Gas Field Operations and Inlet Receiving (*Operasi Lapangan Gas dan Penerimaan Inlet*)

Teknologi Pemrosesan Gas (TKK 564)

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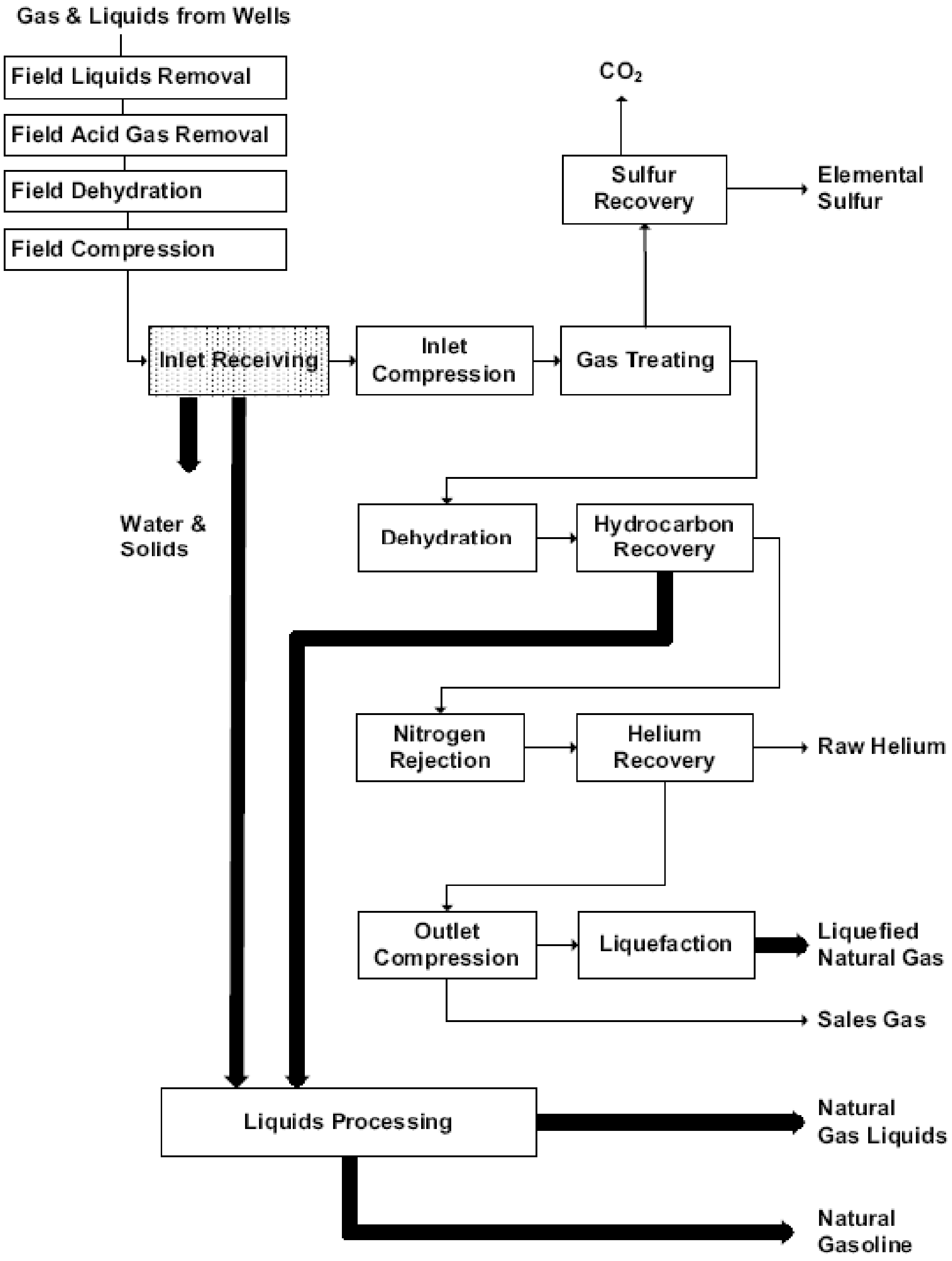
Instructor's Background

- BEng. (1995): Universitas Diponegoro
- Meng. (2000): Institut Teknologi Bandung
- PhD. (2006): Universiti Teknologi Malaysia

- Specialization:
  - Catalyst Design for Energy Conversion
  - Process Design for Energy Conversion
  - Combustion Engineering
  - Computational Fluid Dynamic (CFD)

Course Syllabus: (Part 1)

1. Definitions of Natural Gas, Gas Reservoir, Gas Drilling, and Gas production (*Pengertian gas alam, gas reservoir, gas drilling, dan produksi gas*)
2. Overview of Gas Plant Processing (*Overview Sistem Pemrosesan Gas*)
3. **Gas Field Operations and Inlet Receiving (*Operasi Lapangan Gas dan Penerimaan Inlet*)**
4. Gas Compression System (*Sistem Kompresi Gas*)
5. Gas Treating (*Pengolahan Gas*)
6. Gas Dehydration (*Dehidrasi Gas*)
7. First Assignment
8. *Ujian Tengah Semester*



Gas & Liquids from Wells

Field Liquids Removal

Field Acid Gas Removal

Field Dehydration

Field Compression

Inlet Receiving

Water & Solids

Inlet Compression

Gas Treating

Sulfur Recovery

CO_2

Elemental Sulfur

Dehydration

Hydrocarbon Recovery

Nitrogen Rejection

Helium Recovery

Raw Helium

Outlet Compression

Liquefaction

Liquefied Natural Gas

Sales Gas

Liquids Processing

Natural Gas Liquids

Natural Gasoline

FIELD OPERATIONS: *Wellhead Operations*

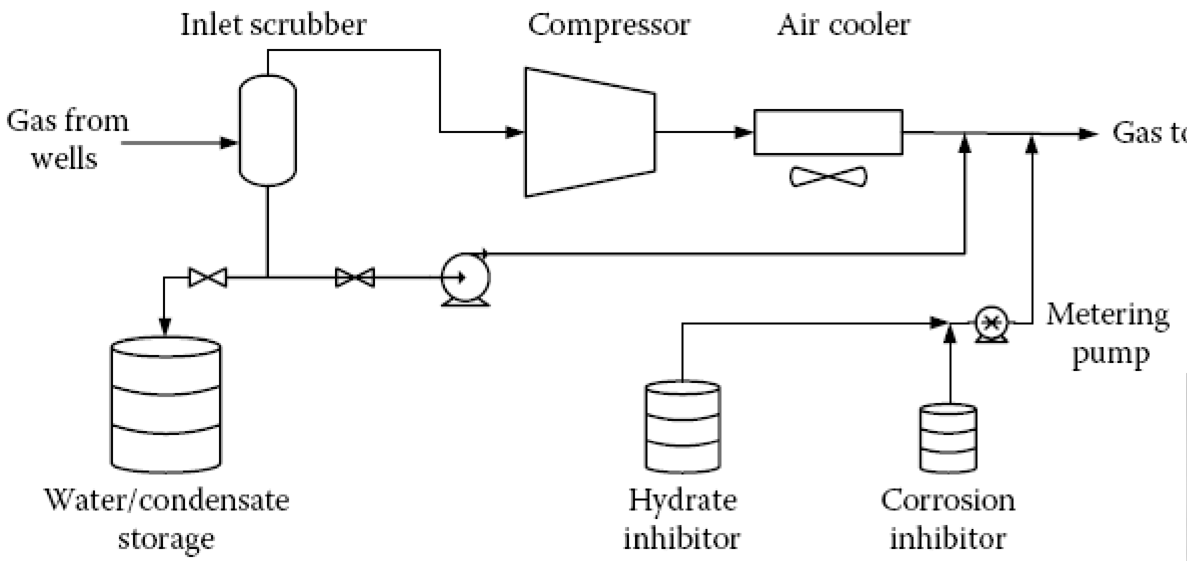
- Wellhead
- Gas-liquid separator
- Instrument shed
- Condensate Tank
- If the gas is nonassociated, hydrocarbon liquids knocked out in the separator may be remixed with the gas or stored in a tank and removed by truck

FIELD OPERATIONS: *Piping*

- **Offshore Production**:
  - Many wells are tied back to platform
  - Gas from multiple platforms are tied together into large pipeline that go to the gas plant (usually onshore)
- **Onshore Production**:
  - Form an extensive network of small lines from individual wells
  - Tie into increasingly larger lines
  - The smaller gathering lines may be aboveground or buried
  - Larger lines are always buried
  - Aboveground lines are much easier to maintain but are exposed to the atmosphere
  - Surface coating for corrosion prevention and possibly insulation may be required

FIELD OPERATIONS: *Compression Stations*

- Onshore compression station ➔ **booster station**
- Booster stations are rarely used in offshore production



- inlet suction separators (scrubbers) to remove condensed liquids
- **Dehydration facilities** ➔ to reduce corrosion and mitigate hydrate formation.
- When required, **chemical inhibitors** for corrosion and gas hydrate prevention are injected into the discharged gas; metering pumps are used to control injection rates

How to handle condensed liquids at booster stations is an economic decision ?

- Liquids collection requires tankage and trucking to move the liquids to the plant.
- The benefits are higher line capacity, reduced corrosion rates, and reduced chemical hydrate and corrosion inhibitor injection rates.
- Pigging requirements are reduced, as well as the potential for large liquid slugs entering the plant.
- Putting liquids back into the pipeline eliminates the need for tanks and trucking but increases chemical costs, puts more importance on good pigging, and probably increases pipeline maintenance costs.

- Compressor power requirements depend upon gas flow and pressure ratio
- Booster-station horsepower ranges from the teens to the thousands.
- Compressors are driven by electric motors, internal-combustion engines, and gas turbines.
- Horsepower requirements and availability of fuel dictate the best choice.
- Some compressor drivers are internal-combustion engines that have been in service for 50 or more years and have been rebuilt many times.
- Compressor engines are usually fueled with natural gas. The best fuel is sales gas from the plant because it is clean and has a constant heating value.
- However, this type of fueling requires running pipe between the plant and booster stations.

FIELD OPERATIONS: *Pigging*

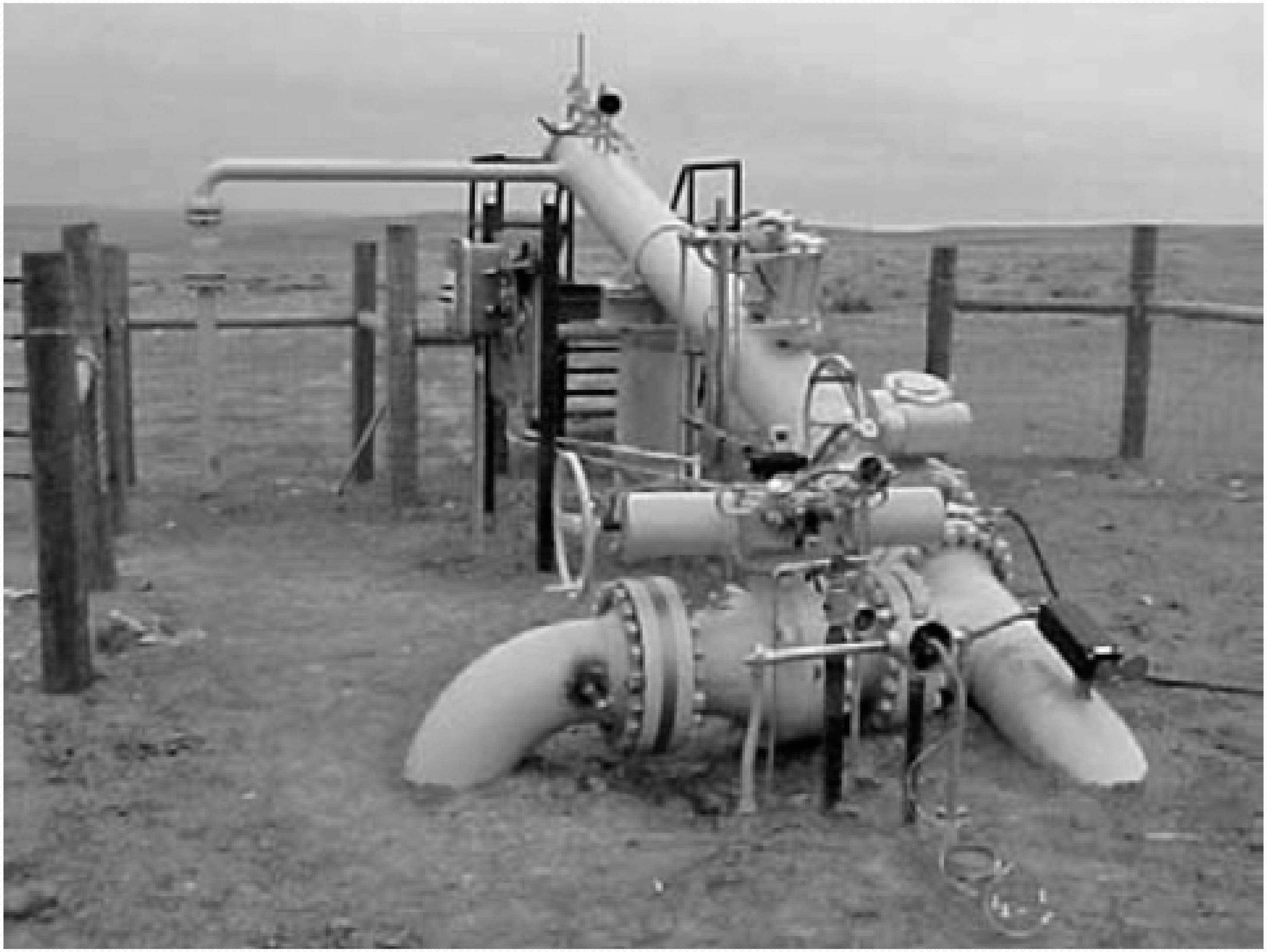
- **Pigging** is the **process of forcing a solid object through a pipeline.**
- The process involves inserting the pig, via **a pig launcher**, into the pipelines and removing it by use of **a pig receiver**.
- Pigging is used to perform any of the following functions:
  - Provide a **barrier** between liquid products that use the same pipeline
  - **Check wall thickness** and **find damaged** sections of lines
  - **Remove debris** such as dirt and wax from lines
  - Provide a **known volume** for calibrating flow meters
  - **Coat inner pipe walls** with inhibitors
  - **Remove condensed hydrocarbon liquids** and water in two phase pipelines

- Field operations must follow **a rigorous pigging schedule** to prevent the plant from being hit by large slugs of liquid that would flood inlet receiving and carry liquids into the gas-processing units.
- Fortunately, plant operators usually know when a "**killer pig**" is coming, and they draw down liquid levels in inlet receiving.
- To protect the plant from large liquid surges, operators respond by shutting in gas, which shuts down field compressors and upsets the plant with the potential for producing off-spec products.

Shapes of foam sphere and pigs

- Foam spheres, like those shown in the left-front of Figure 3.5, are more commonly used in gathering lines because multiple spheres can be loaded into a pig launcher for remote launching.
- The launchers typically hold three to five spheres and are inclined so that spheres can be inserted remotely by gravity feed
- Spheres for nominal 2 to 4 inch (50 to 100 mm) diameter lines are solid, whereas larger ones are inflated, usually with water or ethylene glycol–water mixtures.

Sphere launcher unit



- At the end of the run, the sphere is caught in a sphere catcher (usually called a pig catcher even if spheres are used).
- Both launchers and receivers are on **the straight run of a pipe tee**.
- **Pressure differential** drives the sphere through the line.
- However, it usually stops intermittently when it comes to low points where pools of liquid accumulate.
- Field and plant operators learn the typical run times for spheres in a line, and inline detectors signal a sphere’s location.

GAS HYDRATES

- **Pipeline blockage** is usually caused by:
  - **Wax and asphaltene solids deposition** (lack)
  - **Scale (inorganic salt) deposition**
  - **Gas hydrate solids formation**
- First, hydrate plugs can occur within minutes without prior warning, while the other solids take weeks, months, or years to cause plugging and are usually detected by increased line-pressure drop.
- Second, although hydrate formation can be inhibited in a number of ways, injection pump failure, separator failure, and process upsets can suddenly make pipeline contents vulnerable to hydrate formation.

Properties of Gas Hydrates

- Gas hydrates are a class of solid, nonstoichiometric compounds called ***clathrates***.
- They form when a host material, water for hydrates through **hydrogen bonding**, forms **a caged structure** that contains guest molecules, such as methane.
- Both host and guest must be present for the solid to form, but not all of the cages will be occupied.
- Gas hydrates should not be confused with salt hydrates, which form stoichiometric compounds.

HYDRATE FORMATION PREDICTION

- Thermodynamics provides a powerful tool for prediction of the temperature and pressure for hydrate formation on the basis of gas composition.
- Hydrate formation kinetics is complex and poorly understood, partly because the crystal growth process is random

- For below 1,000 psi (70 bar),

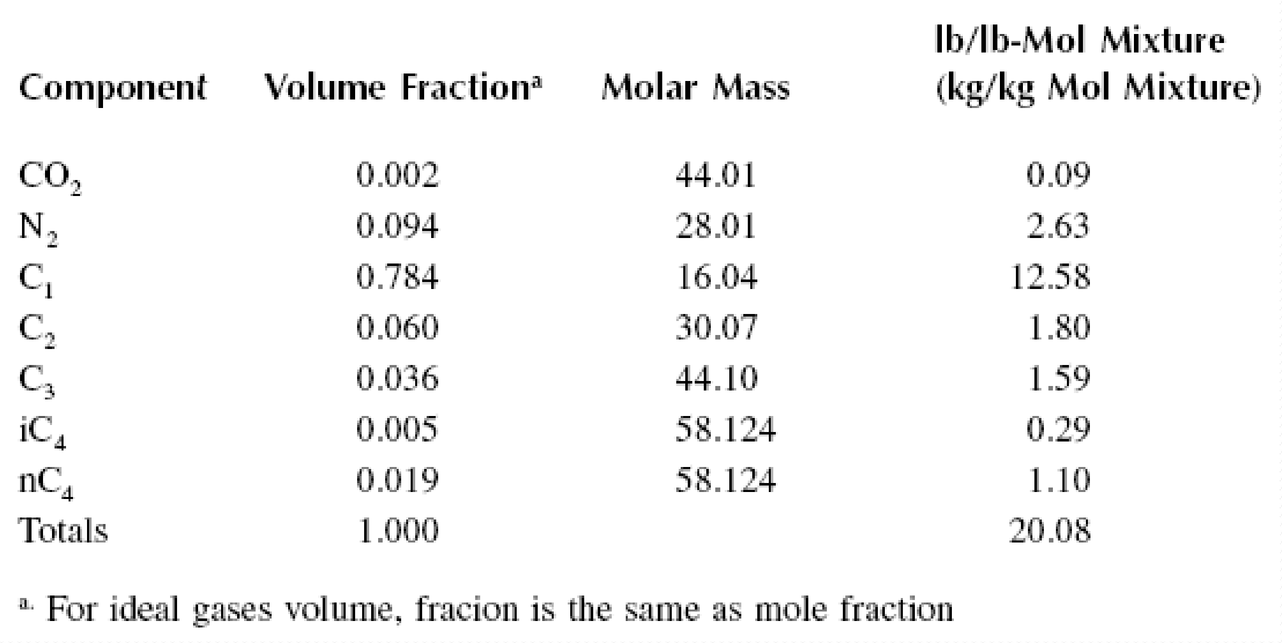
$$t(^\circ\text{F}) = -16.5 - 6.83/(\text{SpGr})^2 + 13.8\ ln[\text{P(psia)}]$$

$$t(^\circ\text{C}) = -6.44 - 3.79/(\text{SpGr})^2 + 7.68\ ln[\text{P(bara)}]$$

- The specific gravity is defined as the ratio of the mass of a given volume of a gas to that of an equal volume of air; both volumes are measured at 14.7 psia and 60°F (1.01 bar and 15.6°C).
- For an ideal gas, the specific gravity is molar mass of the gas divided by the molar mass of air (28.96).

Example

- Gas composition:

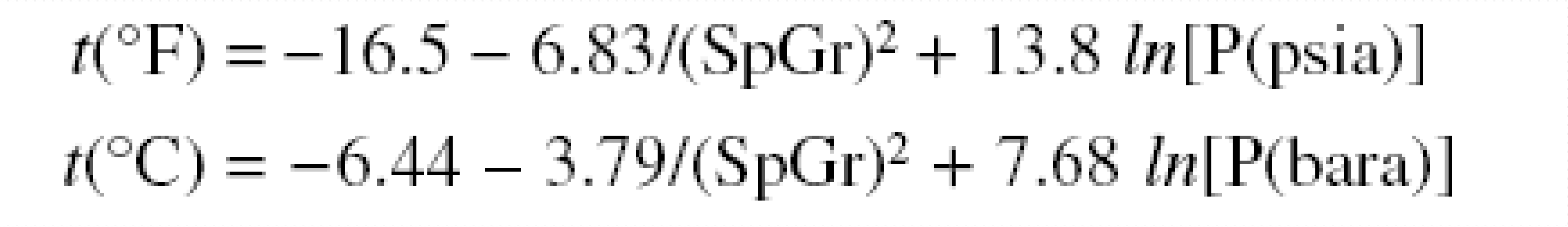


Component	Volume Fraction[a]	Molar Mass	lb/lb-Mol Mixture (kg/kg Mol Mixture)
CO_2	0.002	44.01	0.09
N_2	0.094	28.01	2.63
C_1	0.784	16.04	12.58
C_2	0.060	30.07	1.80
C_3	0.036	44.10	1.59
iC_4	0.005	58.124	0.29
nC_4	0.019	58.124	1.10
Totals	1.000		20.08

[a] For ideal gases volume, fracion is the same as mole fraction

- Estimate the hydrate-formation temperature at 325 psia (22.4 bar) for the above gas composition?

- The specific gravity = molar mass gas /molar mass air = 20.08/28.96 = 0.693.



$$t(^\circ\mathrm{F}) = -16.5 - 6.83/(\mathrm{SpGr})^2 + 13.8\ ln[\mathrm{P(psia)}]$$

$$t(^\circ\mathrm{C}) = -6.44 - 3.79/(\mathrm{SpGr})^2 + 7.68\ ln[\mathrm{P(bara)}]$$

- $t = -16.5 - 6.83/(0.693)2 + 13.8 \times \ln(325) = 49°\mathrm{F}$.

HYDRATE INHIBITION

- Three ways exist to avoid hydrate formation in natural gas streams:
  - **Operate outside the hydrate formation region**. (*impractical*)
  - **Dehydrate the gas**.
  - **Add hydrate inhibitor** (*the most commonly used*)
- Regarding dehydration, how dry a gas should be to prevent hydrate formation is uncertain.
- The gas obviously should have a water dew point below the lowest operating temperature to avoid water condensation.
- Thermodynamics predicts that hydrates can form even when the gas phase is unsaturated with water.

- **Use of chemical inhibitors** is the least attractive hydrate inhibition method for several reasons:
  - The **proper inhibitor dosage** must be known to avoid plugging or needless chemical costs, but oftentimes it is determined empirically.
  - The **chemical cost**, although it is usually a small fraction of overall operating costs.
  - The reliability of inhibitor injection can be a problem because of malfunctioning injection pumps and depleted inhibitor reservoirs, especially at remote sites.
  - The **possible interaction between hydrate inhibitors and other additives** reduces the effectiveness of some of additives, an effect that is usually determined empirically.

Chemical hydrate inhibitors Types

- **Antiagglomerates (AA) → 1990s**
- **Kinetic (KHI) → 1990s**
- **Thermodynamic**

Antiagglomerates

- Antiagglomerates **prevent small hydrate particles from agglomerating into larger sizes** to produce a plug.
- The inhibitors reside in the liquid hydrocarbon phase and are most often used in pipelines where gas is dissolved in oil.
- They require testing to ensure proper concentrations.

Kinetic Inhibitors

- Kinetic inhibitors **slow crystal formation** by interfering with the construction of the cages.
- Their advantage is that they can be used at concentrations in the 1 wt% range in the aqueous phase, and they are **nonvolatile**.
- Their disadvantage is that **the proper dosage** must be determined empirically, as too much inhibitor may enhance hydrate formation rates.
- These inhibitors are limited to a subcooling (difference between desired operating temperature and hydrate formation temperature at constant pressure) of 28°F (15.5°C).

Thermodynamic Inhibitor

- Thermodynamic inhibitors, mainly **methanol** and **ethylene glycol**, are widely used as **antifreeze**.
- Inorganic salts are effective but rarely used, and further discussion relates only to methanol and ethylene glycol.
- The required dosage of thermodynamic inhibitors is predictable, but the concentrations can be high, over 50 wt% of the water phase.
- A number of empirical correlations, on the basis of thermodynamic properties of solutions, predict the amount of any hydrate inhibitor required to depress hydrate formation temperatures.

Hammerschmidt Equations

$$\Delta t(°F) = \frac{2335X_i}{MW_i(1 - X_i)}$$

$$X_i = \frac{\Delta t(°F)MW_i}{\Delta t(°F)MW_i + 2335},$$

- where t is the hydrate-depression temperature,°F,
- Xi is the mass fraction of inhibitor in the free-water phase, and
- MW_i is the molecular weight of the inhibitor.
- Nielsen and Bucklin Equation:
- $\Delta t(°F) = -129.6 \ln x_W$
- x_W is the mole fraction of water in the aqueous phase
- SEE EXAMPLE 3.2

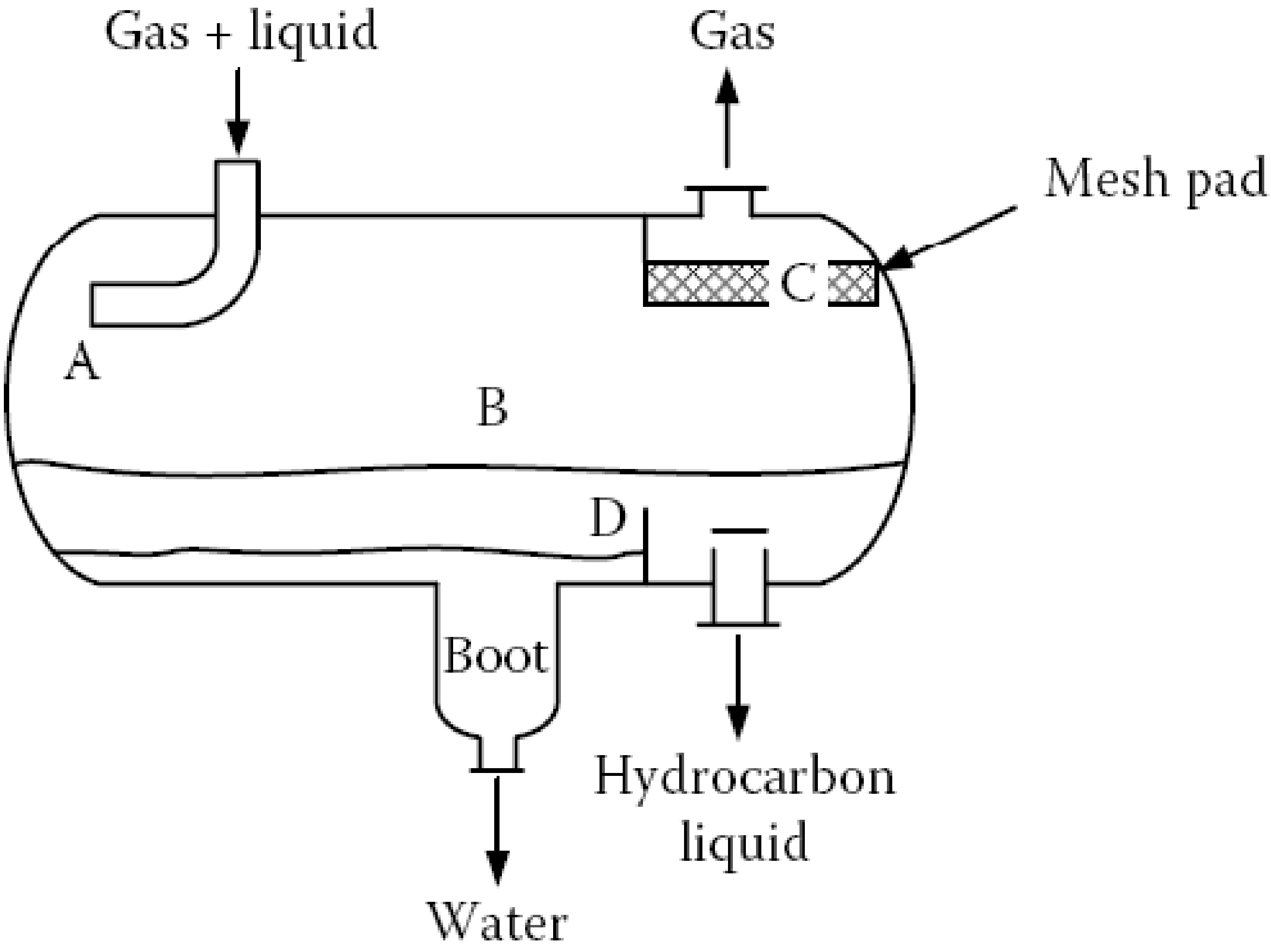
INLET RECEIVING

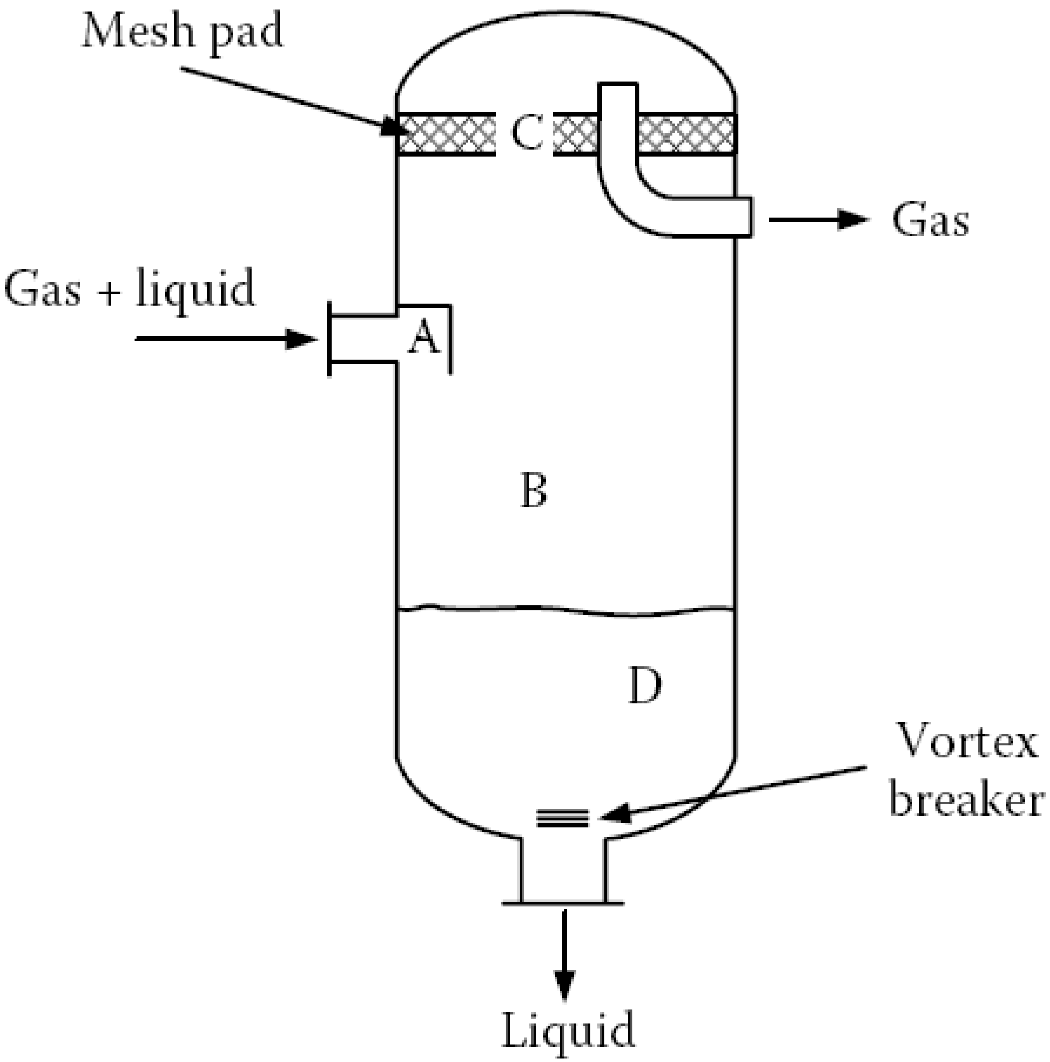
- Gas and liquids that enter the gas plant pass **emergency shutdown valves**, which isolate the plant from incoming streams and pig receivers, and then go to **inlet receiving**, where condensed phases drop out
- Gas from inlet receiving goes to **inlet compression** (if necessary), and the **liquids go to storage** for processing
- The initial gas–liquid separation occurs in a slug catcher.

SEPARATOR PRINCIPLES: Gas-Liquid Separation

- Separator vessel orientation can be **vertical** or **horizontal.**
- **Vertical separators** are :
  - most commonly used **when the liquid-to-gas ratio is low or gas flow rates are low**.
  - For offshore due to less platform area.
  - However, gas flow is upwards and opposes the flow of liquid droplets.
  - Therefore, vertical separators can be bigger and, thus, **more costly than horizontal separators**.
- **Horizontal separators** are :
  - favored for large liquid volumes or if the liquid-to-gas ratio is high.
  - Lower gas flow rates and increased residence times offer better liquid dropout.
  - The larger surface area provides better degassing and more stable liquid level as well

Horizontal separator





Vertical separator

A = inlet device

B = gas gravity separation

C = mist extraction

D = liquid gravity separation

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.

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.
- Reynold Number: $N_{\mathrm{Re}} = D_P V_T \, \rho_g / \mu_g ,$
- where D_P is particle diameter, r_g is the density, and m_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 (Re>500 :

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

Newton's Law

- If the **particle size is too large**, excessive turbulence :

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

- with KCR = 18.13 and 23.64 for engineering and metric units, respectively,

- the **flow is laminar (*NRe < 2*),** *Stokes' law applies:*

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

British Unit

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

SIUnit

Coalescing

- The coalescing section contains an insert that **forces the gas through a torturous path** to bring small mist particles together as they collect on the insert

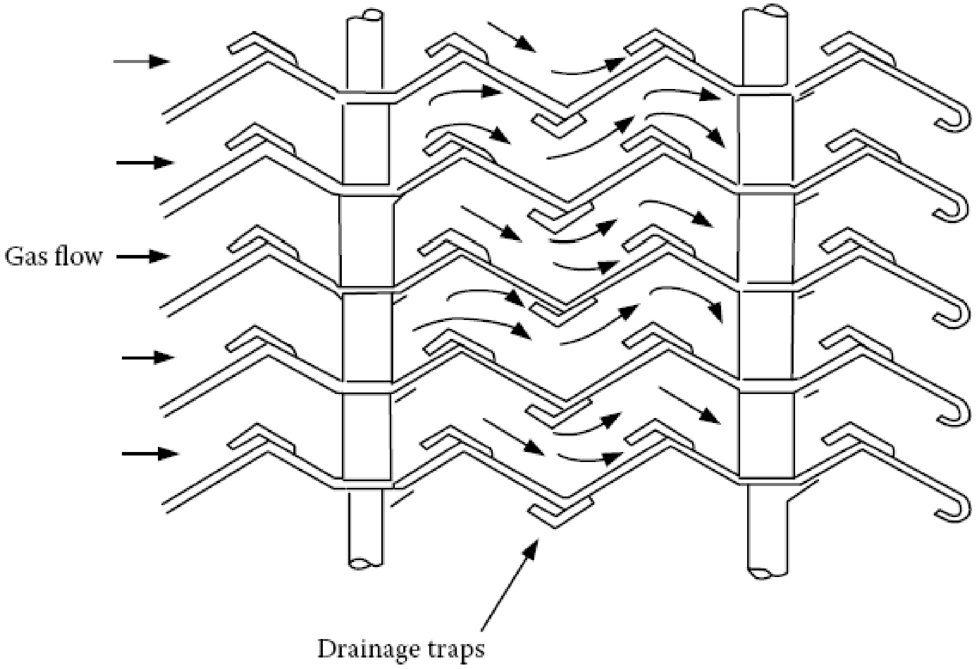


FIGURE 3.12 Sketch of vane pack mist extractor element with liquid drainage traps. (Adapted from Engineering Data Book, 2004b.)

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.
- 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.