

Process Design of Oil and Gas Separators and Scrubbers

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Process Design of Oil and Gas Separators and Scrubbers

1 Scope

This recommended practice provides requirements and recommendations for the process design of pressure-vessel-based gas–liquid and gas–liquid–liquid separators operating on static facilities and facilities subject to motion such as floating production, storage, and offloading (FPSO) and tension leg platforms. Separators covered by this document may be vertical (e.g. scrubbers, knockout drums) or horizontal (e.g. free water knockout) and are limited to those containing conventional, longstanding, separation internals such as inlet devices, mist eliminators, agglomerators, and distribution baffles. Other internals such as solids jetting systems are addressed by company requirements and/or technology supplier designs.

As instrumentation is a key part of separator design, guidelines are given for the pressure, temperature, and level sensors necessary for separator process control and troubleshooting.

While there are well-established mechanical design codes for pressure vessels, the process and mechanical designs are related and as such should not be performed as separate exercises. General steps in establishing the parameters to consider when designing the mechanical aspects of the separator are also included.

Separators outside the scope of this document include spherical separators, flare knockout drums, electrostatic separators, inline separators, mono-cyclone separators, filter separators, de-oiling equipment, and de-sanding equipment.

2 Normative References

No other document is identified as indispensable or required for the application of this standard. A list of documents associated with API 12J are included in the Bibliography.

3 Terms, Definitions, Abbreviations and Symbols

3.1 Terms and Definitions

3.1.1

company

The organization that specifies and purchases a separator for their own use or an intermediary that specifies and purchases the separator for an end user. An intermediary can be a contractor, a packager, a manufacturer, or another similar entity.

3.1.2

technology supplier

The organization that designs the internal components for a separator and may also provide the complete process design for the separator.

3.2 Abbreviations and Symbols

A_f	liquid film flow cross-sectional area (m ²)
$A_{g,h}$	horizontal vessel gas space area (m ²)
$A_{g,v}$	vertical vessel cross-sectional area (m ²)
A_N	inlet nozzle area (m ²)

BOV	bottom of vessel (horizontal vessel) (m)
BS&W	basic sediment and water
BTL	bottom tangent line (vertical vessel) (m)
C_D	drag coefficient (—)
CFD	computational fluid dynamics
D	vessel ID (m)
D_g	gas outlet nozzle ID (m)
D_{in}	inlet nozzle ID (m)
D_h	hydraulic diameter (m)
D_l	liquid outlet nozzle ID (m)
D_o	oil outlet nozzle ID (m)
D_P	inlet pipe ID (m)
D_w	water outlet nozzle ID (m)
d_p	particle diameter (m)
F_B	buoyancy force (N)
F_D	drag force (N)
F_G	gravity force (N)
FEA	finite element analysis
FIV	flow-induced vibration
FPSO	floating production, storage, and offloading
Fr	Froude number (—)
GVF	gas volume fraction (—)
g	gravitational acceleration (m/s ²)
g'	modified gravitational acceleration (m/s ²)
H	gas outlet nozzle–mist eliminator spacings (with subscripts 1 to 4) in a vertical vessel (m)
H_S	nozzle submergence (m)
h	droplet vertical fall distance (m)
HC	hydrocarbon
ID	inside diameter (m)

IVD	inlet vane diffuser
K	K -factor (m/s)—as defined in Equation (1) or Equation (H.3)
L_B	baffle spacing (m)
$L_{g,eff}$	gas space effective separation length (m)
L_H	droplet horizontal travel distance (m)
L_{IVD}	IVD length (m)
$L_{l,eff}$	liquid space effective separation length (two-phase separator) (m)
L_N	spacing from closest edge of gas outlet nozzle to the outlet of the mist eliminator (m)
$L_{oiw,eff}$	water space effective separation length (m)
L_P	length of inlet pipe (m)
L_{TT}	horizontal vessel tangent to tangent length (m)
$L_{wio,eff}$	oil space effective separation length (m)
LAH	high liquid level alarm (m)
LAL	low liquid level alarm (m)
LG	level gauge
LIAH	high interface level alarm (m)
LIAL	low interface liquid level alarm (m)
LISH	high interface level trip (m)
LISL	low interface level trip (m)
LSH	high liquid level trip (m)
LSL	low liquid level trip (m)
LT	level transmitter
M	mass flow rate (kg/s)
M_g	gas mass flow rate (kg/s)
M_o	oil mass flow rate (kg/s)
M_w	water mass flow rate (kg/s)
MMscf	standard $\text{ft}^3 \times 10^6 =$ millions standard ft^3
MSm ³	standard $\text{m}^3 \times 10^6 =$ millions standard m^3
MSm ³ /d	standard $\text{m}^3 \times 10^6/\text{day} =$ millions standard m^3 per day

N_{μ}	viscosity number (—)
NFA	net free area
NIL	normal interface level (m)
NLL	normal liquid level (m)
P	pressure (N/m ²)
P_w	wetted perimeter (m)
Q	volumetric flow rate (m ³ /s)
Q_g	gas volumetric flow rate (m ³ /s)
Q_o	oil volumetric flow rate (m ³ /s)
Q_w	water volumetric flow rate (m ³ /s)
Re	Reynolds number (—)
Re_f	liquid film Reynolds number (—)
RVP	Reid vapor pressure (bar)
T	temperature (°C)
TAN	vessel tangent line
TOV	top of vessel
TT	tangent to tangent
TVP	true vapor pressure (bara)
USG	U.S. gallon
V_B	bulk liquid axial velocity
V_g	gas velocity (m/s)
$V_{g,h}$	horizontal vessel gas space velocity (m/s)
$V_{g,v}$	vertical vessel gas space velocity (m/s)
V_l	liquid nozzle velocity (m/s)
V_m	mixture velocity (m/s)
V_T	particle terminal velocity (m/s)
VB	vortex breaker

α	roll or pitch angle (°)
Δh_d	drainpipe liquid height above vessel liquid level (m)
ΔP	total pressure drop across mist eliminator (Pa)
ΔP_d	drainage pressure drop of mist eliminator (Pa)
θ	gas outlet nozzle–mist eliminator angles (with subscripts 1 to 3) in a horizontal vessel (°)
μ_c	dynamic viscosity of continuous phase (kg/m/s)
μ_l	dynamic viscosity of liquid phase (kg/m/s)
ρ_c	density of continuous phase (kg/m ³)
ρ_d	density of dispersed droplet phase (kg/m ³)
ρ_g	gas density (kg/m ³)
ρ_H	density of heavy phase (kg/m ³)
ρ_l	liquid density (kg/m ³)
ρ_L	density of light phase (kg/m ³)
ρ_m	mixture density (kg/m ³)
σ	interfacial tension (N/m)—gas–liquid surface tension (σ_{gl}), liquid–liquid (σ_{ow})

4 Design Parameters

4.1 Separation Requirements

Vessels should be designed to achieve a separation performance sufficient to meet the requirements of the downstream processing equipment or end use. Hence, different separators do not necessarily require the same level of performance, depending on the application and the equipment downstream.

Some equipment are designed for bulk separation, in which coarse separation is acceptable, provided the downstream equipment can handle the liquid carryover or gas carry-under. Production separators are a good example of a bulk separator. The gas leaving a production separator is frequently mixed with other gases and normally routed to a compressor suction scrubber. In applications where condensation may occur, targeting 0.1 % to 1.0 % of incoming liquid carried over into the gas phase may be acceptable, provided this will not overload the compressor suction scrubber. In other cases, even a total 99.9 % separation efficiency of liquid from gas may not be sufficient depending upon the absolute liquid volumes. Similarly, ~5000 mg/L oil in water and/or ~15 % (by volume) water in oil may be acceptable if downstream processing can handle the entrained liquid.

Other applications may require better separation as the consequences of carryover are more severe. In some applications, carryover can result in lost or deferred production, a significant financial loss, or can result in damage or degradation of equipment. Scrubbers upstream of a gas glycol dehydration unit are good examples of separators that require a high level of liquid removal efficiency. Poor separation of free liquid

hydrocarbons can result in excessive foaming in the absorption column. Foaming can result in solvent losses and poor performance.

Appropriate and sufficient separation performance specifications linked to the application of the separator should be established by company and technology supplier. Typical specifications include:

- absolute entrainment, e.g. L/MSm³ liquid carryover in a gas scrubber, vol% water in oil, mg/L oil in water;
- droplet cutoff criteria, e.g. requirements from manufacturers of downstream equipment such as compressors;
- removal efficiency, e.g. percent liquid from gas;
- liquid control volumes, e.g. downstream pump requirements.

Overspecification of the design should be avoided as it can result in costly designs, rework, and conflicting requirements. For example, degassing of the liquid in a scrubber is rarely critical and vessel design is typically governed by the diameter required for gas–liquid separation and liquid control volume.

The same separator performance requirements should not be used for all services. For example, applying a scrubber specification to a production separator can result in impractical separation efficiencies and/or oversized separators with overdesigned internals.

Commonly quoted high separation performance claims such as 13.4 L/MSm³ (0.1 USG/MMscf) liquid carryover in gas [1] or > 99 % removal of droplets larger than 10 µm diameter should not be used by default. These are often impractical and unnecessary and, in many cases, difficult to prove. Liquid carryover testing [2] show that the widely quoted 0.1 USG/MMscf specification was only met in a very small percentage of the test conditions.

Specifications should be consistent with the available internals technology. For example, a too rigorous liquid carryover specification may require internals that are very sensitive to fouling or unnecessarily large vessels.

4.2 Testing

Test data may be used to justify or validate designs. However, care should be taken to ensure that the fluids and the conditions employed in the testing are representative of the intended application. This can be accomplished by either using the actual fluids being processed or representative model fluids; see 4.4.

4.3 Process Design Cases

The process design of a separator should cover the anticipated operating envelope, which can vary depending on the uncertainty in the system. Several process design cases should be developed that cover the entire expected operating envelope of the separator with a minimum of:

- design flow rate,
- normal operating flow rate,
- minimum flow rate.

For example, a compressor suction scrubber is expected to process 3 MSm³/d of gas. The selected compressor has a maximum throughput of 3.5 MSm³/d, and the flow at the surge control line is 1.5 MSm³/d. Therefore, the scrubber should be designed as follows:

- design flow rate (3.5 MSm³/d),

- normal operating flow rate (3 MSm³/d),
- minimum flow rate (1.5 MSm³/d).

Other systems can have different ranges of minimum and design flow. Expected ranges in liquid density, watercut, gas volume fraction (GVF), and fluid properties (density, viscosity, surface tension) shall also be evaluated.

No margin is required for sizing criteria values provided in this document. All margins should be accounted for in flow rates and fluid properties of the cases described above.

4.4 Fluid Properties

Fluid densities, viscosities, and interfacial tensions for all phases shall be provided for the flow sizing cases of 4.3. Data related to the foaming and emulsion tendency of the oil–water phases should also be supplied.

Note that interfacial tension and hydrocarbon liquid viscosity are difficult to measure and are typically poorly predicted at the desired pressure and temperature. Interfacial tension is a major factor in the estimation of drop/bubble sizes. Liquid viscosity is a determining factor in oil–water separation and degassing. A sensitivity analysis of separator design with these two parameters should be conducted.

4.5 Separator Orientation Selection

The design features of horizontal and vertical separators are summarized in Annex A.

4.6 Mist Eliminator Selection

Performance characteristics for knitted mesh, vane pack, and axial flow cyclone mist eliminators are provided in Annex B.

4.7 Motion Effects

For separators that are installed on offshore floating production facilities, specific design considerations and requirements apply. These specifics along with some background information are presented in Annex C.

4.8 Configurations

Typical configurations of separators and scrubbers are shown in Annex D. Sizing examples using the guidelines in this document are contained in Annex E.

4.9 Process Sizing Data Requirements (Datasheet)

Input process data necessary for designing a separator or scrubber is presented in Annex F in the form of a typical datasheet. Parameters and requirements discussed previously in 4.1 to 4.8 as well as in Section 5 are listed in the datasheet.

4.10 Inlet Piping

Although inlet piping is not part of the separator design, it does play a key role in the separator's performance. Good flow distribution in a separator's inlet nozzle is vital to the performance of a separator. Bends and/or restrictions in the piping upstream of the separator materially impact the flow within the separator. Recommendations of inlet pipe configurations and lengths given in Annex G should be followed.

5 Separator Sizing Specifications

5.1 General Specifications

5.1.1 Separation Components

These specifications cover two-phase and three-phase horizontal separators/scrubbers and two-phase vertical separators/scrubbers. See Annex A for design aspects of vessel orientation.

Design specifications for separators and scrubbers are categorized into areas corresponding to the main separation components as shown in Figure 1 for horizontal vessels and Figure 2 for vertical vessels. The components are:

- a) nozzles:
 - 1) inlet nozzle/inlet devices,
 - 2) gas outlet nozzle,
 - 3) liquid outlet nozzles,
 - 4) solids (sand) outlet nozzles (if applicable);
- b) liquid gravity settling section,
- c) gas gravity settling section, and
- d) gas demisting.

As noted in 4.10 and shown in Figure 1 and Figure 2, inlet piping is not part of the separator design although it does play a key role in the separator's performance [3].

The separator shall be designed for safe control and operation and to meet (as applicable):

- liquid in gas specifications,
- gas in liquid specifications,
- hydrocarbon liquid in water specifications,
- water in hydrocarbon liquid specifications.

The above can be accomplished by using the information and proven industry practices within this document to design the main areas of a separator as follows.

- e) Inlet nozzle/inlet devices shall be designed to:
 - 1) mitigate droplet shatter and foam generation,
 - 2) promote plug flow to the gravity section.
- f) Outlet nozzles shall be designed to:
 - 1) remove the desired phase while minimizing entrainment of unwanted phases,

- 2) minimize effect on the upstream gravity section or mist eliminator (e.g. short-circuiting, maldistribution).
 - 3) mitigate erosion,
- g) The liquid gravity section shall be designed to:
- 1) allow for control and safe operation of the vessel (i.e. level control),
 - 2) meet gas in liquid specifications,
 - 3) meet hydrocarbon liquid in water specifications,
 - 4) meet water in hydrocarbon liquid specifications,
 - 5) accommodate liquid slugs,
 - 6) meet the requirements of downstream equipment (e.g. pump).
- h) The gas gravity section shall be designed to:
- 1) reduce liquid load to within the operating range of the mist eliminator (if applicable),
 - 2) meet the liquid in gas specifications (if applicable, e.g. no mist eliminator).
- i) The gas demisting section (if applicable) shall be designed to meet the liquid in gas specifications.

Many of the sizing criteria are commonly specified using a K -factor (adapted from the original Souders–Brown B capacity parameter [4]). The maximum gas velocity, V_g (m/s), through the gas flow area or mist eliminator is determined from the K -factor (m/s) in Equation (1):

$$V_g = K \sqrt{\frac{\rho_l - \rho_g}{\rho_g}} \quad (1)$$

where

ρ_l is the liquid density (kg/m³);

ρ_g is the gas density (kg/m³).

The physical properties, drop size, and liquid loading have a significant impact on the allowable K -factor and may appreciably reduce its value and hence the maximum gas velocity. See Annex H for discussion on the K -factor and drop settling models.

Typical configurations/sketches of separators are given in Annex D. Sizing calculation examples using the herein described guidelines are provided in Annex E. An example datasheet for process design data necessary to size and specify internals is given in Annex F.

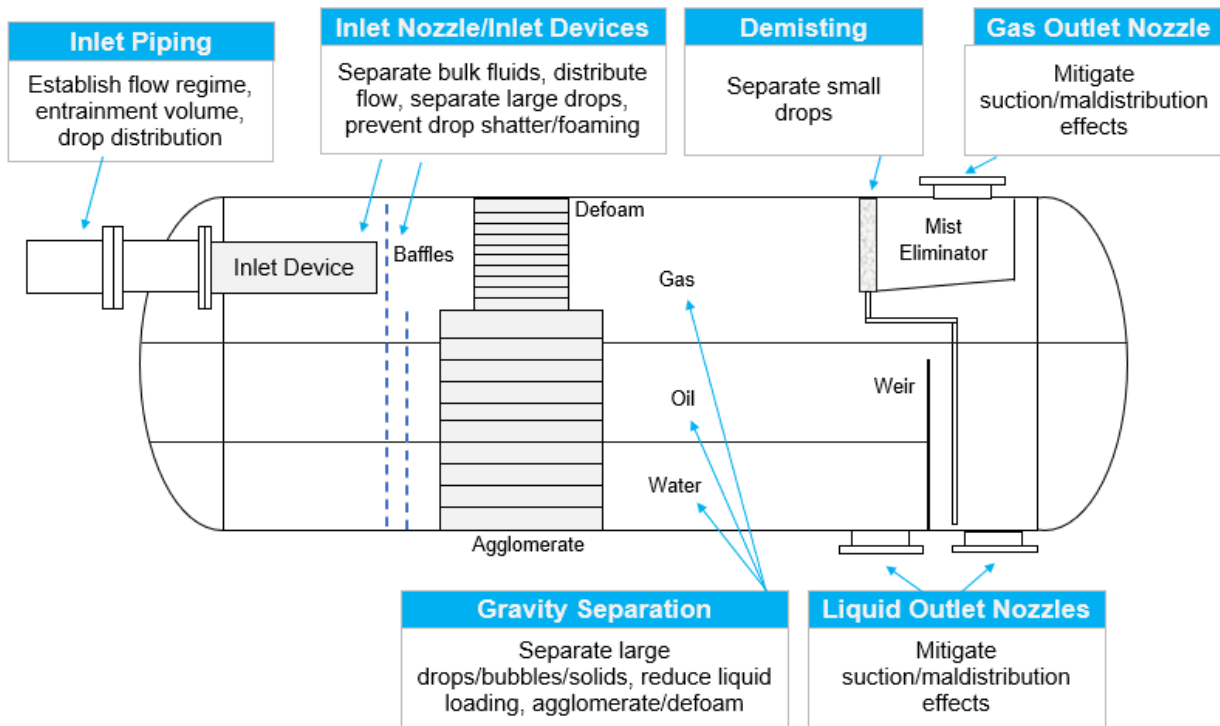


Figure 1—Key Separation Areas of a Horizontal Separator

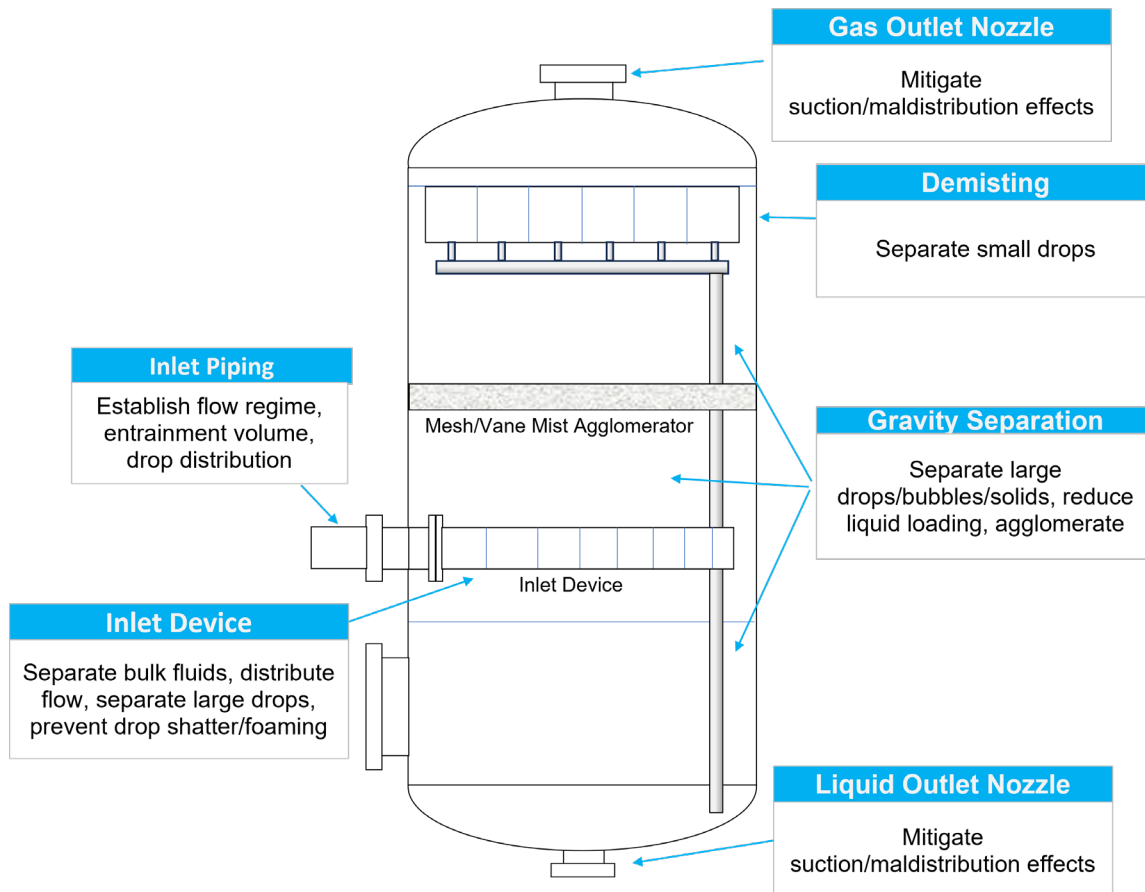


Figure 2—Key Separation Areas of a Vertical Separator

5.1.2 Nozzles

5.1.2.1 Inlet Nozzle/Inlet Devices

The inlet nozzle internal diameter should be sized in conjunction with the selection of the inlet device. The inlet device, depending on the design, can serve many purposes that include separation of bulk liquid from gas, separation of large drops and bubbles, flow distribution into the vessel, and prevention of droplet shatter and foaming. Guidelines for sizing and selecting inlet nozzles and inlet devices are given below.

- a) The inlet nozzle internal diameter (ID), D_{in} , shall be at least the size of the inlet pipe ID, D_p . If the inlet nozzle ID is larger than the inlet piping ID, the piping ID should be expanded to the nozzle ID at least 10 pipe diameters upstream of the nozzle (inlet pipe length/diameter $L_p/D_p \geq 10$). The inlet piping configurations of Figure G.1, Figure G.2, and Figure G.3 in Annex G still apply.
- b) Inlet devices are commonly sized based on a momentum flux, $\rho_m V_m^2$, which is determined assuming homogenous flow. The mixture velocity, V_m (m/s), and density, ρ_m (kg/m³), are calculated as in Equation (2) and Equation (3):

$$V_m = \frac{Q_o + Q_w + Q_g}{A_N} \quad (2)$$

$$\rho_m = \frac{M_o + M_w + M_g}{Q_o + Q_w + Q_g} \quad (3)$$

where

Q is the volumetric flow rate at operating P , T (m³/s);

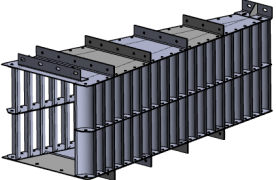
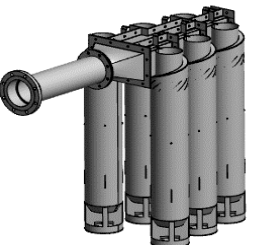
M is the mass flow rate (kg/s);

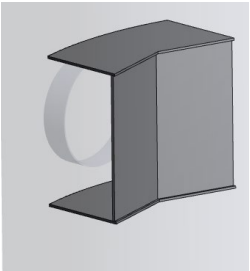
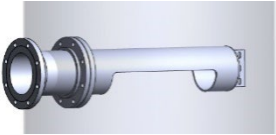
A_N is the inlet nozzle area (m²);

and the subscripts g , o , and w refer to gas, oil, and water phases, respectively.

- For typical inlet devices, Table 1 lists the maximum inlet momentum flux and velocity limits that should be followed.
 - Some devices, such as inlet cyclones, operate within certain liquid levels to prevent carry-under of the bulk gas phase into the liquid phase and to prevent liquid carryover out the top of the cyclones into the gas phase. The liquid levels in 5.1.3.2 shall be checked and adjusted if required to account for these requirements.
- c) For horizontal vessels, distribution baffles should be used in conjunction with the inlet device to promote plug flow to the gravity sections. See 5.2.2.1.

Table 1—Maximum Allowable Inlet Momentum Fluxes of Different Inlet Devices

Multiphase Inlet Device ^{1, 6, 8}	Maximum Nozzle Momentum Flux ^{5, 7} $\rho_m V_m^2$	Maximum Nozzle Velocity ^{2, 3, 5, 7} V_m	Recommendations ⁴		Comments
	Pa (kg/m-s ²)	m/s	Vertical Vessel	Horizontal Vessel	
Inlet Vane Diffuser (IVD) 	≤6,000 to 10,000 Typical design point ≤ 8,000. Lower is better for separation.	≤10 to 20	Recommended. Typically spans the vessel ID.	Recommended. Typically $L_{IVD}/D_{in} = 3$ to 6.	— Generally, the recommended choice for most services, including GVF > 70 %. — The design is technology supplier specific, and details shall therefore be confirmed by the technology supplier. — Liquid splashing onto the liquid surface can generate foam. Guides or splashing reduction plates can be evaluated. — Designs for higher momentum (heavy duty) are available based on specific technology supplier evaluations, including FIV. Under slugging service, the momentum flux can be much higher than noted. The higher momentum flux shall be used for mechanical design.
Inlet Cyclone 	Maximum is by technology supplier/service specific. Do not exceed erosion limits.	Typical ≤ 20.	Acceptable. Inlet cyclones are generally not used due to liquid volume storage loss in the bottom of the separator.	Recommended depending on the specific application.	— The design is highly technology supplier specific; design limits can vary and shall be confirmed by the technology supplier in each case. — There is a risk for gas carry-under to the liquid outlets of the device and liquid carryover with the gas. For this reason, the critical submergence and margins shall be well documented and known to the operators. Similarly, capacity/performance for turndown should be documented. Maldistribution between cyclone cans shall be evaluated by technology supplier. — If solids are present in the fluids, the technology supplier should verify the design for internal erosion risk. — Can be used in foaming service.

Multiphase Inlet Device ^{1, 6, 8}	Maximum Nozzle Momentum Flux ^{5, 7} $\rho_m V_m^2$	Maximum Nozzle Velocity ^{2, 3, 5, 7} V_m	Recommendations ⁴		Comments
	Pa (kg/m-s ²)	m/s	Vertical Vessel	Horizontal Vessel	
V-baffle (Shown), Tangential Baffle 	≤1,500	≤5 to 18	Acceptable. Maldistribution of gas flow and droplet shatter should be assessed by CFD.	Not recommended.	— Inlet impact baffles are high-shear devices that can shatter and mix the inlet flow, generating smaller bubbles and droplets potentially making separation more difficult. — Can result in the creation of foam and emulsion. — Vertical Vessels: Can result in maldistribution of gas flow in the vessel diameter and into the demisting device due to swirling flow in the vessel invalidating gravity separation and demisting calculations. — When the flow is directed towards (around) the separator walls, erosion concerns shall be investigated/mitigated.
Half Pipe (with or Without Elbow)  Includes sparger, slotted pipe designs, and trapezoidal cutouts in a pipe	≤1,500	≤5 to 18	Not recommended.	Acceptable in bulk separation service where stringent separation is not required. Typically GVF ≤ 70 %.	— Vertical Vessel: Directing the inlet flow down can result in maldistribution of gas flow in the vessel and invalidate general gravity separation and demisting calculations (e.g. K-factor). Velocity estimates should be based on CFD simulations. Downward flow can result in gas impacting liquid level resulting in entrainment from the liquid surface. — Horizontal Vessel: Downward flow can result in gas impacting liquid level resulting in entrainment from the liquid surface. — The pipe opening can be facing up or down; both orientations can be problematical for the vessel. — For a gas sparger design, the holes/slots should be directed to the sides or angled down between 0 to 45° from horizontal.

Multiphase Inlet Device ^{1, 6, 8}	Maximum Nozzle Momentum Flux ^{5, 7} $\rho_m V_m^2$	Maximum Nozzle Velocity ^{2, 3, 5, 7} V_m	Recommendations ⁴		Comments
	Pa (kg/m-s ²)	m/s	Vertical Vessel	Horizontal Vessel	
Elbow, Baffle Box (Hood) 	≤950 to 1,500 Typical ≤ 750.	≤5 to 10	Not recommended.	Acceptable Inlet on Shell: Where stringent separation is not required. Inlet device should direct the flow back to upstream head. Inlet in Head: Where stringent separation is not required. Full-diameter distribution baffle should be present. Typically GVF ≤ 15 %.	— Downward flow can result in liquid entrainment from the liquid surface. — If flow is directed toward the vessel head or wall, a wear plate should be installed where the flow impacts the vessel. — Vertical Vessel: Directing the inlet flow down can result in maldistribution of gas flow in the vessel and invalidate general gravity separation and demisting calculations (e.g. <i>K</i>-factor). Velocity estimates should be based on CFD simulations.

Multiphase Inlet Device ^{1, 6, 8}	Maximum Nozzle Momentum Flux ^{5, 7} $\rho_m V_m^2$	Maximum Nozzle Velocity ^{2, 3, 5, 7} V_m	Recommendations ⁴		Comments
	Pa (kg/m-s ²)	m/s	Vertical Vessel	Horizontal Vessel	
None 	≤1,000 Typical ≤ 750.	≤5 to 10	Not recommended	Not recommended. Inlet on Shell: Gas is directed down at liquid level and falling liquid can result in foaming.	— Vertical Vessel: Can result in inlet flow hitting the opposite wall (erosion concern) and severe maldistribution of gas flow. — Horizontal Vessel: Causes extended turbulent inlet section and reduced separation length.
				Acceptable. Inlet in Head: Full-diameter distribution baffle should be present.	

NOTE 1 These represent groups of typical inlet device designs. Design details can vary between suppliers, and the sketches are for illustration purposes only. Other types of inlet distributors may also be acceptable, but their suitability shall then be documented and accepted by the company.

NOTE 2 Always check that erosion velocity is not exceeded, especially when solids are present. In gas-dominated applications under vacuum/low-pressure (typically ≤ 15 barg), the maximum velocity can exceed that noted and is likely limited by erosion limits. Erosion limits in some services may limit fluid velocity below that indicated by the momentum flux limit. Erosion limits are per company guidelines/specifications.

NOTE 3 In gas-dominated applications under vacuum/low-pressure (typically ≤ 15 barg), the maximum velocity may exceed that noted and might be limited by maximum allowed inlet momentum flux.

NOTE 4 “Acceptable” = requires further verification by company subject matter expert/technology supplier for the specific service.

NOTE 5 Recommended momentum and velocities are applicable to typical oil and gas operation services. The inlet sizing and distributor selection and sizing should always be verified by company subject matter expert/technology supplier for the specific service.

NOTE 6 Any inlet that directs the flow toward the liquid level such as an elbow, baffle box, or downward facing impact baffle can cause liquid short-circuiting that can impact oil–water separation. The impact can drive gas into the liquid, impacting degassing and potentially causing foaming as well.

NOTE 7 The maximum momentum fluxes and velocities represent typical values for a system with a low liquid load and moderate physical properties. High liquid loads, high liquid viscosities, and low interfacial tensions can detrimentally impact the performance. The final design of the system, by the technology supplier, should account for these effects for all fluid phases.

NOTE 8 Fouling and plugging should be considered in the inlet device design.

5.1.2.2 Gas Outlet Nozzle

Gas outlet nozzle sizing is dependent on the demisting technology installed in the vessel and more specifically on the pressure drop, ΔP , of the final demisting device. The sizing is such that the nozzle should not negatively impact gas and liquid distribution into and through the demisting device. The flow distribution is also dependent on the distance the demisting device is from the nozzle in the vessel.

Gas outlet nozzles should be sized per Table 2, where V_g is the outlet nozzle gas velocity and ρ_g is the gas density. The outlet piping diameter should match the nozzle diameter for $3D$ to $5D$ downstream of the nozzle before being reduced.

Table 2—Gas Outlet Nozzle Sizing Criteria

Demisting Technology	Gas Outlet Nozzle Momentum Flux Max. ^{1, 2} $\rho_g V_g^2$, Pa (kg/m/s ²)	Gas Outlet Nozzle Velocity Max. ^{2, 3} m/s
None	≤ 4500	20
Mesh or vanes	≤ 4500	20
Cyclones	≤ 9000 < 5400 (typically)	20
NOTE 1 To ensure that the nozzle does not impact the flow distribution through the mist eliminator. NOTE 2 Erosion limits in some services may limit fluid velocity below that indicated by the momentum limit. Erosion limits are per company guidelines/specifications. NOTE 3 In gas-dominated applications under vacuum/low-pressure (typically ≤ 15 barg), the maximum velocity may exceed that noted.		

5.1.2.3 Liquid Outlet Nozzles

Liquid outlet nozzles should be designed to not negatively affect the performance of the gravity section. In most applications, liquid outlet nozzles should be fitted with vortex breakers (VBs). Examples of acceptable designs can be found in IOGP S-619 [7]. Nozzles may be elevated due to solids accumulation. The liquid outlet nozzles should be sized as follows.

- a) Two-phase gas–liquid separators:
 - hydrocarbon or mixed-phase nozzle: 2 m/s velocity maximum.
- b) Three-phase gas–oil–water separators:
 - hydrocarbon nozzle: 2 m/s velocity maximum,
 - water nozzle: 1 m/s velocity maximum.
- c) Feed to pump suction (any service): 1 m/s velocity maximum.

In critical separation services and/or where a vortex breaker is not provided, to mitigate risk of carry-under of the phase above, the liquid outlet nozzle should be designed for self-venting flow (see Annex I).

Critical separation services include operations where gas carry-under or where contamination of liquid flows cannot be tolerated.

Velocity and self-venting criteria are normally acceptable for design if the nozzle ID is less than 24 in. However, if the nozzle ID is greater than 24 in., an additional submergence criterion (see Annex I) should be considered to provide a minimum value for low liquid level trip (LSL) [or low interface level trip (LISL)] above the nozzle.

For separators with solids removal systems (e.g. sand jetting), liquid outlets in the same compartment/section should be designed to reduce solids carry-over (e.g. sand dams or elevated nozzles).

5.1.2.4 Solids (Sand) Outlet Nozzles

Solids outlet nozzles are periodically used to remove solids accumulated at the bottom of a vessel.

The ID of the nozzles should be a minimum of DN50 to avoid blockage, and the vessel should be fitted with internals to limit the lines filling with solids when not in use.

The exit velocity should be limited to avoid erosion; a typical value is 3 m/s.

5.1.3 Liquid Gravity Settling Section

5.1.3.1 General

The liquid gravity section allows large liquid drops, gas bubbles, and solids to separate out to their respective phases, e.g. water drops settle out of the oil phase, oil drops rise out of the water phase, and gas bubbles rise out of the liquid phase. In addition, the liquid section must have sufficient volume to allow proper operation of the vessel.

The liquid section for two- or three-phase separators shall meet minimum requirements for:

- a) level control/reaction time,
- b) degassing and defoaming, and
- c) solids settling (if applicable).

For horizontal three-phase separators (see 5.2.3), there are additional separation requirements for:

- d) velocity limits
- e) water droplets settling out of oil, and
- f) oil droplets settling out of water.

Liquid levels shall be adjusted for proper operation of the inlet device if present. Some devices, such as inlet cyclones, may need to be liquid sealed [e.g. between low liquid level alarm (LAL) and high liquid level alarm (LAH) for two-phase separators], while other inlet devices should not be submerged.

If the distance of the inlet device above the liquid level is excessive, then risk of foaming due to splashing is higher and should be addressed. Also, in systems with large slug volumes, the distance between normal and high level can be large and a large fall height may result. If foaming due to falling liquid is a concern, properly designed mitigation schemes such as downcomer baffles or packing may be used.

The largest of the above requirements should dictate the sizing of the liquid section.

5.1.3.2 Level Control/Reaction Times

Level control volume refers to the volume in a vessel between the settings and alarms on the control system. The vessel liquid volumes shall provide sufficient level control time that allows time for the operators and control systems to respond to disturbances.

Level settings are normally dictated by project specifications, process requirements, and/or safety criteria that may override the recommendations given below. The recommendations below should not be interpreted as limiting the specific project requirements to minimum or maximum values. In the absence of such requirements, Table 3 may be used, provided that the separation performance is met.

- The basis of the flow rate, used to determine the control times, should be clearly stated and is normally the design flow rate.

- Table 3 lists minimum liquid levels for two-phase and three-phase separators where no other overriding criteria are available. Company guidelines should be consulted to determine if some operating levels are not required. See also Figure 3, Figure 4, and Figure 6 through Figure 8.
- See Annex C for vessels subject to motion.

In addition, the level instrumentation for safety shutdowns (low or high level) shall be separate from the operating level instruments, as required by the applicable safety standard or practice.

Other level control time/volume requirements for safety systems, downstream equipment protection, etc. should also be considered in the level settings.

Table 3—Minimum Level Control Spacings and Control Times

	Level	Minimum Spacing Between Levels (mm)	Minimum Time Between Levels (s) ¹
High liquid level trip ^{4, 5}	LSH		
		150	30
High liquid level alarm ³	LAH		
		150	30
Normal liquid level ³	NLL		
		150	30
Low liquid level alarm	LAL		
		150	30
Low liquid level trip	LSL ²		
		See values below for LISL	
Bottom tan line (vertical) or bottom of vessel ² (horizontal)	BTL or BOV		
High interface level trip	LISH		
		150	30
High interface level alarm	LIAH		
		150	30
Normal interface level	NIL		
		150	30
Low interface level alarm	LIAL		
		150	30
Low interface level trip	LISL ²		
	If vertical vessel:	Greater of 1) 150 mm from BTL, 2) 150 mm above elevated outlet, or 3) height of VB ⁶	
	If horizontal vessel:	Greater of 1) 150 mm from BOV, 2) 150 mm from top of elevated outlet, or 3) height of VB ⁶	
Bottom tan line (vertical) or bottom of vessel ² (horizontal)	BTL or BOV		

NOTE 1 The listed control times include any vessel head space for horizontal vessels.

NOTE 2 For horizontal vessels, depending upon the outlet design, the minimum LSL and LISL should be the greater of 1) 150 mm above BOV, 2) 150 mm above an elevated outlet, or 3) the height of the vortex breaker. For vertical vessels, depending upon the outlet design, the minimum LSL should be the greater of 1) 150 mm above BTL, 2) 150 mm above an elevated outlet, or 3) the height of the vortex breaker.

NOTE 3 Where liquid slugs are expected, the separator should be designed to accommodate the volume of the slug within the normal to high liquid level (NLL to LAH). Overall system dynamic behavior including level control response, initial steady state condition, and downstream surge capacity should be considered in the determination of the slug volume to be accommodated.

NOTE 4 Specifications of LSH spacing from the bottom of the mist eliminator should be followed as shown in Figure 3, Figure 4, and Figure 6 through Figure 8.

NOTE 5 Specifications of LSH spacing from the bottom of a non-submerged inlet device should be followed as shown in Figure 3, Figure 4, and Figure 6 through Figure 8.

NOTE 6 The height of a vortex breaker is typically one-half of the nozzle ID.

5.1.3.3 Degassing and Foaming

Many common applications require a specific limit on gas entrainment in liquid, and therefore the design needs to incorporate a degassing criterion. Examples include:

- pumped systems,
- feeds to electrostatic dehydrators,
- systems with Reid vapor pressure/true vapor pressure (RVP/TVP) requirements.

If degassing is required, a commonly used degassing criteria for critical applications may be used: the rise of a 200 μm gas bubble from the bottom of the vessel to NLL (two-phase) or from NIL to NLL (three-phase). In many applications, this may be relaxed to a 600 μm bubble. See Annex H for bubble rising models. For a two-phase separator containing two liquid phases, the highest liquid viscosity should be used in the bubble rise model.

- For horizontal vessels, the effective gas bubble disengagement lengths should be used as shown in Figure 3 and Figure 4.
- For vertical vessels, the calculated bubble rise velocity should exceed the downward liquid bulk velocity.

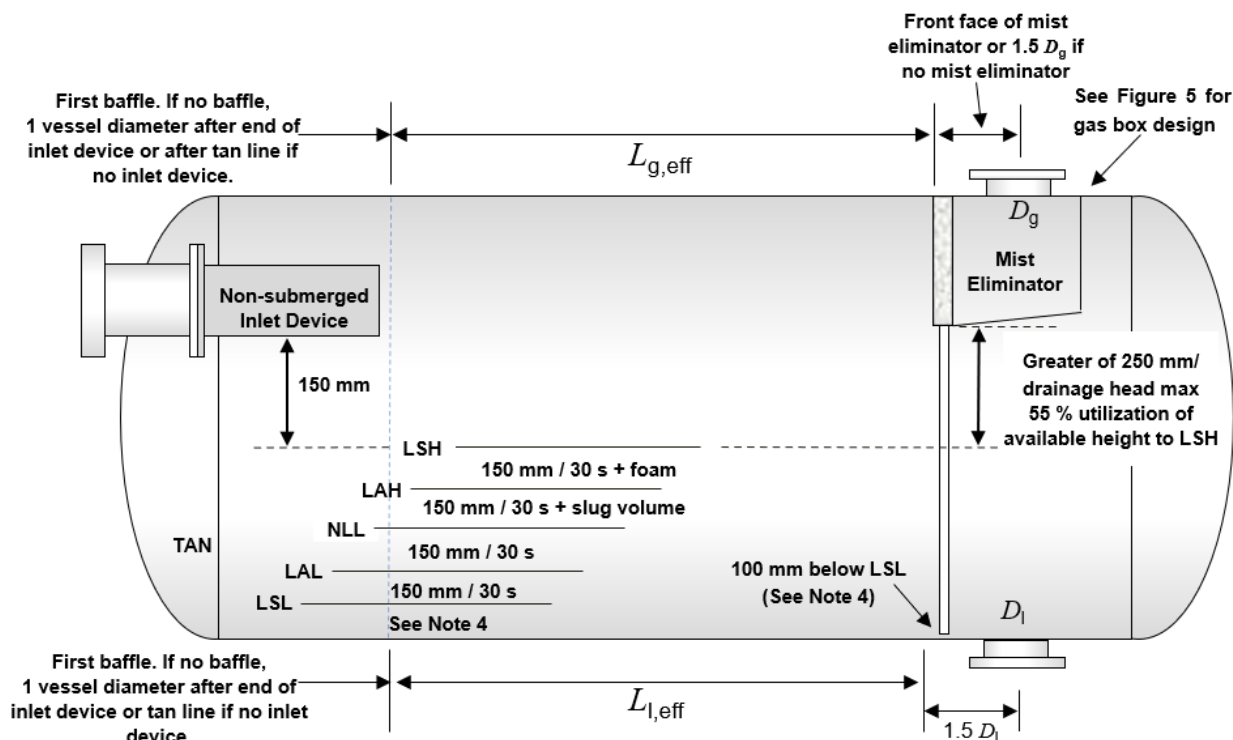
In viscous services, it is not always possible to degas to this level. In such scenarios, the requirements downstream of the system shall be assessed to determine the acceptability of residual gas.

If the system is foamy, the spacing from LAH to LSH should be increased by at least 250 mm to accommodate a foam layer.

The selection of inlet devices and internals can have a significant impact on volume of the dispersed gas in the liquid. Where degassing is required, these impacts should be considered in the design.

5.1.3.4 Solids Removal

It can be advantageous to remove solids in horizontal production separators. A vessel can be sized in order to provide space for the collected solids and appropriate solids handling infrastructure (e.g. jetting systems, sand dams). Solids are typically not accumulated in vertical separators. However, if the liquid outlet is not placed at the bottom of the separator, or if stagnant sections can be expected, solids accumulation/removal should be evaluated. The design of solids handling systems are per company/technology supplier specifications.



NOTE 1 Control times are based on vessel length including heads.

NOTE 2 Separation lengths are determined from a number of parameters, in particular the inlet device configuration, baffle configuration, and nozzle positioning.

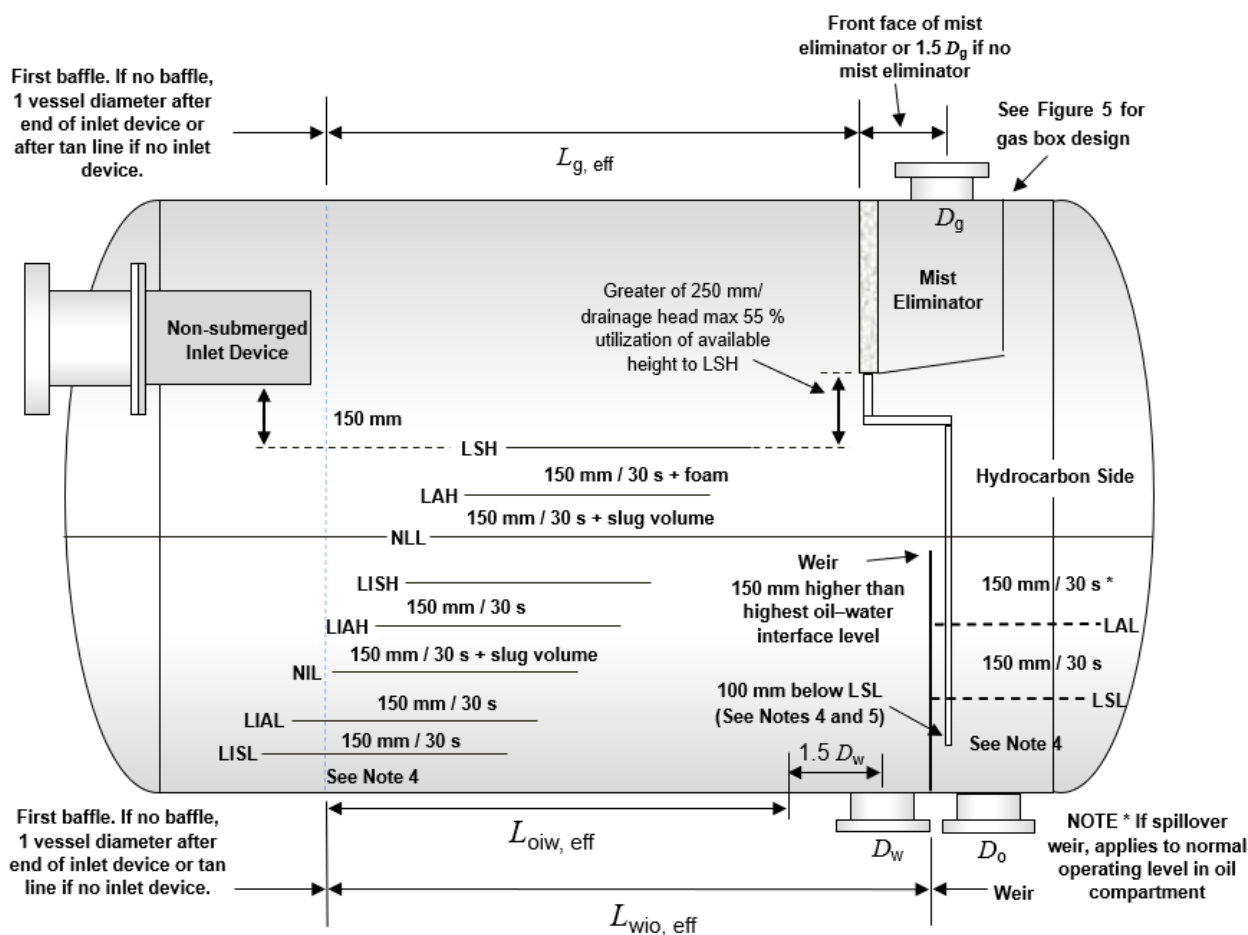
— bubble rise models are based on effective length $L_{l,eff}$;

— droplet in gas settling model is based on effective length $L_{g,eff}$.

NOTE 3 Additional spacing, due to mechanical requirements, may be necessary and should be accounted for in the design.

NOTE 4 The height of LSL from BOV is the greater of 1) 150 mm from BOV, or 2) 150 mm from top of elevated outlet, or 3) height of VB. Solids that may settle at the bottom should also be taken into account in the setting of LSL and the bottom of the drainage pipe.

Figure 3—Overview of Specifications for a Horizontal Two-phase Separator



NOTE 1 Control times are based on vessel length including head(s).

NOTE 3 Separation lengths are determined from several parameters, in particular the inlet device configuration, baffle configuration, and nozzle positioning.

- water droplet settling in oil and bubble rise degassing model are based on effective length $L_{wio, \text{eff}}$;
- oil droplet rising in water model is based on effective length $L_{oiw, \text{eff}}$;
- droplet in gas settling model is based on length $L_{g, \text{eff}}$.

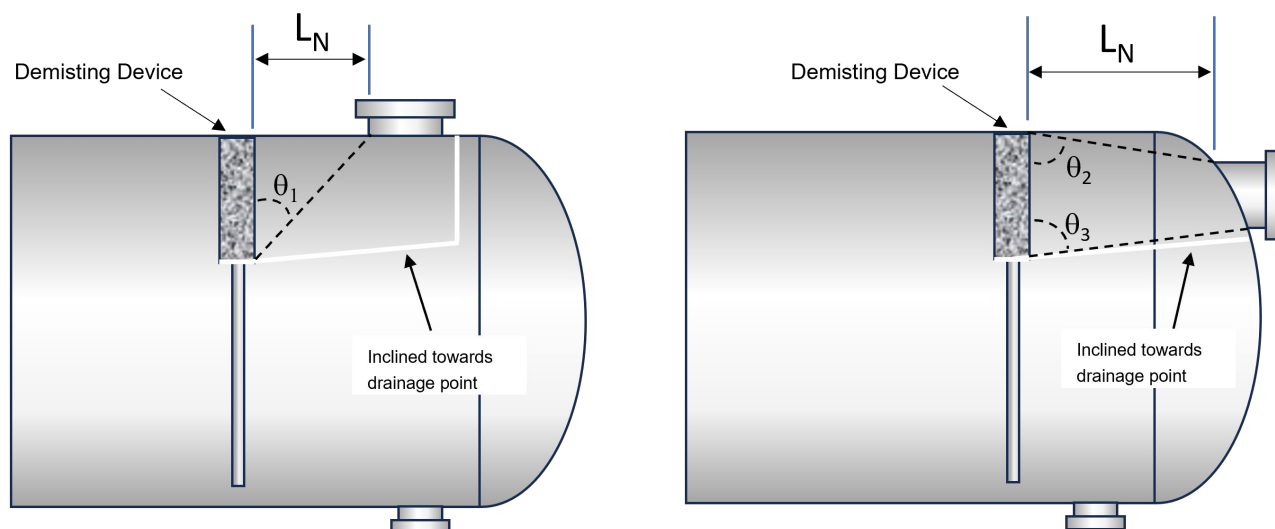
NOTE 4 Additional spacings, due to mechanical requirements, may be necessary and should be accounted for in the design.

NOTE 5 The height of LSL from BOV is the greater of 1) 150 mm from BOV, or 2) 150 mm from top of elevated outlet, or 3) height of VB. Solids that may settle at the bottom should also be taken into account in the setting of LSL and the bottom of the drainage pipe.

NOTE 6 The mist eliminator drains should normally extend to the oil side of the weir. Exceptions should be made when meeting the water in hydrocarbon requirement is challenging and locating the drain upstream of the weir should be considered. In this case, the downcomer should end in the hydrocarbon phase.

NOTE 7 For a spillover weir, LAH and LSH can be below or above the weir depending upon the size of the oil compartment.

Figure 4—Overview of Specifications for a Horizontal Three-phase Separator



Where $\theta_1, \theta_2, \theta_3 \geq 45\text{-deg}$ and distance $L_N \geq 250 \text{ mm}$

Figure 5—Gas Outlet Nozzle Spacings from the Mist Eliminator for a Horizontal Separator

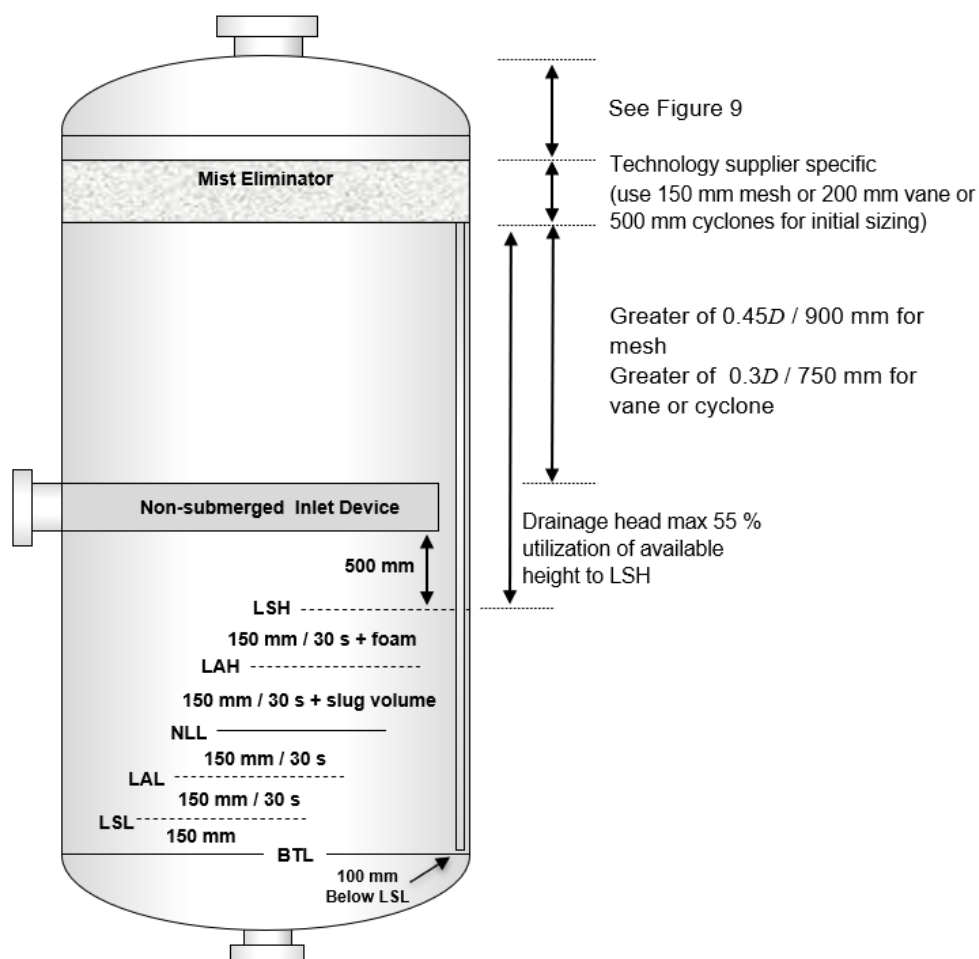


Figure 6—Overview of Specifications for a Vertical Two-phase Separator with a Single Mist Eliminator