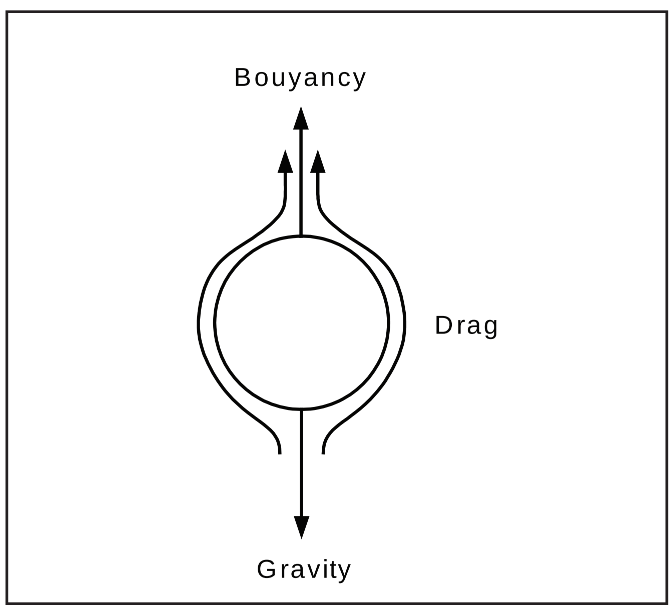


FIG. 7-4

Buoyant Force on a Droplet



design. Proper velocity and piping design upstream of the separator are critical for good separator performance (See "Two and Three-Phase Separator Design and Operating Principles- Inlet Section" in this Chapter for recommendations).

Separation and Re-entrainment Mechanisms

The separation of two phases with different densities will occur by one of several mechanisms which are described in this section. The discussion is applicable to both gas-liquid and liquid-liquid separation.

Gravity Settling Theory — A summary of the equations defining the gravity settling mechanisms described below is presented in Fig.7-7. The figure also includes general information regarding droplet sizes.

Dispersed droplets will settle out of a continuous phase if the gravitational force acting on the droplet is greater than sum of the drag force of the fluid flowing around the droplet and the buoyant force of the continuous phase (see Fig. 7-4). The terminal velocity of the droplet can be calculated directly from the balance of these forces, Equation 7-1.[1]

$$V_t = \sqrt{\frac{2 \cdot g \cdot M_p \cdot (\rho_p - \rho_c)}{\rho_p \cdot \rho_c \cdot A_p \cdot C'}} \qquad \textbf{Eq 7-1}$$

The drag coefficient has been found to be a function of the shape of the particle and the Reynolds number of the flowing fluid. If the particle shape is considered to be a solid, rigid sphere, then the terminal velocity can be calculated using Equation 7-2:

$$V_t = \sqrt{\frac{4 \cdot g \cdot D_p \cdot (\rho_p - \rho_c)}{3 \cdot \rho_c \cdot C'}} \qquad \textbf{Eq 7-2}$$

And the Reynolds number is defined in Equation 7-3.

$$Re = \frac{1000 \cdot D_p \cdot V_t \cdot \rho_c}{\mu_c} \qquad \textbf{Eq 7-3}$$

Fig. 7-5 shows the relationship between drag coefficient and particle Reynolds number for spherical particles.

In this form, a trial and error solution is required since both particle size (D_p) and terminal velocity (V_t) are involved. To eliminate trial and error iterations, the following technique eliminates the velocity term from the expression. The abscissa of Fig. 7-6 is given in Equation 7-4.

$$C' (Re)^2 = \frac{(1.31) \cdot (10^7) \cdot \rho_c \cdot D_p^3 \cdot (\rho_p - \rho_c)}{\mu_c^2} \qquad \textbf{Eq 7-4}$$

As with other fluid flow phenomena, the gravity settling drag coefficient reaches a limiting value at high Reynolds numbers.

As an alternative to using Equation 7-4 and Fig. 7-6 the following approach is commonly used.

The curve shown in Fig. 7-5 can be simplified into three sections from which curve-fit approximations of the C′ vs. Re curve can be derived. When these expressions for C′ vs. Re are substituted into Equations 7-2 and 7-3 (abscissa of Fig. 7-5), three settling laws are obtained as described below.

FIG. 7-5

Drag Coefficient and Reynolds Number for Spherical Particles

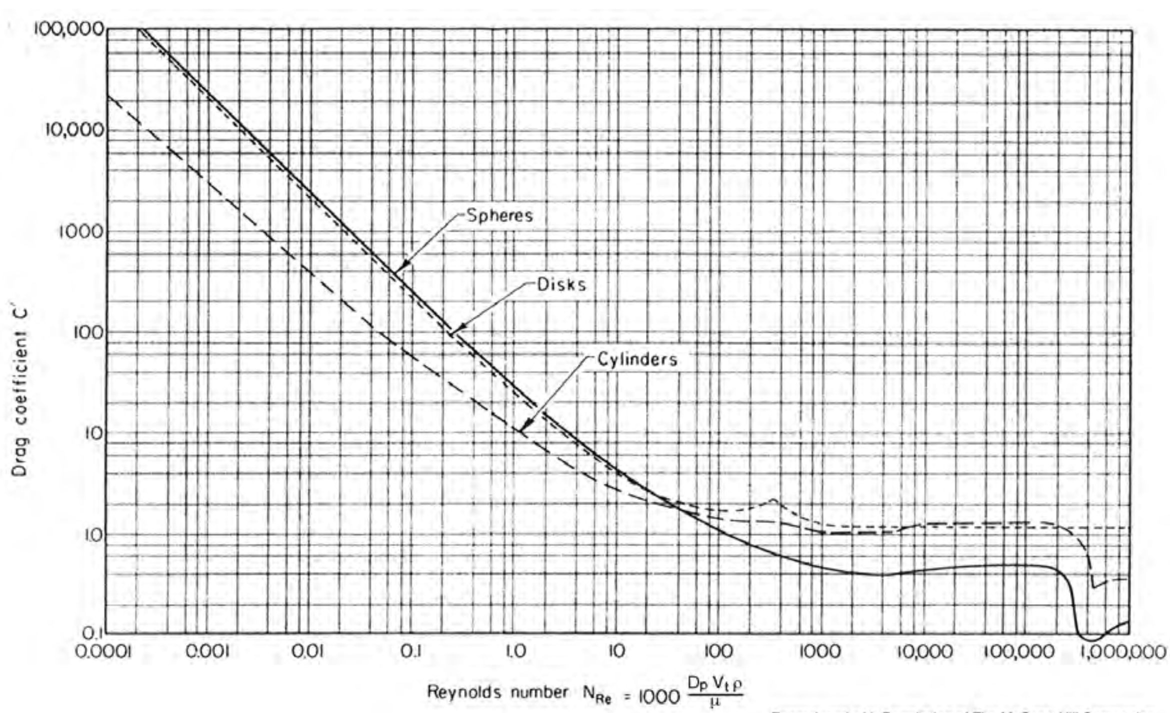
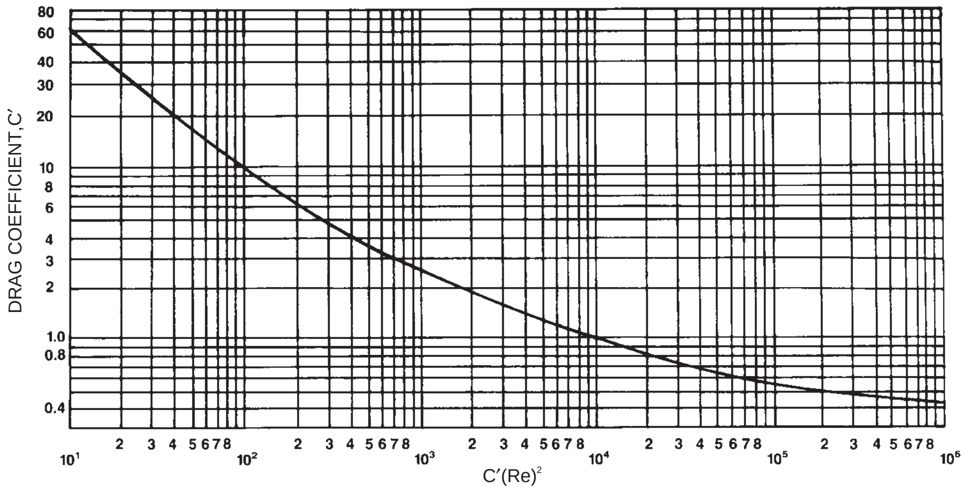


FIG. 7-6

Drag Coefficient of Rigid Spheres



Gravity Settling-Stokes' Law Region — At low Reynolds numbers (less than 2), a linear relationship exists between the drag coefficient and the Reynolds number (corresponding to laminar flow). Stokes' Law applies in this case and Equation 7-1 can be expressed as:

$$V_t = \frac{1000 \cdot g \cdot D_p^2 \cdot (\rho_p - \rho_c)}{18\,\mu_c} \qquad \textbf{Eq 7-5}$$

To find the maximum droplet diameter that Equation 7-5 holds for, the droplet diameter corresponding to a Reynolds number of 2 is found using a value of 0.033 for K_{CR} in Equation 7-6.

$$D_p = K_{CR}\left[\frac{\mu_c^2}{g \cdot \rho_c\,(\rho_p - \rho_c)}\right]^{1/3} \qquad \textbf{Eq 7-6}$$

By inspection of the particle Reynolds number equation (Equation 7-3) it can be seen that Stokes' law is typically applicable for small droplet sizes and/or relatively high viscosity liquid phases.

Gravity Settling Intermediate Law Region — For Reynolds numbers between 2 and 500, the Intermediate Law applies, and the terminal settling velocity can be expressed as:

$$V_t = \frac{2.94 \cdot g^{0.71} \cdot D_p^{1.14} \cdot (\rho_p - \rho_c)^{0.71}}{\rho_c^{0.29} \cdot \mu_c^{0.43}} \qquad \textbf{Eq 7-7}$$

The droplet diameter corresponding to a Reynolds number of 500 can be found using a value of 0.435 for K_{CR} in Equation 7-6.

The Intermediate Law is usually valid for many of the gas-liquid and settling applications encountered in the gas processing industry.

Gravity Settling- Newton's Law Region — Newton's Law is applicable for a Reynold's number range of approximately 500 to 200,000, and finds applicability mainly for separation of large droplets or particles from a gas phase, e.g. flare knock-out drum sizing. The limiting drag coefficient is approximately 0.44 at Reynolds numbers above about 500. Substituting C′ = 0.44 in Equation 7-2 produces the Newton's Law equation expressed as:

$$V_t = 1.74\sqrt{\frac{g \cdot D_p \cdot (\rho_p - \rho_c)}{\rho_c}} \qquad \textbf{Eq 7-8}$$

An upper limit to Newton's Law is where the droplet size is so large that it requires a terminal velocity of such magnitude that excessive turbulence is created. For the Newton's Law region, the upper limit to the Reynolds number is 200,000 and K_{CR} = 23.64.

The latest edition of Perry's Chemical Engineers' Handbook indicates slightly different Reynold's number ranges for the applicable regimes, and a different drag coefficient correlation for the intermediate regime. The differences, however, are within the accuracy of the equations.

Fig. 7-8 shows the impact of hydrocarbon density and viscosity on the Stokes' Law terminal settling velocity of a water droplet in a hydrocarbon continuous phase.

Example 7-1 — Calculate the terminal velocity using the drag coefficient and Stokes' Law terminal settling velocity in a vertical gas-liquid separator for a 150 micron particle for a fluid with the physical properties listed below.

Physical Properties

ρ_c = 33.4 kg/m^3, μ_c = 0.012 mPa-s (cP), ρ_p = 500 kg/m^3

Particle Diameter, $D_p = (150 \cdot 10^{-6}) = 0.000150$ m

From Equation 7-4,

C' (Re) 2 = $((1.31) \cdot (10)^7 \cdot (33.4) \cdot (0.000150)^3 (500-33.4))/(0.012)^2$ = 4785

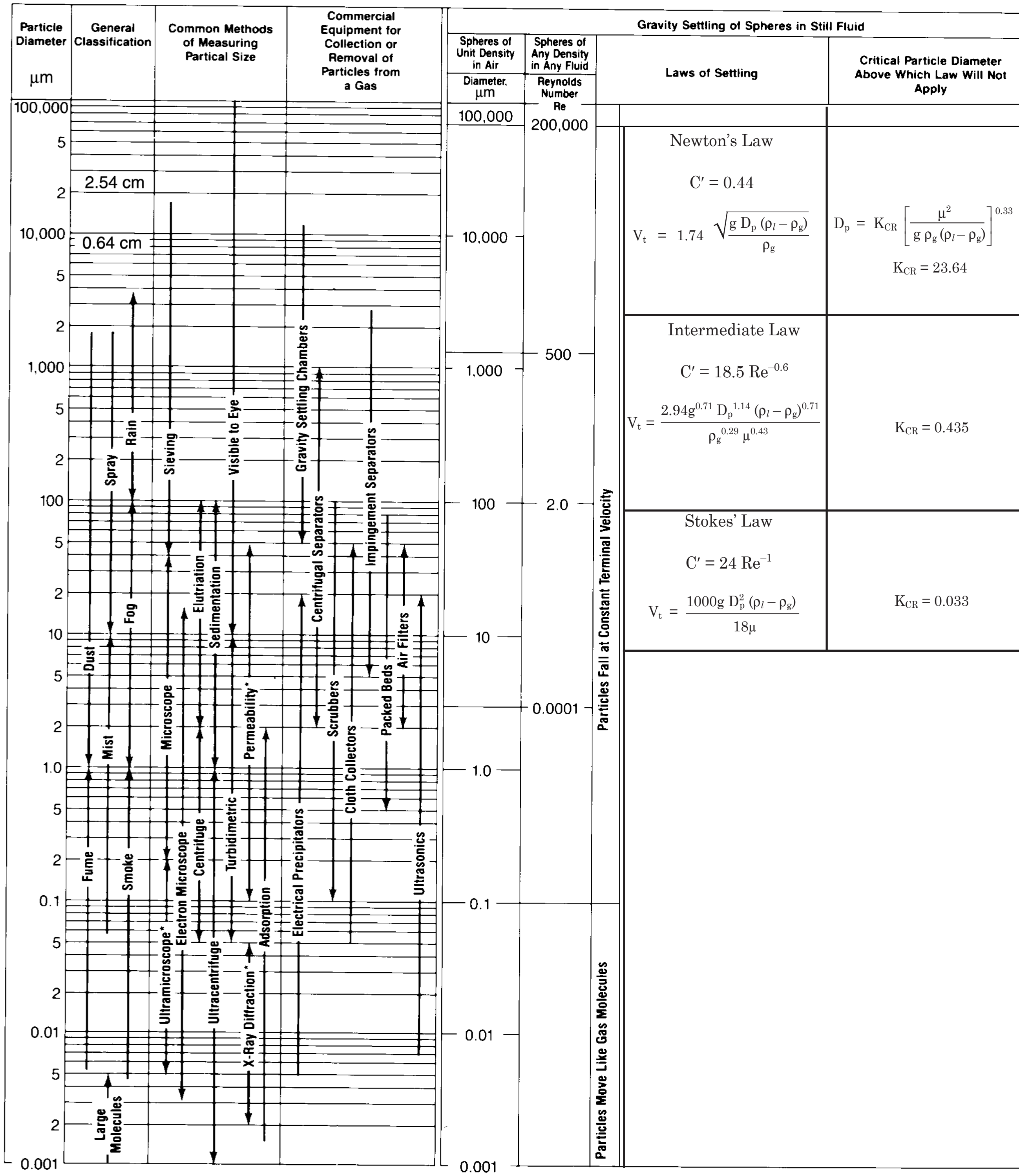
From Fig. 7-5, Drag coefficient, C′ = 1.4

Terminal Velocity,

$$V_t = \left[\frac{(4 \cdot 9.81 \cdot 0.000150 \cdot (500-33.4))}{(3 \cdot 33.4 \cdot 1.4)}\right]^{0.5} = 0.14\ \text{m/s}$$

FIG. 7-7

Gravity Settling Laws and Particle Characteristics



Adapted From Ref. 7-3

Separation by Impingement

Frequently in the natural gas industry, gravity settling alone is not sufficient to achieve the required separation results and internals are required to assist in the separation. The most widely used type of device for droplet collection is an impingement type device. These devices use baffles, wall surface, vanes, wire, or fiber to achieve separation via inertial impaction, direct interception, or diffusion.

Inertial Impaction — Inertial impaction occurs when, because of their mass, droplets will have sufficient momentum to break free of the gas streamline and continue to move in a straight line until they impinge on a target. This is the primary capture mechanism for mesh, vane, and cyclone mist eliminators. The capture efficiency of most mist elimination devices has been found to be related to the Stokes Number, Stk, as described in the Nomenclature for this Chapter. D_c is a characteristic diameter for the particular device (i.e. D_c is the wire diameter for a mesh mist eliminator, and D_c is the tube diameter for cyclones).[2, 4]

Direct Interception — Direct interception occurs when particles are small enough to remain on the gas streamline, and are collected if the droplets pass close enough to the target such that it touches the target. It is a secondary capture mechanism for mesh mist eliminators.

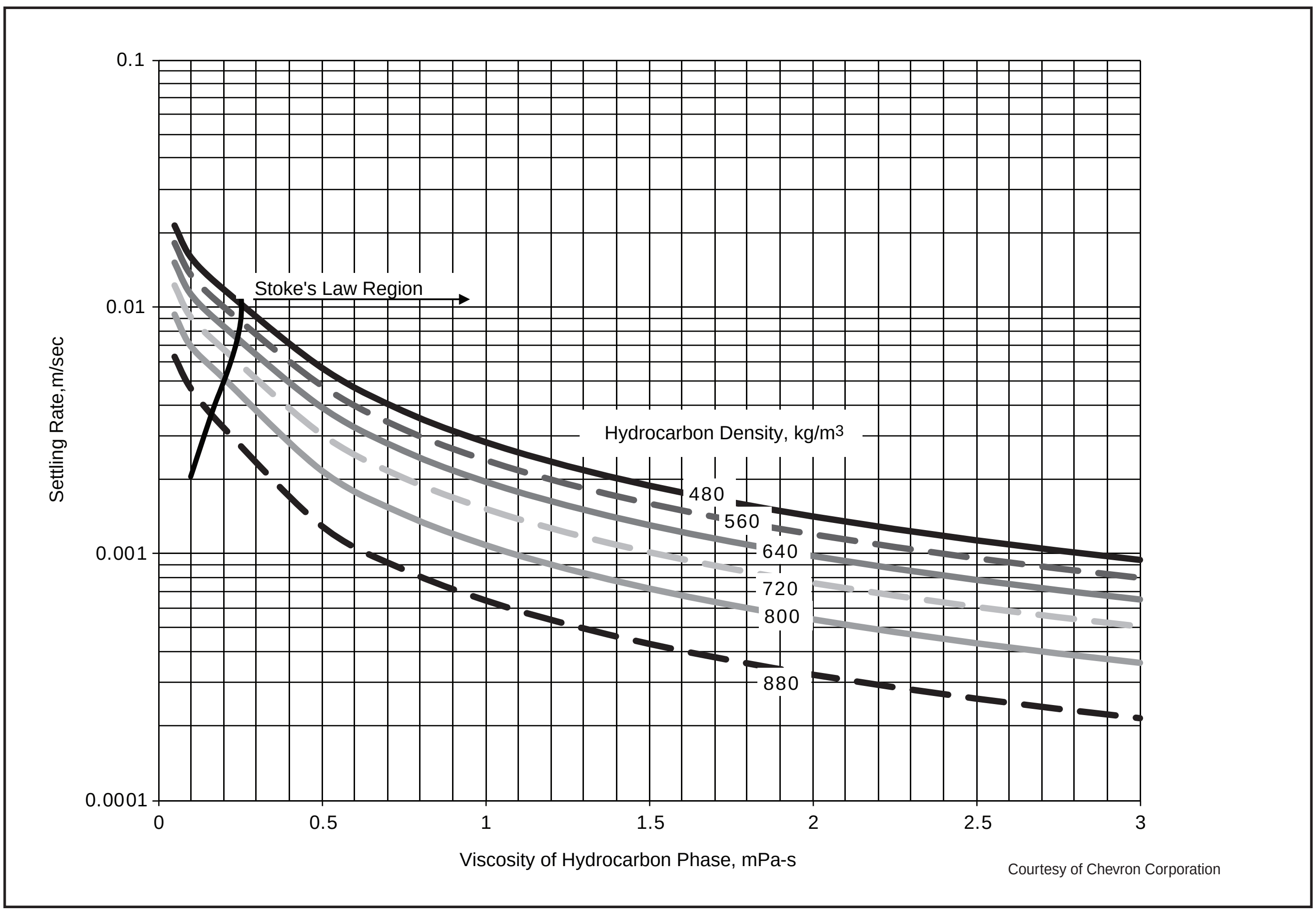
Diffusion — Very small particles (typically less than 1 micron) exhibit random Brownian motion caused by collision with gas molecules. This random motion can cause the particles to strike a target. Diffusion is not a primary mechanism for most separation devices used in the gas processing industry.

Centrifugal Force — Separation of particles can also be enhanced by the imposition of radial or centrifugal force. The typical flow pattern involves the gas spiraling along the wall of a device. The flow patterns are such that radial velocities are directed toward the wall causing the droplets to impinge on the wall and be collected.

Coalescing, Natural and Assisted — Natural coalescing occurs when small droplets join together to form fewer, larger droplets. This process will typically occur very slowly for dispersed droplets in a continuous phase due to limited collisions between droplets. Coalescing can be accelerated by flowing the mixture through media with high specific surface area. In gas-liquid separation, liquid droplets coalesce on the demisting device and drain by gravity to the bulk liquid. In liquid-liquid separation, coalescence is used in the same way to produce larger droplets that can more easily settle by gravity. This is done using parallel plate (enhanced gravity separation) or by contact with a target media such as wire mesh.

FIG. 7-8

Settling Rate of 100-micron Diameter Water Droplet in Hydrocarbons



Gas-Liquid Surface Re-entrainment

When gas flows across a liquid surface, it may re-entrain liquid from the gas-liquid interface to the gas phase. As the gas velocity increases, waves form and build at the liquid surface, releasing liquid droplets into the flowing gas stream. The extent of re-entrainment is a function of the gas velocity, density, and transport properties, including liquid surface tension and gas and liquid viscosity. Reducing surface re-entrainment to a minimum is typically a key design goal for horizontal gas-liquid separators. Criteria for the inception of re-entrainment from a gas-liquid interface surface were developed by Ishii and Grolmes[5,24], and others.

The Ishii-Grolmes criteria can be used to estimate the maximum allowable gas velocity at incipient entrainment in a horizontal separator vapor zone. As shown in Fig 7-9, the criteria is divided into five regimes, based on the Reynold's film number, N_{ref}, and interfacial viscosity number, $N\mu$, Equations 7-9 and 7-10, respectively. Re-entrainment is more likely at higher N_{ref} values. Consequently, gas velocities must be kept lower to prevent re-entrainment. For each design case, Fig. 7-9 should be referenced to determine the controlling equation.

$$N_{ref} = \frac{1000\, \rho_l\, V_l\, D_H}{\mu_l} \qquad \textbf{Eq 7-9}$$

and

$$N_\mu = \frac{0.001\, \mu_l}{\left[\rho_l\, \sigma \left(\frac{\sigma}{g(\rho_l - \rho_g)}\right)^{0.5}\right]^{0.5}} \qquad \textbf{Eq 7-10}$$

Re-entrainment from Collection Devices — Re-entrainment from a collection device is the mechanism where the gas moving through the device causes a previously collected fluid to be removed off the element and carried away by the bulk stream. Surface re-entrainment is a function of the gas flow rate, liquid loading of the device, as well as the physical and transport properties of the gas and liquid (including the gas and liquid viscosity and liquid surface tension). Re-entrainment is always the limiting factor in the design of collection devices.[6]

Degassing of Liquids — The rise rate of a bubble of a given size can be calculated using gravity settling theory, according to Equation 7-2. For most applications, the separation vessel is sized so that there is enough retention time for the entrained gas to be released from the liquid. This is most critical where vapor carry-under is undesirable for contamination reasons, for proper pump performance, or in applications such as physical solvent treating systems where carry-under can affect the process specifications. For most applications, if bubbles larger than 200 µm are able to escape, then carry-under will be negligible. The rise rate for a 200 µm bubble typically will be in the Stokes' Law Settling Region and can be estimated using Equation 7-5. For light fluids frequently encountered in the gas processing industry, a retention time of 1-2 minutes is generally adequate for degassing. For good degassing of a liquid, retention time must increase with increasing gas density and liquid viscosity. See "Design of Liquid Accumulators" in this Chapter.

FIG. 7-9

Ishii-Grolmes Criteria

Eq	N_{ref}	N_μ	$V_{r,\,max}$
A	<160	—	$1500\,(\sigma/\mu_L)\,(\rho_L/\rho_g)^{0.5} \bullet N_{ref}^{-0.5}$
B	$160 < N_{ref} < 1{,}635$	≤0.0667	$11\,780\,(\sigma/\mu_L)\,(\rho_L/\rho_g)^{0.5} \bullet N_\mu^{0.8} \bullet N_{ref}^{-0.333}$
C	$160 < N_{ref} < 1{,}635$	>0.0667	$1350\,(\sigma/\mu_L)\,(\rho_L/\rho_g)^{0.5} \bullet N_{ref}^{-0.333}$
D	>1635	≤0.0667	$1000\,(\sigma/\mu_L)\,(\rho_L/\rho_g)^{0.5} \bullet N_\mu^{0.8}$
E	>1635	>0.0667	$114.6\,(\sigma/\mu_L)\,(\rho_L/\rho_g)^{0.5}$

Gas- Liquid Separation Fundamentals

Liquid separation from the gas phase can be accomplished by any combination of the separation mechanisms previously described.

Souders-Brown Equation for Gravity Settling — Gravity settling of a liquid droplet in a gas can be described by Equation 7-2. This equation can be simplified to describe the liquid spherical droplet terminal velocity as a function of the droplet diameter, and the drag coefficient. The simplified form of the terminal velocity equation is called the Souders-Brown Equation[7]. The equation is valid for vertical gas flow, where the drag due to upward gas flow and the downward gravity force are in balance. The equation is also frequently used to determine the downward vertical terminal velocity of droplets in horizontal fluid flow, even though this relationship is not as rigorous, especially at higher fluid velocities.

The Souders-Brown equation[7] is used in a number of ways to design equipment for gravity settling in the oil and gas industry. A target droplet capture diameter can be specified for a gravity settling application, and then using the settling laws, and fluid properties, a drag coefficient, K, and terminal droplet velocity can be calculated, or determined by empirical testing. The K-factor is also a function of separator geometry, including settling space both upstream and downstream of the mist eliminator.

$$V_t = K \bullet \sqrt{\frac{(\rho_l - \rho_g)}{\rho_g}} \qquad \textbf{Eq 7-11}$$

Where,

$$K = \sqrt{\frac{4gD_p}{3C'}} \qquad \textbf{Eq 7-12}$$

Gravity Settling in Gas-Liquid Separation — In vessels with no internals, gravity settling is the only mechanism of separation. Thus, terminal velocity of the minimum particle size desired for separation is critical. For vertical vessels, a liquid droplet will settle out of the gas phase when the vertical gas velocity is less than the droplet's terminal velocity. The terminal droplet velocity can be obtained by using the appropriate settling law expression, or an industry experience K value. The K value can be calculated by assuming a minimum droplet size that must be removed and equating Equation 7-11 and Equation 7-12. The target droplet diameter, or K value, is selected to prevent excessive entrainment based on experience. In either case a target droplet size of about 250 to 500 microns is typically used for many gas-liquid gravity separator designs. This approach has been found to be adequate to prevent substantial liquid carryover for most applications. The maximum allowable K value used for design, for light hydrocarbon applications, is frequently reduced further at elevated pressures from that calculated by Equation 7-11. This is intended to account for the fact that as the pressure increases, the surface tension for light hydrocarbons decreases, as well as the high gas density, resulting in a higher likelihood of a smaller mean droplet size entering the separator.

For a vertical separator the required cross-sectional area to prevent carryover of a given droplet diameter is defined in Equation 7-13.

$$A = \frac{Q_A}{V_t} \qquad \textbf{Eq 7-13}$$

In theory, for horizontal vessels, the terminal liquid droplet velocity can be used to define the horizontal length required to settle a droplet out of the gas phase before it reaches the gas outlet, for a given gas velocity and depth to the surface. Therefore the theoretical maximum horizontal vapor velocity can be written in terms of the terminal velocity as follows:

$$V_h\,(\max) = \frac{L_{SET}}{H_{SET}} \cdot V_t \qquad \textbf{Eq 7-14}$$

Equation 7-14 is predicated on the settling force balance applying strictly to horizontal flow, an ideal vapor profile, no eddies, and neglects end affects. In practice, a safety factor is required in the design to account for these affects. For many applications, the above approach, if applied for a typical vessel L/D ratio of 3:1 or greater, would result in a effective axial flow K factors (L/H *K) greater than 1.0. In practice, the effective K used has been limited by either calculation of the incipient re-entrainment velocity, an empirical approach, or both.[5] See "Two-Phase and Three Phase Separator Design and Operating Principles Gravity Separation Section" in this Chapter.

Mist Eliminators for Gas Liquid Separations

Mechanism of Mist Carryover for Gas-Liquid Mist Eliminator Devices — Mist eliminators are commonly used in gas-liquid separation to aid gravity separation in the removal of liquid so that more efficient, smaller separators may be used. To be effective, a mist eliminator must accomplish two basic functions. First, it must have a means to capture liquid. Second, it must be able to drain the captured liquid without allowing re-entrainment into the gas stream. There are two mechanisms of liquid carryover from a mist eliminator. In the first mechanism, carryover is due to droplets of mist which are simply not captured by the device. The droplets might be too small to be captured or velocities are too low, causing low efficiency for impaction-type mist extractors. The second is re-entrainment of liquid after it has already been captured in the mist eliminator.

The majority of separator failures are caused by re-entrainment. This is the mechanism that occurs as the gas throughput is increased beyond the tolerable limit. Gas moving through the mist extractor exerts a drag force on the liquid film of the mist eliminator, causing it to be pulled toward the trailing edge of the device. If the drag is excessive, the liquid will be torn off the element and carried away by the gas stream. As flow rate increases, the contact efficiency of most mist eliminators improves. Therefore, increasing gas flow yields improved droplet capture, but also increases re-entrainment which results in liquid carryover and limits separation capacity.

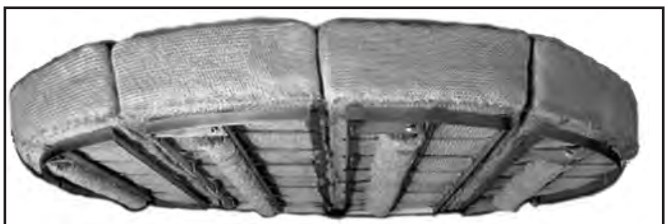
Souders Brown Equation Applied To Mist Eliminators — The Souders-Brown Equation (Equation 7-11) is frequently used to correlate the maximum capacity for mesh, vane, and cyclonic mist eliminators in a similar manner to flooding criteria for towers. While commonly used, this approach can be overly simplistic, since other mechanisms can influence the ultimate capacity of a device. The device supplier literature K coefficient published in catalogues is typically obtained from empirical test data for air-water systems at low pressure, and in theory, is valid for favorable operating conditions with different fluids. For other systems, gas and liquid viscosity, liquid surface tension, liquid loading, and foaming tendency are also factors in setting the device gas load capacity. The required mist extractor area is obtained from the design K, or other design limits, and is typically selected to provide a certain degree of margin before liquid entrainment/carryover becomes excessive.

Mesh Mist Eliminators — Mesh mist eliminators or pads are made by knitting wire, metal, or plastic into tightly packed layers, which are then crimped and stacked to achieve the required pad thickness. Mesh pads remove liquid droplets by impingement of droplets onto the wires, followed by coalescence into droplets large enough to disengage from the bottom of the pad and drop through the rising gas flow into the liquid holding part of the separator. The prominent mechanism for droplet capture is inertial impaction. The capture efficiency for a conventional mesh mist eliminator, at a given droplet size, is a function of the wire or fiber total thickness, mesh density, and wire diameter, as well as properties of the fluids to be separated. Smaller wire/fiber size and thicker mesh are more efficient. Droplet capture efficiency is related to the Stokes Number (see Nomenclature Section), specific surface area of the mist eliminator, number of layers, and other factors. For a typical service condition, and mesh style and thickness, a droplet size with a capture efficiency of 95% (d_{95}) can be determined. Droplets larger than this will be captured almost completely. Smaller droplets will have a lesser capture efficiency. Given an inlet droplet distribution, a total capture efficiency can be predicted.[2, 9]

The most common style of mesh mist eliminator used in gas processing is a 100 mm to 150 mm thick crimped wire mesh pad with 144 to 192 kg/m^3 bulk density. High droplet removal efficiency for droplets 10 microns and larger is common for the above design. Other designs include fiber mesh, mixed wire and fiber mesh, multiple mesh density layers, and special drainage channels. The goals are either to increase removal efficiency at

FIG. 7-10

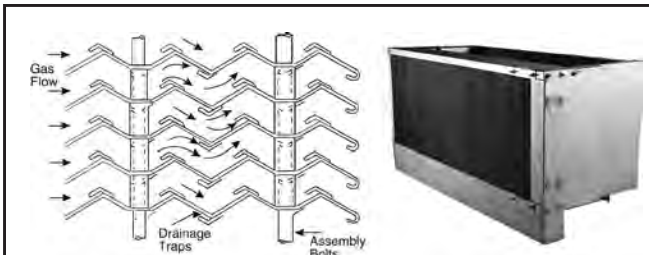
Wire Mesh Mist Eliminator



Courtesy of ACS Separations and Mass Transfer Products

FIG. 7-11

Cross-Section of Vane Element Mist Extractor and Typical Vane Pack



Vane Pack (above) courtesy of Sulzer Chemtech lower droplet diameters, promote better drainage and in turn less carryover, increase throughput for a given mist eliminator area, reduce fouling, or a combination of the above. Manufacturers should be contacted for specific designs. Mesh pads are not recommended for dirty or fouling service as they tend to plug easily and can dislodge at high differential pressure.[10] A typical mesh mist eliminator is shown in Fig. 7-10.

Proper drainage of the mesh mist eliminator is essential to the operation of the unit. As the gas velocity increases at a given inlet liquid loading, the liquid continues to drain until a limiting load point is reached, at which point substantial liquid will carry over with the gas flow. Most mesh mist eliminator designs are based on the load point velocity. The load point will depend on the mist eliminator orientation, since the drainage mechanism is different as the pad orientation changes.

The maximum design Souders-Brown K value is frequently used to quantify the gas capacity of a wire mesh pad and depends upon factors such as mesh type, mesh material, wire packing density, and specific surface area, as well as the fluid properties. Mist eliminator suppliers typically will provide in their catalogues a design K value for their products suitable for design for many applications. At other conditions, the design K value may be lower, due to the liquid load to the device, liquid viscosity, foaming tendency, liquid surface tension, gas mal-distribution, and flow surges.[4, 9]

Separator configurations, sizing considerations, and typical K factors for mesh pad equipped separators are discussed further in the "Two-Phase and Three Phase Separator Design and Operating Principles — Gas Polishing Section" of this Chapter.

Vane Mist Eliminators — Vane or chevron-type mist eliminators (vane-pack) use relatively closely spaced blades arranged to provide sinusoidal or zig-zag gas flow paths. The changes in gas flow direction combined with the inertia of the entrained liquid droplets cause impingement of the droplets onto the plate surface, followed by coalescence and drainage of the liquid to the liquid collection section of the separator. Vane packs may be installed in either horizontal or vertical orientations. Various vane styles are available, including those with and without pockets (both single and double pockets) to promote liquid drainage. Vanes with pockets, allow a higher gas throughput per flow area due to enhanced drainage, but are not typically used in highly fouling service. Fig. 7-11 shows a horizontal, pocketed vane-type mist eliminator. Vane capacity is reduced for vertical up flow applications relative to horizontal flow.

Key performance parameters for vanes are droplet removal efficiency and gas handling capacity. Capture efficiency for a given droplet size depends on the vane design, gas velocity, gas viscosity and other parameters. Simple vanes with no pockets are typically capable of capturing 40 microns droplets, pocketed vanes are capable of 20 microns, and highly complex vanes of 10-20 microns at favorable operating conditions. Maximum vane capacity is set to limit re-entrainment. The Souder-Brown equation (Equation 7-11) and the load/sizing K factor are frequently used for describing the capacity of vane-type mist eliminators. Manufactures provide typical K factors for the various styles. The capacity for a particular vane service may be limited due to the liquid load to the device, liquid viscosity, foaming tendency, liquid surface tension, gas mal-distribution, and flow surges. These factors are not necessarily directly related to the Souders-Brown K value. Manufacturer guidance is necessary for a design.[11, 26]

Testing has shown that for mesh type mist eliminators the low pressure air-water droplet removal efficiency experimental results correlate reasonably well with higher pressure gas-hydrocarbon liquid systems. Vane packs on the other hand show a drop-off in removal efficiency as pressure increases. This is primarily due to the decreased allowable design gas velocity caused by the increased gas density. As gas velocity decreases, droplet inertia decreases, and the droplets tend to follow the gas streamlines through the vane passages more easily. As a result, droplets are able to exit the vane pack without being captured. Mesh pads also rely on velocity/droplet inertia to remove liquid droplets via impingement, but they are less susceptible to efficiency reduction than vane packs because mesh pads have far more collection "targets", i.e. wire/fiber filaments.

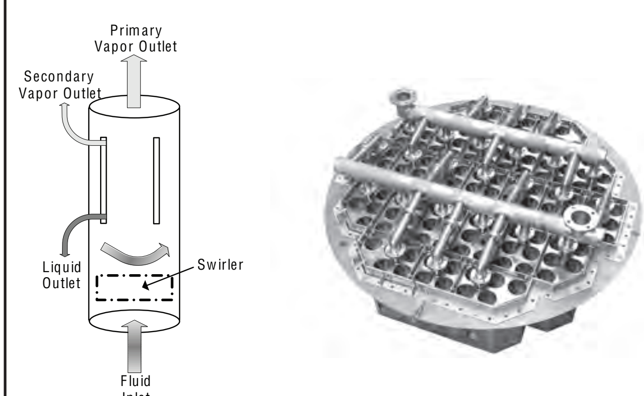
Turndown is generally more of a concern with vane-packs than wire mesh, with droplet removal efficiency decreasing measurably as velocity decreases from design. Vane packs are more tolerant to dirt and fouling than mesh due to the large passage size.

Typical vane separator vessel arrangements are shown in the Types of Common Gas-Liquid Separators Section of this

FIG. 7-12a
Reverse Flow Cyclone

Courtesy of Burgess-Manning

FIG. 7-12b
Axial Flow Cyclone Schematic and Swirltube Deck



Swirltube deck (above) courtesy of Sulzer Chemtech

Chapter. For comparison purposes, typical K values for vane separators are shown in Fig. 7-37.

Cyclonic Mist Eliminators — Cyclonic mist eliminators use centrifugal force to separate liquid droplets and solids from the gas phase based on density difference. Very high G forces (multiples of gravity) can be achieved, which allows for efficient removal of small droplets. The main advantage of cyclonic mist eliminators is that they provide good removal efficiency at high operating pressure, and at high gas capacity. This typically allows for the smallest possible vessel diameter for a given gas flow. In order to create the high G-forces required, cyclonic separators generally have significantly higher pressure drops than other separation mechanisms,. They also have less turn down capability because the G-forces are reduced at lower gas velocities.[4]

There are many types of centrifugal devices used in the industry to separate entrained liquids and solids, from a gas stream. The two most common configurations employed are reverse flow cyclones and axial-flow cyclones. In conventional reverse flow cyclones, each cyclone element consists of a tangential inlet, a cone shaped bottom section, and an upper center gas outlet. The gas swirls downward through the annulus between the inner and outer walls. It then flows, still spinning, into the inner tube and exits out the top. In the axial flow cyclones, the wet gas flows up through a swirl element which induces a spinning flow. The high tangential velocity throws the liquid droplets to the walls of the cylindrical tube, where they form a thin film. The liquid film exits through slots in the cyclone walls, along with a small amount of gas, and then drains to the bottom of the unit. Several techniques can be used to recover liquids from the purge gas.[27]

In order to achieve efficient operation in the most compact space, and for the best recovery for the energy expended, cyclone systems for gas-liquid separation are assembled in multicyclone "bundles". The entire bundle is considered the cyclone separator device. Examples of a reverse flow cyclone tube, and an axial cyclone tube with swirltube deck are shown in Figs. 7-12a and 7-12b, respectively.

In addition to the above styles, the principle of cyclonic force is used in a large number of traditional and cutting edge technology for separation of gas-liquid and gas-liquid-solids in the industry.

LIQUID-LIQUID SEPARATION FUNDAMENTALS

Separation between two liquid phases is not usually limited by re-entrainment, but rather by the mixture's inability to separate due to the characteristics of the two liquids or the size of the separator. Two sizing characteristics are commonly used to calculate liquid separator sizing: droplet settling velocity and retention time.

Gravity Settling in Liquid-Liquid Separation

Droplet settling due to gravity can be used to size liquid separators. Since these separators are most often designed to be in laminar flow to provide reasonable quality separation, Stokes' Law, Equation 7-5, can be typically applied with appropriate safety factors. For horizontal vessels, a dispersed liquid droplet will settle out of the continuous phase when the droplet has sufficient time to reach and be absorbed into the liquid-liquid interface before it reaches the continuous phase draw-off connection. For vertical vessels, a dispersed liquid droplet will settle out when the vertical continuous phase velocity is less than the terminal velocity of the droplet. Stokes' law is based on free fall of liquid droplets through a stagnant continuous phase, when the dispersed phase is dilute. Safety factors must be applied when using Stokes' Law to account for the fact that the flow regime in the separator frequently can be turbulent with eddies and currents and the droplets are not necessarily spherical. In addition, the axial velocity must be limited to minimize turbulence in the separator. Other design factors and/or sizing methods are required where the dispersed concentration is high enough to hinder settling, or where a dispersion layer can be present.[12] See "Gas-Liquid-Liquid Separator Design" in this Chapter.

In a three-phase separator, liquid-liquid (oil-water) separation occurs concurrently with the degassing function, but due to the relatively small density difference of oil and water it progresses more slowly. Since water removal from hydrocarbon liquid is slower than gas removal, a three-phase separator typically has a longer liquid retention time — 3-5 minutes for light oils, longer for heavier liquids. This typically means a larger separator is required for three phase separation than for two-phase separation.

Oil-water separation requires both separation of water from the oil phase (de-watering), and of oil from the water phase (de-oiling). Generally, water de-oiling is much easier than oil de-watering, for heavier oils (crude oil), because of the lower viscosity of the continuous water phase. This is fortunate because the requirements are typically more severe for water quality due to disposal considerations. This is the case even though further treatment is often required of both oil and water. Typical quality specifications for effluent oil are usually stated in percent, while for water specifications are normally stated in parts per million.

Small droplet dispersions of water-in-oil, or oil-in-water may be stabilized by natural or added surfactants, resulting in an emulsion which may not be separable in a gravity separator. A chemical additive upstream of the separator may be needed to de-stabilize such emulsions.

Liquid Residence Time Approach to Design

Liquid residence time is defined as the length of time a fluid remains within the settling compartment of the separator. Longer retention times generally result in a more thorough separation. Actual retention time in a separator is shorter than the idealized or theoretical retention time because of non-uniform flow profiles such as channeling and recirculation. Actual retention time may be made to approach the idealized retention time by achieving a more uniform velocity profile. Perforated distribution baffles are often used to aid liquid distribution. Designing for similar superficial horizontal velocities in both oil and water phases also improves the velocity profile by reducing shear at the liquid-liquid interface.

Selection of residence time is generally based on experience when designing either two-phase or three-phase separators.

The residence time approach for liquid-liquid separator design has been widely used in industry for years. However it is recognized that it has some serious limitations.[13]

- The typical approach of assuming equal residence times for both liquid phases may not be optimum as it is often easier to separate one phase from the other. Settling theory (Equation 7-1) quantifies this relative ease of separation as attributable to the lower viscosity of one phase over the other. Dispersed droplets can move at higher velocities through low viscosity liquid and thus settling is more readily accomplished.

- Residence times do not take into account vessel geometry, i.e. 3 minutes residence time in the bottom of a tall, small diameter vertical vessel will not achieve the same separation performance as 3 minutes in a horizontal separator according to droplet settling theory.
- The residence time method does not provide any indication as to the quality of the separated liquids, e.g. amount of water in the hydrocarbon or the amount of hydrocarbon in the water. Droplet settling theory cannot do this either, but there may be empirical data available which can be correlated against droplet settling velocity to allow for approximate predictions in specific applications.
- The use of Stokes' Law correlations is not valid for very small droplets approaching the Brownian motion range. These services may require the use of specialized internals or electrostatic fields to promote coalescence.
- Residence time is one of many factors affecting separation performance. Other factors include height of liquid levels, length of separation section, and non-linear flow streams within the separator liquid sections.

Dispersion Layer

If the concentration of the dispersed phase in the continuous phase in locally high, the dispersed phase droplets may settle to the interface faster than if they coalesce at the interface and form a dispersion band between the two phases, resulting in the inter-phase boundary being not well defined. In this case the coalescing step will be rate determining, over droplet settling. For this scenario, the dispersion layer must be considered when determining vessel size. This behavior is common for production separators with high water/hydrocarbon ratio, and some mixer-settler applications.

Liquid-Liquid Coalescing Devices

Liquid-Liquid coalescers are internals used to accelerate the merging of many droplets to form a lesser number of droplets with a greater diameter. Elements of this type allow for efficient removal of smaller droplets, that otherwise would be difficult to capture by gravity settling alone. They also can provide a more compact settler design, for a given target droplet size. Typically the coalesced droplets are settled by gravity downstream of the coalescing elements, or by a secondary device followed by gravity separation. The preferred type of coalescer element depends on the type of emulsion to be separated, and the fouling nature of the fluid. The emulsion stability is a function of the upstream processing shear, and chemical addition. The more stable the emulsion, the finer the droplets.

A plate coalescer confines the droplet between parallel sheets or crimped packing sheets in order to reduce the distances a droplet must rise or fall, and provide multiple interface layers on which to coalesce. They also reduce the Reynolds number, and limit turbulence. Plate type coalescers are commonly limited to efficient removal of droplets above 50 microns minimum droplet size. Plates can be installed horizontally, or on angle to resist fouling. The settling mechanism in plates is often referred to as enhanced gravity separation.

A mesh type coalescer depends primarily on direct interception, where a multiplicity of wires or yarns collect fine droplets as they travel in laminar flow around them. As the filament size is decreased, the mesh coalescer efficiency to remove smaller droplets is enhanced. Simple wire mesh coalescers may remove droplets down to 20 micron, while co-knits can be efficient down to 2 microns or less. Fiber cartridge element designs can be used to remove haze from fuel. Mesh elements units may require filtration upstream to remove solid contaminants, and cartridge units will definitely require filtration upstream of the process equipment. Coalescing mesh is also frequently used for applications where the concentration of one fluid is less than 5% of the total, as would be the case either following an upstream primary separator, at the outlet of a condenser or cooler in the process, or from storage.[12]

SEPARATION STRATEGY AND PERFORMANCE REQUIREMENTS

Separation Strategy

The ultimate separation for a particular separator, or in a process system, is often not achieved in a single step. An initial separation achieves bulk phase segregation then a secondary separation is provided for each of the bulk phase streams to obtain more purified phases. This is called progressive separation.

The principle of progressive separation is often utilized in a typical separator design. Within the vessel primary separation (e.g., inlet devices and gravity settling) roughly segregates the phases. Each phase still contains significant portions of the other phases. In secondary separation (e.g., mist eliminators and coalescers plus gravity) mist is removed from the gas phase, gas from the liquid phase, oil from water, and water from oil.

The principle of progressive separation can also apply to a process system where various levels of separation are performed in separate vessels arranged in series. Examples of this would be a slug catcher, an inlet separator, and a filter-separator all installed in the front of a natural gas treating facility for slug removal, liquid-gas separation, and final solids-mist separation.

Performance Requirements

Ideally, a separator should yield a gas stream free of entrained liquid mist and a liquid stream containing no entrained gas bubbles. A three phase separator should, additionally, eliminate water from the oil stream and oil from the discharged water. In real-world process systems these phase separations are never complete and separator performance is measured against a specified allowable carryover of the contaminating phase.

The allowable carryover is determined by requirements of the downstream system or is often set based on customary practice. The treatment goals and the downstream needs should be scrutinized when determining the specified carryover limits. This will provide a perspective on how aggressive or how conservative to be when sizing the separator.

Not all separators have the same process requirements. For most, the critical issue is to minimize liquid carryover in the gas discharge line. For some, water quality may be critical. For others, the hydrocarbon stream water content must be controlled. In many cases the primary separation equipment cannot be effectively designed to meet all of the requirements and specialized equipment (i.e. filter-separators), must be used to remove remaining mist and solids.

Liquid Carry-Over Specification for Gas-Liquid Separators

Usually the most critical carryover specification for separators is that of liquid entrainment in the gas outlet stream. The gas may be routed to a compressor, to downstream processing, or to a flare/vent. For example, severe mechanical damage will result if a significant volume of liquid is ingested into a compressor. In amine or glycol systems, uncontrollable foaming may occur if the solvent is contaminated by liquid hydrocarbons. Liquid carryover for an NGL recovery system can result in off-specification natural gas product, or substantial economic loss. Entrained liquid carried to a flare or vent poses potential fire hazards. These processes are normally protected by a gas scrubber to catch small amounts of separator carryover. Typical industry standard liquid carryover limits are often expressed in one of several ways. Examples of typical specifications for gas scrubbers with internal demisting devices are:

- 0.0134 m^3 / $MMSm^3$ (absolute reference)
- Supplier guarantee based on % removal for a specified droplet size, (i.e. d_{95}, or 99% removal efficiency at 10 microns)
- 98% overall liquid recovery

For amine and glycol systems common industry practice is to limit solvent carryover to 0.0134 m^3 / $MMSm^3$. This may require a more complex mist eliminator design than a standard efficiency wire mesh mist eliminator.

It is not customary in most gas-liquid applications for the user to supply an inlet droplet average size and distribution to the device supplier. For these circumstances an absolute carryover specification quantity can not be provided. It is more common to require a % removal level, for a target micron size, which is consistent with the capabilities of the de-misting device employed. Proper specification of the device type and specific style is essential to the selection process. For critical applications, if an estimate of the average particle size and distribution estimate can be provided (i.e. based on a flow and entrainment model for the inlet piping), then an overall entrainment rate can be provided by the separation device supplier.

The gas compression industry does not use a universal standard for the upstream droplet size removal, or overall required droplet removal efficiency for scrubbers associated with this equipment. Experience has shown that excessive machine wear, and increased maintenance cost, typically result from poor scrubber design (i.e. wrong inlet device, uneven gas distribution), regardless of the de-misting device used.[25] Also, as the overall entrainment level increases, droplets can collect in the compressor inlet pipe, and the periodic flow of these coalesced droplets may result in long term wear on the machine. Liquid slug carryover may result in catastrophic machine failure.

Gas Carry-Under Specification

The discharged liquid phase will typically contain gas bubbles too small to be removed in the separator. If gas carry-under is too high it may impact downstream operations. Carry-under of a few percent by volume is typically allowed for production separators, while minimal carry-under is allowable for most unit operations in the gas processing facility. A typical requirement for light hydrocarbons is minimal carry-under for gas bubbles 200 micron and larger. This is particularly important when the liquid is being pumped downstream of the separator, since pumps are only tolerant of dispersed dissolved gas to a limited extent. Gas volumes above 2% should be checked by the pump manufacturer.

FIG 7-13

Separator Configurations

Vertical Two Phase Separators with Internals	• Vertical with no mesh pad • Vertical with mesh pad • Vertical with vane pack in horizontal flow • Vertical with vane pack in vertical flow • In-line vane pack (in-line separator) • Cyclone • Axial flow multi-cyclone • Conventional (reverse flow) multi-cyclone • Combination configuration (e.g., vertical flow flooded mesh/ vane) • Combination configuration (e.g., horizontal flow flooded mesh/ vane) • Combination configuration (e.g., flooded mesh/ multi-cyclone bank)
Horizontal Two Phase Separators	• Horizontal with no mesh pad • Horizontal with vertical mesh pad • Horizontal with horizontal mesh pad in box under outlet nozzle • Horizontal with vertical vane pack • Horizontal with vane pack canted between vertical and horizontal • Horizontal with inlet cyclones and/or outlet cyclones
Liquid-Liquid and Three Phase Separators	• Gravity separator (no baffles or internals) • Separator with mesh coalescer • Separator with vane or plate coalescer • Three phase separator with single overflow baffle • Three phase separator with overflow-underflow baffle • Three phase separator with water boot • Complex multi-baffle separators • Vertical three phase separator
Cyclonic Two and Three Phase Separators	• Conventional reverse flow cyclonic separator • Advanced compact cyclonic separators • Inline cyclonic devices
Devices with Cartridges	• Filter separator • Gas Coalescing filter (gas-liquid) • Coalescing filter (gas-liquid-solids) • Dust filter • Liquid Coalescer • Liquid-solids cartridge filter • Liquid solids bag filter
Specialized Gas-Liquid Separators	• Wellhead Separator • Test Separator • Vessel type slug catcher • Harp type slug catcher • Flare K.O. drums • Specialized cyclone separators
Specialized Oil Treating Coalescing Separators	• Heater-Treater • Desalter
Specialized Water Treating Coalescing Separators	• Gunbarrel tank • Water hydrocyclone • CPI Separator • API Separator • Dissolved gas flotation unit • Walnut shell filter

Water-in-Hydrocarbon Specification

For three phase separation the water-in-oil specification depends on the operation downstream of the separator. If oil leaving the separator is to meet transport specifications or is going to a tower or heating process the performance is usually more critical. If the separator feeds in-plant treating, the water-in-oil specification is usually less critical. For primary separators, with no emulsions, the typical separation results in 0.1 to 0.5 Vol.% water in hydrocarbon. For other production service the value may be higher or lower depending on the destination.

Oil-in-Water Specification

Oil-in-water carryover may be specified or left as a consequence of a specified water phase sizing. Produced water and process water are ultimately disposed of by injection, disposal to a water way, or further treatment. Direct disposal options require relatively clean water (typically 15-50 ppm$_v$ oil) which often necessitates further treatment of the water discharged from a separator. Permissible values for discharge depend on local regulations. A specified oil-in-water limitation in the separator discharge reflects the maximum carryover for feeding the water treatment equipment.

FIG 7-14

General Gas Separation Selection

Equipment Type	Contaminant Removed	Micron Rating Achievable	Pressure Drop Clean & Wet	Relative Operating Cost
Separator with internals	Liquids	3-40	Low 0.7 kPa-10.3 kPa	Low to higher
Filter – Separator	Liquids & Solids	1 micron	13.8 kPa or less	Higher
Gas Coalescer	Liquids & Solids	0.3 micron	13.8 kPa	Highest
Dry Gas Filter	Solids	Various	13.8 kPa or less	Higher

FIG. 7-15

Factors that Determine Vessel Orientation

Feature	Vertical	Horizontal
Compact Separators	Yes	Yes
Small Footprint	Yes	—
Small Liquid Surge Drums	Yes	—
Solids Removal with Liquid	Yes	—
Small Capacity Flare K.O. Drums	Yes	—
Gas Dominated Services	Yes	—
Liquid Dominated Services	—	Yes
Three-Phase (G/L/L) Separation	—	Yes
Liquid-Liquid Separation	—	Yes
High Liquid Degassing Residence Time	—	Yes
Pigging & Slug Flow Separation	—	Yes
Foaming Feeds	—	Yes
High Liquid Surge Capacity	—	Yes
Large Capacity Flare K.O. Drums	—	Yes
Solid Removal Through Jetting	—	Yes
High Vapor and Liquid Flow Rates	Yes	Yes

FIG. 7-16

Vertical Gas-Liquid Separator Comparison Chart

Separator Type:	No Demisting Internals	Mesh Pad	Vert. Vane Pack	Horiz. Vane Pack	In-line Vane Pack	Axial Flow Multi-Cyclone	Horiz. Flood Mesh/ Vane	Vert. Flood Mesh/Vane	Flood Mesh/ Multi-Cyclone
Gas Handling									
Capacity	Low	Moderate	High	Very High	Very High	Very High	Very High	Very High	Very High
Turndown Capability	∞	4:1	3:1	3:1	3:1	2:1	4:1 or higher	4:1 or higher	4:1 or higher
Liquid Removal Efficiency									
Efficiency Overall	Low	Very High	Moderate	Low/Mod	Low/Mod	High	Moderate	High	High
Efficiency – Fine Mist	Very Low	Very High	Moderate	Moderate	Moderate	High-Very high	Very High	Very High	Very High
Liquid Handling Capacity									
Slugs	High	High	High	Very High	Very Low	High	High	High	High
Droplets	High	High	Moderate	Moderate	Low	High	High	High	High
Fouling Tolerance									
Particulate	Very High	Low	Moderate	Moderate	Moderate	Moderate	Low	Low	Low
Fouling Material	Very High	Very Low	Moderate	Moderate	Moderate	Moderate	Low	Low	Low
Pressure Drop	Very Low	Very Low	Low	Low	Low	High	Low	Low	High

SELECTION GUIDELINES FOR COMMON SEPARATOR DESIGNS

Common Configurations for Separators

Fig. 7-2 is a block flow diagram of a gas treatment system and the types of separation devices that are commonly used. These devices can be further broken down by the most common types of equipment, configurations, and internals used in the industry. Fig. 7-13 provides the more commonly used separator styles for the gas processing industry. For certain applications other specialty devices or configurations not indicated below may be appropriate.

Gas-Liquid Separator Selection Guide

This section is intended to provide basic selection guidelines for the various types of separation equipment.

Application Guidelines for Gas Separation Equipment — Fig. 7-14 is an application guideline for general types of gas separation equipment.

Orientation Selection Guide for Two Phase Separators — Several factors should be considered when selecting the orientation of a separator including the relative flow rates of gas and liquid, the quality of gas-liquid or liquid-liquid separation required, the volume needed for surges and liquid retention time, the time or surface area needed for degassing separated liquid, the plot space available, and the height of the vessel including consideration of transport requirements.

Fig. 7-15 summarizes the typical configuration options used for gas-liquid and three-phase separators.

FIG. 7-17

Horizontal Gas-Liquid Separator Comparison Chart

Separator Types:	No Demisting Internals	Vert. Mesh Pad	Horiz. Mesh Pad in Box	Vert. Vane Pack
Gas Handling				
Capacity	Low	Moderate	Moderate	High
Turndown Capability	∞	4:1	4:1	3:1
Liquid Removal Efficiency				
Overall	Low	Very High	Very High	Moderate
Fine Mist	Very Low	Very High	Very High	Moderate
Liquid Handling Capacity				
Slugs	Very High	Very High	Very High	Very High
Droplets	High	High	High	Moderate
Fouling Tolerance				
Particulate	Very High	Low	Low	Moderate
Fouling Material	Very High	Very Low	Very Low	Moderate
Pressure Drop	Very Low	Very Low	Very Low	Low

Application Guidelines for Two Phase Gas-Liquid Separation Equipment — Fig. 7-16, and 7-17 summarize the principle differences between the common gas-liquid separator configurations.

Liquid-Liquid and Gas-Liquid-Liquid Selection Guideline — Fig. 7-18 summarizes the principle differences between the common liquid-liquid separator configurations.

Fig. 7-19 summarizes the main configuration options for gas-liquid-liquid separators.

DATA AND INFORMATION REQUIRED TO SPECIFY AND SIZE SEPARATORS

The following design parameters are needed to properly specify separation equipment.

- Separator environment: wellhead, offshore, gas plant
- Service: K.O. drum, gas-liquid separator, surge, flash drum, reflux drum, crude oil separator, solids removal
- Physical space limitations
- Typical sizing parameters for this service
- Separator effluent requirements / separation efficiency needed: Bulk liquid removal and/or fine mist removal. Effect of separation efficiency on downstream equipment
- Conditions of service: clean, fouling, or potentially plugging service determines types of entrainment separation devices that may be considered
- Operating Conditions: gas and liquid flow rates, operating temperature and pressure, gas and liquid physical properties (densities at conditions, viscosities of liquid, vapor and emulsion if present, liquid surface tension)
- Two or three phase separation
- Removal of accumulated solids from separator vessel
- Design factor for sizing: Typically design factor is based on either maximum operating flow rate alone or operating flow rate plus a factor. This decision should be based on specific service and project criteria
- De-rating required for K factor due to experience with this service

FIG. 7-18

Liquid-Liquid Separator Selection

Separator Types	Horizontal Open	Vertical Open	Horizontal/ Vertical with Coalescer
Easy Settling Liquids	Yes	Yes	Yes
Bulk Separation	Yes	Yes	—
Most Efficient Separation			Yes
Fouling Service	Yes	Yes	Possible with plate, Mesh may require filtration upstream
High Gas Flow	Possible	Yes	—

FIG. 7-19

Gas-Liquid-Liquid Separator Selection

Separator Types	Horizontal No Internals	Horizontal w/Baffle	Horiz./ Vert. w/ Plate Pack or Mesh	Horizontal w/Boot	Horiz. w/ Bucket & Underflow Baffle	Vertical
Liquid-Liquid Separation						
Easy to Settle	Yes	Yes	Yes	Yes	Yes	Yes
Bulk Separation	Yes	Yes		Yes	Yes	Yes
Most Efficient Separation		With coalescer	Yes	With coalescer	With coalescer	With coalescer
Gas-Liquid Separation						
Bulk Separation	Yes	Yes	Yes	Yes	Yes	Yes
Most Efficient Separation	With mist eliminator	With mist eliminator	With mist eliminator	With mist eliminator	With mist eliminator	With mist eliminator
Liquid Controlled (G/L/L)	Yes	Yes	—	Yes	Yes	—
Gas Controlled (G/L/L)	—	—	—	—	—	Yes
Fouling Service	Yes	Yes	—	Yes	Yes	Yes
Solids Handling	Yes	—	—	—	—	Yes
Interface Level Control not Required	—	—	—	—	Yes	—
Low Light Phase (Oil) Flow Rate	—	—	—	—	Yes	—
Low Water Phase Flow Rate	—	—	—	Yes	—	—

- Liquid residence time requirements for de-gassing or other needs for this service based on experience or specific project criteria
- Liquid-liquid settling time requirements
- Nature of solids that may be present, size if available and solids removal efficiency required
- Inlet slug size and frequency
- Surge time requirements
- Total Surge Time (HHLL to LLLL)
- Control Surge Time (NLL to HLL)
- High Level Surge Time (HLL to HHLL)
- Low Level Response Time (LLLL to LLL)
- Nature of fluids being contained: hazardous properties (toxic, flammable, lethal, etc.) and corrosively
- Mechanical design conditions: design pressure and temperature, corrosion allowance, material of construction, minimum design metal temperature, and any project-specific requirements

TYPES OF COMMON GAS-LIQUID SEPARATORS

Vertical Separator — No Internals

A vertical knock-out drum (Fig. 7-20) provides bulk separation of gas and liquid. It has unlimited turndown, very low pressure drop, can handle slugs well, and is tolerant of fouling.

Overall efficiency depends on the application but typically will be no more than 90%-95% when the vessel diameter is sized for gas flow. Separation efficiency typically decreases at higher pressure due to the presence of smaller droplets than at low pressure.

Knock-out drums without internals are typically used for applications where there is little liquid present and a vertical configuration is preferred, where no internals are allowed due to the service (i.e. flare knock-out drums), fouling is a major consideration, when efficiency of separation is not a major consideration and no internal are preferred They are not recommended for applications where efficient separation is needed.

Vertical Separator with Mesh Pad

The addition of the mesh pad to the vertical separator improves the demisting capability of the separator. Vertical separators with mesh pads have moderate capacity, high liquid droplet removal efficiency, high turndown ratio, and low pressure drop.

The overall efficiency of a separator with a mesh pad is dependent on the liquid droplet size distribution and the liquid load at the pad. A supplier can typically guarantee an overall efficiency of 99% at 7-10 microns for a conventional high efficiency wire mesh mist eliminator. For material balance purposes, an overall liquid removal efficiency of greater than 99% can be assumed for most applications.

Vertical separators with mesh pads are recommended for applications where vapor flow is the controlling condition. They can handle a moderate liquid load to the pad in the form of droplets. The design K value can be affected by the liquid load to the device, therefore proper selection of the feed inlet device is essential. Vertical wire mesh separators can be used when limited upstream pipe slugs are present, if sufficient liquid surge volume is included. They are not recommended for fouling service and for highly viscous liquids when the de-gassing requirement determines the vessel diameter.

Typical applications for vertical separators with mesh pads are compressor suction scrubbers and intermediate scrubbers in non-fouling service, general service separators of all types, production separators, inlet and outlet scrubbers for glycol/amine contactors, upstream of filter-separators, and inlet scrubbers for gas export pipelines. Different styles of mesh elements are available [metal, plastic, composite (wire and fiber), compound (different wire diameter, and/or weave density, and special drainage)], depending on the application. All of these factors will affect both the maximum gas capacity and the droplet removal efficiency. For many gas treating applications, however, conventional simple metal mesh mist eliminator are used. Mesh pads have a low pressure drop, typically about 249 Pa, depending on the pressure and liquid loading.

Vertical Separator with Vane Pack

Vertical separators with vane packs can be used instead of wire mesh for the following reasons: fear of fouling of the wire mesh, where corrosion and life of the demisting device requires a more robust design than mesh pads, to reduce separator size and cost compared to mesh, too high a liquid load for mesh. Vertical separators with vane packs have a moderate turndown ratio, are suitable for slightly fouling service (straight or some single-pocket vanes only). The typical droplet removal efficiency for vane styles is provided in "Vane Separator Devices", earlier in this Chapter. Vane separators are less efficient overall than wire mesh in most applications.

Vertical separators with vanes are best utilized below 4825 kPa (ga). Higher efficiency can be obtained at pressures above 4825 kPa (ga) by using double pocket vanes. Vanes can tolerate higher liquid load than mesh pads. However, they are sensitive to slugs and require adequate bulk separation upstream, similar to mesh pads. Vane elements have a relatively low pressure drop [typically 100 Pa to 1 kPa (ga)]. Vertical separators with vanes are a common alternative to mesh mist eliminators for reciprocating compressors because of their more robust mechanical design, which is advantageous in pulsating service.

Vanes packs may be supplied as part of a package which includes the pressure vessel and internals, or as the vane element alone. Each supplier has proprietary vane pack styles and design correlations. There are several styles available: straight vanes, single pocket vanes for vertical and horizontal flow, and double pocket vanes for horizontal flow. Pocket vanes are, however, more prone to fouling. The liquid collected by the vanes is

FIG. 7-20
Basic Vertical Separators Designs

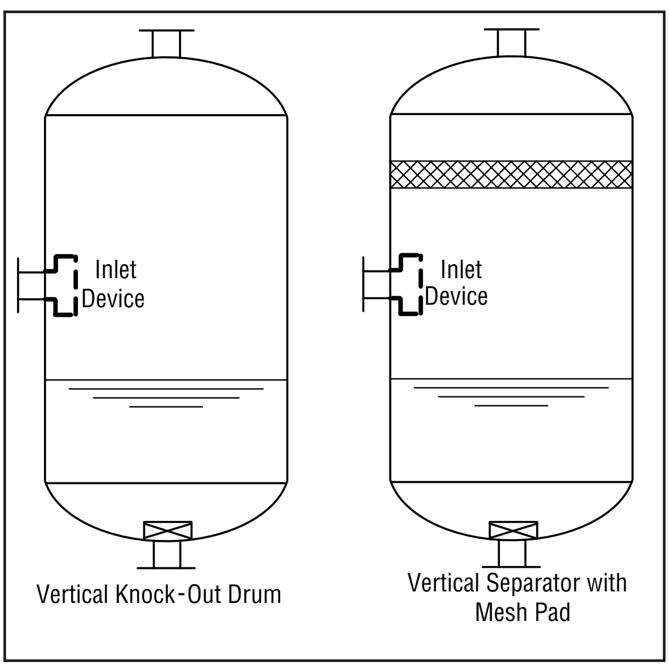


FIG. 7-21
Vertical Separators with Vane Packs

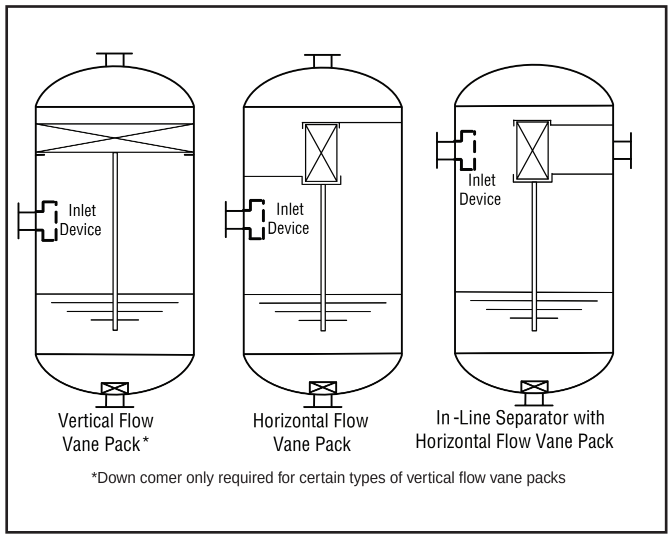
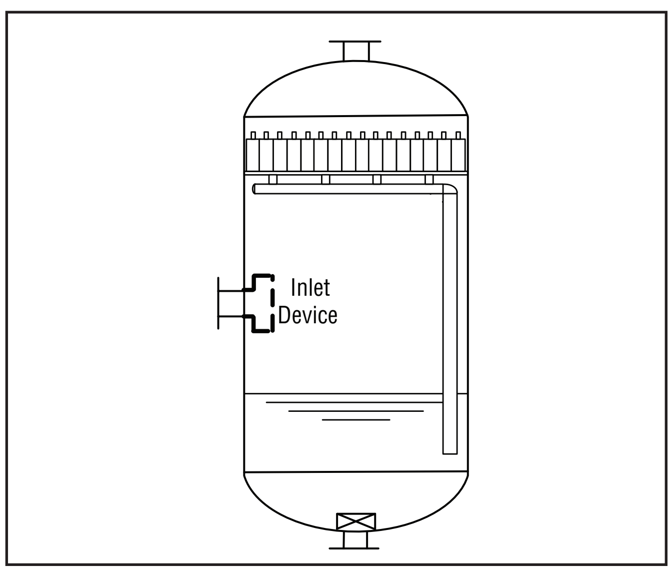


FIG. 7-22
Axial Flow Multi-Cyclone Vertical Separators



typically drained by a pipe(s) to the sump of the separator and sealed. The drain pipe(s) is submerged below the liquid level.

Several different vane configurations may be used in a vertical separator: vertical flow of gas through the vanes, horizontal flow, inline separator with horizontal flow.

Vertical Flow Vane Separator

This configuration is similar to that of a vertical mesh separator. There is a liquid knockout section below the vane section which can handle higher liquid loads during upsets or small slugs. Vertical flow vane separators have the advantage that the gas flow path is vertical after the inlet and does not have to change direction to pass through the vane pack.

Horizontal Flow Vane Separator

In this configuration the gas flows vertically up from the inlet section and then must make a turn to flow horizontally through the vane pack, hence proper spacing must be allowed for good gas distribution. Typically the height of the vane pack is larger than the width, which permits a smaller vessel diameter than the vertical flow vane design. In horizontal flow the allowable K value is often higher depending on the style of vane used. The horizontal flow vane separator is a common configuration for reciprocating compressors since it is compact and lower in cost.

Horizontal Flow Vane Separator (In-Line)

This is the most compact vertical vessel using a vane pack. However, the design cannot handle significant liquids or slugs during an upset.

Vertical Separator with Axial Flow Multi-Cyclones

The concept of banks of small or axial flow cyclones was introduced commercially in the early 1990s (see Fig. 7-22). They are increasingly being employed for new, large, high pressure separators, where significant savings can be achieved by a reduction in vessel diameter and weight. They are most cost competitive operating at high pressure [over 4130 kPa (ga)], but can be used at lower pressure as well.

Cyclones have a higher gas handling capacity than vanes and mesh pads, are compact, and are less sensitive to fouling. The typical minimum efficient droplet size removal is 10–20 microns, not as efficient as wire mesh but better than many vanes, and can be improved by the addition of other elements. The main drawback of cyclones is their complexity and their expense compared to other internals. Other drawbacks are a moderate turndown ratio (factor of 2 for axial cyclones alone) and high pressure drop (7 kPa for cyclone element alone). The high pressure drop of cyclonic demisters requires a liquid seal of the demister drainage tube to prevent bypassing of gas through the drainage tube. To allow drainage of liquid from the cyclones, sufficient vertical space between the demister and the liquid surface must be provided to create adequate drainage head.

Vertical separators with axial cyclones are most commonly used for offshore applications and high pressure, high capacity onshore applications. Typical applications for vertical separators with cyclones are compressor discharge drums, high pressure production separators handling feeds with a moderate gas/oil ratio, and high pressure scrubbers. They can also be used for debottlenecking existing separators for higher capacity if the separator size permits, since they can handle higher K-factors and higher liquid loading than other demisting devices. Industry experience indicates that cyclone separator tolerate fouling service better than high surface area demisters (mesh, vane).

Vertical Separator With Reverse Flow Multi-Cyclone Internals

A vertical reverse flow multi cyclone is a vertical vessel in which an array of small cyclones are installed between a top and a bottom plate. In this way a chamber is created which is shielded from the top and bottom compartment of the vessel. The feed flows directly into the compartment and enters the cyclones through their tangential inlets. The gas liquid separation takes place in these cyclones. Subsequently, the cleaned gas flows to the upper vessel compartment, and the separated liquid is drained to the bottom compartment. Reverse flow multi-clone cyclones can be used for mist separation, solids-mist separation, or for solids separation.

Vertical Separator — Combination Internals

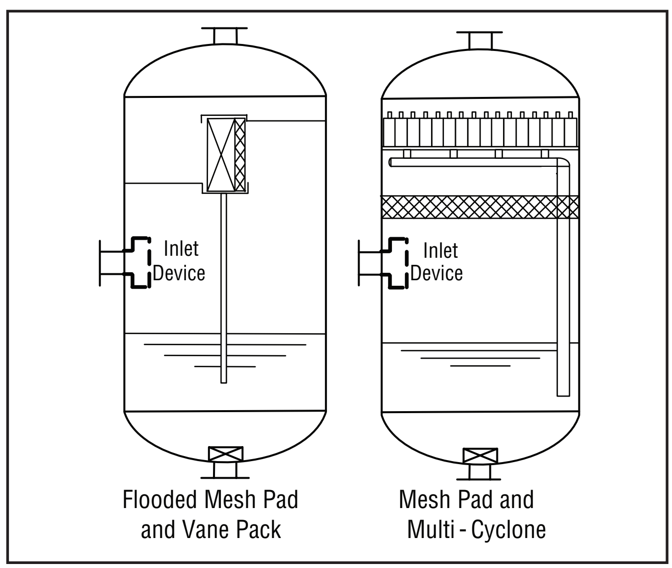
Configurations — Combinations of mesh, vanes, and cyclones can be used to increase the performance of a separator or help resolve potential issues associated with a design based on a single device. Such designs have become more common since the late 1990s, because vessel diameter can be reduced from a mesh pad design. Combination designs can increase the efficiency of the separator, expand the turn-down range over which it functions, or allow it to handle high liquid loads. Combination designs are used to reduce cost for both high and low pressure vertical separators where gas velocity controls the vessel size.

Flooded mesh or vane combination designs offer increased turndown since at low velocity the flooded element provides demisting capabilities when the downstream device may be ineffective due to low velocity.

The main disadvantage of the combination design is added cost and complexity of the internals.

FIG. 7-23

Vertical Vessels with Combination Configuration



Typical combination designs are:

- Flooded mesh pad (coalescing mesh) followed by vanes in either vertical or horizontal flow; Reduces diameter of the scrubber compared to mesh pad and maintains high efficiency
- A vane pack followed by mesh pad; Allows for potentially fouling service and maintains high mesh pad efficiency
- Vertical flow with flooded vanes or mesh pad, followed by multiple axial cyclones; Allows for higher liquid rates with increased turndown at continued high efficiency over cyclones alone

Flooded Mesh Pad Followed by Vane Pack — One common configuration to increase capacity over a conventional mesh pad mist eliminator, while maintaining high efficiency at both high and low gas rates, is a mesh pad followed by a vane pack. This style of separator is designed based on the gas handling criteria for the vane pack, so that during normal operation the mesh pad operates flooded. In this mode smaller droplets are agglomerated and the liquid collected in the mesh is re-entrained downstream and captured by the vane pack. The mesh pad functions as a coalescer to enhance the efficiency of the downstream vanes. At turndown the mesh pad regains its function and efficiency as a mist eliminator and takes over the separation duty from the vanes.

Vane Pack Followed by Mesh Pad — Another configuration for a combination design using both a vane pack and a mesh pad is a vane pack followed by a mesh pad. This style of separator is designed based on the gas handling criteria for the mesh pad. The advantage of this separator is that it will operate at higher liquid loads than a vane pack alone and it can minimize the effect of solids carryover. The vanes remove most of the liquid droplets above 150 microns and the mesh pad removes smaller droplets without becoming flooded or fouled. This separator design is less common than other options, but is useful in the proper circumstances.

Vane or Mesh Axial Cyclone Combination — The vane/cyclone separator has very high efficiency and good turndown ratio (factor of 4). The device has higher pressure drop than other mist eliminators. In this configuration, a vertical vane pack, or mesh is located below a bank of axial flow cyclones. The separator is designed based on the gas handling criteria for the cyclones so that in normal operation the vanes or mesh operates flooded. This is advantageous since the vanes or mesh function as a coalescer to enhance the efficiency of the downstream cyclones. At turndown, the vanes or mesh regain their function as a mist eliminator and take over the separation duty from the cyclones. The vane or mesh cyclone separator is less susceptible to fouling than a mesh/cyclone design. Wire mesh can also be added to the primary or secondary cyclone outlets to further enhance performance (see Fig. 7-23).

Horizontal Separator — No Internals

Horizontal separators-without internals provide bulk separation of gas and liquid. The design is typically used for liquid surge applications where the vapor flow is very low, for fouling services, or where internals are not desirable. The equipment has unlimited turndown, low pressure drop, can handle slugs and high liquid fractions, and is insensitive to fouling. The separation efficiency is dependent on the inlet droplet size distribution and Stokes' Law settling, based on the diameter, length, and liquid levels in the separator. Where gas flow controls sizing knock-out drums are typically designed to remove 250-500 micron droplets. Overall efficiency of 90-95% can be assumed. Where liquid holdup controls the vessel size higher efficiency is possible.

Separators-without internals are recommended where internals must be kept to a minimum such as flare knock-out drums (no bolted internals of any kind) and drums handling fouling fluids. They are not recommended where efficient demisting is required.

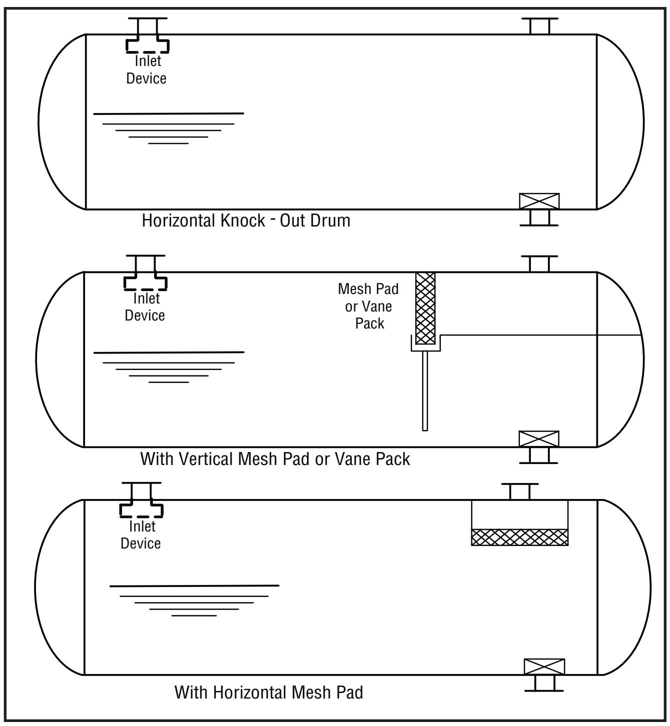
Horizontal Separator with Mesh Pad or Vane Pack

Most horizontal separators have a mesh pad mist elimination device. The addition of a mesh pad greatly improves the demisting capability of the separator. The separator removes droplets both by gravity settling and through the mist eliminator. Horizontal separators with mesh pads have a high turndown ratio (factor of 4), low pressure drop, are able to handle slugs well, have a high liquid handling capacity, and have high efficiency. However, they are sensitive to fouling.

Horizontal separators with mesh pads are generally used for applications where liquid holdup is controlling. This can be high vapor and liquid loads, high liquid loads with some vapor, or long liquid holdup times. They are recommended when slug handling capacity is required and for viscous liquids when the degassing requirement determines vessel size. They are not recommended for fouling service. Typical applications for horizontal separators with mesh pads are numerous (e.g., surge drums, feed drums, reflux drums) since this is the most common separator design. For very high vapor flow where a vertical vessel is not practical due to excessive large diameter, horizontal separators (frequently with multiple inlets) can offer a practical solution.

FIG. 7-24

Horizontal Separator Configurations



A Vane pack is preferred over a mesh mist eliminator in certain applications as discussed below. The mesh or vane can be installed in the following configurations (see Fig. 7-24):

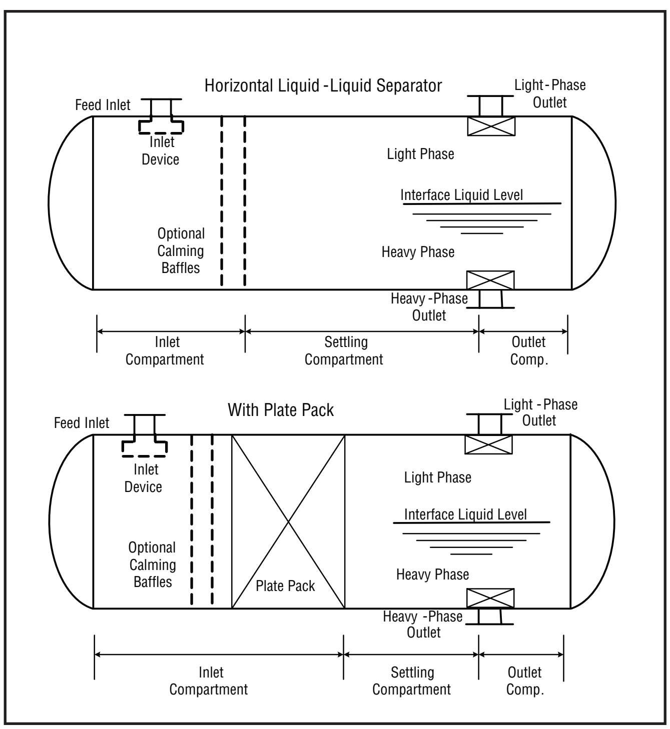
Horizontal Separator with Vertical Mesh Pad (Horizontal Flow) — Horizontal separators with a vertical mesh pad are used where there is significant vapor and liquid flow, and the area needed for vapor flow is large. Generally, in these applications the space required for installing a horizontal mist eliminator at the outlet nozzle is significant and such a design is impractical. The outlet side of the mist eliminator is typically sealed from the liquid accumulation section of the vessel, and a sealed pipe is used to drain the liquid. In some applications, however, the bottom of the mesh pad is submerged in the liquid to eliminate the partition and maximize the mist eliminator flow area.

Horizontal Separator with Vertical Vane Pack (Horizontal Flow) — A horizontal separator with a vertical vane pack can be used in lieu of a mesh pad where fouling is a consideration, or where the vapor rate is high and the liquid rate or slug volume is also high. Common examples for this design are slug catchers and inlet separators. In some applications the bottom of the vanes can be submerged in the liquid to eliminate the box and maximize the mist eliminator flow area.

Horizontal Separator with Hanging Mesh Pad — Horizontal separators with a horizontal mesh pad supported from the top of the drum are used where the vapor flow rate is low enough to allow a design without occupying excessive space above the liquid level. Essentially a box is constructed below the outlet nozzle with the mesh pad mounted at the bottom of the box. Vapor flowing horizontally through the vessel across the liquid surface must turn and enter the mesh pad vertically before exiting through the outlet nozzle. Thus, design must account for proper redistribution of the gas.

FIG. 7-25

Horizontal Liquid-Liquid Separator — No Internals, and With Plate Pack



TYPES OF LIQUID-LIQUID AND GAS-LIQUID-LIQUID SEPARATORS

Horizontal Liquid-Liquid Separator

No Internals — Horizontal liquid-liquid settlers with no internals are used for bulk separation of fluids having good separation characteristics (i.e. relatively low viscosity of the continuous phase, relatively large density difference, relatively large droplets, and moderate dispersed phase concentration). They are recommended for fouling service since there are no fine internals to plug. They should not be used for tight emulsions or where high separation efficiency is required. Separators which see emulsions require upstream unit operations, and/or a coalescing element or to "break" the emulsion and allow gravity separation to occur in the separator. These upstream operations may include heating to affect physical properties or chemical dosing to affect interfacial surface tension and allow formation of larger droplets suitable for gravity settling (see Fig. 7-25).

Horizontal Liquid-Liquid Separator with Plate Pack, Mesh Coalescer, or Combination Internals

The addition of plate packs, coalescing mesh, or combination internals can increase the efficiency of horizontal two-phase settlers compared to a separator with no internals. These internals may be applied to all of the arrangements described for liquid-liquid separators with no coalescing internals. See "Liquid-Liquid Coalescing Devices", in this Chapter, for the operating mechanism, and typical application range for these internals.

FIG. 7-26

Horizontal Gas-Liquid-Liquid Separator — No Internals

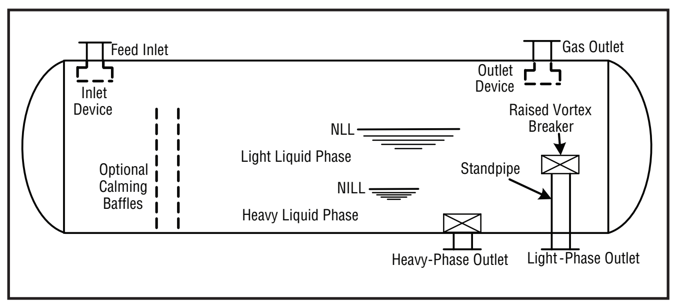
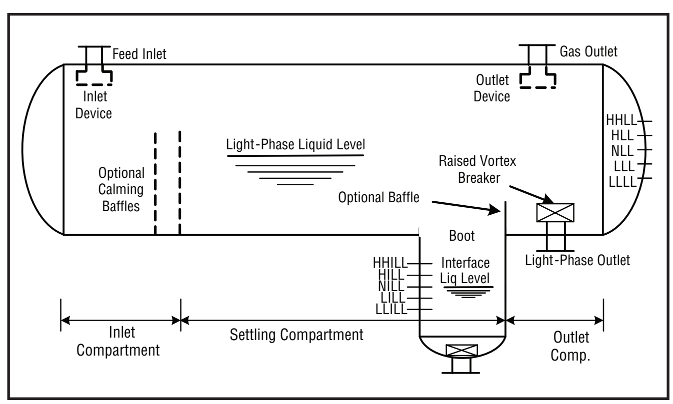


FIG. 7-27

Horizontal Gas-Liquid-Liquid Separator with Boot



For some services a combination of internals may be appropriate. An intermediate settling zone is typically used between each element.[12] Examples of these configurations are:

Plate pack followed by a mesh — Plate device to enhance upstream separation, followed by a mesh coalescer for final droplet removal. Used for high efficiency separation where the dispersed phase is greater than 5-10% of the continuous phase.

Mesh followed by plate pack — For high efficiency separation of small droplets, where the dispersed phase concentration is low (less than 5-10% of the continuous phase).

Mesh followed by plate pack, and with a secondary mesh polishing media downstream of the plate pack — For very high efficiency separation of small droplets, where the dispersed phase concentration is low.

Vertical Liquid-Liquid Separator with Mesh Coalescer

Vertical liquid-liquid separators are typically used to separate dispersions when the concentration of one liquid phase is low (<5 vol. %), as in applications where deoiling of water or dewatering of hydrocarbons is required. This separation is achieved with a coalescing pad constructed of small, tightly knit wire of stainless steel, glass fiber, or polymeric materials. The coalescer produces larger droplets which can be separated downstream of the pad by gravity. A coalescer supplier should be consulted in the design of a vertical liquid-liquid separator.

Horizontal Gas-Liquid-Liquid Separator — No Internals

Horizontal gas-liquid-liquid settlers with no internals, (except a standpipe) are used for bulk separation of fluids having good separation characteristics (i.e. relatively low viscosity of the continuous phase, relatively large density difference, relatively large droplets, and low dispersed phase concentration) (see Fig. 7-26). They are recommended for fouling service since there are no fine internals to plug. They should not be used for tight emulsions or where high separation efficiency is required. Separators which see emulsions require upstream unit operations or treatment to "break" the emulsion and allow gravity separation to occur in the separator.

Horizontal Gas-Liquid-Liquid Separator with Water Boot

A horizontal separator with a boot is commonly used for gas-liquid-liquid separation where a small amount of water is present in hydrocarbon liquid (see Fig. 7-27). It is best used in cases where the volume of the heavy phase is small (less than 5%) and the removal of hydrocarbons in the water to very low concentrations is not required. Because the surge volume spans the entire vessel length this configuration handles slugs well as long as the settling region is sufficient for the heavy phase to settle into the boot as the slug is separated. In the most common configuration the interface is maintained in the boot.

Horizontal Gas-Liquid-Liquid Separator with Single Overflow Weir

A settler with a single overflow weir is a common configuration for gas-liquid-liquid separation, where the liquid-liquid interface is well defined. It can be used for a wide range of heavy

FIG. 7-28

Horizontal Gas-Liquid-Liquid Separator with Single Weir

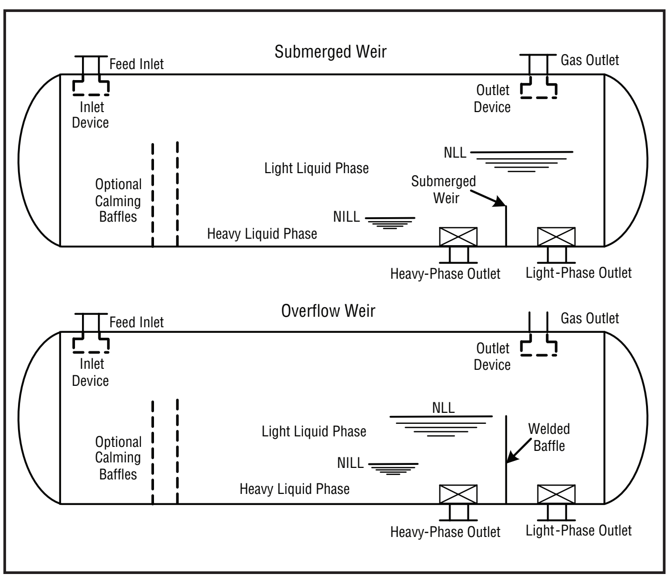


FIG. 7-29

Horizontal Gas-Liquid-Liquid Separator with Bucket and Weir

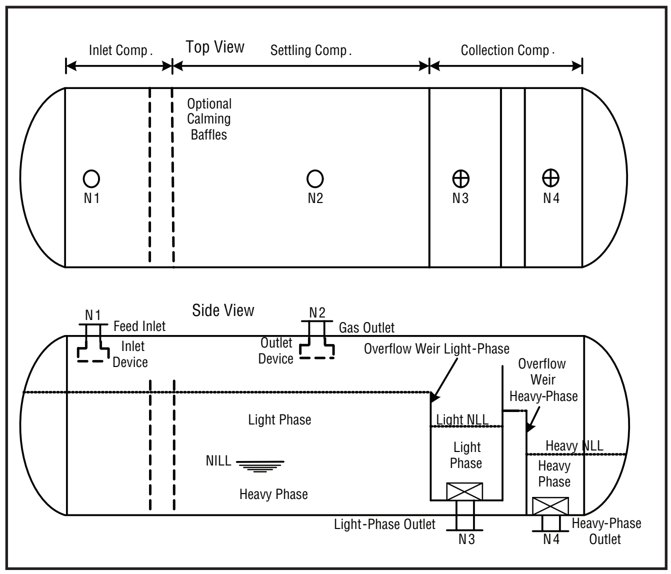


FIG. 7-30

Horizontal Gas-Liquid-Liquid Separator with Coalescer

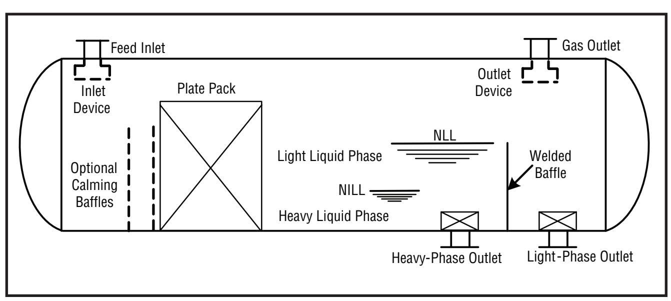
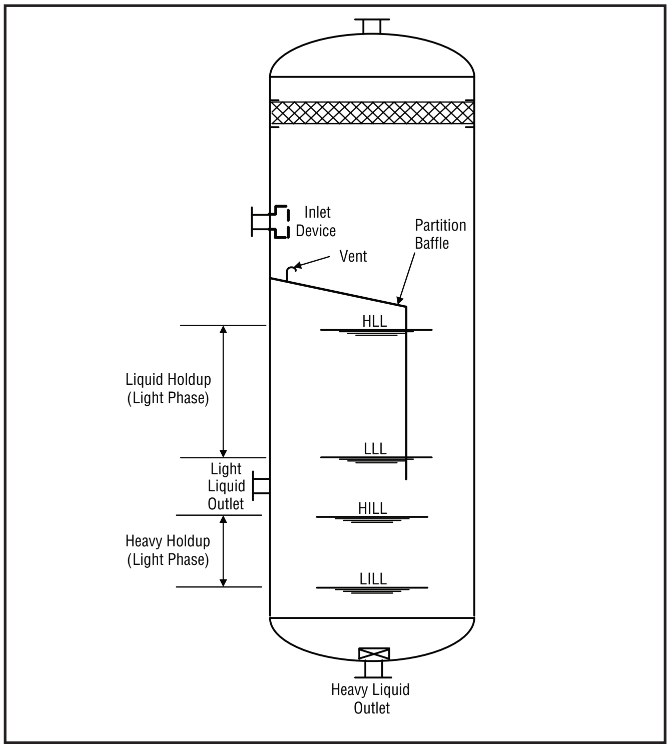


FIG. 7-31

Vertical Gas-Liquid-Liquid Separator



and light phase flows and properties and is quite flexible. There are two styles used: an overflow weir and a submerged weir (see Fig. 7-28).

The overflow weir configuration is more common. The total height of the settling zone is set by the weir height and a surge zone is located behind (downstream of) the weir. Where slugs are possible the submerged weir is preferred. In this design the overall level will rise and liquid residence time will increase when a slug enters the separator.

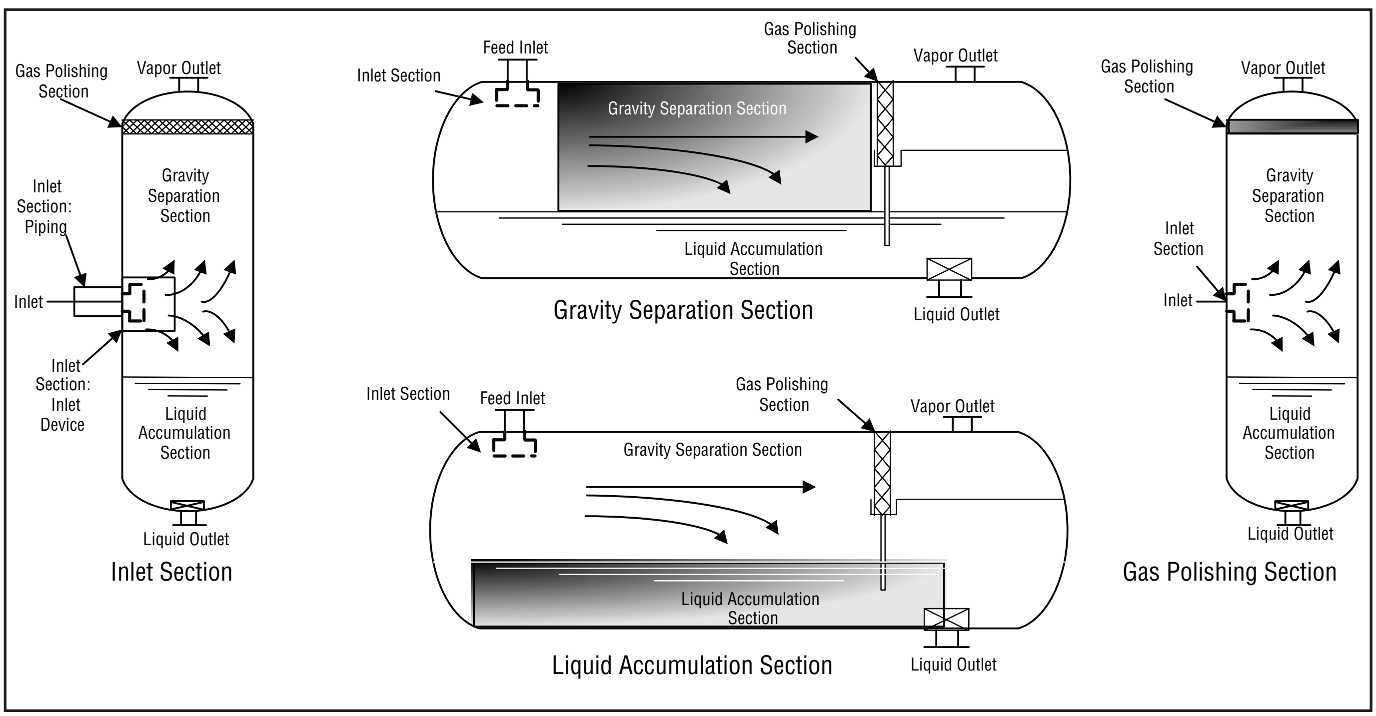
The gas flow area is constant for the overflow weir configuration, since the weir maintains a constant upstream liquid level. In the submerged weir configuration, the gas flow area varies with the liquid level, in a manner similar to a horizontal two-phase separator.

Horizontal Three Phase Separator with Bucket and Overflow Weir

A settler with a "bucket", and an overflow weir, is commonly used for applications where a small amount of hydrocarbon is to be separated from water (see Fig. 7-29). It is best for services where the volume of the light phase is small (less than 5%) and removal of water from the hydrocarbon to very low concentrations is not required. This configuration does not need direct interface control, and therefore it can be used when the liquid-liquid interface is poorly defined or when the light phase flow is unknown or highly variable. However, this configuration does not handle large slugs well.

FIG. 7-32

Zones of a Gas-Liquid Separator



Horizontal Gas-Liquid-Liquid Separator with Coalescer Internals

Coalescer internals can be used with all of the above horizontal three phase separator configurations. The design is best suited for separation of difficult-to-separate dispersions and for high outlet product quality specifications (see Fig. 7-30). The coalescing element(s) can also be used to minimize design uncertainty (due to potential eddies and short circuiting for open separators), and/or reduce equipment size. See "Liquid-Liquid Coalescing Devices", in this Chapter for the operating mechanism, and typical application range for these internals.

Vertical Gas-Liquid-Liquid Separator

In applications with a large gas flow and relatively low flow rates of two liquid phases it may be advantageous to use a vertical three-phase separator. The advantages of vertical three-phase separators are that they are compact, have a small footprint, can have high gas handling capacity (depending on the gas-liquid internals), and are not prone to fouling unless mesh is used. Fig. 7-31 illustrates a vertical gas-liquid-liquid separator. The upper section of the separator is dedicated to separation of the gas and liquid phases and the lower section is dedicated to separation of the two liquid phases.

TWO-PHASE AND THREE-PHASE SEPARATOR DESIGN AND OPERATING PRINCIPLES[10, 14, 15, 16]

This section describes the key design and operating parameters for Gas-Liquid and Gas-Liquid-Liquid Separators

Zones in the Separator

Gas-liquid separation vessels can typically be divided into four general regions (see Fig. 7-32):

- Inlet Section
- Gravity Separation
- Gas Polishing Section
- Liquid Accumulation Section (Outlet Section)

The inlet section provides bulk separation of the liquid from the gas. It includes the inlet piping upstream of the separator, and the inlet device inside the separator. The inlet device dissipates the energy of the incoming stream and changes the direction of the fluid. Ideally, this section is designed to direct gas and liquid in a direction to enhance operation of the gas polishing section and the liquid accumulation section without shearing the liquid and reducing the droplet size. This section can be a very turbulent area and can negatively impact separation, particularly liquid-liquid separation.

The gravity separation section is located downstream of the inlet device and upstream of the mist eliminator. A large cross sectional area will reduce the gas velocity, and allow liquid droplets to settle out by gravity.

The gas polishing section improves the overall separation efficiency by providing a medium to capture and coalesce droplets. To avoid re-entraining the separated droplets in horizontal gas flow mist eliminators, a downcomer pipe connects the gas polishing section to the liquid accumulation section.

The liquid accumulation section collects liquid from the inlet, gravity separation and the gas polishing sections. This liquid accumulation section allows gas trapped in the liquid to escape by providing sufficient liquid residence time. This is particularly important if the system is foaming or highly viscous. The liquid accumulation section also provides sufficient volume to allow for fluctuations in the liquid flow rate or to accommodate slugs of liquid in the inlet flow.

Inlet Section

Field experience and Computational Fluid Dynamics (CFD) modeling have demonstrated that the failure of separation devices to perform as expected is frequently due to the upstream piping configuration, the separator inlet device selection and design, and/or the inlet fluid velocity.[17] The best internals cannot overcome problems caused by submicron droplets or mal-distri-

FIG. 7-33

Common Vertical Vessel Inlet Devices

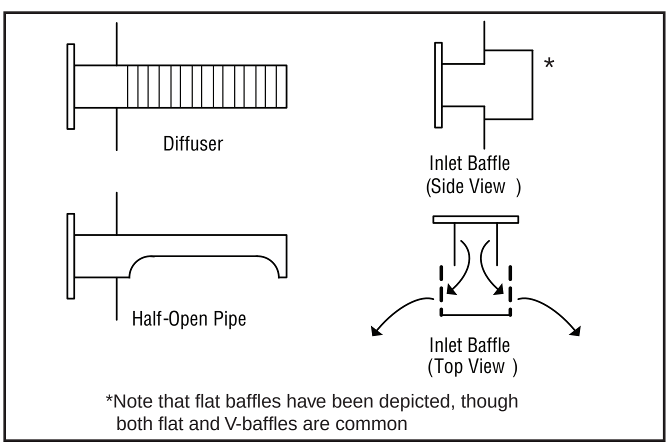


FIG. 7-34

Common Horizontal Vessel Inlet Devices

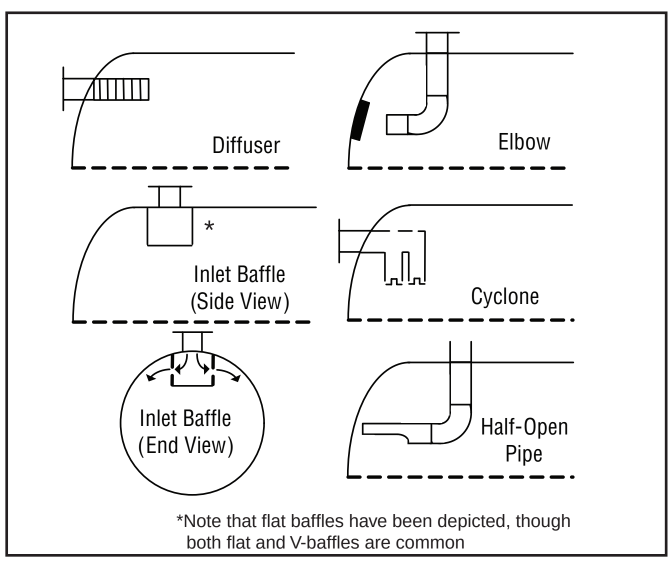


FIG. 7-35a

Typical Inlet Device Performance

Type of Device	None	Baffle	Elbow	Half Pipe	Diffuser	Cyclone
Momentum Reduction	Poor	Good	Good	Good	Good	Good
Bulk Separation	Good	Poor	Average	Average	Good	Good
Prevent Re-entrainment	Good	Average	Average	Average	Good	Average
Substantial Liquid in Gas	Poor	Ave/Poor	Average	Average	Good	Good
Prevent Liquid Shatter	Good	Poor	Poor	Average	Good	Good
Low Differential Pressure	Good	Good	Good	Good	Good	Average
Prevent Foam Creation	Poor	Poor	Poor	Poor	Average	Good
Gas Distribution	Poor	Average	Average	Poor	Good	Avg/ Poor
Prevent Liquid Surge Entrainment	Good	Good	Good	Poor	Good	Good
Orientation	H/V	H/V	H/T	H/V	H/V/T	H/T
Three Phase	Poor	Average	Average	No	Good	Good

1) Vessel orientation – (H) horizontal, (V) vertical, (T) three-phase

bution created by a poorly designed inlet device, or inadequate flow conditioning in the piping upstream of the separator.

Inlet Piping Design — The efficiency of a gas-liquid separator or a gas-liquid-liquid separator can be affected significantly by the flow regime and piping configuration upstream of the separator. Flow patterns that produce fine liquid droplets which are more difficult to separate are not desirable. The inlet flow regime depends on the flow rates and physical properties of the phases (including liquid surface tension), and on the feed pipe characteristics (diameter, length, vertical/ horizontal, location of fittings). Certain flow regimes cause more small droplets to form than others. Slug flow should be avoided and stratified-wavy and annular flows can form small droplets in the feed pipe.

The piping configuration to the separator should not hinder the working of the separator. Piping bends should be avoided close to the inlet of separators because they cause the flow to begin to rotate in the pipe. CFD modeling and field experience have shown that generally the swirling flow cannot be effectively gravity separated until the swirling is stopped, either by it dissipating with distance or by the use of straightening vane devices in the separator inlet. The following design considerations can greatly improve separator performance: avoid the following configurations within 5-10 pipe diameters of the separator: elbows in the horizontal plane, two out of plane elbows, valves and other flow disturbances, and high pressure drop which may cause flashing and atomization. The inlet piping design upstream should minimize low points and pockets. In addition, it is recommended that inlet piping diameter match the velocity requirement of the inlet to the separator 10 pipe diameters upstream of the separator to provide a flow regime which is fully developed before entering the separator.

Inlet Devices — Proper selection of the inlet device is critical in separator design. Inlet devices should reduce the momentum of the inlet stream, initiate gas-liquid separation with minimum creation of fine droplets, and distribute gas flow evenly throughout the inlet and gravity separation section of the vessel. Testing and CFD modeling have shown that if the fluid is distributed poorly separation efficiency will suffer greatly. The use of inlet diffusers for vertical separators and for horizontal separators with high gas flow has become common in recent years. A diffuser reduces droplet fracture as well as providing improved gas distribution inside the separator. A diffuser installed on separator feed with a high liquid to gas ratio can also help relieve the downstream mist elimination device of more than 90% of the inlet liquid load.

There are several types of inlet devices used in the industry. The more common devices are shown in Fig. 7-33 and Fig. 7-34. Relative performance of each device is shown in Fig. 7-35a.

It is also necessary to maintain the inlet velocity head, J, within proper limits for the selected inlet device to insure good gas distribution and minimum liquid shattering.

Where,

$$J = (\rho V^2) \qquad \textbf{Eq 7-15}$$

The maximum mixed phase velocity head range used in the industry guidelines varies for the different inlet devices. Some typical maximums are:

- 6000-9000 max. typ, up to 15 000 max kg/m • s² for diffuser distributor
- 975-2250 max kg/m • s² for no inlet distributor
- 1500-3750 max kg/m • s² for inlet half pipe or elbow distributor
- 1500-3750 max kg/m • s² for v-baffle or other simple inlet diverter designs

In addition, some users limit the inlet vapor phase velocity to 9 m/s or 18 m/s. The velocity should always be below the erosion velocity for the service.

Gravity Separation Section

The gravity separation section is the area where much of the liquid settles prior to entering the mist eliminator device.

Gas-Liquid Gravity Separation Section For Vertical Separators with Downstream Mist Eliminators — The gravity separation section for a vertical separator should be designed to allow a majority of the liquid to drop out upstream of the mist eliminator, to provide an even distribution of the gas to the gas polishing section, and to minimize re-entrainment from the liquid surface below the feed. This can be accomplished without over sizing the vessel diameter, if adequate space is provided above and below the feed nozzle, and the Inlet Section is properly specified (appropriate inlet piping configuration/size, and inlet device). In the past, it was common to oversize the vessel diameter compared to the mist eliminator, in order to provide a more conservative and flexible design. The appropriate approach for a new application depends on the risk tolerance of the owner, and the nature of the application.

Gas-Liquid Gravity Separation Section For Horizontal Separators with Downstream Mist Eliminators — The goal of the gravity separation section for a horizontal separator is to remove a majority of the liquid droplets from the gas prior to the mist eliminator, to minimize surface re-entrainment due to waves and droplet shear at the gas liquid interface, and to promote an even gas flow distribution to the mist eliminator. To accomplish this, it is necessary to limit the gas velocity through the vapor space. For most applications, an approach of applying Stokes' Law to establish a vertical terminal vertical velocity, and then designing for the gas flow velocity and length to drop out say a 250-500 micron droplet would result in high horizontal velocity (greater than that typically used commercially). As an alternative several different approaches have been used: 1) base the design on the maximum velocity which will drop out a target drop size in the length available, yet is below the calculated incipient re-entrainment velocity from the liquid surface (See "Surface Re-entrainment" section earlier in this Chapter)[5], 2) use an empirical equation for maximum gas velocity based on the density expression $((\rho_l-\rho_g)/\rho_g)^{0.5}$, times an factor based on a length ratio, and the height to the interface 3) limit the maximum gas velocity based the gas and liquid density function times a constant, 4) a combination of limiting maximum gas velocity based on an the density function times an empirical equation or a value, combined with a check of incipient re-entrainment velocity. Several typical equations for the maximum allowable horizontal velocity are provided in Fig. 7-35b.

FIG. 7-35b

Typical Equations for Maximum Gas Velocity for Horizontal Separators with Mist Eliminators

Length (L)	Max Velocity ($V_{h,\,max}$)	Reference
L < 3000 mm	$V_{h,\,max} = 0.122 \text{ to } 0.137 \cdot \sqrt{\frac{\rho_1-\rho_g}{\rho_g}}$	(18)
L > 3000 mm	$V_{h,\,max} = 0.122 \text{ to } 0.137 \cdot \left(\frac{L}{3048}\right)^{0.56} \cdot \sqrt{\frac{\rho_1-\rho_g}{\rho_g}}$	(18)
L > 3000 mm	$V_{h,\,max} = 0.137 \cdot \left(\frac{L}{6096}\right)^{0.58} \cdot \sqrt{\frac{\rho_1-\rho_g}{\rho_g}}$	(19)
Other Typically Used Equations		
L > 3000 mm	$V_{h,\,max} = 0.122 \cdot \left(\frac{L}{6096}\right)^{0.50} \cdot \sqrt{\frac{\rho_1-\rho_g}{\rho_g}}$	
L > 3000 mm	$V_{h,\,max} = 0.122 \text{ to } 0.137 \cdot \sqrt{\frac{\rho_1-\rho_g}{\rho_g}}$	

Gas Polishing Section

Selection of the appropriate device for gas polishing should be based on consideration of the application, operating pressure, likely feed droplet size range, allowable downstream carryover requirement, and the relative acceptability of the user for more compact and complex solutions. Internals suppliers have experience with all of the common gas treating applications and can provide guidance.

Separation Efficiency and Sizing Considerations For Wire Mesh Mist Eliminators — The work horse mist eliminator of the process industry for more than 60 years has been the conventional crimped wire mesh mist eliminator (single wire filament, and density). This design is still applicable for a wide variety of gas processing applications. Today however, there is a wide variety of advanced designs using the concept of composites (polymer fibers woven into the wire mesh), complex multi-layer (different density and or filament size in layers), drainage channels, or other concepts. Each design will have its own characteristic droplet removal efficiency at standard conditions, ability to tolerate liquid load, and throughput capacity. Difficult applications in the gas treating industry are those with small droplet size (low temperature treating separators, low surface tension high pressure light hydrocarbons), high viscosity (glycols, sulfur) and stringent outlet specifications (low temperature treating, amines and glycols). Internals suppliers should be consulted to provide the optimum alternatives for these applications. For any selected style, mist eliminator supplier can provide the d_{95} (droplet size for 95% removal efficiency), and for a given an estimated inlet droplet size distribution, an overall separation efficiency.

Sizing for wire mesh mist eliminators is based on operating the mist eliminator at a maximum flow rate which is a safe distance from the flood point at the operating conditions. The Souders-Brown K value (Equation 7-11) has been found to be a good correlating factor for determining this velocity. A conventional, 192 kg/m^3, 0.3 mm filament, crimped wire mesh mist eliminator, will typically have a design K value of 0.11 m/s, for vertical flow to the mist eliminator, at low pressure, low liquid/gas load, and liquid viscosity of 1.0 mPa • s or lower. In horizontal gas flow, a design K value of 0.13 is typical for these conditions. At other conditions, the design K value may be lower, due to the liquid/gas flow parameter (Φ) to the device ($\Phi = W_g/W_l(\rho_g/$

FIG. 7-36

De-rating Factor to K-value for Pressure

Pressure, kPa (ga)	De-rating For Mesh Demisters At Elevated Pressure
Atmospheric	1.00
1034	0.90
2068	0.85
4137	0.80
7929	0.75

$\rho_l)^{0.5}$), liquid viscosity, foaming tendency, liquid surface tension, gas mal-distribution, and flow surges. Note, that the average droplet size to the separator, the type of inlet distributor, and the device spacing in the vessel can affect the gas/liquid flow parameter at the mist eliminator for a given set of inlet conditions to the separator. For gas treating applications, liquid viscosity is important mainly for high viscosity fluids, such as glycols and sulfur. Surface tension is important for low surface tension light hydrocarbon fluids, typically found in low temperature gas processing.

FIG. 7-37

Typical Souder's-Brown K Values for Mist Eliminator Devices

Device	Typical Souders-Brown K Value* m/s
Mesh Vertical Flow to Mesh	0.11
Mesh Horizontal Flow to Mesh	0.13
Vane (simple profile) — Vertical Flow to Vane	0.15
Vane (simple profile) — Horizontal Flow to Vane	0.20
Vanes with single or double pockets — Vertical and Horizontal Flow to Vane	0.20 to 0.30
Vertical Flow To Axial cyclone	0.15 to 0.24
Combination Vane / Mesh Vertical Flow	0.15
Combination Vane / Mesh Horizontal Flow	0.20
Axial cyclone Combinations Vertical Flow	0.15 to 0.24

*Values for comparison purposes only

Fabian[10] proposed that it is prudent to de-rate mist eliminators at pressures above 690 kPa (ga). This de-rating is not for pressure per se, but rather for the potential for local high velocity areas, as the mist eliminator becomes more compact at higher pressures. These de-rating factors are shown in Fig. 7-36. Systems known to foam, such as amines and glycols should be de-rated, in a similar manner to a system factor for trays or packing in these services. In addition, it is common to apply a system factor to the gas design flow rate, which can vary from 1.05 to 1.2 depending on the application (i.e. inlet production, steady state gas processing, gas compression).

For many services in the gas treating industry that handle light hydrocarbons gases and liquids at low liquid load, with a conventional wire mesh mist eliminator, use of a K value of 0.11, de-rated per Fig. 7-36, will provide an acceptable design. For other applications, an internals supplier should be consulted since the design K can be a complex function of the device characteristics, and the system physical property parameters. It is important that the specific application be clearly described in the mist eliminator inquiry, to insure an effective end result. In all cases, it is recommended that the final mist eliminator sizing should be checked by the selected internals supplier.

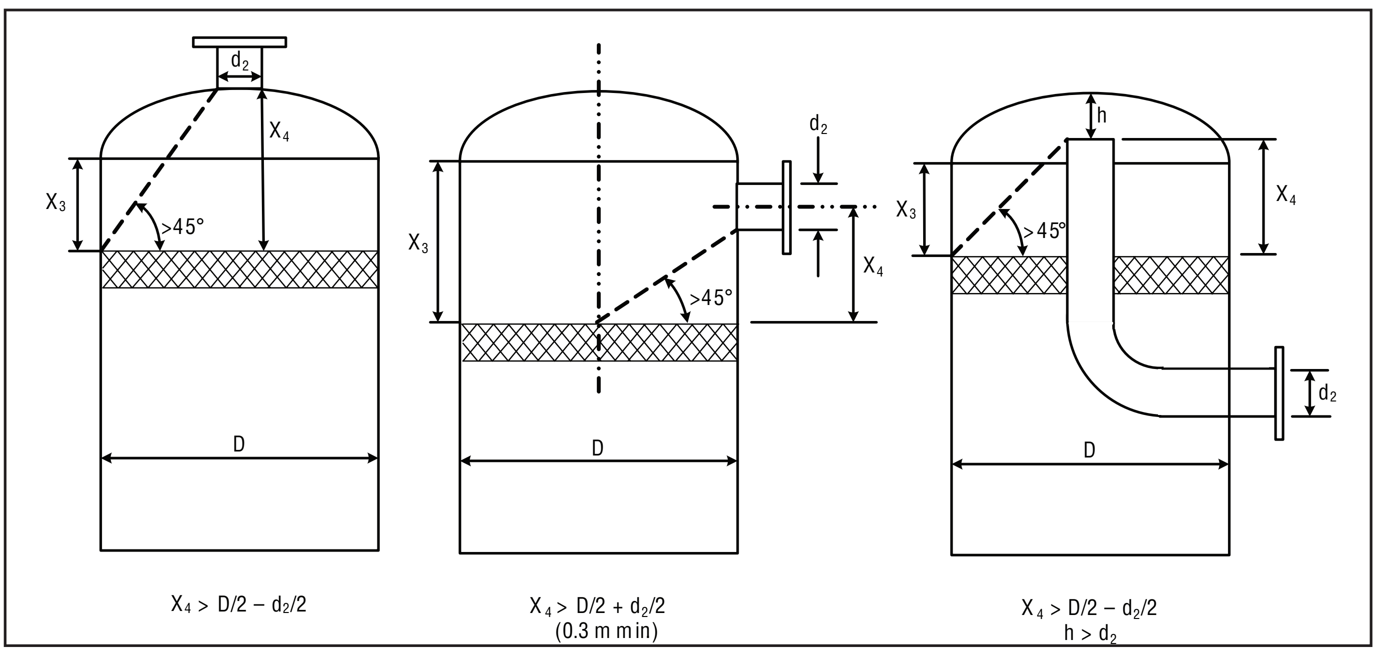
Relative Capacity For Vanes, Cyclones, and Combination Devices — The design of vanes, cyclones, and combination devices varies between suppliers, and factors in addition to the Souders-Brown K value may well determine the maximum flow capacity of the device at given operating conditions. Typically these factors are a function of the liquid surface tension, gas and liquid viscosity, liquid/gas load factor, as well as gas and liquid density. The Souders-Brown K values shown in Fig. 7-37 are typical and may be used for preliminary evaluations, to compare the relative capacity of various alternatives.

Vapor Outlet Section

Fig. 7-38 illustrates some typical outlet section design configurations for vertical separators.

FIG. 7-38

Vapor Outlet Configurations



The sizing of the vapor outlet nozzle should be such that given the above placement of the mesh pad, the velocity is not high enough to cause channeling of the gas through the mesh pad. The nozzle outlet size is typically based on the lesser of that required for piping pressure drop, or a maximum velocity head criteria. Typical ranges for the maximum velocity head allowed for the vapor outlet are 4500–5400 kg/m • s^2. In addition some users limit the absolute velocity to 18 m/s. The pipe size can be decreased to the appropriate size based on pressure drop considerations, 5-10 pipe diameters downstream of the separator, as required.

Liquid Accumulation Section

The purpose of the liquid accumulation section is to provide time for control (surge time) and de-gassing and space for the outlet nozzles

Surge Time and Retention Time — The surge times in a vessel provide operations personnel time to respond to process changes and still maintain smooth unit operation. "Surge time" is defined as the liquid volume between two levels divided by the design liquid flow rate and is usually expressed in minutes. Commonly used surge times are those within the control range (LLL to HLL) or between the control range and the LL or HH shutdown levels.

Total Surge Time — Total surge time is the time between the HHLL and LLLL levels needed to ensure stable continuous operation without shutdown. This time is set based on a review of the process configuration, upstream and downstream systems, and on previous experience with designs of similar systems.

Control Surge Time — Control surge time is time from LLL to HLL needed for proper level control or to provide sufficient response time for upstream or downstream process upsets. Typical control surge times used in the gas processing industry are presented in Fig. 7-40.

High Level Surge Time — High level surge time is the minimum operator response time to take corrective action from HLL to HHLL to prevent a shutdown in the process or in upstream processes in the event of a level control problem, a loss of vessel outflow, or an upset in the downstream process. The minimum time is 1 minute if the situation can be handled by inside operator intervention. Typical times are 1-2 minutes. If outside operator intervention is needed 5 minutes or more may be required.

Low Level Surge Time — Low level surge time is the minimum operator response time to take corrective action from LLL to LLLL to prevent a shutdown in the process or downstream processes in the event of a level control failure or an upset of flow into the system. The minimum time is 1 minute if inside operator intervention is used. Typical times are 1-2 minutes. If outside operator intervention is needed to start a pump 5 minutes or more may be required. Values vary widely by industry and client on this subject.

Liquid Retention Time — Liquid retention time is the residence time for the liquid from empty to NLL at the design flow rate. This time can be provided for liquid degassing or for liquid-liquid separation. Typically 2 minutes is sufficient for degassing most light hydrocarbons but as much as 15 minutes might be needed for foaming or viscous liquid (such as rich physical solvent drums). A traditional point of confusion is that

FIG. 7-39

Level Heights and Surge Volumes

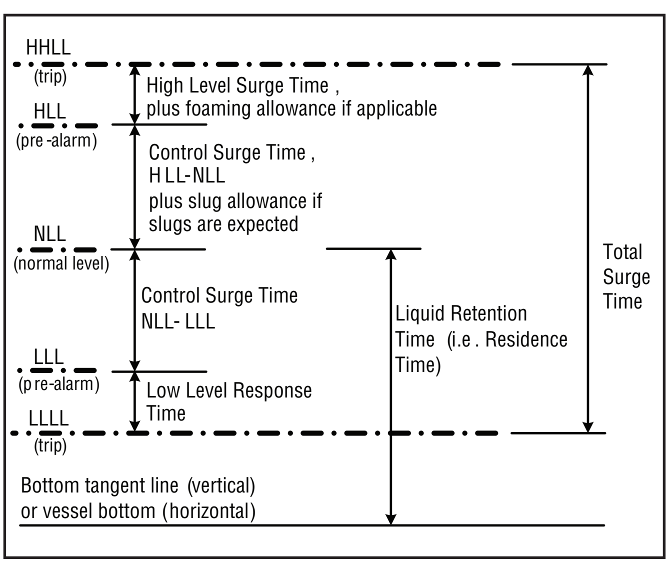


FIG. 7-40

Typical Gas Liquid Surge and Retention Times for Gas Production and Processing

Service	Control Surge Time LLL to HLL	Retention time
Compressor Drum	2 minutes	—
Flash Drum	2-5 minutes	—
Reflux Drum	5 minutes on product plus reflux	—
Surge Drum Upstream of a Tower	5-10 minutes	—
Surge Drum Upstream of a Fired Heat	10 minutes	—
Net Product to Storage	5 Minutes	
Amine Flash Drum	—	5-10 minutes, depending on presence of hydrocarbons
Glycol Flash Drum	—	10-20 minutes depending on presence of hydrocarbons
Refrigeration Accumulator	5 minutes, or based on system or storage requirements	—
Refrigeration Economizer	3 minutes	—
Heat Medium Surge Drum	Maximum liquid expansion, based on 25% to 75% full	—

the sizing for many common vessel services has been specified in terms of minutes from empty to half full, or retention time.

In some services it is important for the vessel to be sized for release of gas from the liquid collection section. This is especially necessary in cases where vapor carry-under is not permissible. In practice it can be assumed that if bubbles larger than 200 µm are able to escape, then the vapor carry-under will be negligible. If the terminal velocity of the gas bubble is greater than the liquid velocity the bubble will be able to escape.

For a vertical vessel:

$$V_l = \frac{Q_{l,\ max}}{A} \leq V_t \qquad \textbf{Eq 7-16a}$$

For a horizontal vessel:

$$V_h \leq \frac{L_{SET}}{H_{SET}} \cdot V_t \qquad \textbf{Eq 7-16b}$$

Based on Stokes' Law for a 200 micron bubble:

$$V_t = 2.18 \cdot 10^{-5} \frac{\rho_g - \rho_l}{\mu_l} \qquad \textbf{Eq 7-17}$$

Liquid Outlet Nozzle — Many users limit the liquid outlet nozzle velocity based on pump suction line criteria (i.e. 11 kPa/100 m for fluid at or near boil, 22 kPa/100 m otherwise) or other line sizing criteria. For three phase separators, the velocity may be further reduced. Other users set a maximum outlet nozzle velocity (i.e. 0.9–1.5 m/sec) regardless of the service.

SIZING EXAMPLES FOR VERTICAL AND HORIZONTAL TWO PHASE SEPARATORS

Sizing Methodology —Vertical Separator with Wire Mesh Mist Eliminator

For many applications the diameter of both the vessel and the mesh separator is determined by the allowable vapor velocity through the mist eliminator. At a velocity somewhat above this maximum (typically 10-25%) a wire mesh pad will flood resulting in high re-entrainment and significantly reduced separation efficiency. Where the separator diameter is set by gas flow rate Equation 7-18 is used.

$$D \geq \sqrt{\frac{4Q}{\pi V_{max}}} \qquad \textbf{Eq 7-18}$$

To the vessel diameter determined by Equation 7-18, an additional allowance for a support ring should be made.

In some cases the mist eliminator is specified smaller in diameter than the vessel. This can occur 1) when vapor is not the controlling the sizing of the vessel, or 2) when the design approach is to use a conservative sizing for the vessel diameter. An alternative is to design the vessel for a larger diameter than is required by the mesh pad, install a full diameter mesh pad, and then install blanking strips on top of the mesh to reduce the cross-sectional area open to flow.

For applications where the diameter is gas controlled the height will be determined by the sum of the required distances to the HHLL, distance from HHLL to the inlet nozzle bottom, inlet nozzle size, required distance from the top of the inlet nozzle to mesh mist eliminator, thickness of the mesh mist eliminator, and distance from the top of the mist eliminator to the vessel upper tangent line. Common heights are shown in Fig. 7-41. For applications that are liquid controlled, surge time will determine vessel diameter and height consistent with the best economic ratio for the total installed cost of the application.

Example Problem — Sizing Two Phase Vertical Wire Mesh Separator

Example 7-2 — Determine the size of a vertical gas-liquid separator with a high efficiency wire mesh mist eliminator to handle 4.25 MMSm^3/day (MW = 17.55) of gas and 22.7 m^3/h of condensate. A design factor of 10% will be used.

Operating Conditions —

Operating temperature = 49°C,
Operating pressure = 3447 kPa (ga)

Gas flowrate = 4.25 MMSm^3/day (131 181 kg/h)

Liquid flowrate = 22.7 m^3/h (16 262 kg/h)

Physical Properties —

ρ_g = 24.86 kg/m^3, μ_g = 0.013 cP, ρ_l = 715.7 kg/m^3,
μ_l = 0.574 cP, ρ_m = 28.03 kg/m^3

Project Surge Times for this Application —

LLLL to LL = 1 min, LLL to HLL = 5 min, HLL to HHLL = 1 min

Internals Selected —

High efficiency wire mesh mist eliminator

Diffuser inlet device for high gas rate with significant liquids

Vessel Diameter Sizing —

$$Q_A = 131\,181 \frac{kg}{h} \cdot \frac{1}{24.86 \frac{kg}{m^3}} \cdot \frac{1\ h}{3600\ s} \cdot 1.1 = 1.612 \frac{m^3}{s}$$

$K = 0.11 \frac{m}{s}$ for a high efficiency mist eliminator at low pressure

K is corrected for pressure using Fig. 7-36

$$V_{max} = (0.09) \sqrt{\frac{715.7 - 24.86}{24.86}} = 0.47 \frac{m}{s} \quad \text{(Equation 7-11)}$$

$$A = \frac{1.612 \frac{m^3}{s}}{0.47 \frac{m}{s}} = 3.4\ m^2 \quad \text{(Equation 7-13)}$$

$$D = \sqrt{\frac{4 \cdot 1.612 \frac{m^3}{s}}{\pi \cdot 0.47 \frac{m}{s}}} + \frac{1000\ mm}{1\ m} + 100\ mm = 2190\ mm \quad \text{(Equation 7-18)}$$

100 mm added for support ring and then rounded to nearest 100 mm

Actual dimensions —

D = 2200 mm, A = 3.8 m^2

Liquid Surge Section —

$$Q \;=\; 16\,262\ \frac{\text{kg}}{\text{h}} \cdot \frac{1}{715.7\,\frac{\text{kg}}{\text{m}^3}} \cdot \frac{1\ \text{h}}{60\ \text{min}} \cdot 1.1 = 0.417\ \frac{\text{m}^3}{\text{min}}$$

H_1 (Bottom tangent to LALL) = 450 mm to allow level bridle taps above tangent.

LLL to HLL

$$\frac{0.417\ \text{m}^3/\text{min}}{4.1\ \text{m}^2} \cdot 5\ \text{min} = 0.51\ \text{m} = 510\ \text{mm, use } 550\ \text{mm}$$

LLLL to LLL, and HLL to HHLL

$$\frac{0.417\ \text{m}^3/\text{min}}{4.1\ \text{m}^2} \cdot 1\ \text{min} = 0.10\ \text{m} = 100\ \text{mm, use } 100\ \text{mm}$$

H_2 = 100 + 450 + 100 = 650 mm, use 700 mm

Check De-Gassing (200 micron bubble)

Using Equation 7-16a:

$$V_l \;=\; \frac{0.417\ \frac{\text{m}^3}{\text{min}}}{4.1\ \text{m}^2} \cdot \frac{1\ \text{min}}{60\ \text{s}} \;=\; 0.0017\ \frac{\text{m}}{\text{s}}$$

Using Equation 7-17:

$$V_t = 2.18 \cdot 10^{-5}\ \frac{715.7\ \frac{\text{kg}}{\text{m}^3}\ 24.86\ \frac{\text{kg}}{\text{m}^3}}{0.574} \;=\; 0.026\ \frac{\text{m}}{\text{s}}$$

As $V_l < V_t$ for a 200 micron bubble, de-gassing of 200 micron particles can occur

Check Inlet Velocity Head —

Inlet Piping is 457 mm Sch. 40 (ID = 428 mm), based on acceptable line sizing criteria.

Assuming the inlet nozzle is the same size as piping, check that the inlet velocity satisfies allowable limits.

$$V = \left(\frac{(131\,181 + 16\,262)\ \frac{\text{kg}}{\text{h}} \cdot 1\ \text{h}}{28.03\ \frac{\text{kg}}{\text{m}^3} \cdot \pi \cdot \left(\frac{0.428}{2}\right)^2 \text{m}^2 \cdot 3600\ \text{s}}\right) = 10.16\ \frac{\text{m}}{\text{s}}$$

Using Equation 7-15:

$$J \;=\; (\rho_m V^2) = (28.03 \cdot 10.16^2) \;=\; 2893\ \frac{\text{kg}}{\text{m} \cdot \text{s}^2} \;<\; 9000\ \frac{\text{kg}}{\text{m} \cdot \text{s}^2}$$

therefore

457 mm nozzle with diffuser is acceptable.

Vessel Length —

$H_1 + H_2$ = 450 mm + 700 mm = 1150 mm

H_3 (HHLL to Nozzle Bottom) = 600 mm (for diffuser)

H_4 (Nozzle) = 450 mm

H_5 (Nozzle Top to Demister Bottom) = 900 mm

H_6 (Demister Thickness) = 150 mm

(Demister to Outlet Nozzle) = 0.84 m min (Fig. 7-38), Use 1.0 m

H_7 (Demister to Top Tangent) = 300 mm (based on 2:1 elliptical head), Fig. 6-23

Total Vessel Length = 3550 mm, use 3600 mm T-T

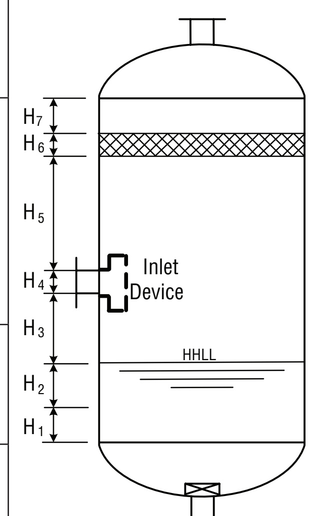
Sizing Methodology — Vertical Separator Without Internals

Refer to "Gas-Liquid Separation Fundamentals", presented earlier in this Chapter. A vertical separator without mist eliminating internals can be sized in a similar manner to that used for separators with internals. For applications that are gas controlled, the diameter is based on a maximum allowable terminal gas velocity. The K value used should be selected to insure massive entrainment does not occur, and a reasonable separation efficiency is achieved. The design terminal velocity can be based on the appropriate Stokes' Law, and is based on a droplet size of 250-500 micron, the gas and liquid properties, and the calculated drag coefficient, plus a safety factor. An alternative approach which is common in the industry is to base the design on a K value of approximately 0.046 m/s. For fluids with low surface tension at high pressure, or in other circumstances where small droplets are expected, either the target droplet size, or the design

FIG. 7-41

Level Distances for a Vertical Vessel

Dim	Section	Distance
H_1	Bottom Tangent to LLLL	300–450 mm, can be lower depending on instrument mount
H_2	LLLL to HHLL	Per required surge time or retention time
H_3	HHLL to Feed Nozzle Bottom	300–600 mm for diffuser 0.25 D for all other inlet devices, with 600 mm minimum
H_4	Nozzle Diameter	Larger of piping size or velocity head criteria
H_5	Nozzle Top to Mist Eliminator Bottom	300–900 mm for diffuser 0.5D for all other inlet devices
H_6	Mist Eliminator	100-150 mm typical
H_7	Mist Eliminator to Top Tangent	150 mm minimum or per Fig. 7-38



K, depending on the approach used, should be further reduced. The maximum allowable velocity is then calculated via Equation 7-11 and the area (and then diameter) calculated via Equation 7-13. The liquid accumulation section and levels can be calculated as given in Fig. 7-41. The height above the inlet nozzle is calculated as given for dimension H_5 in Fig. 7-41.

For applications that are liquid controlled, the liquid surge time will determine the vessel dimensions (height and diameter) based on economics.

See "Flare K.O. Drums", later in this Chapter, for sizing practices for vertical drums associated with flare systems.

Sizing Methodology — Two Phase Horizontal Separator with a Hanging Mesh

Horizontal separator drums with hanging mesh pads are sized so that the diameter and length are sufficient to provide the proper gas velocity through the vessel and mist eliminator and to provide the required liquid volume. The vapor space is a function of the gas flow area, and the settling length required to settle the majority of the droplets upstream of the mist eliminator (See Equations 7-13) and to minimize re-entrainment from the liquid surface (See Equations 7-9, 7-10, 7-14, and Fig. 7-35b). The liquid volume required is determined by the sum of the surge volumes, and/or the required retention time, and/or a degassing criterion. The mist eliminator is sized based on the Souders–Brown equation with appropriate derating (See Equation 7-11). Adequate space must be provided above the mist eliminator, and between the HHLL and the mist eliminator to insure an even velocity profile through the mist eliminator. Other considerations that affect the required vessel diameter and length are the height required to install the feed inlet device above the liquid level, and the need for minimum space between the maximum level and the top of the vessel. In order to size the separator, the vessel diameter and length are adjusted to achieve an optimum (generally lowest weight but practical layout) which meets all of these criteria. Typically a length to diameter (L/D) ratio of three is used as the starting point, and the length to diameter ratio adjusted upward as required.

Example Problem — Two Phase Horizontal Separator with a Hanging Mesh

Example 7-3 — Determine the configuration and size of a separator vessel to provide surge upstream of a process unit and to separate liquids and gas. The stream is 3975 m^3/day of condensate and 0.425 MMSm^3/day of gas (MW = 17.55). Process conditions are as follows:

Operating Conditions —

Operating temperature = 49°C,
Operating pressure = 1724 kPa (ga)

Gas flowrate = 0.425 MMSm^3/day (13 113.6 kg/h)

Liquid flowrate = 3975 m^3/day (121 655 kg/h)

Physical Properties —

$\rho_g = 12.4$ kg/m^3, $\mu_g = 0.012$ cP, $\rho_l = 714.1$ kg/m^3, $\mu_l = 0.573$ cP, $\rho_m = 110$ kg/m^3

Project Surge Times for this Application —

LLLL to LLL = 1 min, LLL to HLL = 5 min,
HLL to HHLL = 1 min

Configuration — Select a horizontal drum with a hanging mesh for this application due to high liquid rate, 5 minute surge time, and relatively small gas flow rate.

Preliminary Vessel Size — Calculate a preliminary vessel size as a starting point to calculate partially filled cylinder areas/volumes. Assume required liquid surge volume controls separator sizing (as opposed to gas flowrate):

- Use 70% (typical maximum) full to HHLL required total surge time of 7 minutes, with 3:1 L/D, and 450 mm LLLL
- Assume 10% of volume for min liquid level (LLLL) and ignore volume in heads, therefore 60% of volume is used for surge time

$$\text{Total vessel volume: } \frac{2.76\left(\frac{m^3}{min} \cdot 7 \text{ min}\right)}{0.60} = 32.2 \text{ m}^3$$

At 3:1 L/D:

$$\text{volume} = 32.2 \text{ m}^3 = 3 \cdot D \cdot \pi \left(\frac{D}{2}\right)^2 \Rightarrow D = 2.4 \text{ m} = 2400 \text{ mm}$$

Therefore preliminary size is 2500 mm ID × 7500 mm T/T

Liquid Level Calculation —

LLLL = 450 mm (per Fig. 6-24, interpolated fraction of cylinder volume at H/D = 450/2500 = > 0.122)

Surge volume (LLLL to HHLL) =

$$\left(2.76 \frac{m^3}{min} \cdot 7 \text{ min}\right) = 19.3 \text{ m}^3$$

$$\text{Volume fraction at HHLL} = \frac{19.3 \text{ m}^3}{32.2 \text{ m}^3} + 0.122 = 0.722$$

From Fig. 6-24 @ vol. fraction = 0.722, H/D ~ 0.685 (hence, 70% was an acceptable preliminary assumption)

Therefore H = HHLL = 1700 mm

Volume fraction at NLL (assume as 3.5 min above LLLL)=

$$\frac{2.76\left(\frac{m^3}{min}\right) \cdot 3.5 \text{ min}}{32.2 \text{ m}^3} + 0.122 = 0.422$$

From Fig. 6-24 @ vol. fraction = 0.422, H/D ~ 0.440
= > NLL = 1100 mm

Check Gas flow factor @HHLL in Gravity Separation Section —

$$A = (1 - 0.722)\, \pi \left(\frac{2.5 \text{ m}}{2}\right)^2 = 1.36 \text{ m}^2$$

$$V = \frac{13\,113.6 \text{ kg/h}}{12.4 \text{ kg/m}^3} \cdot \frac{1}{1.36 \text{ m}^2} \cdot \frac{1 \text{ h}}{3600 \text{ s}} = 0.215 \frac{m}{s}$$

Flow factor =

$$\frac{0.215 \frac{m}{s}}{\sqrt{\frac{714.1 - 12.4}{12.4}}} = 0.029 \frac{m}{s} \text{ (Equation 7-11)}$$

The flow Factor is significantly below 0.15 m/s (typical maximum), therefore the gas area above HHLL is acceptable. Additionally, liquid re-entrainment is not plausible at this low a K value.

Check De-Gassing —

At these surge times de-gassing is not an issue.

Calculate Mesh Pad Area & Height —

Utilizing the Souders-Brown equation for vertical flow through the hanging mesh:

$K = 0.11 \ \frac{m}{s}$ for high efficiency mist eliminator

0.867 (derating factor) — interpolation for actual pressure (Fig. 7-36)

$$V_{max} = (0.11 \cdot 0.867) \sqrt{\frac{714.1 - 12.4}{12.4}} = 0.717 \ \frac{m}{s}$$

(Equation 7-11)

$$A_{mesh} = \frac{\dfrac{13\,113.6 \ \frac{kg}{h}}{12.4 \ \frac{kg}{m^3}} \cdot \dfrac{1\ h}{3600\ s}}{0.717 \ \frac{m}{s}} = 0.410\ m^2 \quad \text{(Equation 7-13)}$$

This is approximately a 640 mm by 640 mm square mesh pad

Similar to Fig. 7-38, based on a 45° angle from the edge of the mesh pad to the edge of the outlet nozzle, the height above the mesh pad to the nozzle should be ½ of the mesh pad width minus ½ of the nozzle diameter. Use 300 mm height above mesh pad.

Inlet Device Selection —

Inlet device can be diffuser, half open pipe, or elbow at these liquid/gas rates. Diffuser is preferred.

Nozzle Sizing

Inlet Piping = 273 mm Sch. 40 (ID = 254.5 mm), based on acceptable line sizing criteria, and inlet nozzle size equals pipe size.

Check Inlet Velocity Head

$$V = \left(\frac{(121\,655 + 13\,113.6) \frac{kg}{h} \cdot 1\ h}{110 \ \frac{kg}{m^3} \cdot \pi \cdot \left(\frac{0.2545}{2}\right)^2 m^2 \cdot 3600\ s} \right) = 6.69 \ \frac{m}{s}$$

Using Equation 7-15:

$$J = (\rho_m V^2) = (110 \cdot 6.69^2) = 4923 \ \frac{kg}{m \cdot s^2} < 9000 \ \frac{kg}{m \cdot s^2}$$

therefore

273 mm nozzle with diffuser is acceptable.

Outlet Nozzle Size = 16.3 mm Sch. 40 (ID = 154.1 mm)

Check Outlet Velocity Head

$$V = \left(\frac{13\,113.6 \frac{kg}{h} \cdot 10^6\ mm^2 \cdot 1h}{12.4 \ \frac{kg}{m^3} \cdot 1\ m^2 \cdot \pi \cdot \left(\frac{154}{2}\right)^2 mm^2 \cdot 3600\ s} \right) = 15.8 \ \frac{m}{s}$$

$$J = (12.4 \cdot 15.8^2) = 3084 \ \frac{kg}{m \cdot s^2} < 5400 \ \frac{kg}{m \cdot s^2}$$

Therefore 168.3 mm outlet nozzle is acceptable.

Sizing Methodology — Horizontal Two-Phase Separator without Internals

Refer to Gas-Liquid Separation Fundamentals, presented earlier in this Chapter. A horizontal separators without mist eliminating internals (i.e. mesh pads, vanes, etc), is generally used where there is little or no vapor present. The size is normally based on the liquid accumulation section, with the levels determined the same as for separators with internals. The maximum allowable velocity in the gravity separation section is set to ensure adequate liquid drop-out, which is usually not an issue even at 80% full.

See “Flare K.O. Drums” in this Chapter, for sizing methods for horizontal drums in a flare system.

For other services with significant gas, the general techniques described in “Gas-Liquid Gravity Separation Section For Horizontal Separators, with Downstream Mist Eliminators”, in this chapter, can also be applied. Commonly the axial velocity of the gas in the vapor space is limited to 0.40-0.50 $((\rho_l - \rho_g)/\rho_g)^{0.5}$ at low to medium operating pressure. Additionally, the K-value should be derated for pressure and presence of light hydrocarbons As an alternative, the maximum velocity can be based on staying below the incipient surface re-entrainment velocity, while achieving the required droplet removal.

Based on an initial % liquid full estimate, and an appropriate L/D the approximate vessel diameter can be determined for preliminary sizing. The maximum gas velocity, the actual liquid levels, de-gassing and liquid re-entrainment criteria can be checked at this diameter to ensure all requirements are met. If necessary, the vessel dimensions can be iterated.

OTHER INTERNALS FOR GAS-LIQUID SEPARATORS

Many different types of internals can be used to improve separation performance.

De-foaming Inlet Cyclones

De-foaming cyclones are used to minimize the formation of foam or to aid in degassing. They are typically used for oil/gas wellhead or production separators for oils known to foam due to well chemicals or other particulates. Sizing and spacing is provided by the suppliers.

Outlet Axial Cyclones For Horizontal Separators

Axial cyclones can be installed at the outlet of a horizontal separator in either the vertical or horizontal position to reduce the overall separator size. Their main application is large, high pressure production separators. They are also commonly used to increase the capacity of existing high pressure production separators.

Degassing Baffles and Screens For De-gassing

Perforated baffles are sometimes used in the liquid accumulation zone to minimize sloshing due to slugs of liquid entering the vessel. This is common for many production separators. Mesh coalescers or perforated baffles (fouling service) are sometimes used in the liquid accumulation zone to minimize degassing time when that time controls the vessel size. An example of where these devices are used is a circulating solvent system where vapor disengagement is critical to prevent gas from leaving with the liquid.

Distribution Baffles

Volumetric efficiency in a separator can be improved by the use of distribution baffles. These are typically on or two perforated plates installed perpendicular to the flow area at appropriate locations. They help create a laminar, plug-flow pattern in the liquid phase and thereby promote phase separation.

GAS-LIQUID-LIQUID SEPARATOR DESIGN

Zones in the Separator

Regardless of the internal configuration all liquid / liquid and gas / liquid / liquid separators consist of three basic zones: an inlet section, a liquid-liquid settling section, and a gravity separation zone for gas-liquid separation.

Inlet Section

The feed enters the inlet section via the inlet nozzle which is typically equipped with a feed inlet device. The inlet device may be any of the devices illustrated in Fig. 7-33 or Fig. 7-34, or may be a slotted vertical pipe for a horizontal three phase separator with minimal vapor flow.

For "open" settlers two perforated plate calming baffles typically separate the inlet compartment from the settling compartment. For settlers with plate packs or mesh coalescing pads only one calming baffle is typically used. These perforated plate baffles minimize flow mal-distribution in the downstream settling section. The resulting uniform flow in the settling section facilitates separation of the two liquid phases.

Liquid-Liquid Settling Section

Separation between the two liquid phases takes place in this region. The section can be an open compartment with separation quantified by Stokes' Law, or it can include a plate pack or mesh coalescing pad, or combination internals to enhance separation. A boot can be used if the quantity of heavy phase is small. A liquid-liquid interface is maintained in this compartment and the interface can be controlled through interface controller if it is well defined, or it can be established (but not controlled) by the use of a double weir arrangement.

The settling compartment consists of three horizontal zones:

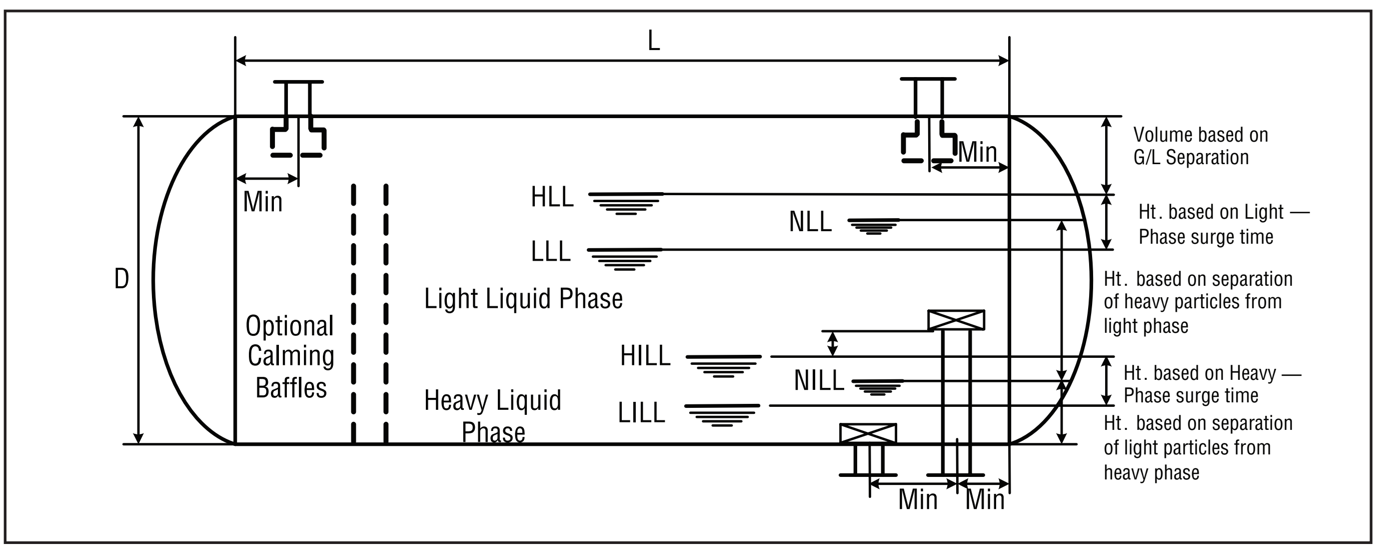
- An upper zone which contains the light phase and from which the dispersed heavy phase droplets are separated. This zone is above the high interface level, HILL
- An intermediate zone for interface level control and accommodation of a dispersion band. This zone is between the high and the low interface levels (HILL to LILL)
- A lower zone which contains the heavy phase and from which the dispersed light phase droplets are separated. This zone is below the low interface level (LILL)

Liquid Outlet Section

Liquid draw-off from the separator may be accomplished in several different ways depending on the design of the upstream settling section as dictated by the needs of the separator. In general the liquid outlet "section" consists of the draw-off nozzles and any baffles needed to control the interface. Depending on the separator configuration (light phase outlet standpipe, over-

FIG. 7-42

Design of a Conventional Vapor-Liquid-Liquid Separator



flow baffle, bucket and weir, or light phase boot) the surge times for the light and heavy phases may be accommodated within the settling section or in a separate compartment (downstream of overflow baffle, in bucket, or in boot).

Gas-Liquid Separation Section

For gas-liquid-liquid separators the gas-liquid separation area, and the mist eliminator (if used) are sized using the same methods as for gas-liquid separator sizing.

Coalescers for Horizontal Separators

Liquid-liquid coalescer elements, including parallel plate, wire mesh (metal, fiber, fiberglass, plastic fiber, or a combination of materials) or other styles are frequently used in separators upstream of the liquid / liquid settling section to insure uniform flow, enhance separation efficiency, reduce separator size, and/or to produce strict product requirements. A supplier should be consulted for the appropriate design for coalescer elements.

Design of a Horizontal Gas-Liquid-Liquid Separator

The design of three-phase separators involves three separations taking place simultaneously and in parallel within the same vessel. The sketches below illustrate the three distinct phases and their respective locations within the separator and the discussion below describes the design calculation approach for each type of horizontal gas-liquid-liquid separator.

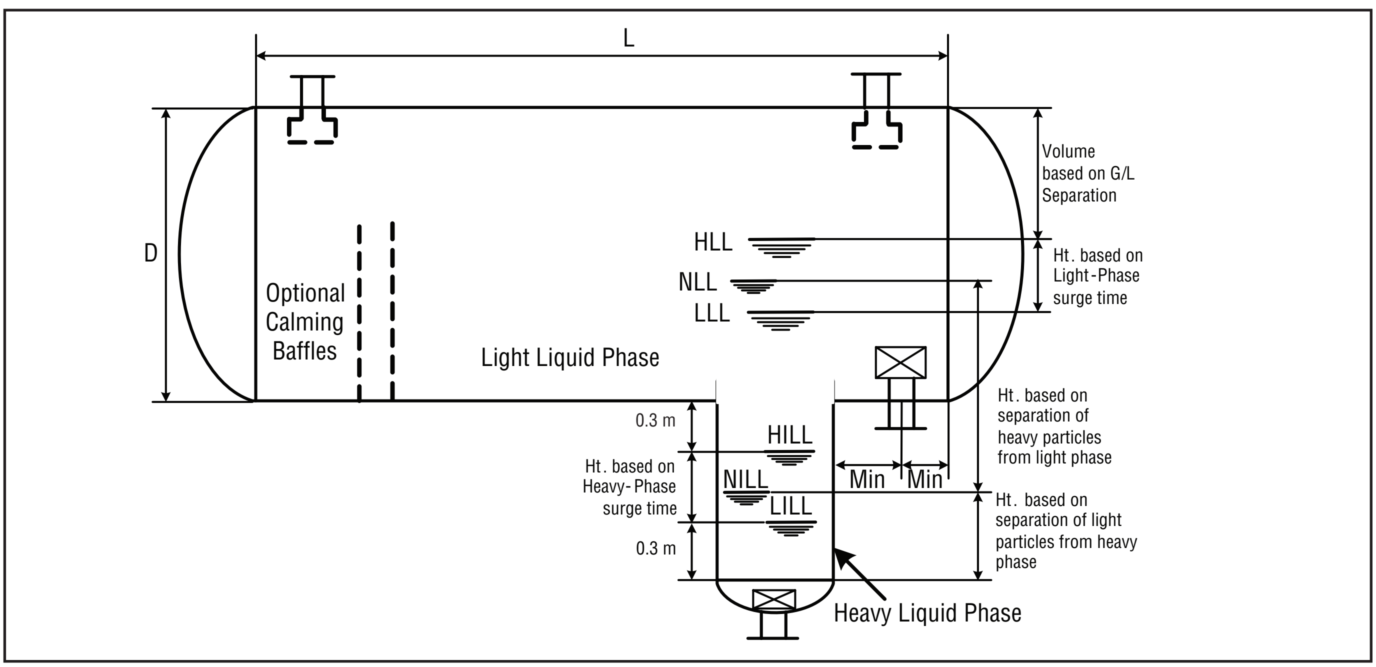
Design of a Gas-Liquid-Liquid Separator with Standpipe

The following describes the design requirements of a Gas-Liquid Liquid Separator

- There are two separate, distinct surge volumes for the two liquid phases. The surge volume for the light phase liquid is calculated from the high to low liquid levels (HLL to LLL) and the surge volume for the heavy phase is calculated from the high to low interface levels (HILL to LILL).
- Similarly there are two separate, distinct volumes for separation of the two liquid phases. Separation volumes and corresponding times are calculated based on the effective volume of the phases at normal liquid levels and assuming fluctuation from normal level for the interface The separation volume in a Gas-Liquid-Liquid separator should not include the full volume between the vessel tangential lines since some initial volume is required for the vapor phase to disengage from the two liquid phases before separation of the two liquid phases can proceed, and to allow more even liquid distribution. Perforated plate calming baffles which separate the inlet compartment from the settling compartment are frequently used to achieve this purpose, and the separation volume is calculated as the volume downstream of this baffle to the outlet zone of the vessel.
- Typical requirements for the inlet zone and outlet zone depend on the application and internals used, but are normally are about 0.5D and 0.25 D respectively. In addition, it is common to limit the individual phase axial (horizontal) velocity to 0.015 m/s, at normal levels. Some users also will limit the maximum settling rate of any phase to no more than 0.25 m/min.
- The volume for separation of the vapor and liquid phases is the volume in the top vapor space of the separator above the high high liquid level (HHLL), or high liquid level (HLL, depending on the service), and between the top tan line of the vessel.
- The light phase is withdrawn via a standpipe which terminates above the highest interface level (HILL or HHILL).

FIG. 7-43

Design of a Conventional Vapor-Liquid-Liquid Separator With Boot



Design of a Vapor-Liquid-Liquid Separator Drum with Boot

Low heavy phase flow rates are often separated in an integral boot. The boot diameter is sized based on the light-from-heavy phase settling rate and the heavy phase flow rate. Boot diameters of 0.2 to 0.46 m, or larger are typical. The boot design must insure that the vertical heavy phase velocity is less than the terminal velocity of a light fluid target droplet in the heavy phase. For designs with an integral boot a standpipe, or small internal baffle, is provided on the light phase draw-off nozzle to prevent the heavy phase material flowing along the bottom of the drum from being drawn off with the light phase.

Gas-Liquid-Liquid Separator Drum with Overflow Weir

For low light phase flows an overflow baffle may be used. The light phase is collected in a separate compartment downstream of the overflow baffle and the surge volume for the light phase is provided between the HLL and LLL in that compartment. The Spillover LL and the high and low interface levels are set and separation is calculated the same as for the conventional gas-liquid-liquid separator above. The volume on the downstream size of the baffle is set by surge requirements for the light phase. The spillover baffle should be welded to the vessel shell or provided with a leak tight joint.

Example Problem — Horizontal Gas-Liquid-Liquid Separator

Example 7-4 — Provide a vessel to separate gas, light liquid, and heavy liquid at the conditions given below.

Design Basis —

Operating pressure = 1724 kPa (ga)

Gas flowrate = 36 288 kg/h (2926 m^3/h)

Light Liquid flowrate = 120 716 kg/h (172.5 m^3/h)

Heavy Liquid flowrate = 34 020 kg/h (34.3 m^3/h)

Liquid droplet removal size (for liq/liq separation) 150 micron

Liquid retention time (for each phase) 10 minutes (normal) or 5 minutes (minimum)

Liquid surge time (LLL to HLL) 5 minutes (or 300 mm)

Physical Properties —

$\rho_g = 12.4$ kg/m^3, $\rho_{ll} = 700$ kg/m^3, $\mu_{ll} = 0.31$ cP, $\rho_{hl} = 991.5$ kg/m^3, $\mu_{hl} = 0.65$ cP

Preliminary Vessel Size — Calculate a preliminary vessel size as a starting point to calculate partially filled cylinder areas/volumes in order to check liquid-liquid separation. Assume required liquid retention volumes control separator sizing (as opposed to gas flowrate):

- Utilize a standpipe as light liquid flowrate is larger than heavy liquid flowrate

Use 70% full to HHLL, required light and heavy phase normal retention times of 10 minutes each (bottom to NILL and NILL to NLL), and ½ of the light surge time between NLL and HLL, and another 1 minute between HLL and HHLL. Assume a 3:1 L/D for the settling chamber.

Total vessel volume:

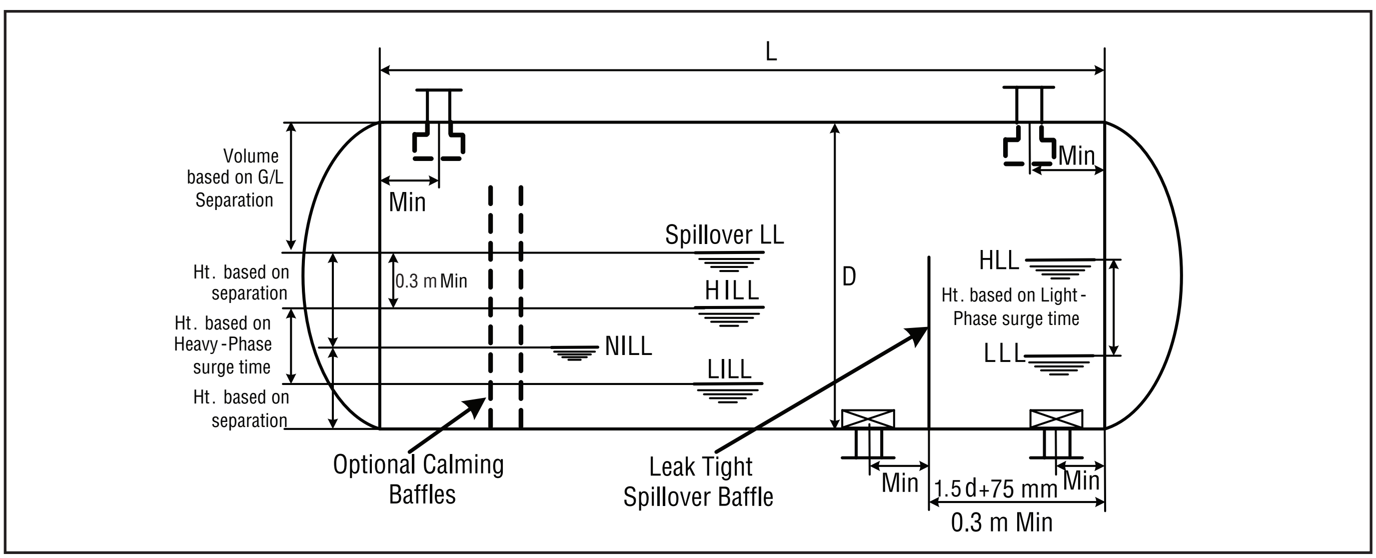
$$\frac{\left(172.5\ \frac{m^3}{h} \cdot (10\ \text{min} + 3.5\ \text{min}) \cdot \frac{1\ h}{60\ \text{min}} + 34.3\ \frac{m^3}{h} \cdot 10\ \text{min} \cdot \frac{1\ h}{60\ \text{min}}\right)}{0.70} = 63.6\ m^3$$

At 3:1 L/D:

$$\text{volume} = 63.6\ m^3 = 3 \cdot D \cdot \pi \left(\frac{D}{2}\right)^2 \Rightarrow \quad D = 3.0\ m = 3000\ mm$$

FIG. 7-44

Gas-Liquid-Liquid Separator with a Overflow Weir



- Therefore preliminary size for settling chamber is 3000 mm-ID × 9000 mm-L (Actual volume of settling chamber = 63.6 m^3)

Calculate Levels for Preliminary Vessel Size —

$$@NILL,\ Volfrac = \left(\frac{34.3\ \frac{m^3}{h} \cdot 10\ min \cdot \frac{1\ h}{60\ min}}{63.6\ m^3} \right) = 0.090$$

From Fig. 6-24 @ vol. fraction = 0.09, H/D ~ 0.146, which corresponds to a level of 440 mm. As a minimum, LLILL should be set at 300 mm, LILL set at 100 mm above LLILL, and NILL set at 150 mm above LILL, therefore set NILL at 550 mm (vol. frac of 0.125)

$$@NLL,\ Volfrac = \left(\frac{172.5\ \frac{m^3}{h} \cdot 10\ min \cdot \frac{1\ h}{60\ min}}{63.6\ m^3} \right) + 0.125 = 0.577$$

From Fig. 6-24 @ vol. fraction = 0.577, H/D ~ 0.562

Therefore set NLL at 1700 mm

$$@HLL,\ Volfrac = \left(\frac{172.5\ \frac{m^3}{h} \cdot 2.5\ min \cdot \frac{1\ h}{60\ min}}{63.6\ m^3} \right) + 0.577 = 0.69$$

From Fig. 6-24 @ vol. fraction = 0.69, H/D ~ 0.65

Therefore set HLL at 1950 mm

Remaining Level Estimate (based on above calculated levels above): LILL = 400 mm, HILL = 700 mm (150 mm above NILL), Standpipe level = 850 mm (150 mm above HILL), LLL = 1150 mm (300 mm, above standpipe), HHLL = 2100 mm (150 mm above HLL)

Calculate Stokes' Law Terminal Velocity, Required Setting Time, and Axial Velocity —

NLL to NILL (Heavy particles from light phase) (using Equation 7-5):

$$V_t = \frac{1000 \cdot 9.81\ \frac{m}{s^2} \left(150\ \mu m\ \frac{1\ m}{1\,000\,000\ \mu m}\right)^2 \cdot \left(991.5\ \frac{kg}{m^3} - 700\ \frac{kg}{m^3}\right)}{18 \cdot 0.31} = 0.0115\ \frac{m}{s}$$

However, use 0.25 m/min or 0.00424 m/s as max settling velocity

Stokes' Law settling time required =

$$\frac{Ht_{NLL\ to\ NILL}}{V_t} = \frac{1.15\ m}{0.00424\ \frac{m}{s}} = 271\ s = 4.5\ min$$

Available settling time = 10 min > 4.5 min, therefore heavy particles larger than 150 micron can settle from light phase between normal levels.

Vessel Bottom to NILL (Light particles from heavy phase):

V_t = 0.005 m/s (using Equation 7-5), use 0.25 m/min as max settling velocity

Stokes' Law settling time required = 2.2 min

Available settling time = 10 min > 2.2 min, therefore 150 micron and larger light particles can settle from heavy phase between normal levels.

Axial Velocity (heavy phase):

$$V_l = \frac{34.3\ \frac{m^3}{h} \cdot \frac{1\ h}{3600\ s}}{(.125 \cdot \pi \left(\frac{3\ m}{2}\right)^2} = 0.0108\ \frac{m}{s}$$

Axial Velocity (light phase):

$$V_l = \frac{172.5\ \frac{m^3}{h} \cdot \frac{1\ h}{3600\ s}}{(.577 - .125) \cdot \pi \left(\frac{3\ m}{2}\right)^2} = 0.015\ \frac{m}{s}$$

As both heavy and light phase axial velocities (horizontal) at NILL and NLL are <0.015 m/s, axial velocity is acceptable

Check Settling Time for Off-Normal level Operation —

Light Phase @ LLL and Heavy Phase @ NILL:

Heavy phase retention time (bot to NILL) = 10 min, therefore light particles (150 micron) can settle from heavy phase as shown above

Light phase retention time (NILL to LLL) =

$$\frac{(.35 - .125) \cdot 63.6\ m^3}{172.5\ \frac{m^3}{h} \cdot \frac{1\ h}{60\ min}} = 5\ min$$

Stokes' Law settling time required =

$$\frac{Ht_{LLL\ to\ NILL}}{V_t} = \frac{0.6\ m}{0.00424\frac{m}{s}} = 142\ s = 2.4\ min$$

Available settling time = 5 min > 2.4 min, therefore 150 micron heavy particles can settle from light phase between these levels.

Light Phase @ NLL and Heavy Phase @ HILL:

Heavy phase retention time (bottom to HILL)=

$$\frac{(.177) \cdot 63.6\ \ m^3}{34.3\ \frac{m^3}{h} \cdot \frac{1\ h}{60\ min}} = 19.7\ min$$

Stokes' Law settling time required =

$$\frac{Ht_{BOTTOM\ to\ HILL}}{V_t} = \frac{0.7\ m}{0.00424\ \frac{m}{s}} = 165\ s = 2.8\ min$$

Available settling time = 19.7 min > 2.8min, therefore 150 micron light particles can settle from heavy phase between these levels

Light phase retention time (HILL to NLL)=

$$\frac{(.577 - .177) \cdot 63.6 \text{ m}^3}{172.5 \ \frac{\text{m}^3}{\text{h}} \cdot \frac{1 \text{ h}}{60 \text{ min}}} = 8.85 \text{ min}$$

Stokes' Law settling time required =

$$\frac{Ht_{\text{HILL to NLL}}}{V_t} = \frac{1.0 \text{ m}}{0.00424 \ \frac{\text{m}}{\text{s}}} = 234 \text{ s} = 3.9 \text{ min}$$

Available settling time = 8.85 min > 3.9 min, therefore 150 micron heavy particles can settle from light phase between these levels

Light Phase @ HLL and Heavy Phase @ NILL:

Heavy phase retention time (bot to NILL) = 10 minutes, therefore light particles (150 micron) can settle from heavy phase as shown above

Light phase retention time (NILL to HLL) =

$$\frac{(0.69 - .125) \cdot 63.6 \text{ m}^3}{172.5 \ \frac{\text{m}^3}{\text{h}} \cdot \frac{1 \text{ h}}{60 \text{ min}}} = 12.5 \text{ min}$$

Stokes' Law settling time required =

$$\frac{Ht_{\text{NILL to HLL}}}{V_t} = \frac{1.4 \text{ m}}{0.00424 \ \frac{\text{m}}{\text{s}}} = 330 \text{ s} = 5.5 \text{ min}$$

Available settling time = 12.1 min > 5.5 min, therefore 150 micron heavy particles can settle from light phase between these levels

Calculate Final Vessel Length —

Inlet zone to include 2 distribution baffles, therefore use 0.5D = 1500 mm

Outlet zone to account for outlet liquid nozzles, use 0.25 D = 750 mm

Total Length = 1500 mm + 750 mm + 9000 mm = 11 250 mm

Gravity Separation and Gas Polishing Section —

The vapor zone, and inlet/outlet nozzles should be addressed as shown in Example 7-3. Check K through a horizontal flow mesh pad (assume mesh pad area is equal to the cross sectional area above the HHLL) using Equation 7-11:

K calculated = 0.061

As K calculated is less than 0.11 (derated for pressure from 0.13) for a typical wire mesh mist eliminator, the gas section is acceptable (vapor zone and inlet/outlet nozzle check not shown).

Vessel Sizing Summary —

The size for the above vessel was calculated to be 3000 mm D • 11 250 mm L which corresponds to an L/D of 3.75. Final levels are as follows:

LLILL = 300 mm, LILL = 400 mm, NILL = 550 mm, HILL = 700 mm, LLL = 1150 mm, NLL = 1700 mm, HLL = 1950 mm, HHLL = 2100 mm

As the settling times calculated for the above level sections for 150 micron particles were less than the available retention time, it is anticipated that smaller particles could be separated.

FIG. 7-45
Horizontal Filter-Separator

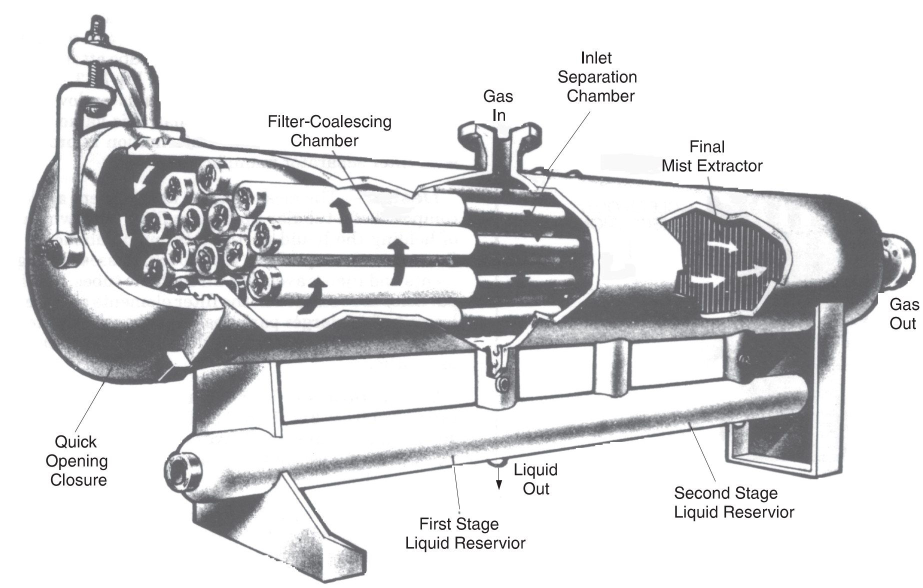
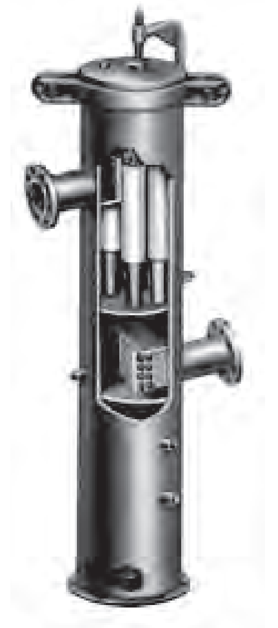


FIG. 7-46
Vertical Filter Separators



Some safety factor when applying Stokes' Law is required. Multiple iterations can be performed to achieve optimal dimensions based on vessel economics, particle separation size, and desired safety factor, however all parameters (settling times, surge times, etc) must be recalculated. This trial and error approach is typically performed via the use of a spreadsheet.

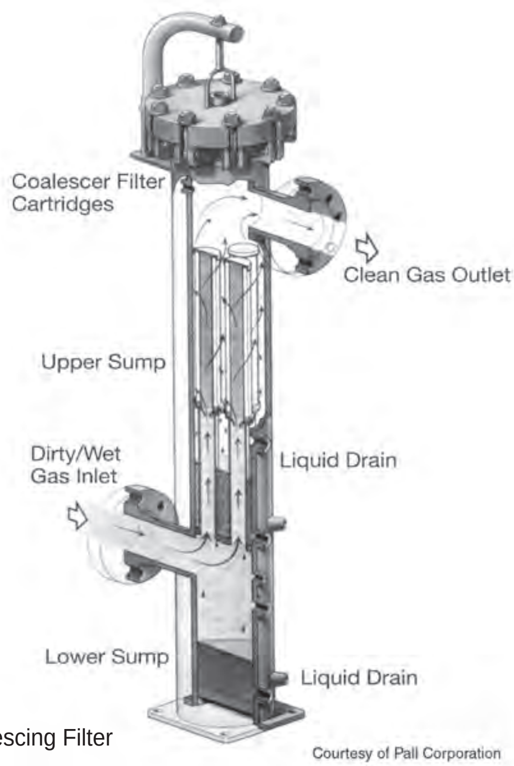
FILTRATION AND COALESCING DEVICES

Filter-Separators

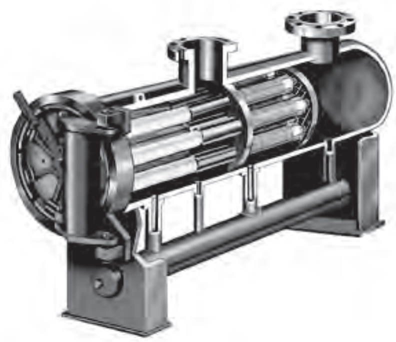
Coalesce means to come together to form a larger whole. Hence, the process or mechanism of bringing small droplets or aerosols together and creating larger droplets that can more easily be removed by gravity, is referred to as coalescing.

Filter-Separators were developed in the 1950s to remove both solids and liquids from natural gas. They are still very widely used for moderate to low loadings of solids and liquids. For high liquid loadings a scrubber with a vane or cyclonic device should be placed upstream to remove the bulk liquids. For very high solid contamination, consider placing a bulk removal device such as a cyclonic separator upstream. Liquid loading may limit the capacity of a filter-separator. The liquid loading for a typical unit should be less than 0.114 m^3/h per 113 mm × .91 m to 1.8 m long cartridge. Filter separators are available in horizontal and vertical orientations, with horizontal the most common. Fig. 7-45 and Fig. 7-46 show a horizontal and a verti-

FIG. 7-47
Filter Coalescers



Coalescing Filter



Two Stage Filter — Coalescer

Courtesy of PECOFacet

cal filter separator. A filter separator is a two-stage device. The first stage is used to separate large liquid droplets and remove solid contaminants and to coalesce smaller aerosols and droplets into larger droplets. Gas enters the inlet nozzle and passes through the filter section, where solid particles are filtered from the gas stream and liquid particles are coalesced into larger droplets. Any free liquids are also removed in the first section. The coalesced droplets pass through the filter riser tubes and are carried into the second section of the separator, where a final mist extraction element removes these droplets from the gas stream. The flow through the filter elements is from an outside-to-inside direction. This allows optimal removal of solids.

The second stage of a filter separator contains a mist extraction device. As for a conventional separator this may be a mesh pad, vane pack or multi-cyclone bundle. The same issues regarding mist extractor selection criteria, sizing, etc. apply as discussed previously. A vane pack is most commonly utilized. A pressure drop of 6.9–13.8 kPa is normal in a clean filter separator. If solids are present, it will normally be necessary to replace the filter elements at regular intervals. A 69.8 kPa pressure drop criteria is often used for filter change-out. Removal of the filters is achieved via a quick-opening closure.

The design of filter separators is proprietary and a manufacturer should be consulted for specific sizing and recommendations. Generally, filter-separators are nominal 1 micron devices, removing a percentage of solids and liquids that are 1 microns and larger. When properly applied, filter-separators are very effective devices to clean contaminants from natural gas. However, if there is a significant amount of sub-micron mists or aerosols present, a gas coalescing filter should be used.

Gas Coalescing Filter

The coalescing filter was developed in the early 1980s for 'gas polishing' and for removal of very fine liquid aerosols/mist from gas streams where entrained liquid loads are low. Fig. 7-47 illustrates a typical coalescing filter. This coalescing occurs as the gas flows from the inside of the coalescing element to the outside of this element in the vertical filter-coalescer. Properly designed this coalescing stage will remove solids and fine aerosol's down to 0.3 micron and larger. The gas with entrained liquids enters the filter-coalescer below the tube sheet containing the coalescing elements. Any bulk liquids and large droplets will fall out in the bottom of the vessel by gravity. The gas then flows through the tube sheet into the inside of the element. As the gas flows from the inside of the element to outside of the element, solids and fine aerosols, are removed by direct interception, inertial impaction, and coalescing. The coalesced liquids are collected above the tube sheet and removed from the vessel. The cleaned gas flows out the vessel at the top. Because of their design and the fact that a potion of inlet liquid is frequently in the submicron range, gas coalescing filter can not handle the same liquid or particulate loads that filter-separators can.

Coalescing filters are normally used to protect equipment/processes that are particularly sensitive to contamination. Two of the most common applications are upstream of mole sieve dehydration beds and amine contactors. The unit is typically intended to remove carryover from an upstream conventional separator and/or any liquids that may condense from the gas phase due to temperature or pressure reduction.

The inside to outside flow through the coalescing elements provides outstanding performance for capturing fine liquid aerosol droplets and growing them through coalescing so that the liquid can be removed. This inside to outside flow is not optimal for removing solid contaminants. Because of the inside to outside gas flow and the tightness of the elements to achieve the 0.3 removal coalescing filters can experience short filter element life if the gas contains appreciable amounts of solids, e.g. corrosion products.

The design of filter separators is proprietary and a manufacturer should be consulted for specific sizing and recommendations.

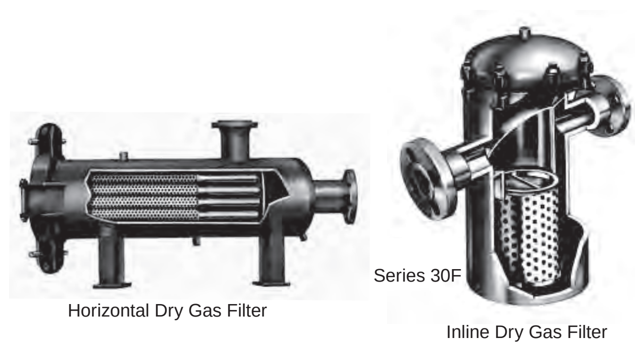
In the late 1990s high efficiency horizontal coalescers were developed. These overcame the disadvantage of the vertical gas coalescer as to the ability to handle moderate liquid and solids loading. These coalescers combine the advantages of a filter-separator to effectively remove solids in an outside to inside gas flow and the ability to coalesce very fine aerosols for the removal efficiency down to 0.3 micron and larger. This can in many cases eliminate the need for a filter-separator or scrubber to be placed in front of the vertical gas coalescer. An example is shown in Fig. 7-47. Because of the proprietary nature of these devices, the manufacturer should be consulted.

Dry Gas Filters

Sometimes solids are present in the pipeline or gas stream, but there are no liquids or aerosols. In this case strainers or dry gas filters are recommended to remove small particles. If the level of contaminant in the gas stream is fairly low, an inline filter as shown in Fig. 7-48 will suffice. If the contaminant loading is greater or the flow rate is larger than can be handled by an inline dry gas filter, then a vertical or horizontal dry gas filter as shown in Fig. 7-48 is recommended.

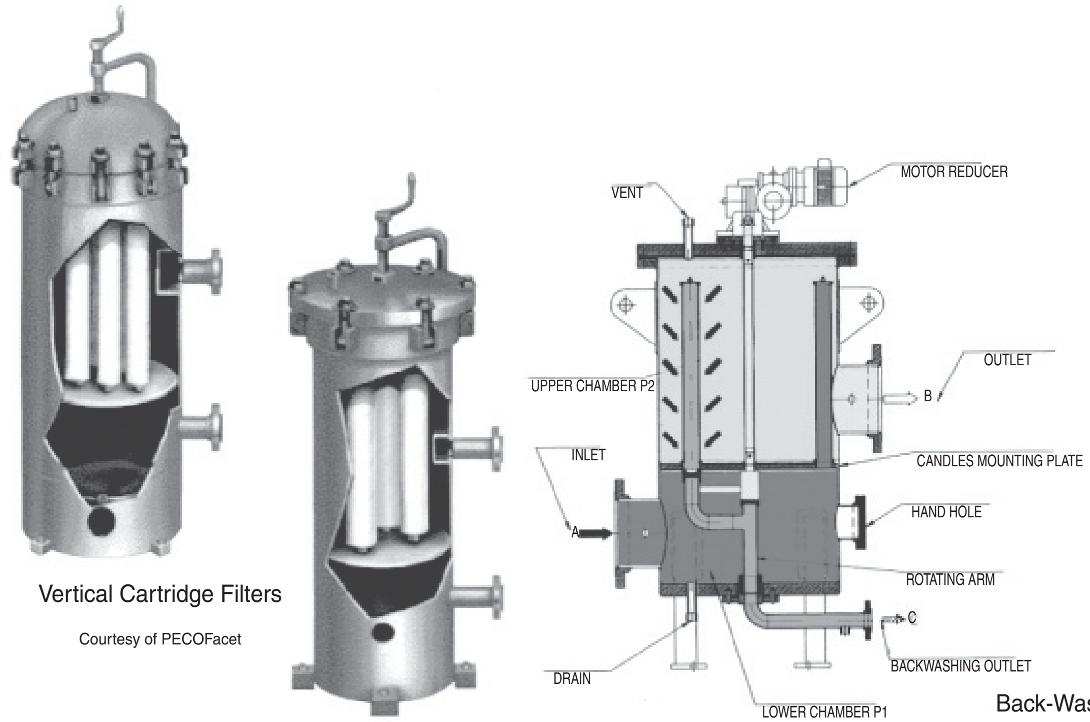
Dry gas filters use elements to remove solid particles by direct interception or inertial impaction. Generally, pleated elements of a synthetic media such as polyester are used. Various combinations of cellulose and fiberglass cartridges are also available. The gas in in-line dry gas filters generally flows into the center of the element and then to the outside of the element and to the outlet nozzle. In the standard vertical or horizontal dry gas filter the gas flows from the outside of the element to the inside of the element prior to exiting through the outlet nozzle. Various efficiencies down to one micron and lower are available based upon the design and element efficiency.

FIG. 7-48
Dry Gas Filters



Both courtesy of PECOFacet

FIG. 7-49
Cartridge Filters



Vertical Cartridge Filters

Courtesy of PECOFacet

Back-Washable Filter

Courtesy of PECOFacet

Generally, dry gas filters are applied in gas plants downstream of molecular sieves and in distribution systems. Upstream of natural gas plants there is normally a liquid in some form present, so a filter-separator designed to handle liquids or a filter-coalescer is a better choice. Though most cartridges used for dry gas filters are pleated, if the solids are deformable, like a wax, or shear sensitive like iron sulfide, then a depth element should be considered in place of the pleated elements mentioned above. These depth elements are generally used in vertical or horizontal dry gas filter and not the in-line design. With a properly designed and applied depth element, iron sulfides down to 0.3 micron can be removed.

Liquid Particulate Filtration

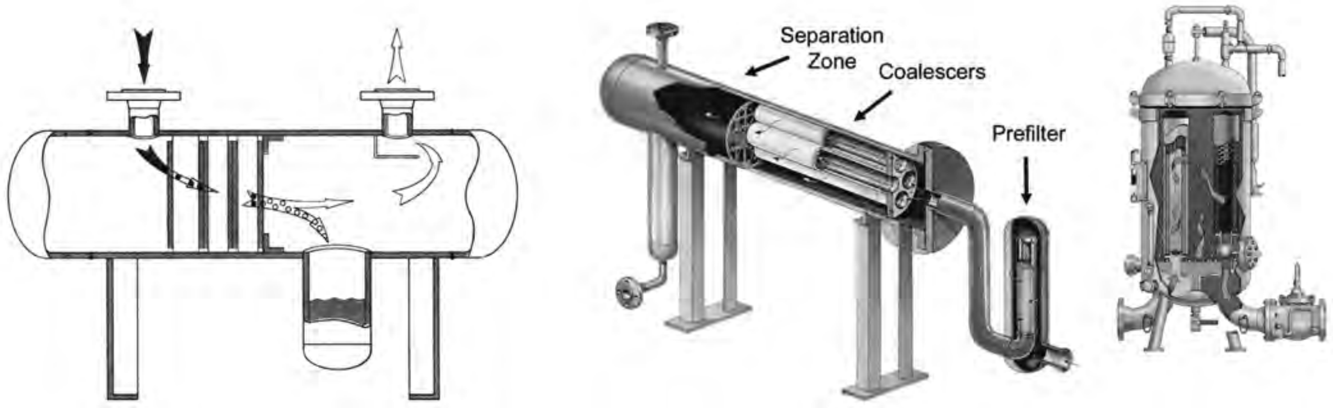
Filtration, in the strictest sense, applies only to the separation of solid particles from a fluid by passage through a porous medium. The most commonly used particulate filter in the gas processing industry is a cartridge filter. Cartridge filters are constructed of either a self-supporting filter medium or a filter medium attached to a support core. Depending on the application, a number of filter elements are fitted into a filter vessel. Flow is normally from the outside, through the filter element, and out through a common discharge. When pores in the filter medium become blocked, or as the filter cake is developed, the higher differential pressure across the elements will indicate that the filter elements must be cleaned or replaced. Generally, filters are designed for a 13.8–34.5 kPa differential when clean, and filter change out made at 172 kPa differential or higher depending upon design. The elements in the filters determine the removal efficiency and a discussion of rating filter elements is given below.

Cartridge filters are commonly used to remove solid contaminants from amines, glycols, and lube oils. Other uses include the filtration of solids and liquids from hydrocarbon vapors and the filtration of solids from air intakes of engines and turbine combustion chambers. See Fig. 7-49 for a typical filter housing. These cartridges come in generally two types: pleated and depth. Pleated cartridges are generally better when removing hard particles. Depth filters generally work better with deformable and shear sensitive contaminants. Traditionally the filter cartridges have been 62 mm to 75 mm OD. There are currently a large variety of element configurations offered from 150 mm OD and down. Some filters are arranged to flow through the elements from outside to inside and some flow inside to outside.

Metal filter cartridges are also offered. These come in three types: wedge wire, woven mesh and sintered metal. These are generally used in extreme conditions (either from temperature or chemical compatibility) or in a cleanable form. Some may be cleaned in process through backwashing and some may be cleaned by removing the elements from service and cleaning. Back washable filters come in many types. One type is shown in Fig. 7-49.

Pre-coat filters find use some use in the gas processing industry; however, they are complicated and require considerable attention. Most frequent use is in larger amine plants where frequent replacement of cartridge elements is considerably more expensive than the additional attention required by pre-coat filters. The pre-coat filter consists of a coarse filter medium over which a coating has been deposited. In many applications, the coating is one of the various grades of diatomaceous earth

FIG. 7-50
Liquid-Liquid Coalescers



Wafer Pack Coalescer   Liquid-Liquid Coalescer   Typical Two-Stage Coalescer

Courtesy of PECOFacet and Pall Corporation

that is mixed in a slurry and deposited on the filter medium. During operation, additional coating material is often added continuously to the liquid feed. When the pressure drop across the filter reaches a specified maximum, the filter is taken offline and backwashed to remove the spent coating and accumulated solids. Applications for pre-coat filters include water treatment for water facilities as well as amine filtration to reduce foaming. Typical designs for amine plants use 2.45–4.9 m^3/h flow per square meter of filter surface area. Sizes range upward from 10-20% of the full stream rates.

Filtration Equipment Removal Ratings

There is no commonly accepted standard for rating filter cartridges. Some common tests for rating filters are listed in the Filter Testing Standards on page 7-47.

Manufacturer's specified removal ratings generally fall into two categories: nominal rating and absolute rating. Generally a nominal rating means that the filter will remove approximately 90% of the contaminants above a specified size (e.g. 10 µm). (Nominal ratings can vary from 50% to 95% depending upon manufacturer and filter type.) With a nominally rated filter it is possible to have particles much larger than the nominal size in the effluent (e.g. 30 µm to 100 µm).

Absolute ratings can be determined by the NFPA standard as to the largest hard particle that will pass through the filter, or by one of the other test methods referred to above. The rating can be stated in two ways: filter efficiency or Beta Ratio. These two terms are related. Efficiency rating is the number of particles (or number of particles by weight) removed by the filter above a specified size. Beta Ratio, β, is the number of particles in the influent of the filter at or above the specified micron size divided by the number of particles in the effluent of the filter at or above the same micron size. This results in the following equation for relating the β value to removal efficiency:

$$\% \text{ removal} = \frac{(\beta - 1)}{\beta \cdot 100} \qquad \textbf{Eq 7-19}$$

Most "absolute" filters typically have a β of 5,000 (99.98% removal) or 10,000 (99.99% removal). However, some manufacturers will provide absolute ratings based upon a efficiency of 99% and above (β greater than 100).

When comparing and evaluating filter ratings it is important to realize the filters are rated using standard test methods using a hard test dirt or beads. While these methods should give a good indication of actual performance in a process, the actual contaminant in the process may not be similar to the test contaminant.

Liquid/Liquid Coalescer Separators — Supplier Design

Liquid / Liquid coalescers are mechanical devices used primarily for purifying hydrocarbon products by removing emulsified water and solids. The phase separator removes free water. The dissolved water, which is in solution, remains in the hydrocarbon product. This is an important point to remember in the design and application of liquid / liquid coalescers. Interfacial tension (IFT), density, viscosity and temperature are important factors in phase separation. The basics of liquid / liquid separation have been covered earlier in this section.

The basic premise of all liquid / liquid coalescers is to take an emulsion or fine droplets and break the emulsion and grow these droplets to sufficient size that the discontinuous phase will separate from the continuous phase by gravity. In order to accomplish this, the coalescer media first breaks the emulsion and then agglomerates the discontinuous liquid into large droplets. Once these large droplets form, gravity causes the heavier phase to settle to the bottom and the lighter phase to float to the top. If the discontinuous phase is heavier than the continuous phase (water being removed from hydrocarbon for example), the droplets will settle into the vessel sump for removal. If the discontinuous phase is lighter than the continuous phase (hydrocarbon being removed from water for example), the droplets will float to the top of the vessel for removal. If high efficiency separation is not required, the coalescing can be performed using a packed bed or wafer pack. Fig 7-50 shows a wafer pack coalescer. The vessels are horizontal. The wafer pack may typically be excelsior, fiberglass, synthetic media, or stainless steel.

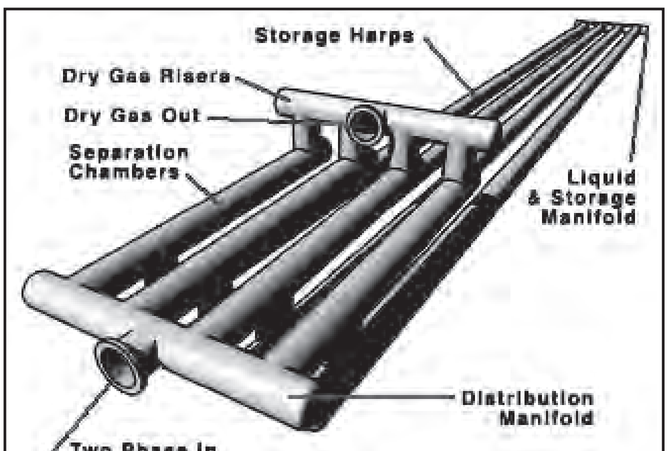
High efficiency separation of water from hydrocarbons is generally accomplished using coalescer elements. In some cases two stage vessels designed like the EI 1581 Aviation Fuel coalescers will be used. These can be either vertical or horizontal. Both configurations are shown in Fig. 7-50. The fluid to be coalesced enters the vessel and passes through the coalescing elements first. The flow through this element is from inside to outside. The emulsion is broken and the fine liquid droplets of the immiscible water phase are coalesced into large droplets that are separated by settling. Because of small pores in this element it will also filter out solid particles. The filtered and coalesced liquid then flows outside to inside through the second stage separation element. This further separates the immiscible phase. The separation element, being selectively wetted by the continuous hydrocarbon phase is hydrophobic and impervious to the flow of water. Water droplets literally "bounce off" the element. These separator elements are generally made from silicone impregnated cellulose, fluorocarbon, or some other synthetic hydrophobic media. After flowing through the second stage element, only clean liquid, free of suspended water and solids, exits the unit.

Because of the cost of the coalescing elements and the fact that they are not optimally designed to remove particulates, if there is a significant load of solid particles (greater than 0.5 ppm) it is advisable to use a pre-filter. Fig. 7-50 shows a liquid / liquid coalescer with a prefilter.

SPECIALIZED SEPARATORS

A number of specialized separators are available for specific applications in the gas processing industry The main purpose of these devices is to achieve gas-liquid or gas-liquid-liquid separation in a compact package. Many different custom and proprietary devices are available. Each device has a specific application that they are geared to. Some are useful in removing streams high in solids, other can used as a first upstream separator to reduce the load on the main gas plant, and still others are geared to gross liquid knockout upstream of the main gas plant separator. Some examples of the types of devices available are described below. Many of these separators use the same or similar mechanisms as discussed previously in this chapter. A detailed discussion of them and their sizing is outside the scope of this document.

FIG. 7-51
Harp Slug Catcher



Courtesy of Taylor Forge

WELLHEAD, PLANT INLET, AND FLARE SEPARATORS

Gas Processing Wellhead Production Separators

Note that the following discussion is limited to gas processing wellhead separators, and is not generally applicable to separators for crude oil production, or for associated gas from crude production.

Wellhead separators are used as the primary devices for separation of gas, hydrocarbon condensate, produced water, and solids (if present) at the wellhead. The separators may serve a single well or several producing wells. The typical separator is either a horizontal drum with no internals, a low baffle, a full overflow baffle, or an underflow overflow baffle. In some cases a vertical separator is preferred. The style of the drum is determined by the ratio of gas, condensate and produced water, and the ease of settling of the liquid phases. Sand can be present in the feed to the drum, and a de-sanding system may be required in the drum, or upstream at the wellhead. Both the separated condensate, and the produced water, will be further processed in a central processing plant, or by settling in   batch tanks, or storage tanks.

The feed conditions to the separator, and ease of settling, can vary widely depending the field hydrocarbon and water production rates, chemicals added at the wellhead, gathering pipelines, and pressure drop across the well chokes. The settling mode inside the separator can vary. Any water-oil system consists of a dispersed phase and a continuous phase. If oil is volumetrically the predominant fluid, then it will normally be an oil-continuous mixture; if water is predominant then the continuous phase will usually be water. The water volume fraction (or 'water cut') at which the mixture becomes water-continuous is called the 'inversion point.' Over the life of a producing field a production separator may experience mixtures ranging from very low water cut to very high water cut. Likely the stream will change from oil-continuous early in the field life to water-continuous later in the field life. The inversion point is usually in the range 45-65% water cut, but it can be outside of this range. De-watering of the oil phase improves significantly when the mixture becomes water-continuous.

In production separators the water-oil mixture may have experienced severe shear due to pressure drop across chokes or valves or due to pumping, and this shear results in the formation of many small droplets. These droplets tend to coalesce during their flow to the separator, which is critical to good separation. However, production hydrocarbons often contain solids and naturally occurring surfactants that migrate to the droplet surfaces (the interface between the droplet and the surrounding continuous phase), and hinder coalescence. The result is a stable emulsion. To overcome this, chemical additives called 'demulsifiers' are often mixed into the flowing stream to allow coalescence to occur. Water treatment chemicals may also be added to aid oil-in-water coalescence. The effectiveness of the demulsifier depends on its specific suitability for the fluids, its dosage, the extent of its dispersion within the flowing stream, and available reaction time. Coalescence and subsequent separation performance are dependent upon the effectiveness of this demulsification process. If effective, many of the entrained water droplets will grow through coalescence to a size that can be removed in the separator. Since the D_P term is squared in Stokes' law, droplet coalescence into larger droplets is very important for optimum oil-water separation.

Test Separator

A test separator is a separator vessel used near the wellhead, which separates the phases for well test metering. The units can service a single well, or multiple wells in rotation. Design configurations for test separators are similar to wellhead separators.

Compact Production Separators

Deep water drilling and exploration is currently an intense area of interest to the oil and natural gas industry. Undersea separation techniques are being developed to support this trend. The key is using compact separation to reduce equipment size. Many of these developments have also been applied to platform or on-shore applications, to reduce equipment size and cost. Generally these separators rely on centrifugal force to enhance separation. Specialized compact devices for liquid dominated systems, gas dominated systems, and compact three phase separation have been commercialized. The downside of many of these devices is the potential for large carryover during an upset.

Slug Catchers

Slug catchers are devices at the downstream end, or other intermediate points of production or transmission pipelines used to absorb the fluctuating liquid inlet flow rates caused by liquid slugging. Liquid slugs may form in pipelines due to the following: 1) two-phase flow variation in velocity (due to changes in pipe size or pipeline flow rate) resulting in liquid holdup, 2) changes in terrain resulting in a pipeline low-point (or multiple low-points) where liquid can build up, 3) wave formation on the gas-liquid interface causing a liquid slug to push through, or 4) pigging of the pipeline in which all liquid is removed. Further details regarding slugging are discussed in Chapter 17, "Fluid Flow and Piping"

Slug catchers may be either a vessel or constructed of pipe (harp type) and the selection is based on economics. Vessels are typically used in lower pressure services [(below 3447 kPa (ga)] and/or when smaller slug sizes are expected (<159 m^3). In order to avoid thick wall vessels, harp type slug catchers are used for higher pressure and larger slug size applications, since multiple sections of smaller diameter (and thinner-walled) piping are utilized.[20]

Slug size is the primary parameter when determining the size and type of slug catcher to be used. For detailed designs, a multi-phase dynamic analysis is recommended in order to evaluate transient effects, various operating scenarios, changes in terrain, and impacts due to ambient conditions in order to determine the final slug volume. For a preliminary estimate of slug size, a steady state thermodynamic model with a pipeline simulator can be utilized. An estimate of the piping lengths, changes in elevation, and fluid properties is required. Based on the pipe size simulated and flow regime, the liquid holdup fraction is calculated at a given operating flow rate. A second liquid holdup fraction should then be calculated at an alternative off-normal flow rate (such as max. turndown). Total liquid volume in the pipeline at each holdup fraction should be calculated based on the total pipe volume, and the difference between these two liquid volumes can be used as a preliminary slug size. If frequent pigging is required, the liquid volume in the pipeline between pigging cycles may control the slug catcher size.

Vessel Type Slug Catchers — Slug catcher vessels are designed to be able to absorb sustained in-flow of large liquid volumes at irregular intervals in addition to the normal gas and liquid flow. The vessel frequently has special internals, such as a unique inlet deflection baffle which reduces the momentum of the incoming liquid. One advantage of vessel type slug catchers is the ability to incorporate a sand removal system, if required based on inlet fluid characteristics. The addition of mist elimination internals are based on the fouling tendency of the service. Normal level is kept at a minimum and slug volume is considered between the HLL and HHLL.

Harp Type Slug Catchers — Harp type slug catchers are constructed of multiple lengths of pipe. Frequently these devices are treated as part of the pipeline, and are designed to pipeline specifications rather than the ASME pressure vessel code. Harp type slug catchers are typically built of sections of 0.61–1.22 m pipe, 15.2–152.4 m long. The upper section is short and consists of two or more pipe sections designed to reduce the gas velocity to provide the necessary separation. Gas flows from the upper section and liquid flows to a lower bank of piping. The lower liquid section consists of multiple downward sloped pipes with sufficient volume to provide storage for the required pipeline slug volume.

Double Barrel Separator — A double barrel separator (vessel with lower pipe section) enables high gas flowrates to be maintained, while removing slugs with high efficiency. The lower barrel collects the liquids, eliminating re-entrainment concerns. The liquid level is maintained in the lower barrel, maximizing the gas flow separation area available.

Flare K.O. Drums

Flare K.O. Drums are vertical or horizontal vessels located upstream of a flare, or upstream of a flare water seal drum. The preferred orientation of the separator is based on the flare maximum flow rate. Larger flare gas rates favor a long horizontal configuration, with two inlets. In some cases, where the flow rate will permit, a vertical drum built into the bottom portion of a self supported flare stack, can be used to avoid a separate drum. A flare K.O. drum is not allowed to have any internals, which could break off and plug the free path to the flare. Flare K.O. drum sizing and design is specified in API-521, "Design of Pressure Relief and De-pressuring Systems".[21] The design approach uses Stokes' Law, and targets removal of a 300-600 micron droplet.

WATER TREATMENT SEPARATORS

Treatment of produced water or process wastewater is a specialized area that is beyond the scope of this document. The following is a brief introduction to the common types of equipment used.

Several types of specialized equipment and systems are utilized for secondary clean-up of produced water or waste water. Some devices are used for oil removal from water following primary process separation, and others are used for final oil removal in order to allow water discharge to a waterway, or to an injection well.

Gunbarrel Tank

A gunbarrel tank is an atmospheric settling tank commonly used for on-shore for separation of oil from produced water downstream of the primary gas-oil- water separator. Oily water is introduced by a special distributor near the interface, and the oil overflows via a weir at the top of the tank after several hours of residence time. Tank level interface is maintained via a water leg on the water outlet. Typical oil recovery is down to 100-500 ppmv oil in water, if emulsions are not present. Micro gas bubbles can be added to the tank to increase separation efficiency and/or reduce the tank size.

Water-Oil Hydrocyclone

A hydrocyclone consists of multiple cyclones in a common shell. It is used for removal of oil from water or water from oil, typically following the production separator. Hydroclones are common for off-shore production operations. They are becoming more common for on-shore applications. Typically 345–689.5 kPa of pressure drop is required, for proper operation.

Solid-Liquid Hydrocyclone

Solid-liquid hydrocyclones are used to continuously remove solids from water, such as in a desanding operation. They can achieve separation of particles down to 5 microns.

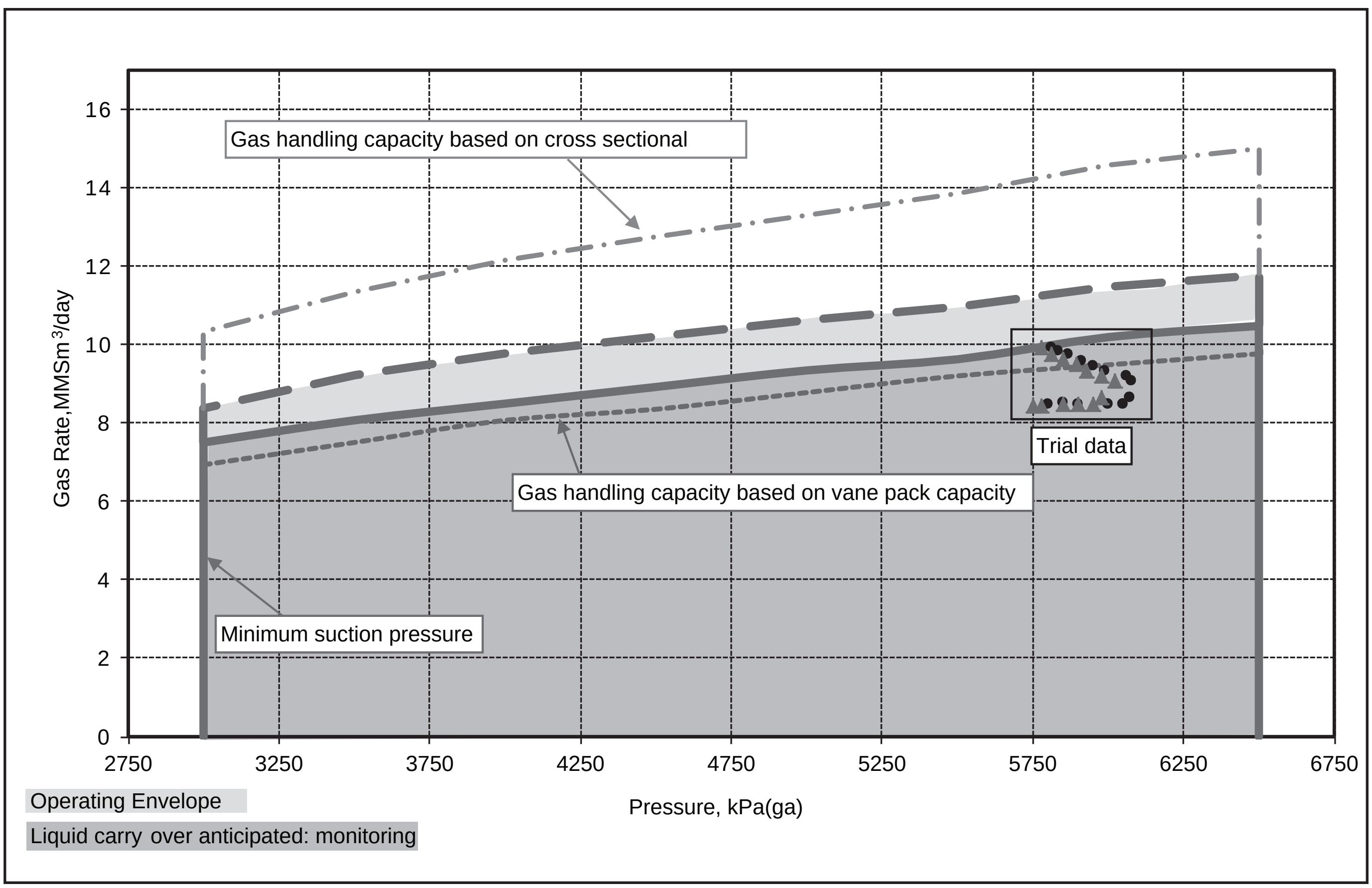
CPI Separator

A CPI separator is a horizontal separator with angled parallel plates, for water clean-up. The design can be either liquid full and pressurized, or vented and atmospheric. A CPI separator can be used for secondary separation of produced water and/or waste water for discharge, but is more frequently installed upstream of a final clean-up device (i.e. dissolved gas floatation unit). The separators are effective for droplet sizes above 25 micron. A typical outlet water specification is 25-50 ppm_v of hydrocarbon in water.[22]

API-Separator

An API separator is commonly used for separation of oily water from drain systems. The technology originated in refineries but has wide application to many industries. The separator typically contains internals, a large gravity settling zone, and moving mechanical elements for oil and solids removal. The equipment can handle water with oil and solids at very large flow rates. Secondary treating with flotation equipment and or biological treatment of the water may be required, depending on the application. API separators can remove droplets to 150 micron without coalescing plates, and to 40 microns with coalescing plates.[22]

FIG. 7-52
Example Operating Envelope



Dissolved Gas Flotation Unit

A dissolved gas flotation unit is a water treatment device which is used either as the final element for water disposal offshore, or the treating step upstream of biological waste treatment on-shore. The equipment uses micro-bubbles of gas or air to coalesce and float oil and fine solids to the gas-liquid interface, where they are skimmed from the surface. The units are typically horizontal, but can also be vertical where space is a limitation. Gas floatation units are used in both produced water and waste water treating. Chemical addition upstream of the unit is common. High oil removal efficiency is possible for droplets down to 5-10 microns. An outlet specification of 15-50 ppm_v oil in water is common.[22]

Walnut Shell Filter

A walnut shell is a backwash filter used to remove oil and solids from produced water prior to re-injection in a deep well. Efficient removal for 5 microns droplets and particles is possible. A discharge specification of less than 5 ppm_v oil, and 5 ppm_v solids, is frequently required in order to permit water disposal into a deep well.

Media Filter

A media filter is a backwashable filter which can be used for produced water cleanup. The filter media can be sand, anthracite, garnet, or a combination.

OIL TREATMENT SEPARATORS

Electrostatic Dehydrators and Desalters

Electrostatic devices are frequently used to remove dispersed produced water from oil. The devices use a high voltage field to polarize and/or charge dispersed water droplet, to promote coalescence and remove water. This is the called the dehydration process. If the salinity is high, fresh water and demulsifier chemicals are added and mixed with the process fluid upstream of the dehydrator. This is called the desalting process. The process system can be designed with either single stage or two stage desalting.

Heater-Treaters

Heater Treaters are devices commonly used to process hydrocarbon condensate in a natural gas treating facility. They will remove small quantities of residual water to meet transportation specifications. The units consist of an inlet section heated by a fire tube, a primary settling section, a coalescing section with internals, and a final settling section. The settling section may be open, utilize a plate coalescing element, or utilize an electrostatic field.

DEBOTTLENECKING AND TROUBLESHOOTING

Debottlenecking and troubleshooting of separators are distinct but related activities.

- Debottlenecking involves establishing the capacity limitations of an existing vessel, and altering the vessel or system to increase the capacity.
- Troubleshooting involves establishing the causes of why a vessel is not performing to design specifications and taking corrective action to return it to design performance. Design specifications may refer to either capacity or product specification.

Knowing the design capacity of the separator is a first step in troubleshooting or debottlenecking a separator. The capacity of a separator is often visualized by drawing an Operating Envelope where the vessel performance is displayed as a function of variables such as gas and liquid flow rate, or as in Fig. 7-52, gas flow rate and pressure.

This Operating Envelope shows the capacity of various aspects of the separator such as gas handling capacity of the gravity section, calculated demister capacity, and bounding of the separator operating pressure based on a downstream compressor.

The capacity curves in Fig. 7-52 are based on design equations, not field performance testing. Field trial data plotted on the diagram confirms that the separator can operate satisfactorily at gas rates higher than the calculated demister capacity, and illustrates the usefulness of establishing operating envelopes in a debottlenecking exercise. Performance testing is essential in troubleshooting a separator.

Operating Envelopes are a powerful tool and are valuable in troubleshooting and debottlenecking exercises. Other useful information can be shown in an Operating Envelope such as:

- Nozzle capacities, inlet and outlet
- Residence time for control capacity
- Degassing capacity
- Relief valve capacity
- Technical limits such as Maximum Allowable Operating Pressure

Debottlenecking a separator typically involves replacing or upgrading a separator to meet an increased capacity specification. Identifying the limiting part of the separator is usually necessary. Relief valves and control valves are often capacity limiting devices and frequently can be upgraded. Vessel internals can be added or upgraded. A common example of this is replacing a wire mesh or vane pack demister with demisting cyclones. Inlet devices can also be replaced. The addition of separation aids external to the separator, such as adding a post-separator to catch carryover or adding de-foaming chemical to the inlet, can be useful.

Troubleshooting a separator involves identifying the capacity limiting part of a separator not meeting design specifications and correcting the problems with it. Troubleshooting can be approached as a failure analysis and benefits from the use of a structured process like Root Cause Failure Analysis (RCFA). A structured process provides an organized framework for problem solving and is a useful tool for communicating progress and requirements with management and stakeholders.

The structured process can take many forms but involves:

1. Define the problem.
2. Gather data/evidence.
3. Ask why and identify the causal relationships associated with the defined problem.
4. Identify potential causes

5. Identify potential solutions that prevent recurrence, are within your control, meet your goals and objectives and do not cause other problems.

6. Implement the solutions.

There are many tools available to help with identifying the causal relationships including "5 whys?" and Fishbone diagrams. It is essential that problem definition and data gathering include the observations of the equipment operators. Data gathering should be performed by the troubleshooter, and includes on-site observations in addition to reviewing plant data records. Construction drawings of the vessel should be available for reference. Observed liquid levels can be compared to the location of internals in construction drawings.

The goal of the troubleshooter is to identify the root cause of the problem and not just symptoms. Treating symptoms by making physical changes to process equipment, e.g. replacing separator internals, can lead to repeat shutdowns when the first attempt fails. This leads to excessive downtime and production loss.

An example of a problem where the root cause identification can be difficult is liquid damage to a compressor downstream of a scrubber. The presence of liquid in the compressor is not necessarily caused by liquid carryover from the scrubber. Another source of liquid that could impact the compressor is condensation in the piping between the scrubber and the compressor caused by JT effect (pressure drop in a valve or piping) or changing atmospheric conditions. An appropriate action to take might be a comparison of the composition of the liquid in the scrubber and liquid near the compressor. Other checks might be to identify whether the piping between the scrubber and the compressor has pockets where liquid could accumulate and to verify the condition of the separator internals and level device(s).

The two most common modes of separator failure are excessive liquid carryover in the gas outlet and gas carry under in the liquid outlet. Liquid carryover can be caused by: high gas velocity in vessel gas space, high gas velocity in demister, high gas velocity in gas outlet nozzle, high inlet momentum or poorly designed inlet piping causing liquid flooding in the gas space and the demister, inadequate demister drainage, foaming, high liquid level, damaged or missing internals.

Gas carry-under is often caused by: inadequate degassing area, foaming, inadequate or missing vortex breaker, low liquid level, damaged or missing internals.

FILTER TESTING STANDARDS

National Fluid Power Association's (NFPA's) standard of absolute rating stating that the diameter of the largest hard spherical particle that will pass through a filter under specified test conditions is an indication of the largest opening in the filter.

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ASTM F797 – Standard Practice for Determining the Performance of a Filter Medium employing a Multi-pass, Constant rate, Liquid Test.

ISO 12956 – Geotextiles and Geotextile Related Products – Determination of the Characteristic Opening Size.

ISO 16889 – Hydraulic Fluid Power Filters – Multi-pass Method for Evaluating Filtration Performance of a Filter Element.

The Oklahoma State University, "OSU F-2 Single Pass Filter Performance Test."

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