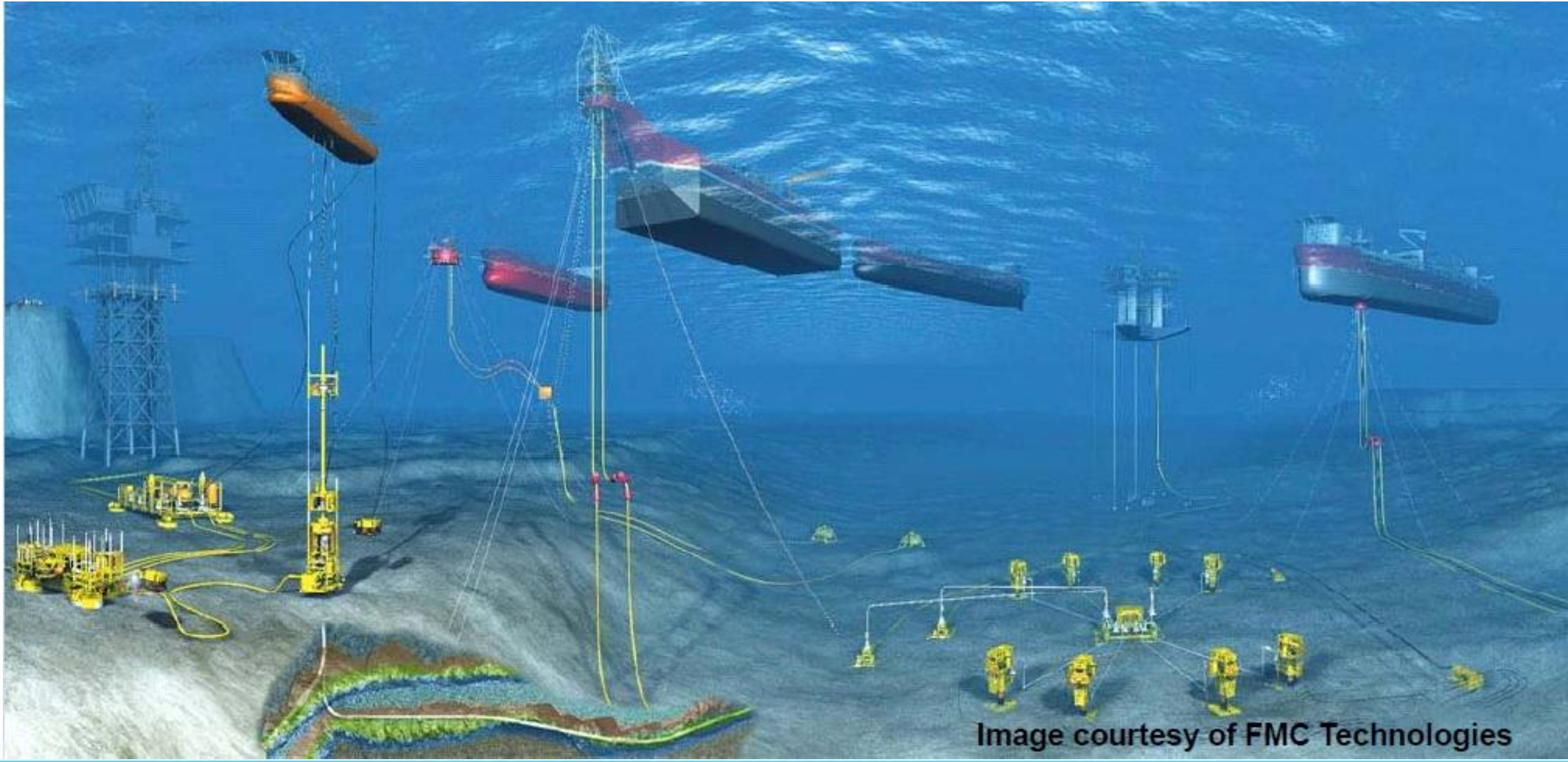


Offshore platform FEED

Yutaek Seo

Equation of State (EOS)

- Definition

  : An analytic expression relating pressure to temperature and volume

- The EOS for petroleum mixtures are mathematical relations between volume, pressure, temperature, and composition, which are used for describing the system state and transitions between states.

- Most thermodynamic and transport properties in engineering analyses are derived from the EOS.

Ideal gas law

- Combining Boyle's Law with Charles' Law gives us the ideal gas law:

$$PV = nRT$$

P = absolute pressure of the gas

V = total volume occupied by the gas

n = number of moles of the gas

R = ideal gas constant

T = absolute temperature of the gas

- Sometimes the ideal gas law is written:

$$PV' = RT$$

V = specific molar volume of the gas
(volume per mole)

Ideal gas law - assumptions

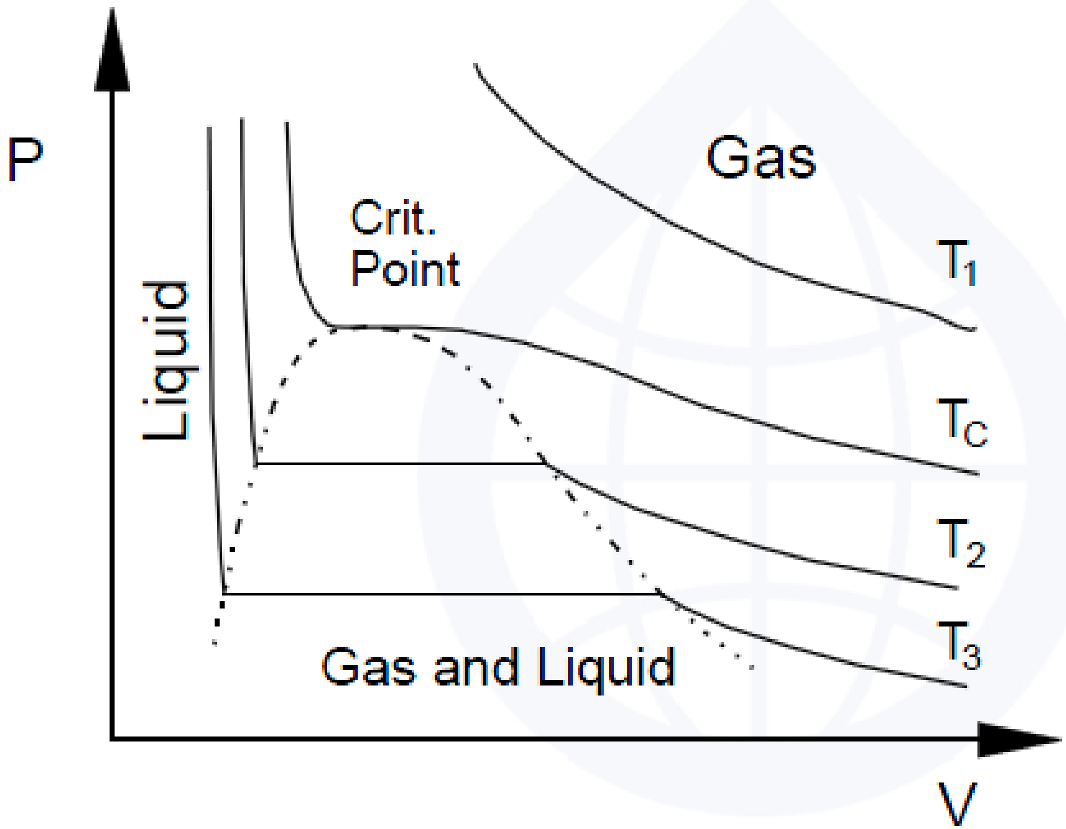
- Most gases are not ideal, certainly not over the range of conditions encountered in oil field applications.
- However, many gases (including mixtures such as air) exhibit behavior approximating closely to ideal at and around standard conditions.
- Ideal behavior pre-supposes properties of a gas as follows

  (neither of which are true)

  1. The molecules of an ideal gas do not occupy any space; they are infinitely small
  2. No attractive forces exist between the molecules so that no gaseous element or compound could ever change state into a liquid or a solid. (no condensation)
  3. The gas molecules move in random and the collisions between the molecules, and between the molecules and the walls are perfectly elastic

Real gas – Phase change & critical point

- At which, vapor and liquid coexist.
- For CO_2, T_c= 31^{o}C and P_c = 72.9atm
- At higher Temperature, only gas exists
- Reduced variables
  : corrected conditions of T, P or V normalized by critical conditions



$$T_1 > T_c > T_2 > T_3$$

$$T_r = \frac{T}{T_c}$$

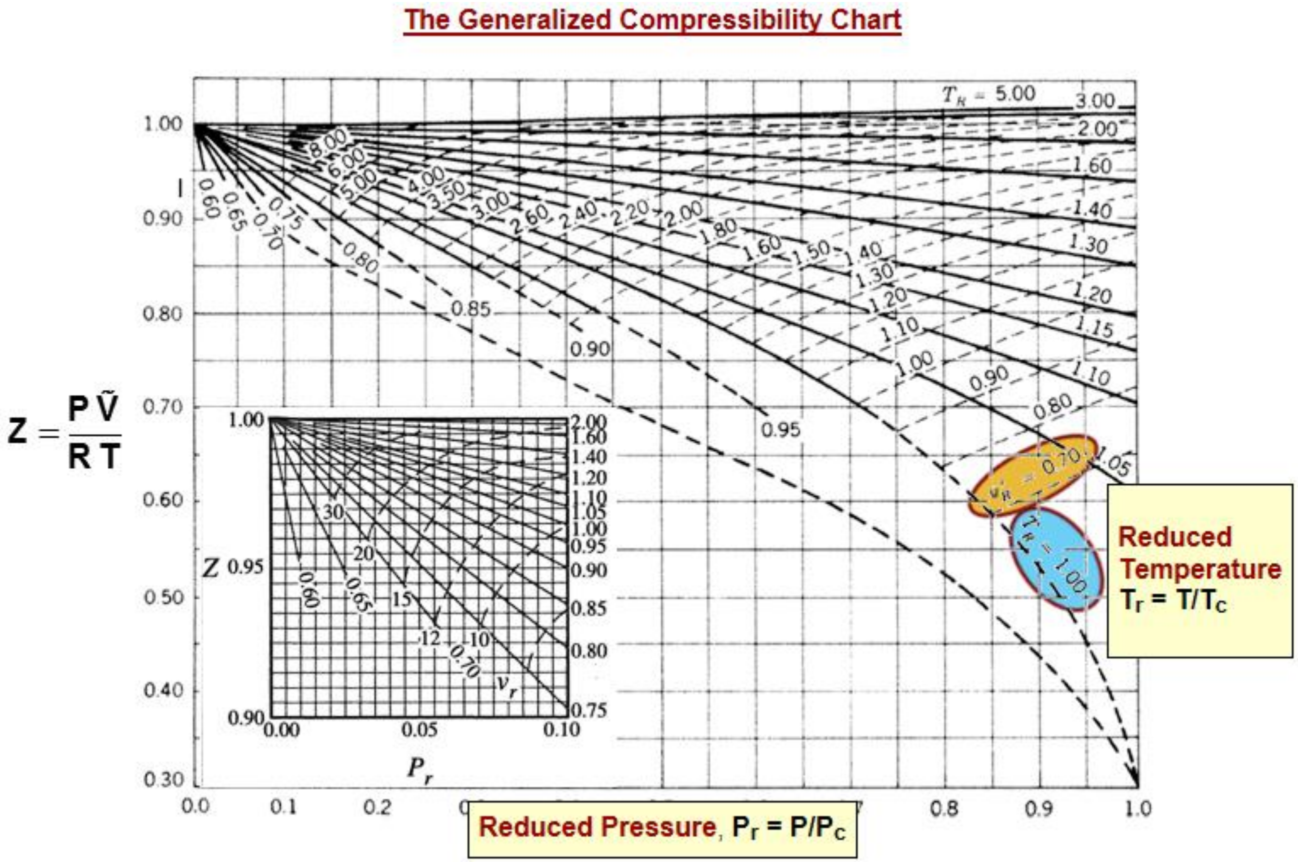
$$P_r = \frac{P}{P_c}$$

$$V_r = \frac{V}{V_c}$$

Compressibility factor - z

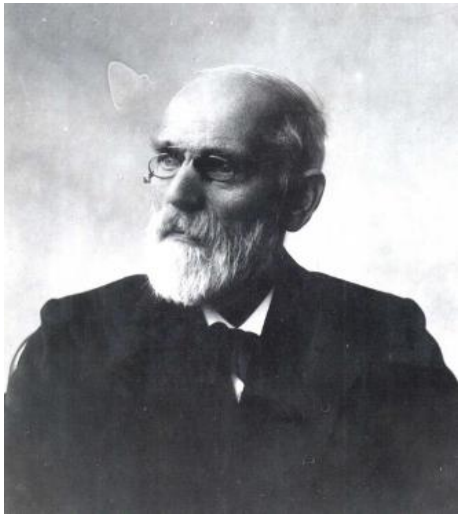
- An adjustable coefficient to compensate for the nonideality of the gas
- The ideal gas law is turned into a real gas law,

$$PV = znRT$$



van der Waals EOS (1873)

- Capable of handling the transition from vapor to liqiuid



$$\left(P + \frac{a}{V^2}\right)(V - b) = RT$$

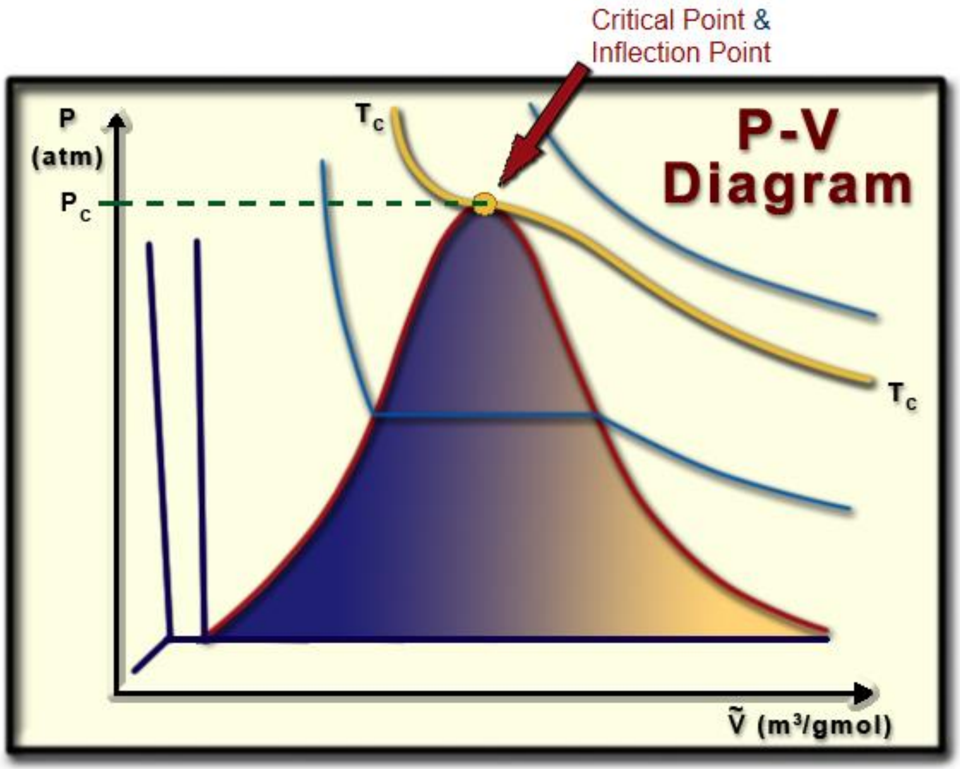
or

$$P = \frac{RT}{(V - b)} - \frac{a}{V^2}$$

- a and b are van der Waals constants
- “a” was introduced to account for the attractive force between molecules, and the “b” parameter to account for the finite (non-zero) volume of the molecules.
- The numerical values of the constants a and b are specific to the gas

- The values of the (a, b) coefficients can be found from noting the behavior of the isotherms on a P-V plot.

$$a = \frac{27\,R^2\,T_c^2}{64\,P_c},\ b = \frac{1\,RT_c}{8\,P_c},\ then\,V_c = \frac{3\,RT_c}{8\,P_c}$$



Soave-Redlich-Kwong (SRK)

- Redlich-Kwong (1949) involves involved a correction of the attractive pressure term

$$P = \frac{RT}{(V-b)} - \frac{a}{V(V+b)T^{1/2}}$$

$$a = 0.42748\frac{R^2T_c^{2.5}}{P_c}, b = 0.08664\frac{RT_c}{P_c}$$

- Soave (1972) introduces additional term for “a” as a function of Acentric factor as well as reduced temperature,

$$P = \frac{RT}{(V-b)} - \frac{\alpha\, a}{V(V+b)}$$

$$a = 0.42748\frac{R^2T_c^{2}}{P_c}, b = 0.08664\frac{RT_c}{P_c}$$

$$\alpha = \left(1 + m\left(1 - T_R^{1/2}\right)\right)^2$$

$$m = 0.48508 + 1.55171\cdot\varpi - 0.1561\cdot\varpi^2$$

Peng-Robinson (PR)

- The major failing of the RK and SRK EoS is the unrealistically high compressibilities Zc=0.333 and consequent poor prediction of liquid densities.
- Peng and Robinson (1976) modified SRK

$$P = \frac{RT}{(V-b)} - \frac{\alpha\, a}{V(V+b)+b(V-b)}$$

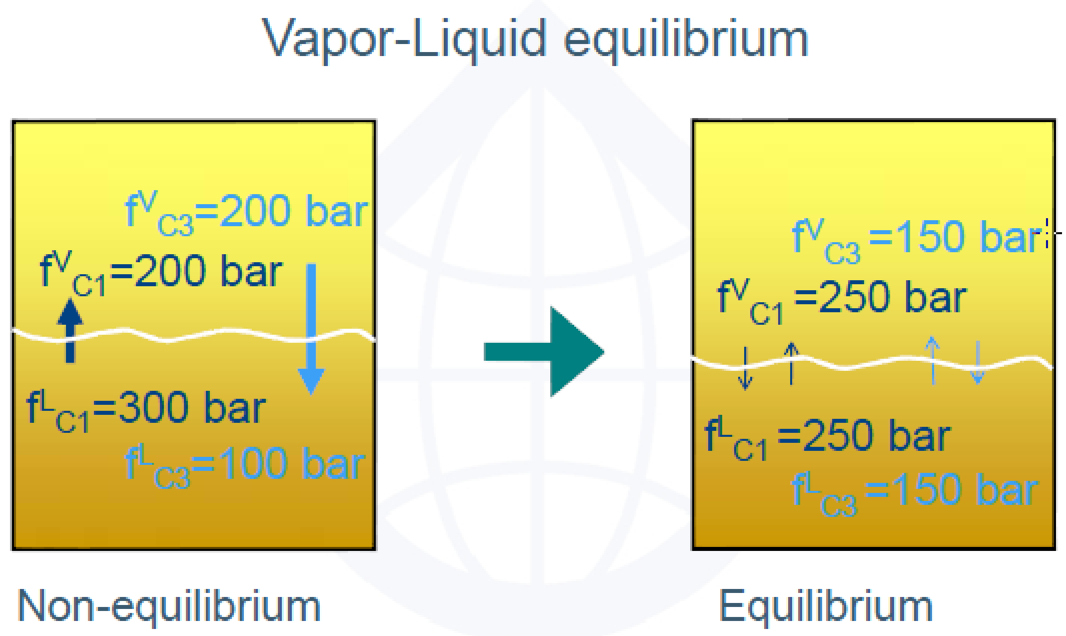
$$a = 0.45724\frac{R^2T_c^2}{P_c},\ b = 0.07780\frac{RT_c}{P_c}$$

$$\alpha = \left(1 + m\left(1 - T_R^{1/2}\right)\right)^2$$

$$m = 0.37464 + 1.5422 \cdot \varpi - 0.26992 \cdot \varpi^2$$

Phase equilibrium

- At equilibrium all components will have the same fugacity (f_i) in all phases.
- Fugacities may be understood as effective partial pressures taking into account non-ideal interactions with other molecules



Partial pressure and fugacity

- Partial pressure of components i: $p_i = z_i P$
- Fugacity of component i: $f_i = z_i \varphi_i P$
- φ_i = fugacity coefficient of component i

$$\ln \varphi_i = \frac{1}{RT} \int_0^P \left[\left(\frac{\partial V}{\partial z_i} \right)_{T,V,z_j} - \frac{RT}{P} \right] dP$$

Fluid modeling

- Parameters for EOS modeling of reservoir fluids

- Temperature range
- Pressure range
- Composition
- Experimental data
- Critical and other properties of components

    Tc, Pc, *Acentric factor*

    Molecular weight

    Ideal gas heat capacities

    Liquid density

    Normal boiling point

- Binary interaction parameters (k_{ij})

- The EOS models calculate (for a given composition, T & P):

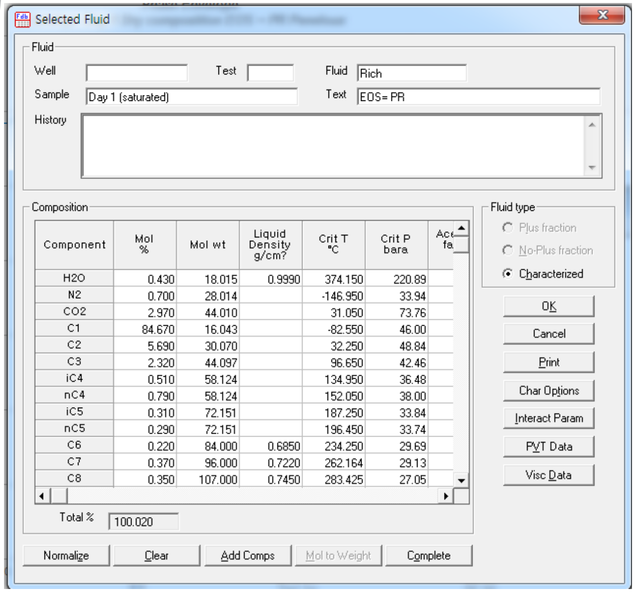
- Density
- Phase behavior
- Enthalpy & entropy

- They do not calculate (done with other correlations)

- Viscosity
- Thermal conductivity
- Interfacial tension

- Aqueous and polar components require special calculations

Simulation Example – PVTSim



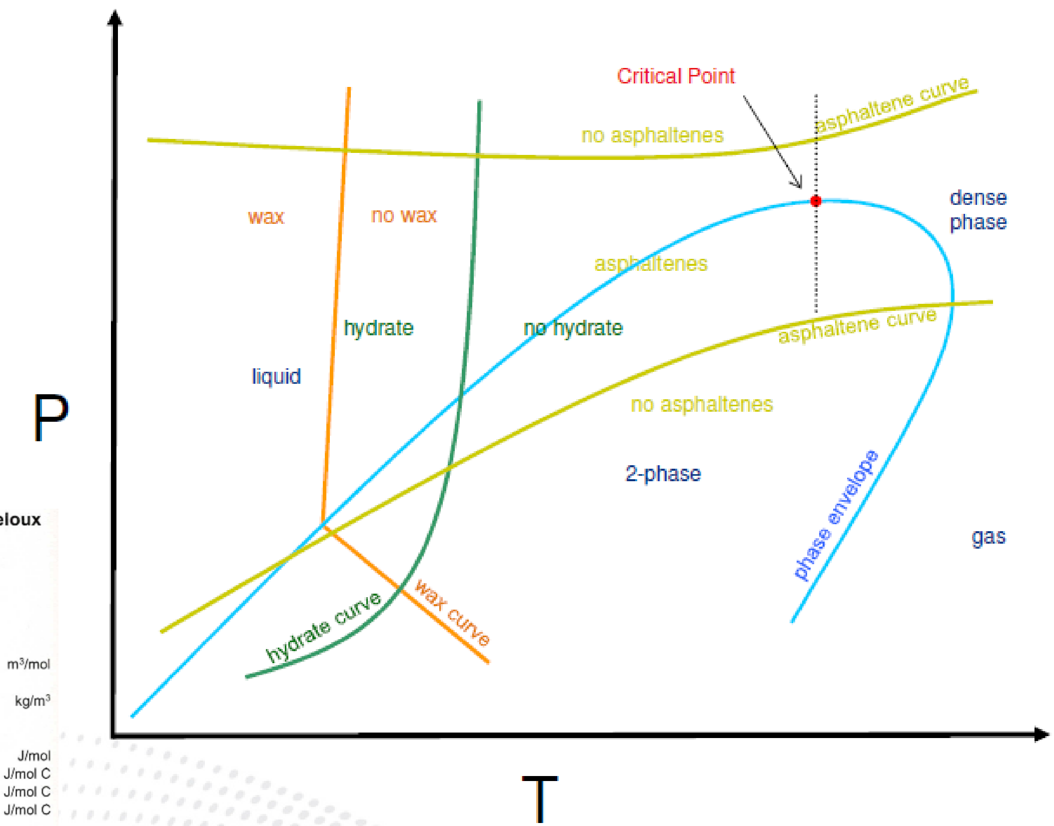
Component	Mol %	Mol wt	Liquid Density g/cm?	Crit T °C	Crit P bara
H2O	0.430	18.015	0.9990	374.150	220.89
N2	0.700	28.014		-146.950	33.94
CO2	2.970	44.010		31.050	73.76
C1	84.670	16.043		-82.550	46.00
C2	5.690	30.070		32.250	48.84
C3	2.320	44.097		96.650	42.46
iC4	0.510	58.124		134.950	36.48
nC4	0.790	58.124		152.050	38.00
iC5	0.310	72.151		187.250	33.84
nC5	0.290	72.151		196.450	33.74
C6	0.220	84.000	0.6850	234.250	29.69
C7	0.370	96.000	0.7220	262.164	29.13
C8	0.350	107.000	0.7450	283.425	27.05

Test1 DST1 Gas Cond Recombined to C 10+ EOS = SRK Peneloux

PT Flash at
101.32 kPa
288.15 K

	Total	Vapor	Liquid	
Mole %	100.00	92.60	7.40	
Weight %	100.00	59.50	40.50	
Volume	0.02	0.02	0.00	m³/mol
Volume%	100.00	99.92	0.08	
Density	1.5303	0.9112	811.5367	kg/m³
Z Factor	0.9234	0.9964	0.0095	
Molecular Weight	33.41	21.47	182.76	
Enthalpy	-4088.4	576.9	-62435.0	J/mol
Entropy	0.20	9.05	-110.56	J/mol C
Heat Capacity (Cp)	65.28	41.12	367.48	J/mol C
Heat Capacity (Cv)	55.52	32.67	341.33	J/mol C
Kappa (Cp/Cv)	1.176	1.259	1.077	
JT Coefficient		0.6841	-0.0503	C/bara
Velocity of Sound		373.5	1177.6	m/s
Viscosity		0.0000	0.0036	Pa s
Thermal Conductivity		28.993	130.668	mW/m C
Surface Tension		0.022	0.022	N/m

Volume, Enthalpy, Cp and Cv are Per Mole Phase



Which EOS to use?

- SRK or PR(78) company standard?
  - Choose that one
  - PR densities better than SRK if no volume correction
- Peneloux volume correction
  - Always to be used when density counts
  - SRK and PR equally good with volume correction
- Peneloux(T)

$$c = c + c'(T - 288.15\,K)$$

  - Recommended for heavy oils (improves shrinkage factor from reservoir to surface conditions)

Natural Gas Pipeline Modeling

- Once natural gas is produced and processed, few to several hundred kilometers may lie in between it and its final consumers.
- A cost-effective means of transport is essential to bridge the gap between the producer and consumer. In the technological area, one of the challenges pertains to the capacity of the industry to ensure continuous delivery of natural gas while its demand is steadily increasing.
- Thus, it is no wonder that pipelines have become the most popular means of transporting natural gas from the wellhead to processing — and from there to the final consumer — since it better guarantees continuous delivery and assures lower maintenance costs.

- The major variables that affect the design of gas pipelines are

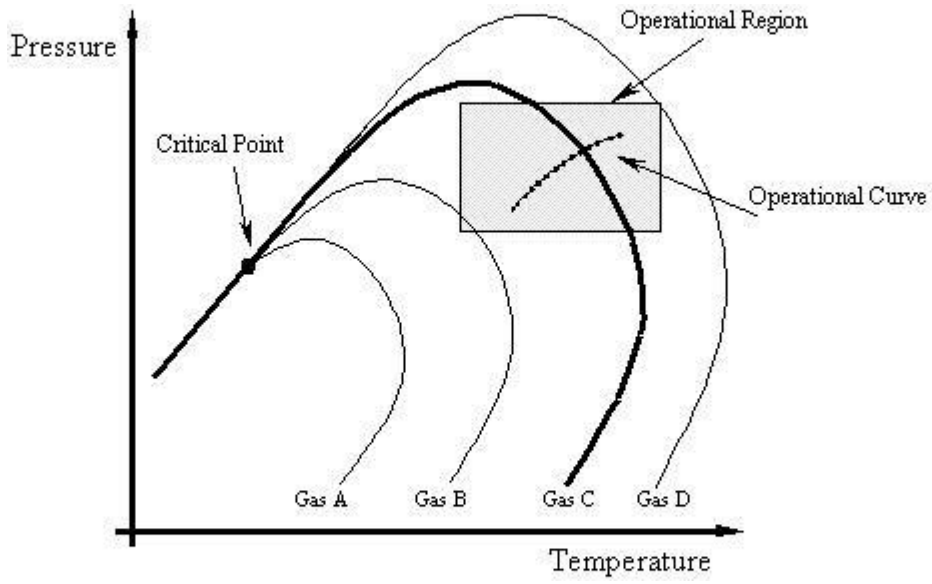
  : the projected volumes that will be transported,

  : the required delivery pressure (subject to the requirements of the facilities at the consumer end),

  : the estimated losses due to friction,

  : the elevation changes imposed by the terrain topography.
- Overcoming such losses will likely require higher pressure than the one available when the gas is being produced. Thus, forcing a given gas rate to pass through a pipeline will inevitably require the use of compressor stations.

- The foregoing description of the operational region is shown schematically as the shaded area in this figure.



- In natural gas flow, pressure and temperature changes (P-T trace) may cause formation of a liquid phase owing to partial condensation of the gaseous medium.

- Retrograde phenomenon — typically found in multi-component hydrocarbon systems — takes place by allowing condensation of the gas phase and liquid appearance even under expansion of the flowing stream.
- The same phenomenon may also cause vaporization of the liquid phase such that it reenters the gas phase.
- Liquid and gas phase composition are continuously changing throughout the pipe due to the continuing mass transfer between the phases.
- In general, the amount of heavies in the stream determines the extent of the retrograde behavior and liquid appearance. Previous figure shows a P-T trace or operational curve for a given pipeline, which is always found within the pipeline operational region.

- The wetness of the gas is an important concept that helps to explain the different features in the figure.
- This concept pertains to the amount of heavy hydrocarbons (high molecular weight) that are present in the gas composition.
- In the figure the driest gas — i.e., the least wet — can be recognized as that whose left and right arms are the closest to each other, having the smallest two-phase region (gas A).
- In this figure, it can be seen that the right arm is extremely susceptible to the presence of heavies in the natural gas composition. Depending on the gas composition, the pipeline operational region can be either completely free of liquid (gas A, the driest) or partially submerged in the two-phase region (gas B, C). If the gas is wet enough, the pipeline will be entirely subjected to two-phase conditions (gas D, the wettest).

- In the figure, a pipeline handling a dry gas (gas A) will be operating a single-phase mode from its inlet through its outlet. For this case, any of the popular single-phase gas equations (Weymouth, Panhandle type, AGA equation) can be used for design purposes and to help to predict the actual operational curve (P-T trace).
- If a richer gas comes into the system (gas C), it will show a single-phase condition at the inlet, but after a certain distance the pressure and temperature conditions will be within the two-phase region.
- The case might also be that the system is transporting a wetter gas (gas D), in which case it would encounter two-phase conditions both at the inlet and at the outlet of the pipe.

Two-phase oil and gas separation

Introduction

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

Phase equilibrium

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

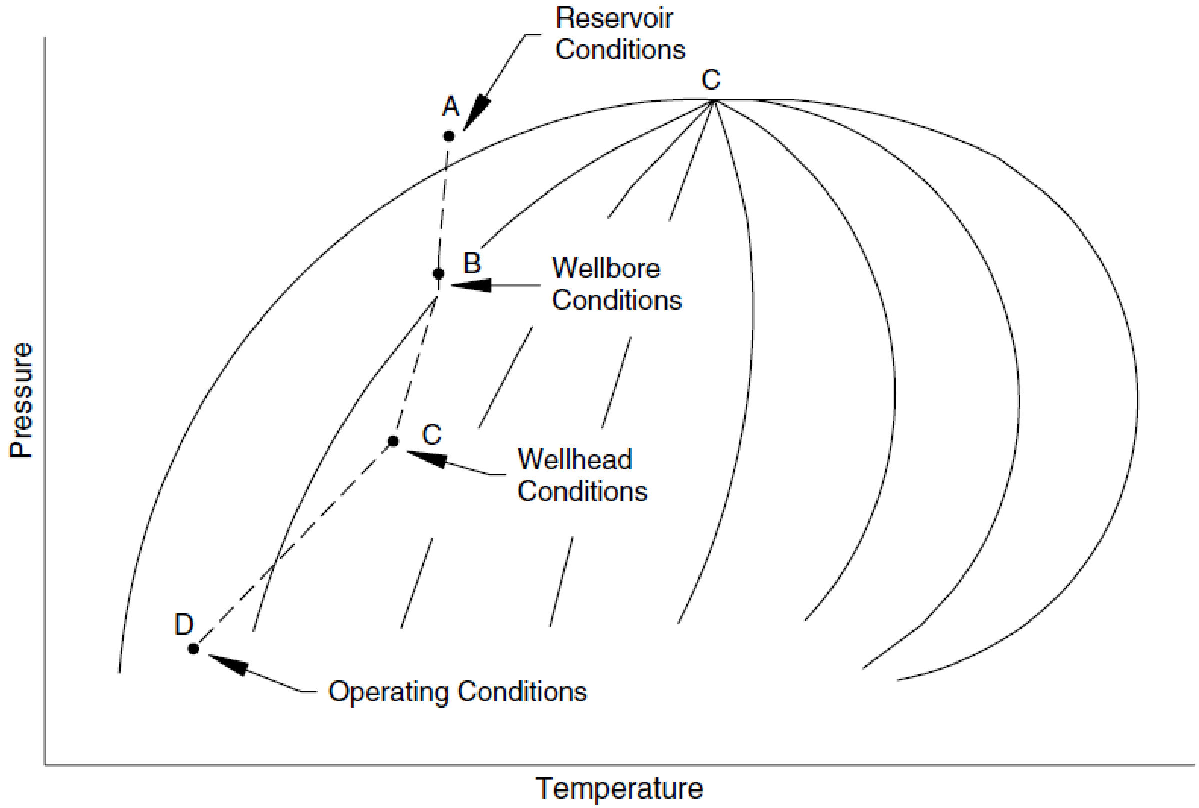


Figure 4-1. Phase equilibrium phase diagram for a typical production system.

Factors affecting separation

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

Functional section of a Gas-Liquid separator

- Inlet Diverter Section

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

- Liquid Collection Section

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

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

- Gravity Settling Section

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

- Mist Extractor Section

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

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

Equipment description

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

<u>Horizontal separators</u>

: The liquid collection section provides the retention time required to let entrained gas evolve out of the oil and rise to the vapor space and reach a state of “equilibrium.”

: It also provides a surge volume, if necessary, to handle intermittent slugs of liquid.

: The liquid dump valve is regulated by a level controller. The level controller senses changes in liquid level and controls the dump valve accordingly.

: The pressure in the separator is maintained by a pressure controller mounted on the gas outlet. The pressure controller senses changes in the pressure in the separator and sends a signal to either open or close the pressure control valve accordingly.

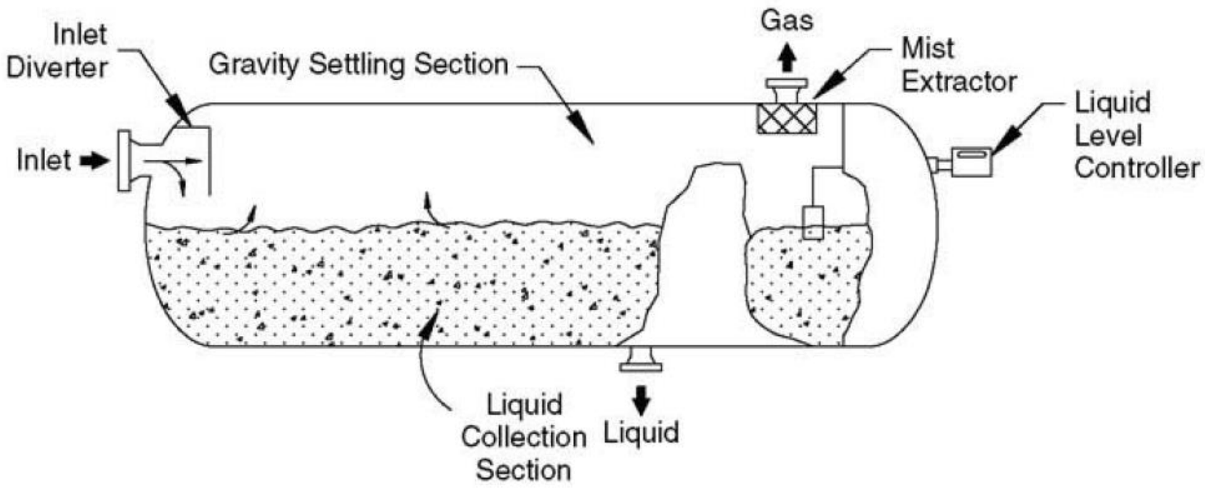


Figure 4-4. Cutaway view of a horizontal two-phase separator.

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

Vertical separators

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

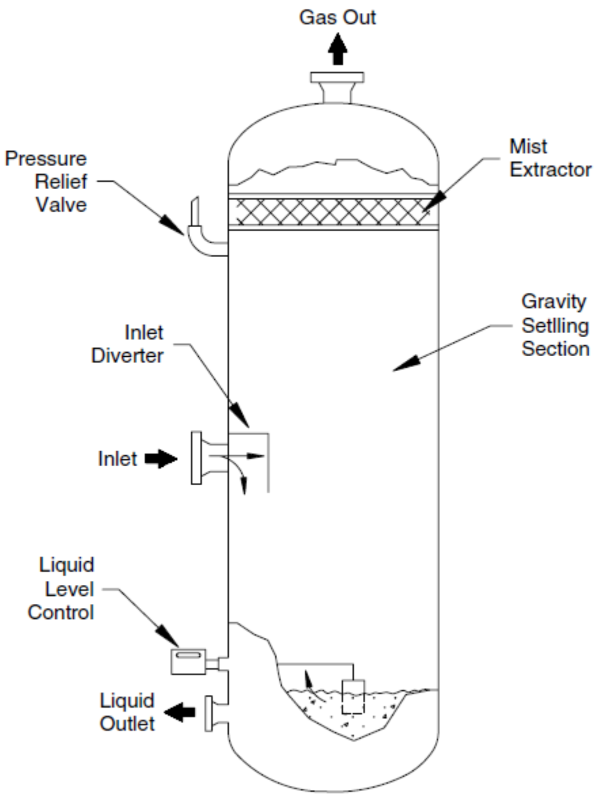


Figure 4-5. Cutaway view of a vertical two-phase separator.

Primary separation

- Primary separation is accomplished by utilizing the difference in momentum between gas and liquid.
- Larger liquid droplets fail to make the sharp turn and impinge on the inlet wall.
- This action coalesces finer droplets so that they drop out quickly.
- Although inlet geometries vary, most separators use this approach to knock out a major portion of the incoming liquid.

Vessel internals

Inlet diverters

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

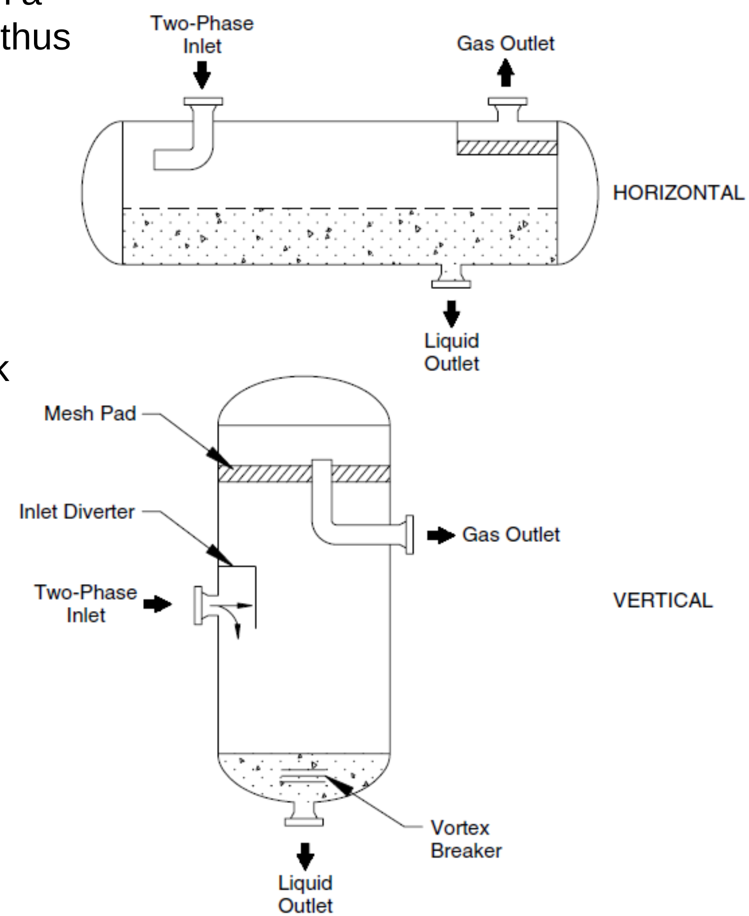


Figure 4-17. Elbow inlet diverter.

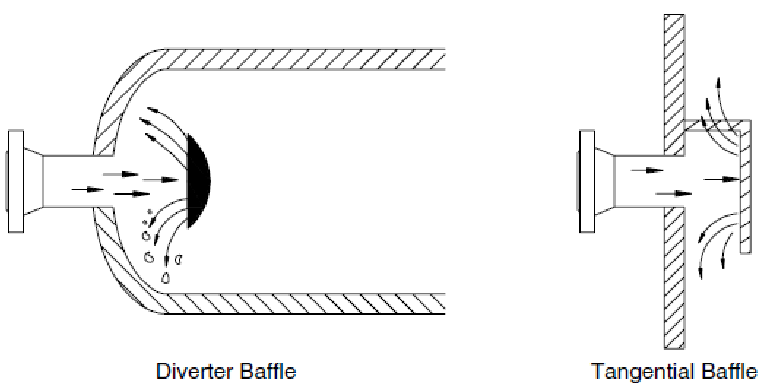


Figure 4-15. Baffle plates.

Defoaming plates

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

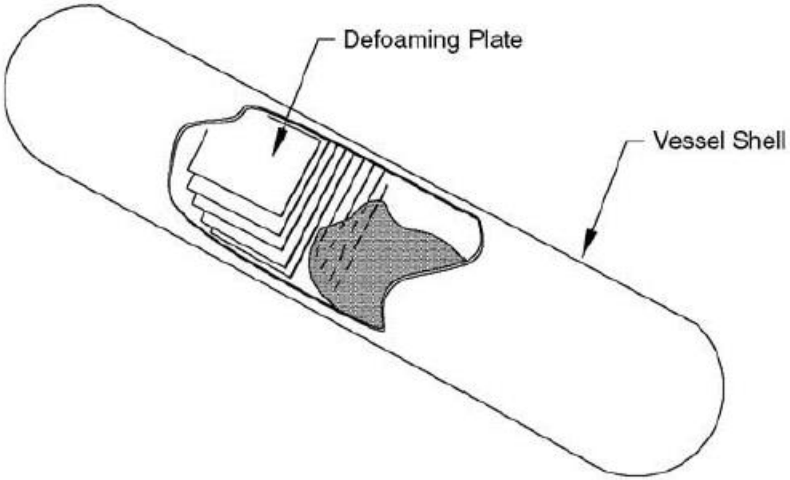


Figure 4-20. Defoaming plates.

Gravity settling

- Gravity settling requires low gas velocities with minimal turbulence to permit droplet fallout.
- The terminal-settling velocity, V_T, for a sphere falling through a stagnant fluid is governed by particle diameter, density differences, gas viscosity, and a drag coefficient that is a function of both droplet shape and Reynolds number.
- the Reynolds number is defined as

$$N_{Re} = D_P V_T \rho_g / \mu_g, \qquad (3.4)$$

where D_p is particle diameter, ρ_g is the density, and μ_g is the viscosity.

- Thus, calculations for V_T are an iterative process.

- For large particles (1,000 to ~70,000 micron), the terminal velocity is computed by the equation

$$V_T = 1.74\sqrt{\frac{gD_p(\rho_l - \rho_g)}{\rho_g}} \quad , \qquad (3.5)$$

where g is the gravitational constant.

- This equation, known as Newton's law, applies when the Reynolds number is greater than 500.
- If the particle size is too large, excessive turbulence occurs and Eq (3.5) fails. The upper limit is found by use of the equation

$$D_P = K_{CR}\left[\frac{\mu_g^2}{g\rho_g(\rho_l - \rho_g)}\right]^{\frac{1}{3}} \qquad (3.6)$$

With K_{CR} = 18.13 and 23.64 for engineering and metric units, respectively, and is based upon a Reynolds number of 200,000, which is the upper limit for Newton's law to hold.

- At the other extreme, where the flow is laminar (NRe < 2), Stokes' law applies. The terminal velocity is

$$V_T = \frac{1{,}488 g D_p^2 (\rho_g - \rho_l)}{18\mu_g} \qquad (3.7a)$$

$$V_T = \frac{1{,}000 g D_p^2 (\rho_g - \rho_l)}{18\mu_g} \qquad (3.7b)$$

where Eq (3.7a) is in English units and Eq (3.7b) is in SI.

- Stokes' law applies to particles in the 3 to 100 micron range.
- To find the maximum size particle in this flow regime, use K_{CR} = 0.0080 in Eq (3.6), which corresponds to an N_{Re} of 2.
- Particles smaller than 3 microns will not settle because of Brownian motion.

- Unfortunately, droplets that condense from a vapor tend to be in the 0.1 to 10 micronrange; the majority are around 1 micron.
- Entrained droplets are 100 times larger. To reduce turbulence, the settling section may contain vanes. They also act as droplet collectors to reduce the distance droplets must fall.

Liquid collection

- The liquid collection section acts as a holder for the liquids removed from the gas in the above three separation sections.
- This section also provides for degassing of the liquid and for water and solids separation from the hydrocarbon phase.
- The most common solid is iron sulfide from corrosion, which can interfere with the liquid-liquid separation. If a large amount of water is present, separators often have a “boot,” as shown in the horizontal separator, at the bottom of the separator for the water to collect.
- The Engineering Data Book (2004) estimates that retention times of 3 to 5 minutes are required for hydrocarbon-water separation by settling.

Residence time for separator applications

- The residence time is simply the volume of the phase present in the vessel divided by the volumetric flow rate of the phase.
- Table 3.3 provides typical retention times for common gas-liquid separations

TABLE 3.3
Typical Retention Times for Gas-Liquid Separations

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

[a] If the fractionator column sump is feeding a downstream fractionator column, it should be sized as a feed tank (McCartney, 2005).
[b] This vessel must have adequate space to allow for expansion of the heat medium from ambient to operating temperature (McCartney, 2005).

Source: Engineering Data Book (2004b).

Wave breakers

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

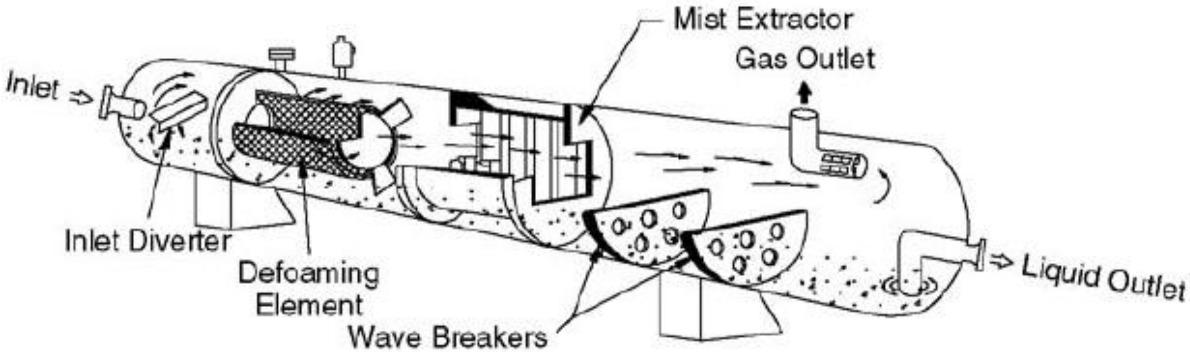


Figure 4-19. Three-dimensional view of a horizontal separator fitted with an inlet diverter, defoaming element, mist extractor, and wave breaker.

Vortex breaker

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

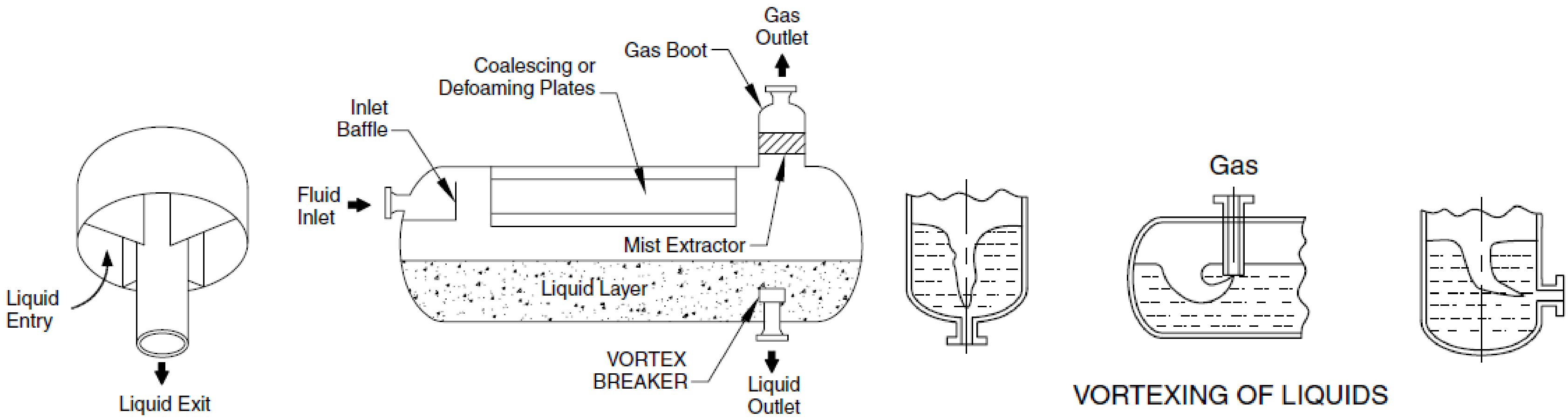


Figure 4-21. Vortex breaker.

Stilling well

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

Sand jets and drains

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

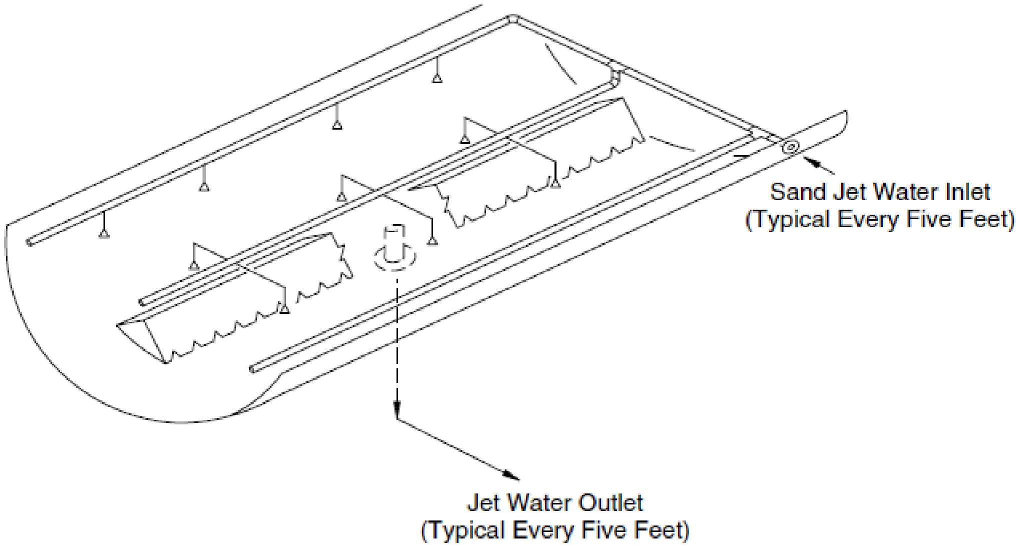


Figure 4-23. Schematic of a horizontal separator fitted with sand jets and inverted trough.

Coalescing

Mist extractors

- Before a selection can be made, one must evaluate the following factors:

  : Size of droplets the separator must remove

  : Pressure drop that can be tolerated in achieving the required level of removal

  : Susceptibility of the separator to plugging by solids, if solids are present

  : Liquid handling capability of the separator

  : Whether the mist extractor/eliminator can be installed inside existing equipment, or if it requires a standalone vessel instead

  : Availability of the materials of construction that are comparable with the process

  : Cost of the mist extractor/eliminator itself and required vessels, piping, instrumentation, and utilities

- All mist extractor types are based on the some kind of intervention in the natural balance between gravitational and drag forces

  : Overcoming drag force by reducing the gas velocity (gravity separators or settling chambers)

  : Introducing additional forces (venturi scrubbers, cyclones, electrostatic precipitators)

  : Increasing gravitational force by boosting the droplet size (impingement-type)

- Baffles

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

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

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

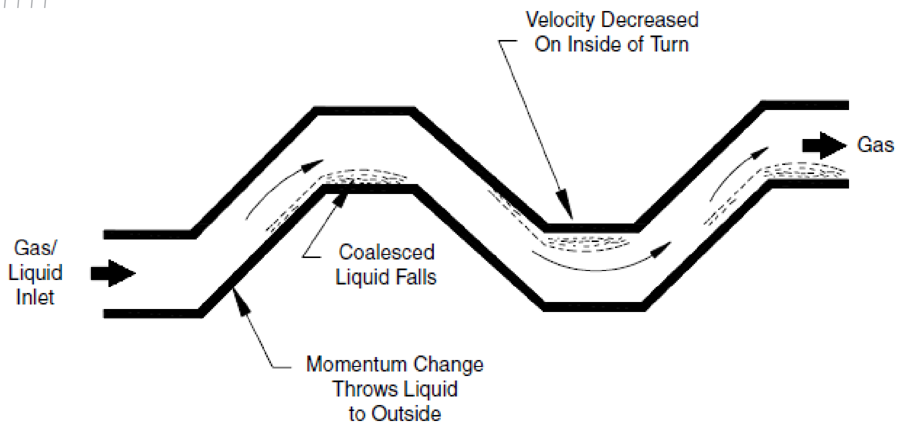


Figure 4-25. Typical vane-type mist extractor/eliminator.

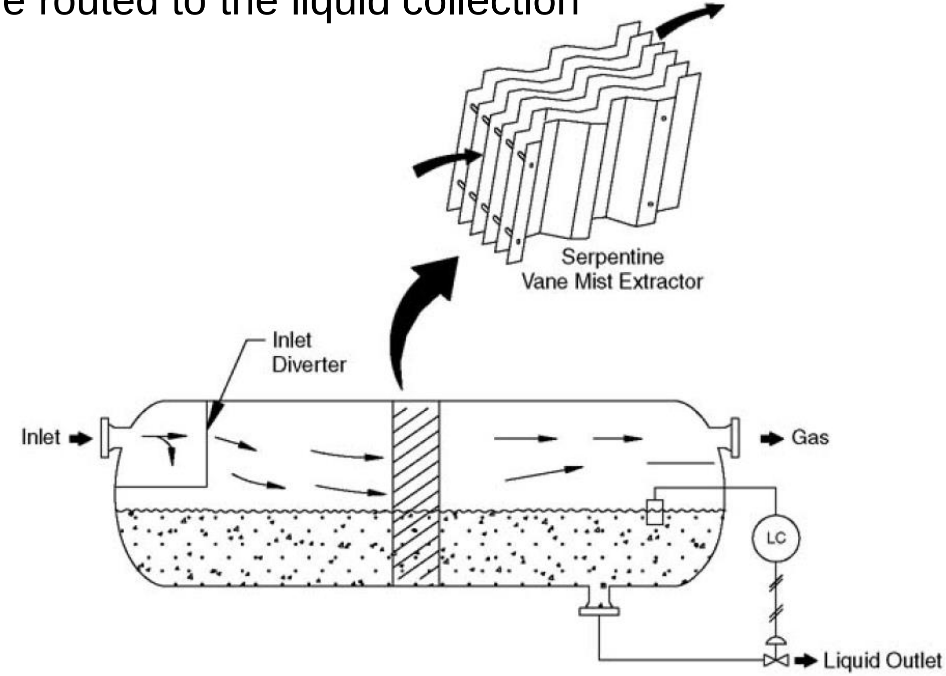


Figure 4-28. Cutaway view of a horizontal separator fitted with a vane-type mist extractor.

- Wire-mesh

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

  : have high surface area and void volume.

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

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

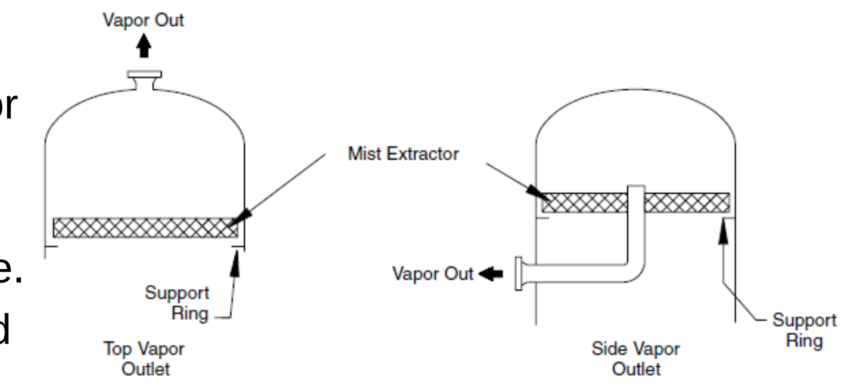


Figure 4-32. Vertical separators fitted with wire-mesh pads supported by support rings.

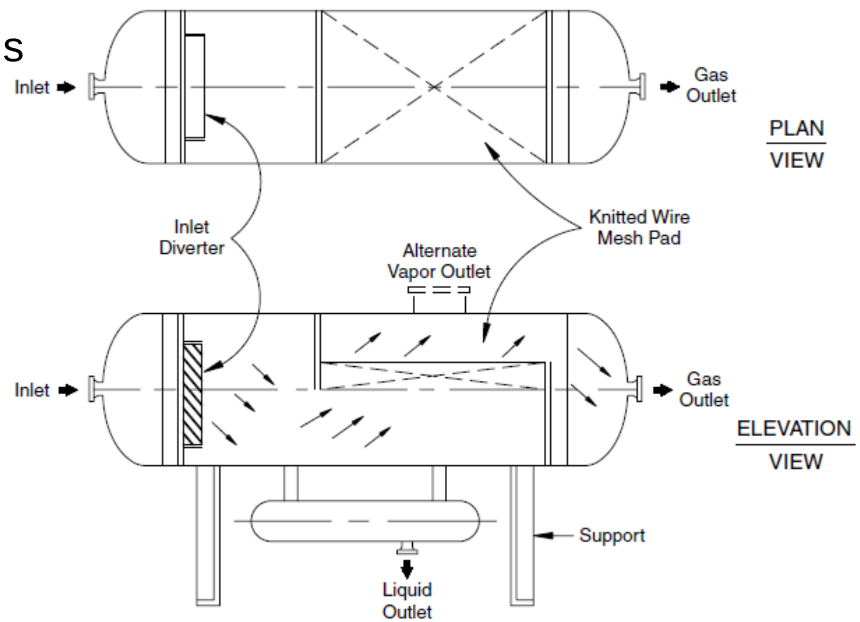


Figure 4-33. Horizontal separator fitted with wire-mesh pads supported by a frame.

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

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

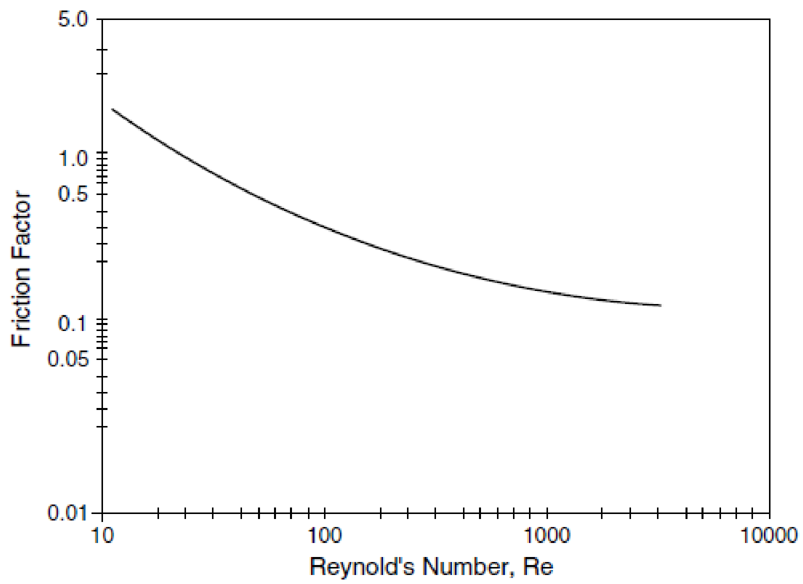


Figure 4-34. Friction factor versus Reynolds number for a dry knitted wire-mesh extractor.

- Micro-fiber

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

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

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

Table 4-1
Features of Impingement-Type Mist Extractors

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

- Final selection

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

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

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

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

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

- Figure 3.13 shows qualitatively the range for mist pads and vane packs. The data are based upon an air-water system and differs from natural gas data because of density and surface tension.

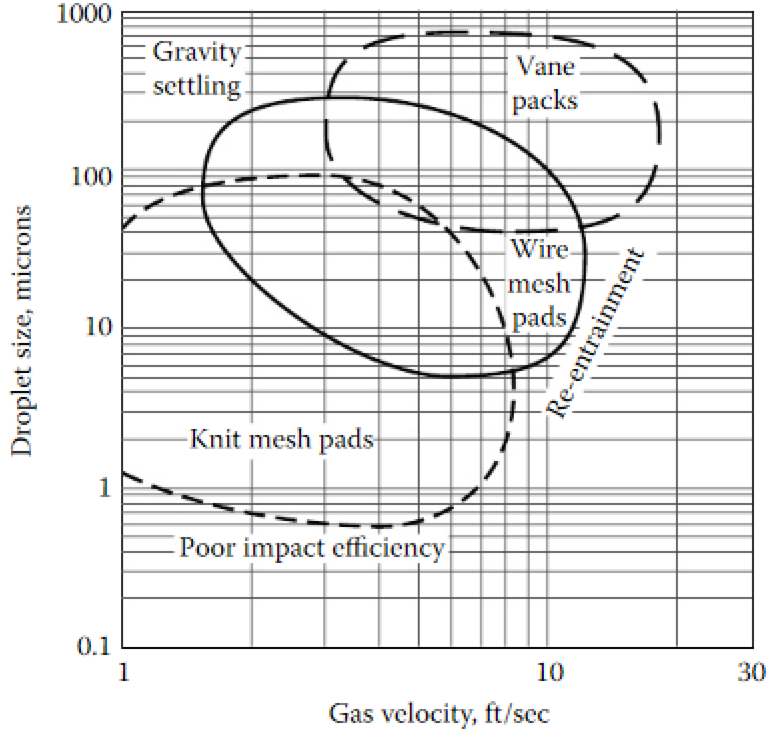


FIGURE 3.13 Approximate operating ranges for different kinds of demisters. Data are based upon water and air. (Courtesy of ACS Industries, 2005.)

- Figure 3.13 shows the regions where each demister type is effective.
- Note that these devices fail to coalesce droplets below around 0.5 micron, and each has both upper and lower velocity limits.
- The lower limit is caused by too low a velocity to force sufficient impinging of the droplets on the solid surface to provide coalescing. At high velocities, the coalesced droplets are stripped from the solid by the high velocity gas.
- The Engineering Data Book (2004) and Bacon (2001) provide design calculations for wire mesh and vane pack coalescing units.

1. Engineering Data Book, 12th ed., Sec. 7, Separation Equipment, Gas Processors Supply Association, Tulsa, OK, 2004.
2. Bacon, T.R, Fundamentals of Separation of Gases, Liquids, and Solids, Proceedings of the Laurance Reid Gas Conditioning Conference, Norman, OK, 2001.

Slug catcher configurations

- This section briefly describes two kinds of slug catchers, manifolded piping and inlet vessels.
- The most difficult part of a slug catcher design is the proper sizing. Sizing requires knowledge of the largest expected liquid slug, as liquid pump discharge capacity on the slug catcher will be trivial compared with the sudden liquid influx.
- Manifolded Piping

  : One reason piping is used instead of separators is to minimize vessel wall thickness. This feature makes piping attractive at pressures above 500 psi (35bar).

  : The simplest slug-catcher design is a single-pipe design that is an increased diameter on the inlet piping. However, this design requires special pigs to accommodate the change in line size.

Slug catcher

: is a special case of a two-phase gas-liquid separator that is designed to handle large gas capacities and liquid slugs on a regular basis.

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

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

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

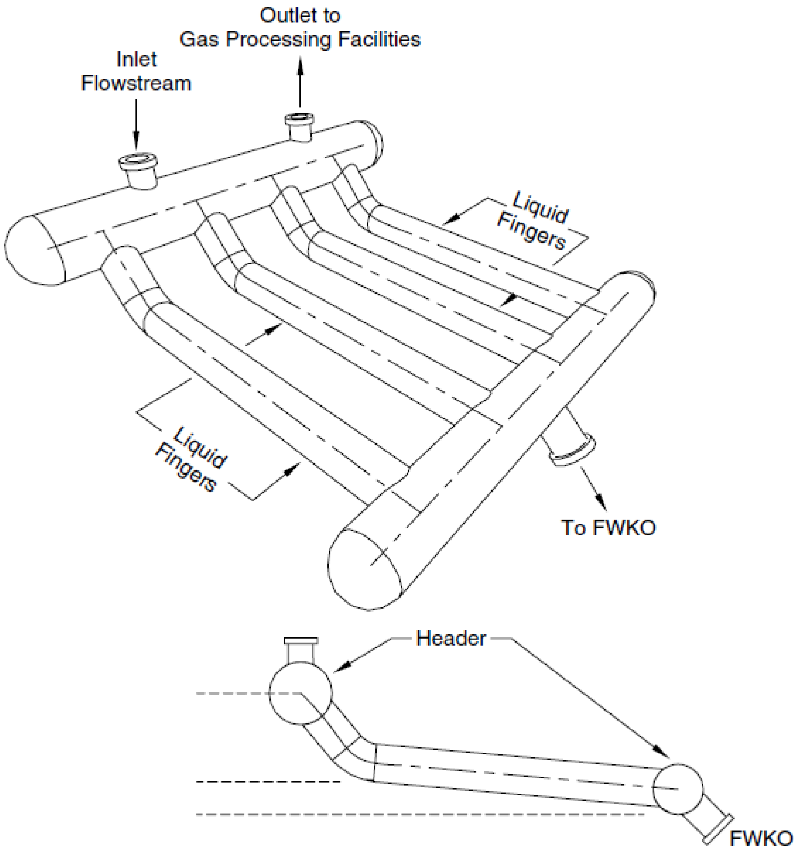
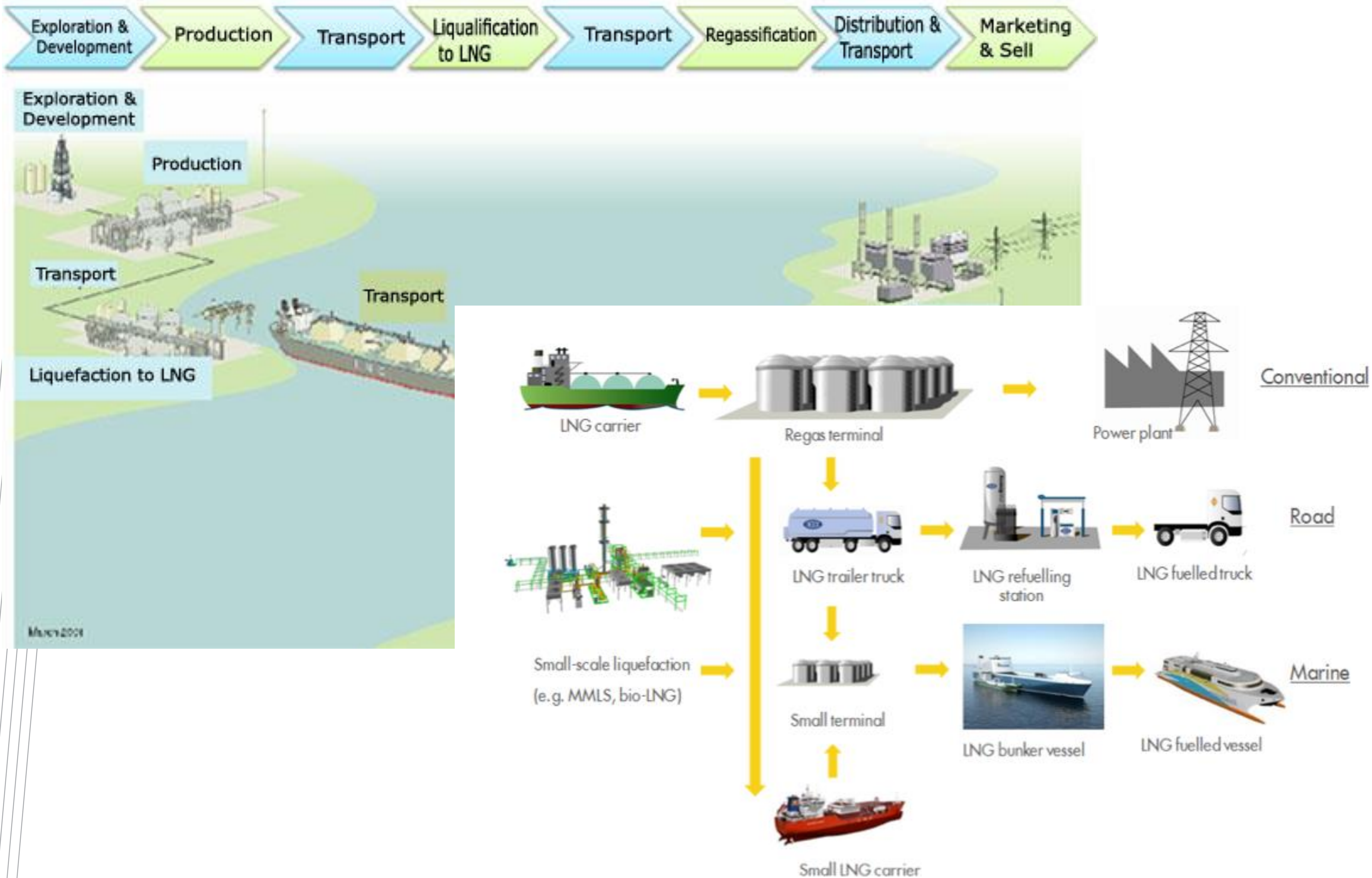


Figure 4-13. Schematic of a two-phase horizontal slug catcher with liquid “fingers.”

- The number of pipes varies, depending upon the required volume and operating pressure. Also, some designs include a loop line, where some of the incoming gas bypasses the slug catcher.
- Primary separation occurs when the gas makes the turn at the inlet and goes down the pipes. Liquid distribution between pipes can be a problem, and additional lines between the tubes are often used to balance the liquid levels. In harp designs, the pipes are sloped so that the liquid drains toward the outlet.
- Gravity settling occurs as the gas flows to the vapor outlet on the top while the liquid flows out the bottom outlet.
- Pipe diameters are usually relatively small(usually less than 48 inches [120 cm]), so settling distances are short.

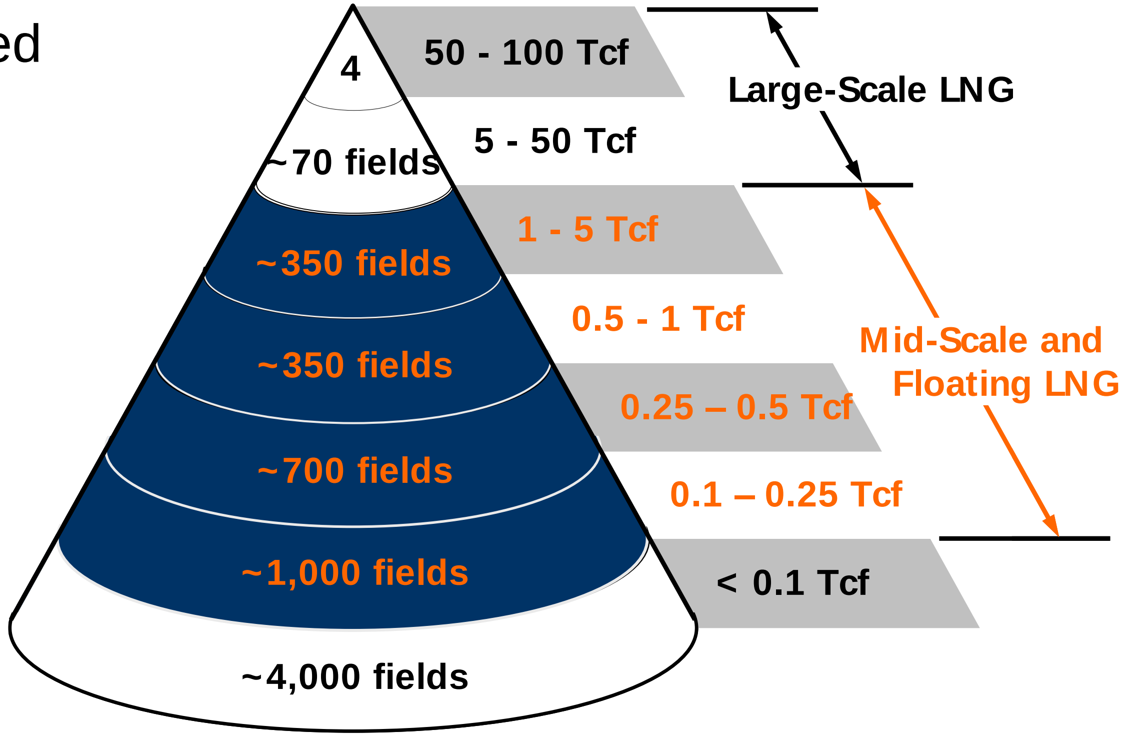
- Because manifolded piping is strictly for catching liquid slugs, demisters are usually installed downstream in scrubbers. Likewise, liquid goes to other vessels, where degassing and hydrocarbon-water separation occurs.
- Several advantages to the pipe design include the fact that design specifications are based upon pipe codes instead of vessel codes.
- Also, the slug catcher can be underground, which reduces maintenance costs and insulation costs if the slug catcher would otherwise need to be heated.

LNG value chain



FLNG opening more gas to development

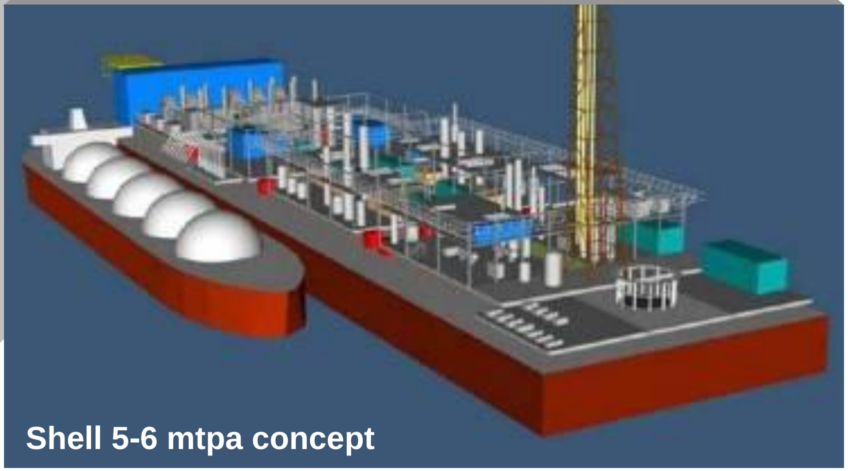
- Accesses gas unsuitable for baseload development
- Eliminates pipeline & loading infrastructure costs
- Reduces security and political risks
- Constructed in controlled shipyard environment
- Can relocate facility upon field depletion



Two distinct development paths emerging

Characteristic	Small-scale Floating LNG	Large-scale Floating LNG
Liquefaction capacity:	less than 3.0 mtpa	3.5 to 6.0 mtpa
Required reserves:	0.5 to 3.0 Tcf	more than 3.0 Tcf
Hull:	Ship-like	Barge-like
Storage capacity:	up to 220,000 m^3	more than 250,000 m^3
Liquefaction processes:	Simpler processes (e.g., Single Mixed Refrigerant processes, dual expander processes)	Baseload-type processes (e.g., Dual MR, Mixed Fluid Cascade)

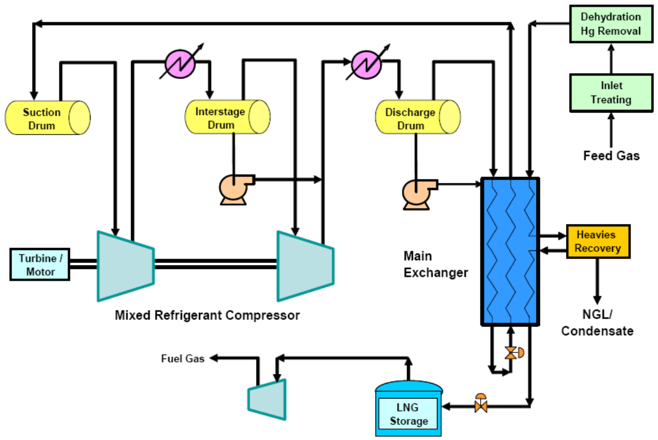
SBM Offshore 2.5 mtpa


Shell 5-6 mtpa concept

Liquefaction choices far from mature

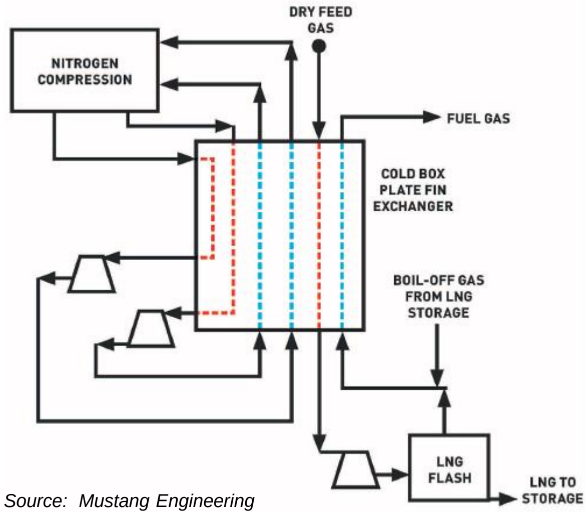
- Need simple, robust and compact liquefaction solutions
  - Single mixed refrigerant cycles
  - Gas expander-based cycles
- Concerns
  - Process efficiencies
  - Scale-up performance
  - LPG refrigerant storage
  - Marine performance and reliability

Black & Veatch PRICO SMR Process



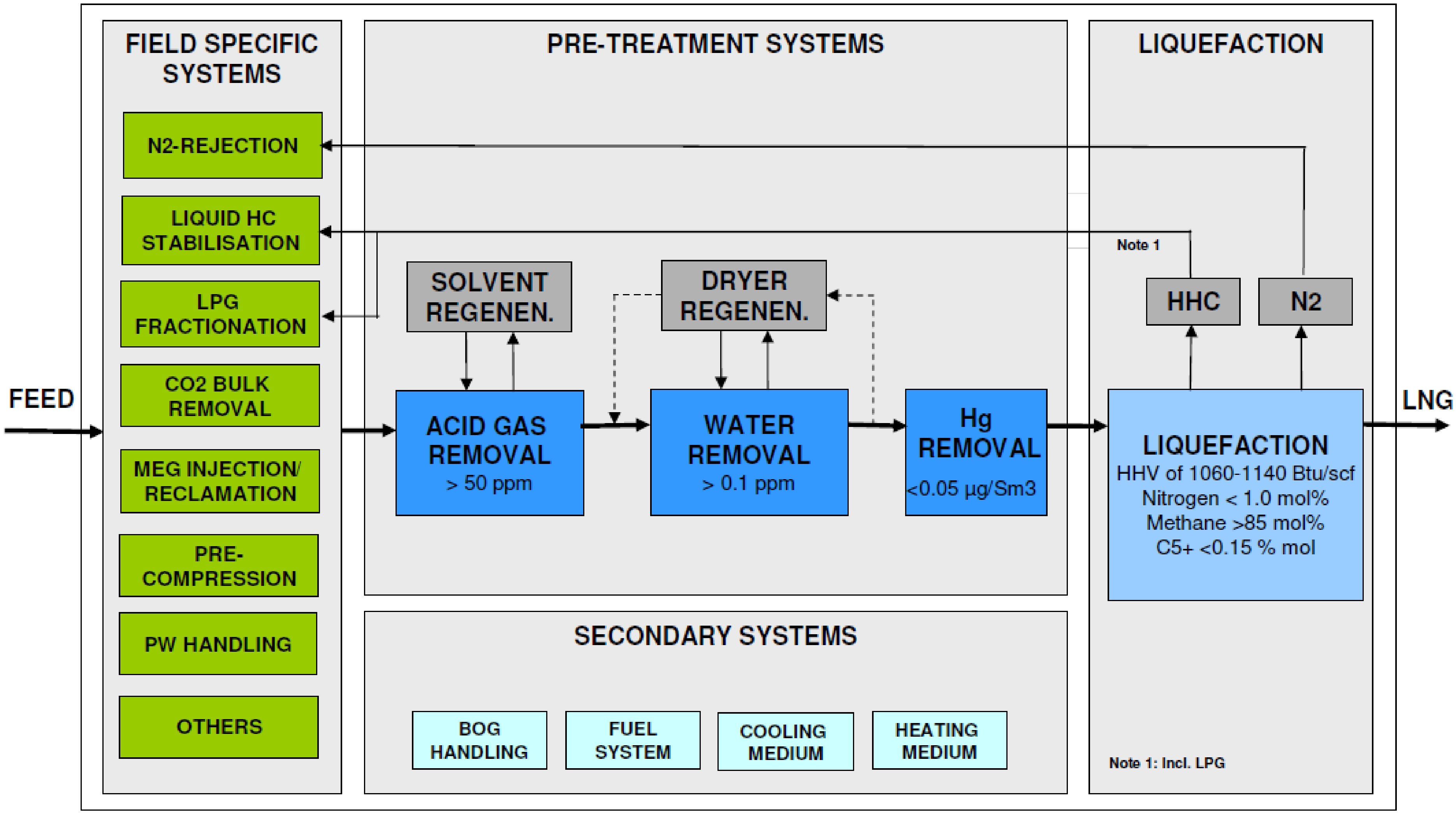
Source: Black & Veatch

Mustang NDX-1 Process (patent pending)



Source: Mustang Engineering

Field specific and pre-treatment systems



Field specific and pre-treatment systems

- Field specific and pre-treatment systems are conventional and not new to the offshore environment.
- Energy optimization is required to integrate the heat- and energy demanding systems in the overall topside.
- Optimize and include the pre-treatment and field specific systems in the fuel gas balance.
- Tall columns with internals must be carefully designed in order to minimize flow maldistribution.
- Avoiding stabilization issues of the condensate or recycle of middle components like propane and butane through the process system.

SYSTEMS	FPSO	LNG FPSO
Liquid separation and stabilisation	X	X
MEG injection and reclamation	X	X
Bulk acid gas removal system	X	X
Acid gas polishing system	✓	X
Molsieve dehydration system	Limited	X
Mercury removal system	X	X
LPG fractionation and stabilisation system	Limited	X
Produced water treatment	X	X
N2-Rejection	✓	X
BOG handling	X	X