Technology of Natural Gas Engineering

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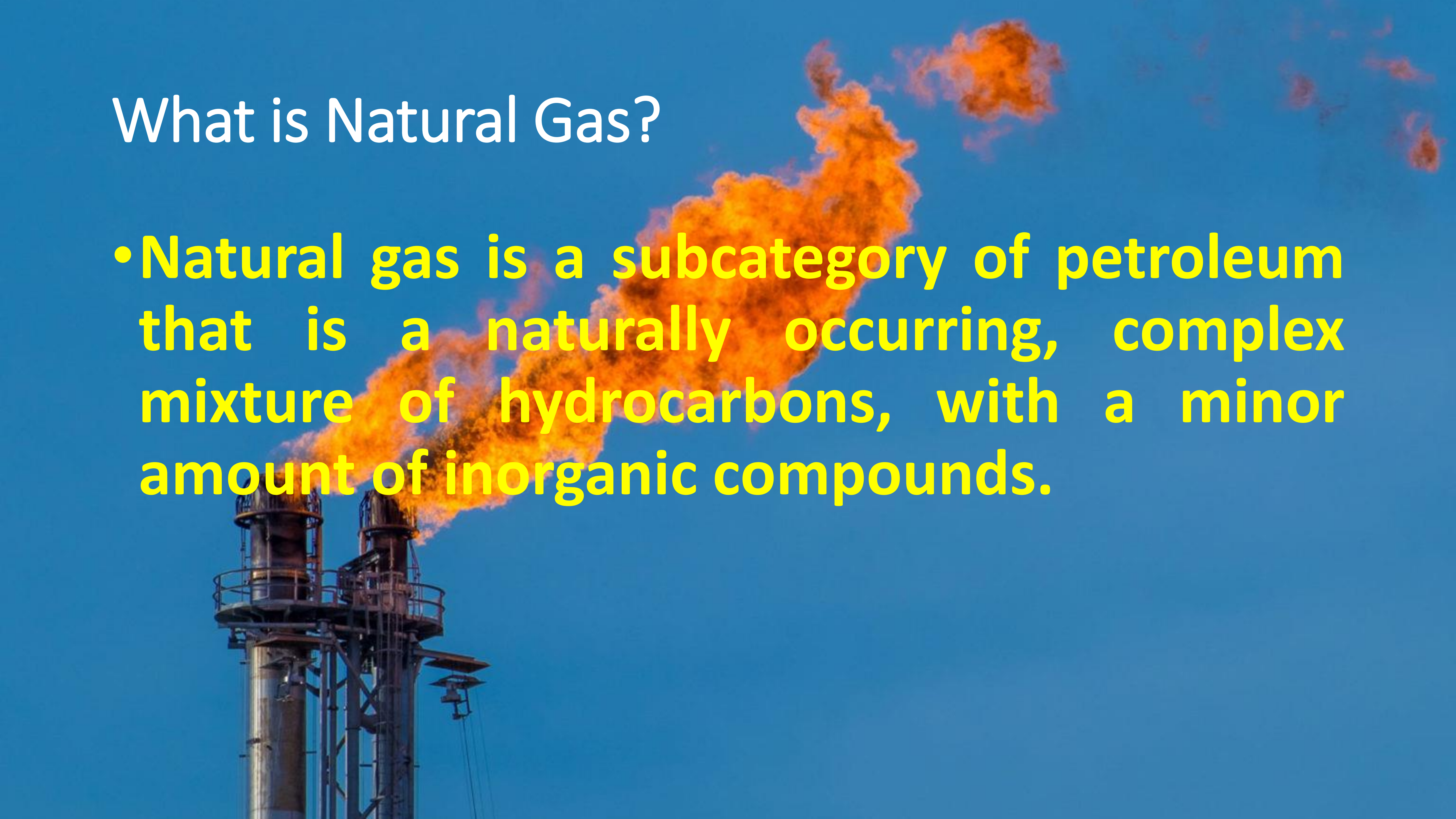


What is Natural Gas?

- **Natural gas is a subcategory of petroleum that is a naturally occurring, complex mixture of hydrocarbons, with a minor amount of inorganic compounds.**

Composition of Natural Gas

- Depending upon gas composition, especially the content of inorganic compounds, the heating value of natural gas usually varies from 700 Btu/scf to 1,600 Btu/scf

Table 1–1 Composition of a Typical Natural Gas

Compound	Mole Fraction
Methane	0.8407
Ethane	0.0586
Propane	0.0220
i-Butane	0.0035
n-Butane	0.0058
i-Pentane	0.0027
n-Pentane	0.0025
Hexane	0.0028
Heptanes and Heavier	0.0076
Carbon Dioxide	0.0130
Hydrogen Sulfide	0.0063
Nitrogen	0.0345
Total	1.0000

Classification of Natural Gas

Reservoir

- A reservoir is a porous and permeable underground formation containing an individual bank of hydrocarbons confined by impermeable rock or water barriers and is characterized by a single natural pressure system

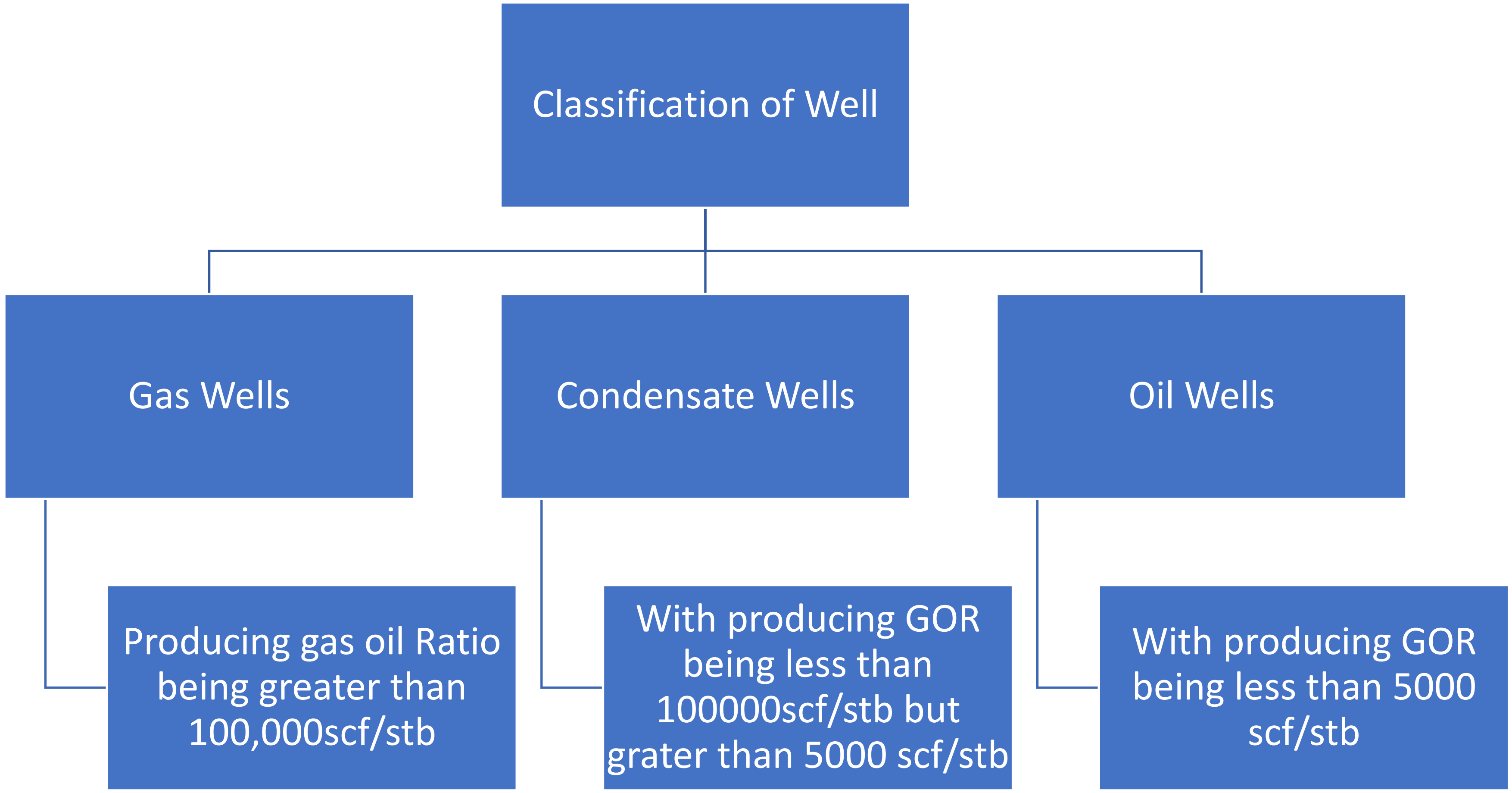
Field

- A field is an area that consists of one or more reservoirs all related to the same structural feature

Pool

- A pool contains one or more reservoirs in isolated structures

Classification of Well



Types of natural gas

Non-associated Gas

- From reservoir with minimal oil

Associated Gas

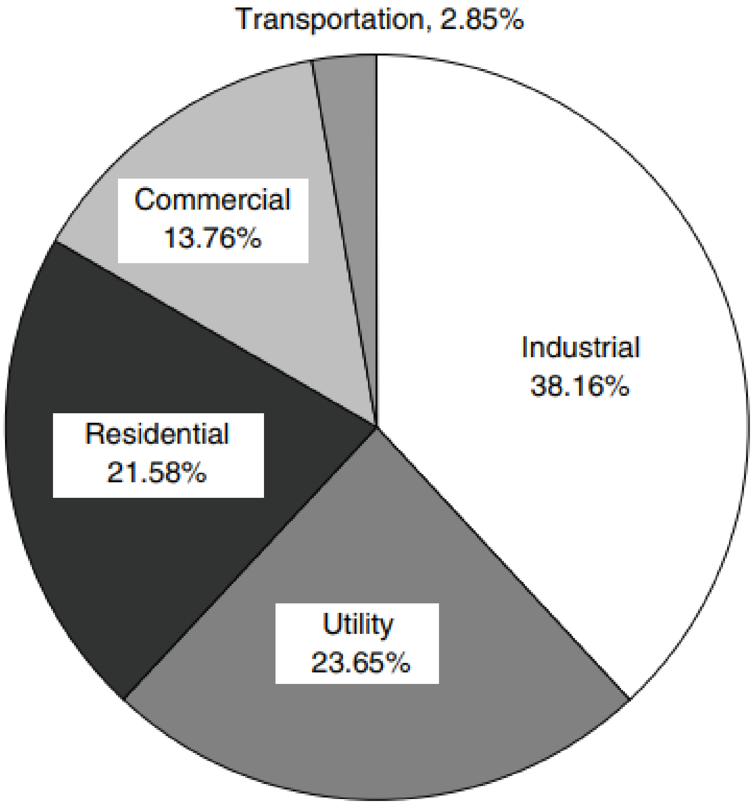
- Gas dissolved in oil under natural conditions in the oil reservoirs

Gas condensate

- Gas with high content of liquid hydrocarbon at reduced pressures and temperatures

Utilization of Natural Gas

- Natural gas is one of the major fossil energy sources.
- When ***one standard cubic feet*** of natural gas is combusted, it generates ***700 Btu to 1,600 Btu*** of heat, depending upon gas composition.



Example 1.1

- Natural gas from the Schleicher County, Texas, Straw Reef has a heating value of 1,598 Btu/scf. If this gas is combusted to generate power of 1,000 kW, what is the required gas flow rate in Mscf/day? Assume that the overall efficiency is 50 percent (1 kW = 3,412 Btu/h)

Solution:-

Power required = 1000 kW

convert to BS units

$= 1000 * 3412 = 3.412 \times 10^6$ BTU/h $= \frac{3.412 \times 10^6 \text{ BTU/hr}}{}$

$\frac{3.412 \text{ BTU}}{\cancel{h}} \Big| \frac{24 \cancel{h}}{\text{day}} \Big| = 8.19 * 10^7$ BTU/day.

Fuel gas Requirment:-

Heat generated required = 8.19×10^7 BTU/day

The η = 50 %

Heat generated = fuel gas flow rate ? $\times$ Heat of combust $\times \eta$

$$\text{Fuel gas} = \frac{8.19 \times 10^7 \text{ BTU/hr}}{1598 \text{ BTU/scf} \times 0.5} = 1.05 \times 10^5 \frac{\text{scf}}{\text{day}}$$

= 102.5 MSCuf/day.

Natural Gas Industry

- The consumption of natural gas in all end-use classifications (residential, commercial, industrial, and power generation) has increased rapidly since World War II.
- This growth has resulted from several factors,
  - *including development of new markets,*
  - *replacement of coal as fuel for providing space and industrial process heat,*
  - *use of natural gas in making petrochemicals and fertilizers,*
  - *and strong demand for low-sulfur fuels.*

Natural Gas Reserves

- Two terms are frequently used to express natural gas reserves:

Proved

- ***Proved reserves*** are those quantities of gas that have been found by the drill. They can be proved by known reservoir characteristics such as production data, pressure relationships, and other data, so that volumes of gas can be determined with reasonable accuracy.

Potential

- ***Potential resources*** constitute those quantities of natural gas that are believed to exist in various rocks of the Earth's crust but have not yet been found by the drill. They are future supplies beyond the proved reserves

Types of Natural Gas Resources

- Conventional natural gas,
- Gas in tight sands
- Gas in tight shales
- Coal-bed methane
- Gas in geopressured reservoirs
- Gas in gas hydrates

Conventional natural gas

- Conventional natural gas is either associated or nonassociated gas. Associated or dissolved gas is found with crude oil. Dissolved gas is that portion of the gas dissolved in the crude oil and associated gas (sometimes called gas-cap gas) is free gas in contact with the crude oil.
- All crude oil reservoirs contain dissolved gas and may or may not contain associated gas.
- Nonassociated gas is found in a reservoir that contains a minimal quantity of crude oil.
- Some gases are called gas condensates or simply condensates. Although they occur as gases in underground reservoirs, they have a high content of hydrocarbon liquids. On production, they may yield considerable quantities of hydrocarbon liquids.

Gases in tight sands

- Gases in tight sands are found in many areas that contain formations generally having porosities of 0.001 to 1 millidarcy (md).
- At higher gas permeabilities, the formations are generally amenable to conventional fracturing and completion methods.

Gases in tight shales

- Gases in tight shales are found in the eastern United States.
- The shale is generally fissile, finely laminated, and varicolored but predominantly black, brown, or greenish-gray.
- Core analysis has determined that the shale itself may have up to 12 percent porosity, however, permeability values are commonly less than 1 md.
- It is thought, therefore, that the majority of production is controlled by naturally occurring fractures and is further influenced by bedding planes and jointing (Ikoku 1984)

Coalbed methane

- Coal-bed methane is the methane gas in minable coal beds with depths less than 3,000 ft. Although the estimated size of the resource base seems significant, the recovery of this type of gas may be limited owing to practical constraints.

Gas in geopressured reservoirs

- In a rapidly subsiding basin area, clays often seal underlying formations and trap their contained fluids.
- After further subsidence, the pressure and temperature of the trapped fluids exceed those normally anticipated at reservoir depth.
- These reservoirs, commonly called geopressured reservoirs, have been found in many parts of the world during the search for oil and gas.

Gas hydrates

- Gas Hydrates are snow-like solids in which each water molecule forms hydrogen bonds with the four nearest water molecules to build a crystalline lattice structure that traps gas molecules in its cavities.
- Gas hydrates contain about **170 times** the natural gas by volume under standard conditions.
- Because gas hydrate is a highly concentrated form of natural gas and extensive deposits of naturally occurring gas hydrates have been found in various regions of the world, they are considered as a future, unconventional resource of natural gas.

Assignment 1

- Natural gas from the Morgan County, Colorado, D-Sand, has a heating value of 1,228 Btu/scf. If this gas is combusted to drive a gas turbine for a gas compressor of 1,000 hp, what is the required gas flow rate in MMscf/day? Assume that the overall efficiency is 30% (1 hp = 2,544 Btu/h).

Properties of Natural Gas

3rd stage

Dr.Omar

Properties of Natural Gas

- gas-specific gravity
- Pseudocritical pressure and temperature
- viscosity,
- compressibility factor,
- gas density,
- gas compressibility

Specific gravity

- Gas-specific gravity (γ) is defined as the ratio of the apparent molecular weight of a natural gas to that of air, itself a mixture of gases. The molecular weight of air is usually taken as equal to 28.97 (approximately 79%nitrogen and 21% oxygen). Therefore the gas gravity is

$$\gamma_g = \frac{MW_a}{28.97} \qquad \textbf{(2.1)}$$

- Where MW_a is the apparent molecular weight which is equal to:

$$MW_a = \sum_{i=1}^{Nc} y_i MW_i$$

Specific Gravity

- A light gas reservoir is one that contains primarily methane with some ethane. Pure methane would have a gravity equal to (16.04/28.97) = 0.55.
- A rich or heavy gas reservoir may have a gravity equal to 0.75 or, in some rare cases, higher than 0.9.

Pseudocritical Properties(Composition Known)

- The critical properties of a gas can be determined on the basis of the critical properties of compounds in the gas using the mixing rule.
- The gas critical properties determined in such a way are called pseudocritical properties.
- Gas pseudocritical pressure (P_{pc}) and pseudocritical temperature (T_{pc})

$$p_{pc} = \sum_{i=1}^{N_c} y_i p_{ci} \qquad T_{pc} = \sum_{i=1}^{N_c} y_i T_{ci}$$

- P_{ci} and T_{ci} are critical pressure and critical temperature of component i, respectively.

Problem

- For the gas con apparent mole pseudocritical ten
- Solution:

Compound	y_i	MW_i	y_iMW_i	p_{ci} (psia)	y_ip_{ci} (psia)	T_{ci} (°R)	y_iT_{ci} (°R)
C_1	0.775	16.04	12.43	673	521.58	344	266.60
C_2	0.083	30.07	2.50	709	58.85	550	45.65
C_3	0.021	44.10	0.93	618	12.98	666	13.99
i-C_4	0.006	58.12	0.35	530	3.18	733	4.40
n-C_4	0.002	58.12	0.12	551	1.10	766	1.53
i-C_5	0.003	72.15	0.22	482	1.45	830	2.49
n-C[illegible]	[illegible]	[illegible]	0.58	485	3.88	847	6.78
[illegible]	[illegible]	[illegible]	0.09	434	0.43	915	0.92
[illegible]	[illegible]	[illegible]	0.11	361	0.36	1024	1.02
[illegible]	[illegible]	28.02	1.40	227	11.35	492	24.60
CO_2	0.030	44.01	1.32	1073	32.19	548	16.44
H_2S	0.020	34.08	0.68	672	13.45	1306	26.12
	1.000	MW_a =	20.71	p_{pc} =	661	T_{pc} =	411

This problem is solved with spreadsheet program MixingRule.xls

Pseudocritical properties:(Unknown composition)

- If the gas composition is not known but gas-specific gravity is given, the pseudocritical pressure and temperature can be determined from various charts or correlations developed based on the charts. One set of simple correlations is

$$p_{pc} = 709.604 - 58.718\gamma_g$$

$$T_{pc} = 170.491 + 307.344\gamma_g$$

which are valid for H_2S < 3%, N_2 < 5%, and total content of inorganic compounds less than 7%.

Corrections for impurities in sour gases

- Corrections for impurities in sour gases are always necessary. The corrections can be made using either charts or correlations such as the Wichert Aziz (1972) correction expressed:

$$A = y_{H_2S} + y_{CO_2}$$

$$B = y_{H_2S}$$

$$\varepsilon_3 = 120\left(A^{0.9} - A^{1.6}\right) + 15\left(B^{0.5} - B^{4.0}\right)$$

$$T_{pc}' = T_{pc} - \varepsilon_3 \quad \text{(corrected } T_{pc}\text{)}$$

$$P_{pc}' = \frac{P_{pc} T_{pc}'}{T_{pc} + B(1-B)\varepsilon_3} \quad \text{(corrected } p_{pc}\text{)}$$

Correlations with impurity corrections

$$p_{pc} = 678 - 50(\gamma_g - 0.5) - 206.7 y_{N_2} + 440 y_{CO_2} + 606.7 y_{H_2S}$$

$$T_{pc} = 326 + 315.7(\gamma_g - 0.5) - 240 y_{N_2} - 83.3 y_{CO_2} + 133.3 y_{H_2S}$$

$$p_{pr} = \frac{p}{p_{pc}}$$

$$T_{pr} = \frac{T}{T_{pc}}$$

Viscosity

- Gas viscosity is a measure of the resistance to flow exerted by the gas. Dynamic viscosity (μ_g) in centipoises (cp) is usually used in the natural engineering:

$$1 \text{ cp} = 6.72 \times 10^{-4} \text{ lbm/ft-sec}$$

- Kinematic viscosity (ν_g) is related to the dynamic viscosity through

density (ρ_g)

$$\nu_g = \frac{\mu_g}{\rho_g}$$

How to measure the viscosity?

- Direct measure are preferred for new gas
- If gas composition and component viscosity are known, the mixing rule can be used for determining the viscosity of the gas mixture:

$$\mu_g = \frac{\sum\left(\mu_{gi} y_i \sqrt{MW_i}\right)}{\sum\left(y_i \sqrt{MW_i}\right)}$$

The gas viscosity correlation of Carr, Kobayashi, and Burrows (1954)

- This correlation involve two-step procedure:

The gas viscosity at temperature and atmospheric pressure is estimated first from gas-specific gravity and inorganic compound content

The atmospheric value is then adjusted to pressure conditions by means of a correction factor on the basis of reduced temperature and pressure state of the gas.

Step 1: The atmospheric pressure viscosity (μ1)

- The atmospheric pressure viscosity (μ1) can be expressed as:

$$\mu_1 = \mu_{1HC} + \mu_{1N_2} + \mu_{1CO_2} + \mu_{1H_2S}$$

$$\mu_{1HC} = 8.188 \times 10^{-3} - 6.15 \times 10^{-3} \log(\gamma_g) + (1.709 \times 10^{-5} - 2.062 \times 10^{-6} \gamma_g) T$$

$$\mu_{1N_2} = [9.59 \times 10^{-3} + 8.48 \times 10^{-3} \log(\gamma_g)] y_{N_2}$$

$$\mu_{1CO_2} = [6.24 \times 10^{-3} + 9.08 \times 10^{-3} \log(\gamma_g)] y_{CO_2}$$

$$\mu_{1H_2S} = [3.73 \times 10^{-3} + 8.49 \times 10^{-3} \log(\gamma_g)] y_{H_2S}$$

Step 2: Viscosity estimation

$$\mu_r = \ln\left(\frac{\mu_g}{\mu_1} T_{pr}\right) = a_0 + a_1 p_{pr} + a_2 p_{pr}^2 + a_3 p_{pr}^3$$

$$+T_{pr}(a_4 + a_5 p_{pr} + a_6 p_{pr}^2 + a_7 p_{pr}^3)$$

$$+T_{pr}^2(a_8 + a_9 p_{pr} + a_{10} p_{pr}^2 + a_{11} p_{pr}^3)$$

$$+T_{pr}^3(a_{12} + a_{13} p_{pr} + a_{14} p_{pr}^2 + a_{15} p_{pr}^3)$$

where

$a_0 = -2.46211820$

$a_1 = 2.97054714$

$a_2 = -0.28626405$

$a_3 = 0.00805420$

$a_4 = 2.80860949$

$a_5 = -3.49803305$

$a_6 = 0.36037302$

$a_7 = -0.01044324$

$a_8 = -0.79338568$

$a_9 = 1.39643306$

$a_{10} = -0.14914493$

$a_{11} = 0.00441016$

$a_{12} = 0.08393872$

$a_{13} = -0.18640885$

$a_{14} = 0.02033679$

$a_{15} = -0.00060958$

Correlated viscosity:

$$\mu_g = \frac{\mu_1}{T_{pr}} e^{\mu_r}$$

A 0.65 specific gravity natural gas contains 10% nitrogen, 8% carbon dioxide, and 2% hydrogen sulfide. Estimate viscosity of the gas at 10,000 psia and 180 °F.

Compressibility Factor

- Gas compressibility factor is also called deviation factor, or z-factor. Its value reflects how much the real gas deviates from the ideal gas at given pressure and temperature. Definition of the compressibility factor is expressed as:

$$z = \frac{V_{actual}}{V_{ideal\ gas}}$$

$$pV = nzRT$$

where n is the number of moles of gas. When pressure p is entered in psia, volume V in ft^3, and temperature in °R, the gas constant R is equal to

$$10.73 \frac{psia - ft^3}{mole - {}^\circ R}$$

Gas Compressibility Factor Calculation

- The gas compressibility factor can be determined on the basis of measurements in PVT laboratories. For a given amount of gas, if temperature is kept constant and volume is measured at 14.7 psia and an elevated pressure p1, z-factor can then be determined with the following for:

$$z = \frac{p_1}{14.7} \frac{V_1}{V_0}$$

where V_0 and V_1 are gas volumes measured at 14.7 psia and P_1, respectively.

Brill and Beggs' z-factor correlation

$$A = 1.39(T_{pr} - 0.92)^{0.5} - 0.36T_{pr} - 0.10$$

$$B = (0.62 - 0.23T_{pr})p_{pr} + \left(\frac{0.066}{T_{pr} - 0.86} - 0.037\right)p_{pr}^2 + \frac{0.32p_{pr}^6}{10^E}$$

$$C = 0.132 - 0.32\log(T_{pr})$$

$$D = 10^F$$

$$E = 9(T_{pr} - 1)$$

$$F = 0.3106 - 0.49T_{pr} + 0.1824T_{pr}^2$$

and

$$z = A + \frac{1 - A}{e^B} + Cp_{pr}^D$$

- Because natural gas is compressible, its density depends upon pressure and temperature. Gas density can be calculated from gas law for real gas with good accuracy:

$$\rho = \frac{m}{V} = \frac{MW_a p}{zRT}$$

where *m* is mass of gas and ρ is gas density

Taking air molecular weight 29 and R =10.73 $\frac{psia.ft^3}{mole.\,^oR}$

Choke Performance

Introduction

- Gas production rates from individual wells are controlled for preventing water coning and/or sand production, meeting limitations of rate or pressure imposed by production facilities, and satisfying production limits set by regulatory authorities.

What is the meaning of Choke?

- Choke is a device installed at wellhead or down hole to cause a restriction to flow of fluids, and thus control gas production rate.
- Classification of Choke :

  - Nozzle: fixed diameter
  - Orifice: fixed diameter
  - Modern: Adjustable diameter

Sonic and Subsonic flow

- Pressure drop across well chokes is usually very significant.
- When the fluid flow velocity in a choke reaches the traveling velocity of sound in the fluid under the in situ condition, the flow is called **sonic flow**. Under sonic condition:
  - The pressure wave downstream of the choke cannot go upstream through the choke because the medium (fluid) is traveling in the opposite direction at the same velocity
  - Therefore, a pressure discontinuity exists at the choke, that is, the downstream pressure does not affect the upstream pressure

What gives the choke unique feature?

- Because of the pressure discontinuity at the choke, any change in the downstream pressure cannot be detected from the upstream pressure gauge. Of course, any change in the upstream pressure cannot be detected from the downstream pressure gauge either. This sonic flow provides a unique well choke feature that stabilizes well production rate and separation operation conditions.

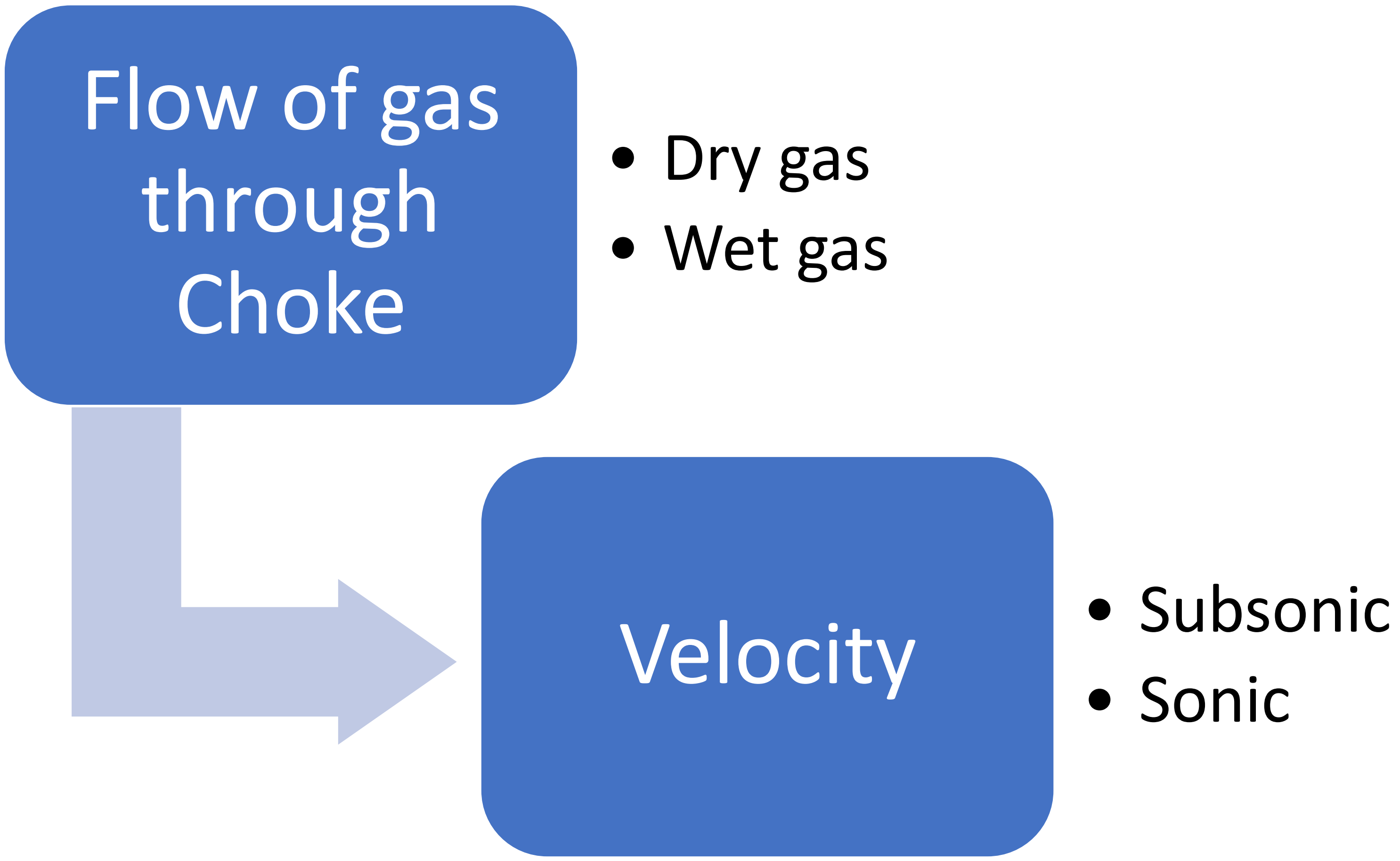
Flow through choke

- Whether or not a sonic flow exists at a choke depends on a downstream to upstream pressure ratio.
  - If this pressure ratio is less than a critical pressure ratio, sonic (critical) flow exists.
  - If this pressure ratio is greater or equal to the critical pressure ratio, subsonic (subcritical) flow exists.
  - The critical pressure ratio through chokes is expressed as:

$$\left(\frac{p_{outlet}}{p_{up}}\right)_c = \left(\frac{2}{k+1}\right)^{\frac{k}{k-1}}$$

  - Where:
    - P_{outlet} is the pressure at choke outlet,
    - P_{up} is the upstream pressure,
    - $k = C_p/C_v$ is the specific heat ratio.
  - The value of the k is 1.4 for air and 1.28 for natural gas.
  - Thus, the critical pressure ratio is **0.528** for air and **0.549** for natural gas.

Flow of gas


Flow of gas through Choke
Dry gas
Wet gas
Velocity
Subsonic
Sonic

Dry Gas Flow through Chokes

- Pressure equations for choke flow are derived based on isentropic process.
- This is because there is no time for heat to transfer (adiabatic) and the friction loss is negligible (assuming reversible) at chokes.
- In addition to the concern of pressure drop across the chokes, temperature drop associated with choke flow is also an important issue for gas wells as hydrates may form that may plug flow lines.

Subsonic flow

Under subsonic flow conditions, gas passage through a choke can be expressed as:

$$Q_{sc} = 1{,}248CAp_{up}\sqrt{\frac{k}{(k-1)\gamma_g T_{up}}\left[\left(\frac{p_{dn}}{p_{up}}\right)^{\frac{2}{k}} - \left(\frac{p_{dn}}{p_{up}}\right)^{\frac{k+1}{k}}\right]}$$

Where:
Q_{sc} = gas flow rate, Mscf/d
P_{up}= upstream pressure at choke, psia
A = cross-sectional area of choke, in^2
T_{up}= upstream temperature, °R
g = acceleration of gravity, 32.2 ft/sec^2
γg = gas specific gravity related to air
C = choke flow coefficient

Estimation of Choke flow coefficient

- The choke flow coefficient can be determined using charts in Figure and Figure for nozzle-type and orifice-type chokes, respectively.
- The following correlation has been found to give reasonable accuracy for Reynolds numbers between 10^4 and 10^6 for nozzle-type chokes:

$$C = \frac{d}{D} + \frac{0.3167}{\left(\frac{d}{D}\right)^{0.6}} + 0.025[\log(N_{Re}) - 4]$$

- Where:
  - d = choke diameter, in
  - D = pipe diameter, in
  - N_{Re} = Reynolds number

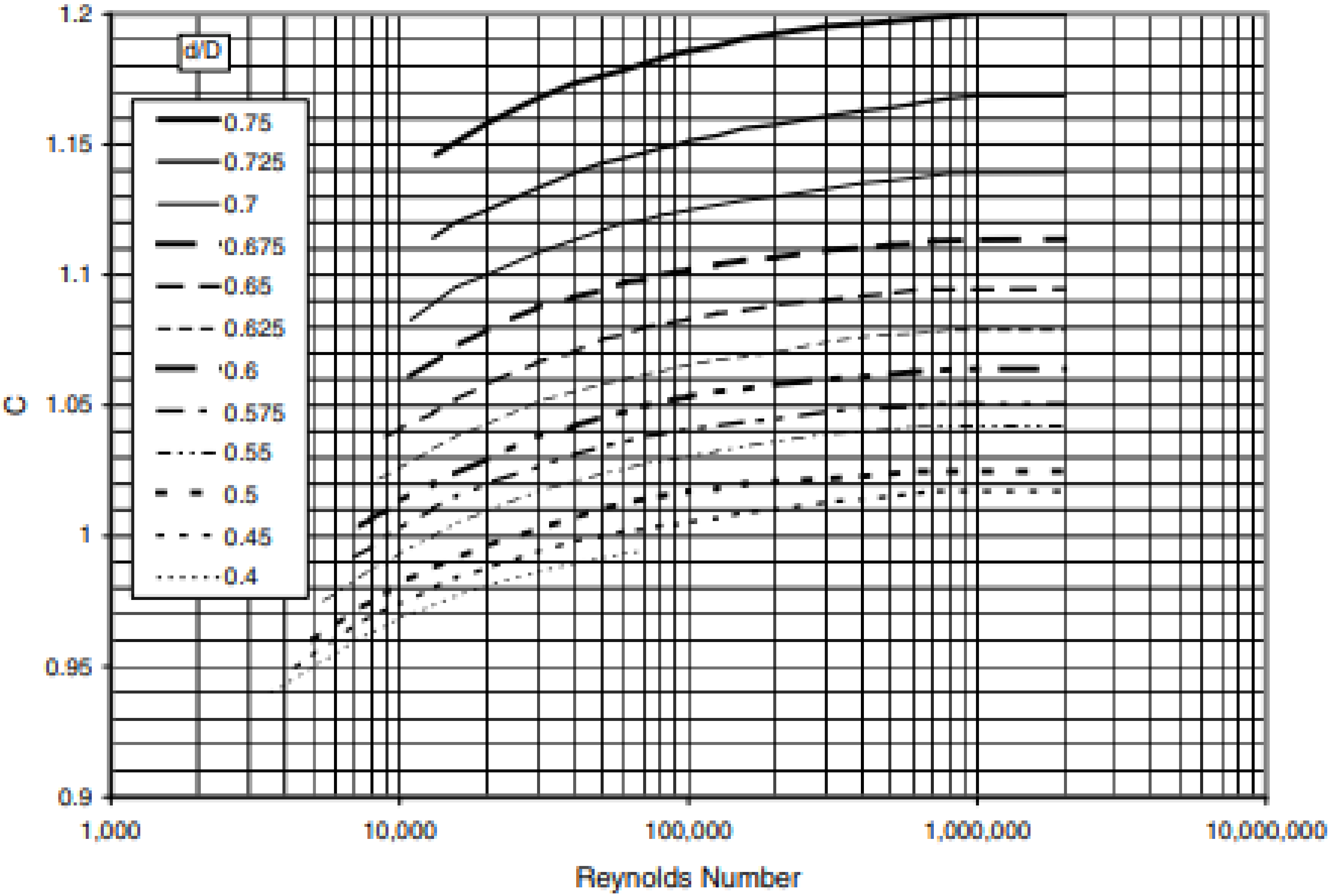
Gas velocity under subsonic flow condition

- Gas velocity under subsonic flow conditions is less than the sound velocity in the gas at the in situ conditions:

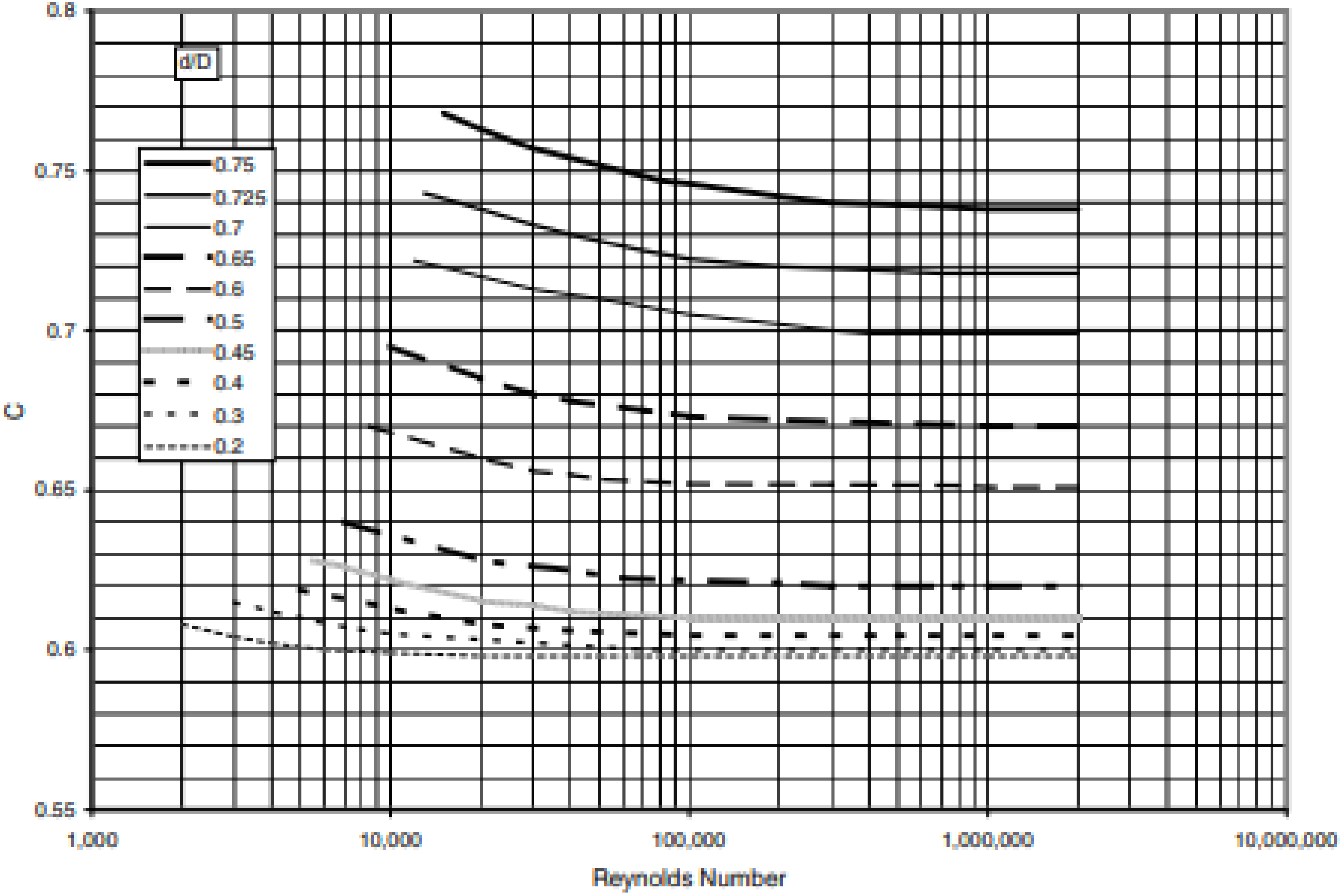
$$v = \sqrt{v_{up}^2 + 2g_c C_p T_{up}\left[1 - \frac{z_{up}}{z_{dn}}\left(\frac{p_{down}}{p_{up}}\right)^{\frac{k-1}{k}}\right]}$$

- where C_p = specific heat of gas at constant pressure (187.7 lb_f-ft/lb_m-R for air)

Choke flow coefficient for nozzle-type chokes.



Choke flow coefficient for orifice-type chokes.



Choke Performance

Sonic flow

Sonic flow

- Under sonic flow conditions the gas passage rate reaches its maximum value. Gas passage rate is expressed in the following equation for ideal gases:

$$Q_{sc} = 879 C A p_{up} \sqrt{\left(\frac{k}{\gamma_g T_{up}}\right)\left(\frac{2}{k+1}\right)^{\frac{k+1}{k-1}}}$$

- Important Note:
  - The choke flow coefficient C is not sensitive to the Reynolds number for Reynolds number values greater than 10^6 .

Gas velocity under sonic flow

- Gas velocity under sonic flow conditions is equal to sound velocity in the gas under the in situ conditions:

$$v = \sqrt{{v_{up}}^2 + 2g_c C_p T_{up}\left[1 - \frac{z_{up}}{z_{outlet}}\left(\frac{2}{k+1}\right)\right]}$$

or

$$v \approx 44.76\sqrt{T_{up}}$$

Temperature at Choke

- Depending on upstream to downstream pressure ratio, the temperature at choke can be much lower than expected. Why?
    - This low temperature is due to the Joule-Thomson cooling effect, that is, a sudden gas expansion below the nozzle causes a significant temperature drop.
- The temperature can easily drop to below ice point resulting in ice-plugging if water exists.
- Even though the temperature still can be above ice point, hydrates can form and cause plugging problems. Assuming an isentropic process for an ideal gas flowing through chokes, the temperature at the choke downstream can be predicted using the following equation:

Estimation of Temperature:

- Assuming an isentropic process for an ideal gas flowing through chokes, the temperature at the choke downstream can be predicted using the following equation:

$$T_{dn} = T_{up} \frac{z_{up}}{z_{outlet}} \left(\frac{p_{outlet}}{p_{up}} \right)^{\frac{k-1}{k}}$$

- The outlet pressure is equal to the downstream pressure in subsonic flow conditions.

Equation Backup sheet

$$\left(\frac{p_{outlet}}{p_{up}}\right)_c = \left(\frac{2}{k+1}\right)^{\frac{k}{k-1}} \quad \textbf{(5.1)}$$

$$Q_{sc} = 1{,}248CAp_{up}\sqrt{\frac{k}{(k-1)\gamma_g T_{up}}\left[\left(\frac{p_{dn}}{p_{up}}\right)^{\frac{2}{k}} - \left(\frac{p_{dn}}{p_{up}}\right)^{\frac{k+1}{k}}\right]} \quad \textbf{(5.2)}$$

$$C = \frac{d}{D} + \frac{0.3167}{\left(\frac{d}{D}\right)^{0.6}} + 0.025[\log(N_{Re}) - 4] \quad \textbf{(5.3)}$$

$$v = \sqrt{v_{up}^{\ 2} + 2g_c C_p T_{up}\left[1 - \frac{z_{up}}{z_{dn}}\left(\frac{p_{down}}{p_{up}}\right)^{\frac{k-1}{k}}\right]} \quad \textbf{(5.4)}$$

$$Q_{sc} = 879CAp_{up}\sqrt{\left(\frac{k}{\gamma_g T_{up}}\right)\left(\frac{2}{k+1}\right)^{\frac{k+1}{k-1}}} \quad \textbf{(5.5)}$$

$$v = \sqrt{v_{up}^{\ 2} + 2g_c C_p T_{up}\left[1 - \frac{z_{up}}{z_{outlet}}\left(\frac{2}{k+1}\right)\right]} \quad \textbf{(5.6)}$$

or

$$v \approx 44.76\sqrt{T_{up}} \quad \textbf{(5.7)}$$

$$T_{dn} = T_{up}\frac{z_{up}}{z_{outlet}}\left(\frac{p_{outlet}}{p_{up}}\right)^{\frac{k-1}{k}} \quad \textbf{(5.8)}$$

- Equation (5.1) through Equation (5.8) can be used for estimating
- Downstream temperature (Equation (5.8))
- Gas passage rate at given upstream and downstream pressures
- Upstream pressure at given downstream pressure and gas passage
- Downstream pressure at given upstream pressure and gas passage
  - To estimate gas passage rate at given upstream and downstream pressures, the following procedure can be taken:
  - Calculate the critical pressure ratio with Equation (5.1).
  - Calculate the downstream to upstream pressure ratio.
  - If the downstream to upstream pressure ratio is greater than the critical pressure ratio, use Equation (5.2) to calculate gas passage. Otherwise, use Equation (5.5) to calculate gas passage.

Problem 1

- A 0.6 specific gravity gas flows from a 2-in pipe through a 1-in orifice-type choke. The upstream pressure and temperature are 800 psia and 75 °F, respectively. The downstream pressure is 200 psia (measured 2 ft from the orifice). The gas-specific heat ratio is 1.3. (a) What is the expected daily flow rate? (b) Does heating need to be applied to assure that the frost does not clog the orifice? (c) What is the expected pressure at the orifice outlet?

Problem 2

- A 0.65 specific gravity natural gas flows from a 2-in pipe through a 1.5-in nozzle-type choke. The upstream pressure and temperature are 100 psia and 70 °F, respectively. The downstream pressure is 80 psia (measured 2 ft from the nozzle). The gas specific heat ratio is 1.25. (a) What is the expected daily flow rate? (b) Is icing a potential problem? (c) What is the expected pressure at the nozzle outlet?

Problem 3

- For the following given data, estimate upstream pressure at choke:
  - Downstream pressure: 300 psia
  - Choke size: 32 1/64 in
  - Flowline ID: 2 in
  - Gas production rate: 5,000 Mscf/d
  - Gas-specific gravity: 0.75 1
  - for air Gas-specific heat ratio: 1.3
  - Upstream temperature: 110 °F
  - Choke discharge coefficient: 0.99

Problem 4

- *Example Problem 5.4*
- For the following given data, estimate downstream pressure at
- choke:
- Upstream pressure: 600 psia
- Choke size: 32 1/64 in
- Flowline ID: 2 in
- Gas production rate: 2500 Mscf/d
- Gas-specific gravity: 0.75 1 for air
- Gas-specific heat ratio: 1.3
- Upstream temperature: 110 °F
- Choke discharge coefficient: 0.99

Application

Applications

- Equation (5.1) through Equation (5.8) can be used for estimating
- Downstream temperature (Equation (5.8))
- Gas passage rate at given upstream and downstream pressures
- Upstream pressure at given downstream pressure and gas passage
- •Downstream pressure at given upstream pressure and gas passage
- To estimate gas passage rate at given upstream and downstream pressures, the following procedure can be taken:
  - Calculate the critical pressure ratio with Equation (5.1).
  - Calculate the downstream to upstream pressure ratio.
  - If the downstream to upstream pressure ratio is greater than the critical pressure ratio, use Equation (5.2) to calculate gas passage.

Otherwise, use Equation (5.5) to calculate gas passage.

To estimate upstream pressure at given downstream pressure and gas passage, the following procedure can be taken:

Calculate the critical pressure ratio with Equation (5.1).

- Calculate the minimum upstream pressure required for sonic flow by dividing the downstream pressure by the critical pressure ratio. Calculate gas flow rate at the minimum sonic flow condition withEquation (5.5).
- If the given gas passage is less than the calculated gas flow rate at the minimum sonic flow condition, use Equation (5.2) to solve upstream pressure numerically. Otherwise, Equation (5.5) to calculate upstream pressure.

Downstream pressure cannot be calculated on the basis of given upstream pressure and gas passage under sonic flow conditions. But it can be calculated under subsonic flow conditions. The following procedure can be followed:

- Calculate the critical pressure ratio with Equation (5.1).
- Calculate the maximum downstream pressure for minimum sonic flow by multiplying the upstream pressure by the critical pressure ratio.
- Calculate gas flow rate at the minimum sonic flow condition with Equation (5.5).
- If the given gas passage is less than the calculated gas flow rate at the minimum sonic flow condition, use Equation (5.2) to solve downstream pressure numerically. Otherwise, the downstream pressure cannot be calculated.
- The maximum possible downstream pressure for sonic flow can be estimated by multiplying the upstream pressure by the critical pressure ratio.

Separation

Natural gases produced from gas wells are normally complex mixtures of hundreds of different compounds. A typical gas well stream is a high-velocity, turbulent, constantly expanding mixture of gases and hydrocarbon liquids, intimately mixed with water vapor, free water, and sometimes solids. The well stream should be processed as soon as possible after bringing it to the surface.

Field Processing of Natural Gas

- Separating the gas from free liquids such as crude oil
- Processing the gas to remove condensable and recoverable hydrocarbon vapors
- Processing the gas to remove condensable water vapors
- Processing the gas to remove other undesirable compounds such as hydrogen sulfide or carbon dioxide.

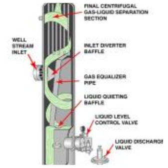
Separation of Gas and Solids

- Composition of the fluid mixture determines what type and size of separator is required.
- Separators are also used in other locations such as upstream and downstream of compressors, dehydration units, and gas sweetening units. At these locations, separators are referred to as scrubbers, knockouts, and free liquid knockouts.
- All these vessels are used for the same purpose: to separate free liquids from the gas stream

What are the basic functions of the separators?

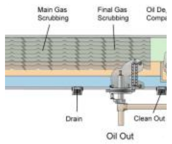
Separators should be designed to perform the following basic functions:

Cause a primary-phase separation of the mostly liquid hydrocarbons from the gas stream



Refine the primary separation by further removing most of the entrained liquid mist from the gas

liquid Refine the separation by further removing the entrained gas from the stream



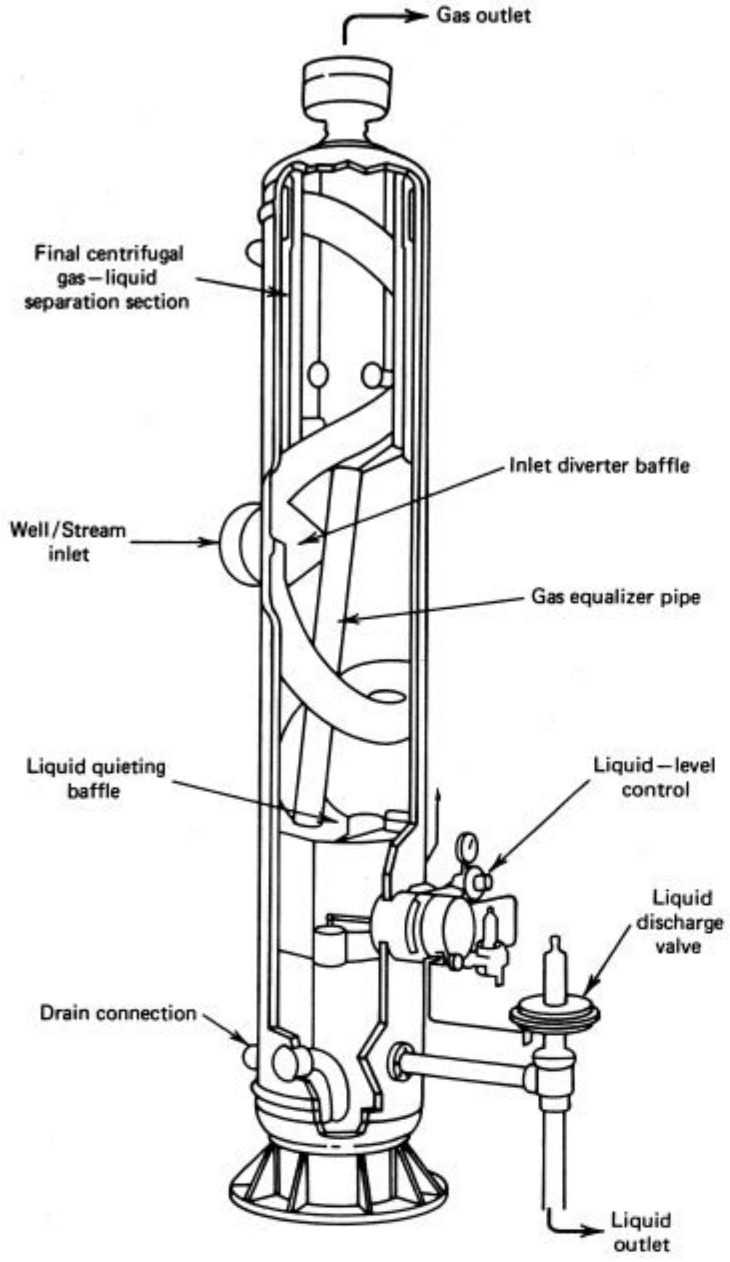
Discharge the separated gas and liquid from the vessel and ensure that no re-entrainment of one into the other occurs

Principles of Separation

- Most separators work based on the principles of gravity segregation and/or centrifugal segregation. A separator is normally constructed in such a way that it has the following features:
  - it has a centrifugal inlet device where the primary separation of the liquid and gas is made
  - it provides a large settling section of sufficient height or length to allow liquid droplets to settle out of the gas stream with adequate surge room for slugs of liquid
  - it is equipped with a mist extractor or eliminator near the gas outlet to coalesce small particles of liquid that do not settle out by gravity
  - it allows adequate controls consisting of level control, liquid dump valve, gas backpressure valve, safety relief valve, pressure gauge, gauge glass, instrument gas regulator, and piping

How it works?

- The centrifugal inlet device makes the incoming stream spin around. Depending upon the mixture flow rate, the reaction force from the separator wall can be up to 500 G of centripetal acceleration. This action forces the liquid droplets together where they fall to the bottom of the separator into the settling section.
- Use of internal baffling or plates may produce more liquid to be discharged from the separator. However, the product may not be stable due to the light ends entrained in it. Sufficient surge room is essential in the settling section to handle slugs of liquid without carryover to the gas outlet. This can be achieved by placing the liquid level control in the separator, which in turn determines the liquid level. The amount of surge room required depends on the surge level of the production steam and the separator size used for a particular application.

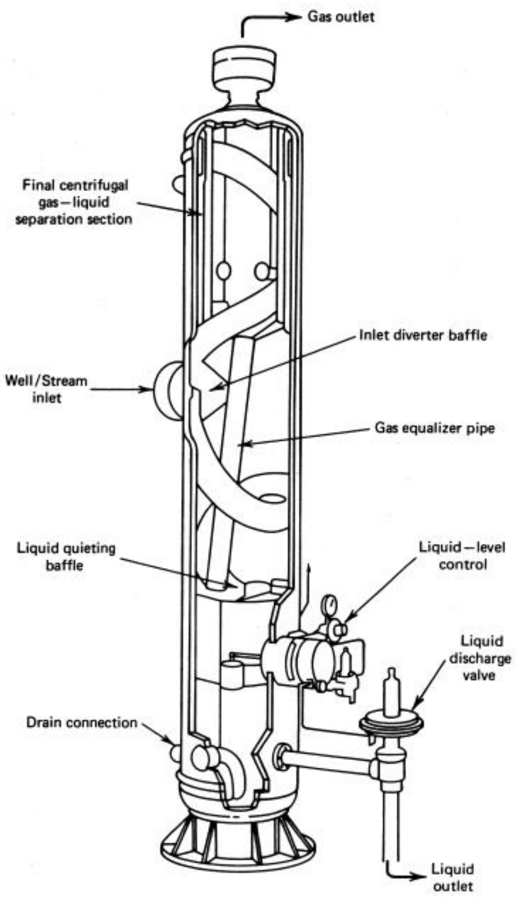


How we can eliminate the small liquid droplet?

- Small liquid droplets that do not settle out of the gas stream due to little gravity difference between them and the gas phase tend to be entrained and pass out of the separator with the gas. A mist eliminator or extractor near the gas outlet allows this to be almost eliminated. The small liquid droplets will hit the eliminator or extractor surfaces, coalesce, and collect to form larger droplets that will then drain back to the liquid section in the bottom of the separator. A stainless steel woven-wire mesh mist eliminator can remove up to 99.9% of the entrained liquids from the gas stream. Cane mist eliminators can be used in areas where there is entrained solid material in the gas phase that may collect and plug a wire mesh mist eliminator.

Types of Separator

- Vertical Separator
- Horizontal Separator
  - Single tube
  - Double tube
- Spherical Separator



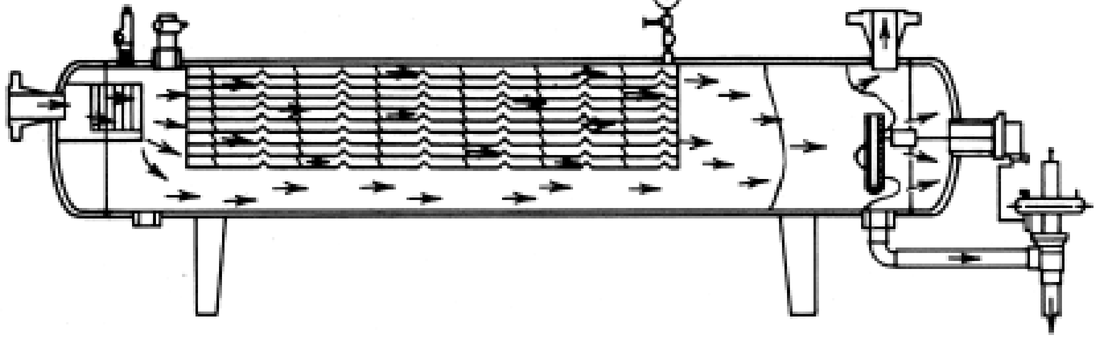
Vertical Separators

Vertical Separator Demo

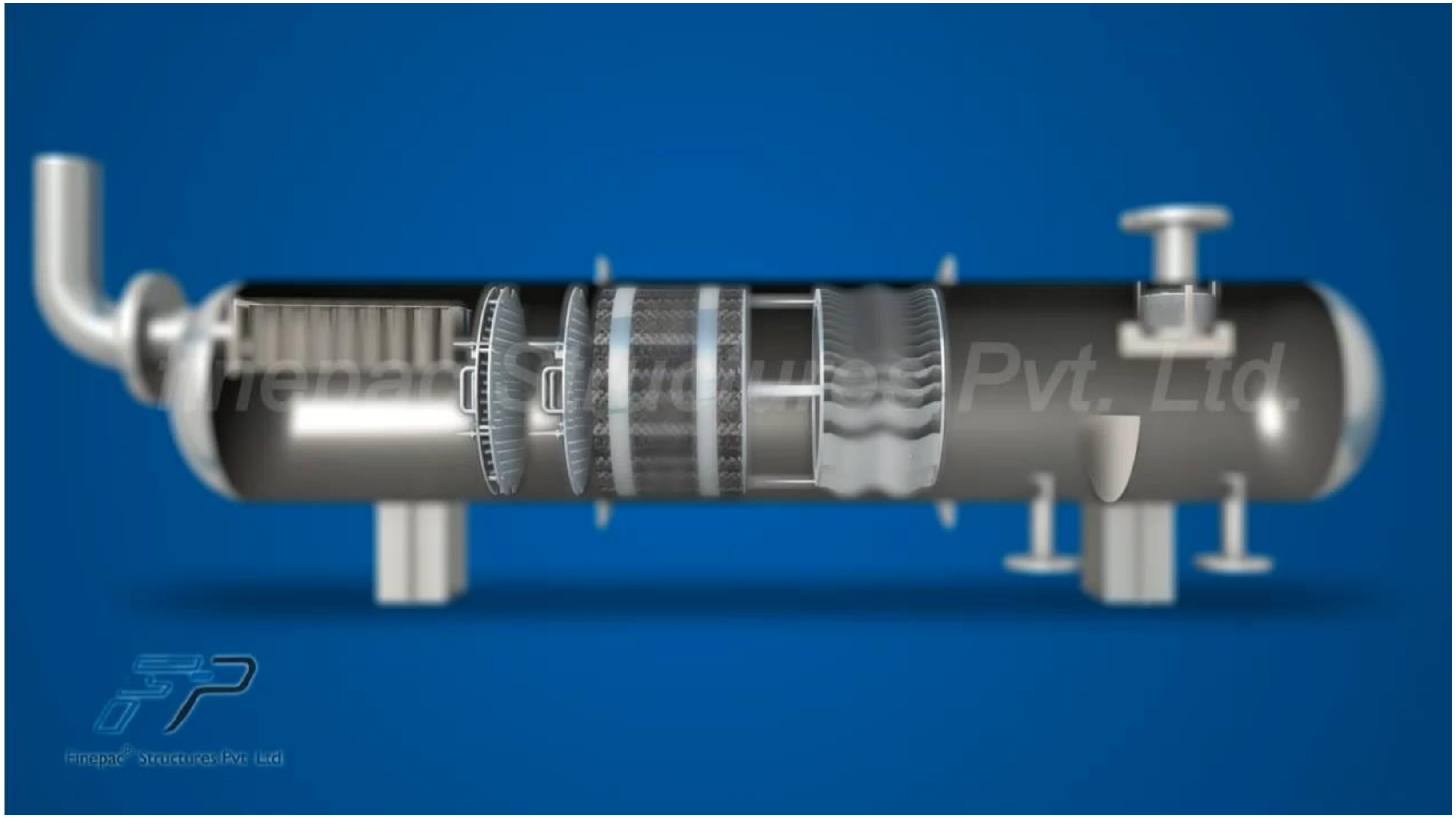
Vertical Separator

- Vertical separators are often used to treat low to intermediate gas/oil ratio well streams and streams with relatively large slugs of liquid.
- Vertical separators occupy less floor space, which is important for facility sites such as those on offshore platforms where space is limited.
- Owing to the large vertical distance between the liquid level and the gas outlet, the chance for liquid to revaporize into the gas phase is limited. However, due to the natural upward flow of gas in a vertical separator against the falling droplets of liquid, adequate separator diameter is required.
- Vertical separators are more costly to fabricate and ship in skid-mounted assemblies

Horizontal Separators



Horizontal Separator Demo



Characteristics of Horizontal Separator

- Separators are usually the first choice because of their low costs. Horizontal separators are widely used for high gas/oil ratio well streams, foaming well streams, or liquid-from-liquid separation.
- They have much greater gas/liquid interface due to a large, long, baffled gas separation section.
- Horizontal separators are easier to skid-mount and service, and require less piping for field connections. Individual separators can be stacked easily into stage-separation assemblies to minimize space requirements.

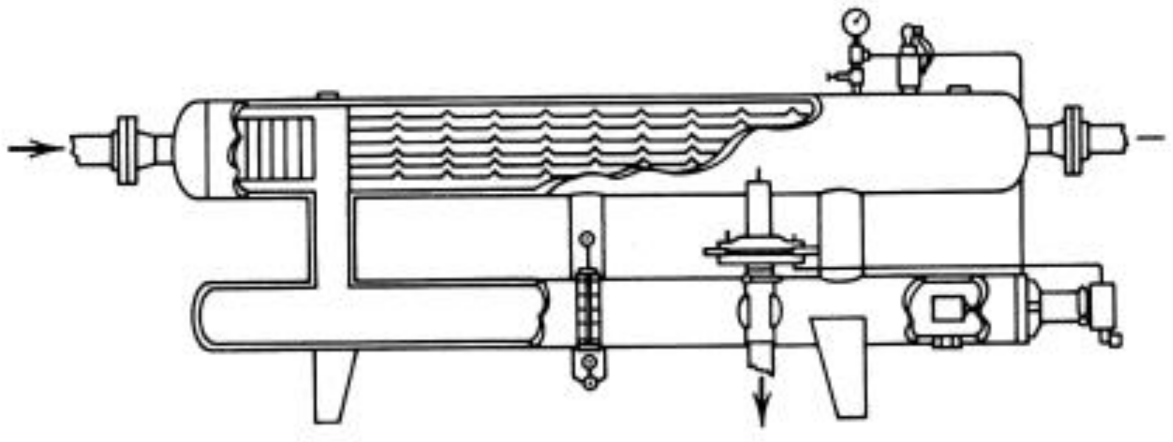
How horizontal separator works…

- In horizontal separators, gas flows horizontally and, at the same time, liquid droplets fall toward the liquid surface.
- The moisture gas flows in the baffle surface and forms a liquid film that is drained away to the liquid section of the separator. The baffles need to be longer than the distance of liquid trajectory travel.
- The liquid-level control placement more critical in a horizontal separator than in a vertical separator due to limited surge space.

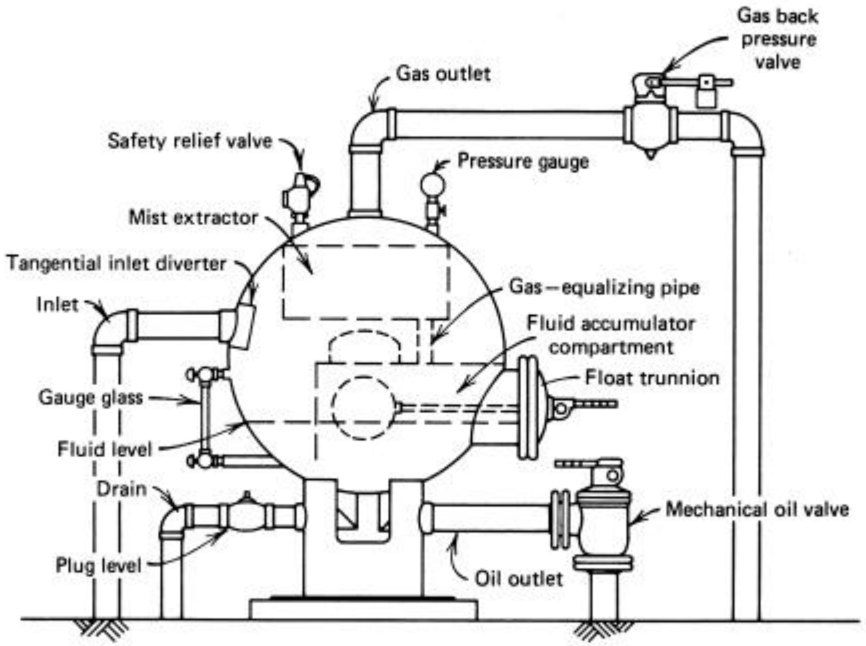
A horizontal double-tube separator

A horizontal double-tube separator consists of two tube sections.

- The upper tube section is filled with baffles, and gas flows straight through and at higher velocities, and the incoming free liquid is immediately drained away from the upper tube section into the lower tube section. Horizontal double-tube separators have all the advantages of normal horizontal single-tube separators plus much higher liquid capacities.

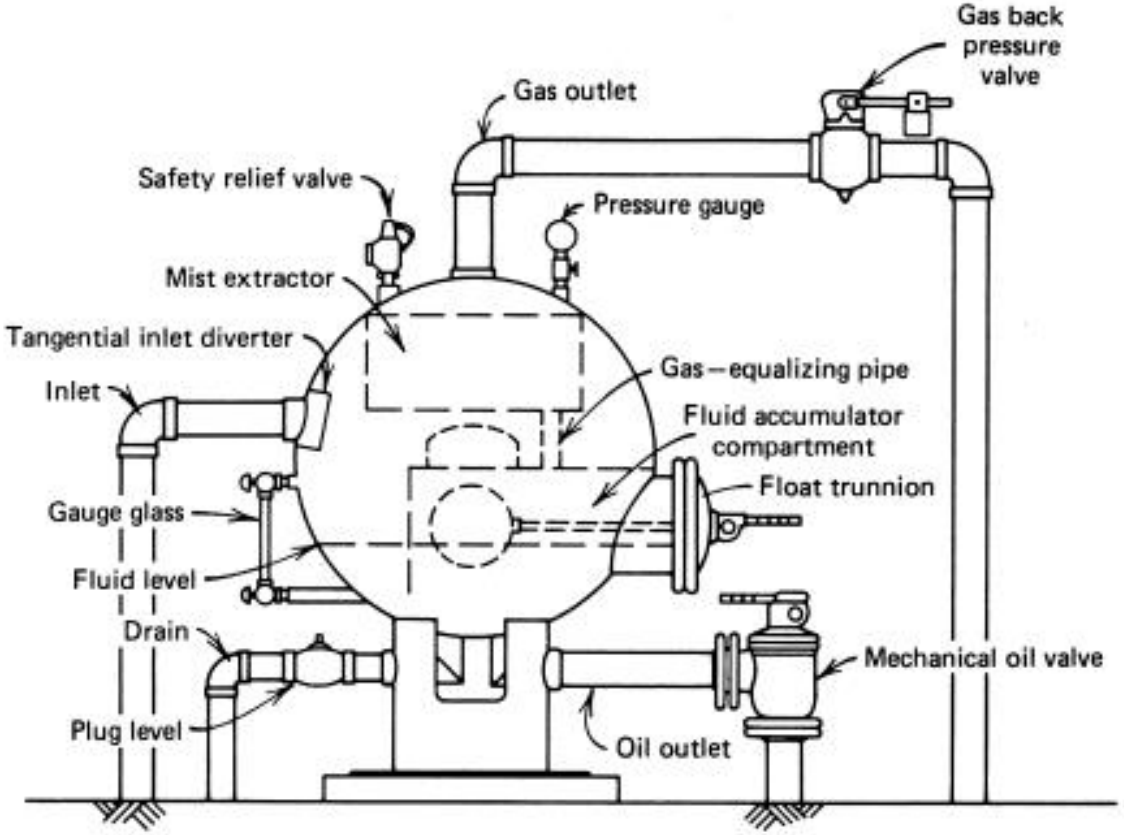


Spherical Separators



Spherical Separator

- Spherical separators offer an inexpensive and compact means of the separation arrangement.
- Owing to their compact configurations, this type of separator has a very limited surge space and liquid settling section.
- Also, the placement and action of the liquid-level control in this type of separator is more critical.



Separator Design

Natural gas engineers normally do not perform detailed designing of separators but carry out selection of separators suitable for their operations from manufacturers' product catalogs. This section addresses how to determine separator specifications based on well stream conditions. The specifications are used for separator selections.

Outline

- Gas capacity
- Liquid capacity

Gas Capacity

- The following equation are widely used for calculating gas capacity of oil/gas separator:

$$v = K\sqrt{\frac{\rho_L - \rho_g}{\rho_g}}$$

$$q = Av$$

$$q_{st} = \frac{2.4D^2Kp}{z(T+460)}\sqrt{\frac{\rho_L - \rho_g}{\rho_g}}$$

q_{st} = gas capacity at standard conditions, MMscfd

D = internal diameter of vessel, ft

p = operation pressure, psia

T = operating temperature, °F

z = gas compressibility factor

A = total cross-sectional area of separator, ft^2

v = superficial gas velocity based on total cross-sectional area A, ft/s

q = gas flow rate at operating conditions, ft^3/s

ρ_L = density of liquid at operating conditions, lb$_m$/ft^3

ρ_g = density of gas at operating conditions, lb$_m$/ft^3

K = empirical factor

Separator Type	K	Remarks
Vertical separators	0.06 to 0.35	
Horizontal separators	0.40 to 0.50	
Wire mesh mist eliminators	0.35	
Bubble cap trayed columns	0.16	24-in spacing
Volume tray columns	0.18	24-in spacing

***K*-Values Used for Designing Separators**

Liquid Capacity

- Retention time of the liquid within the vessel determines liquid capacity of a separator.
- Adequate separation requires sufficient time to obtain an equilibrium condition between the liquid and gas phase at the temperature and pressure of separation.
- The liquid capacity of a separator relates to the retention time through the settling volume:

$$q_L = \frac{1440 V_L}{t}$$

where

q_L = liquid capacity, bbl/day

V_L = liquid settling volume, bbl

t = retention time, min

- From Table we can see a strong effect of temperature on the

Three –Phase separations at low pressures.

Retention Time Required under Various Separation Conditions

Separation Condition	T (°F)	t (min.)
Oil/gas separation		1
High-pressure oil/gas/water separation		2 to 5
Low-pressure oil/gas/water separation	>100	5 to 10
	90	10 to 15
	80	15 to 20
	70	20 to 25
	60	25 to 30

Sizing of the separator

- Proper sizing of a separator requires the use of both Equations for gas capacity and Equation for liquid capacity.
- Experience shows that for high-pressure separators used for treating high gas/oil ratio well streams, the gas capacity is usually the controlling factor for separator selection.
- However, the reverse may be true for low-pressure separators used on wellstreams with low gas/oil ratios.

Problem 7.1

- Calculate the minimum required size of a standard oil/gas separator for the following conditions. Consider both vertical and horizontal separators.
  Gas flow rate: 5.0 MMscfd
  Gas-specific gravity: 0.7
  Condensate flow rate: 20 bbl/MMscf
  Condensate gravity: 60 °API
  Operating pressure: 800 psig
  Operating temperature: 80 °F

Settling Volume of Standard Separators

Appendix

Settling Volumes of Standard Vertical High-Pressure Separators (230 psi to 2,000 psi working pressure) (Continued)

Size (D × H)	V_L (bbl)	
	Oil/Gas Separators	Oil/Gas/Water Separators
16" × 5'	0.27	0.44
16" × 7-1/2'	0.41	0.72
16" × 10'	0.51	0.94
20" × 5'	0.44	0.71

Size (D × H)	V_L (bbl)	
	Oil/Gas Separators	Oil/Gas/Water Separators
20" × 7-1/2'	0.65	1.15
20" × 10'	0.82	1.48
24" × 5'	0.66	1.05
24" × 7-1/2'	0.97	1.68
24" × 10'	1.21	2.15
30" × 5'	1.13	1.76
30" × 7-1/2'	1.64	2.78
30" × 10'	2.02	3.54
36" × 7-1/2'	2.47	4.13
36" × 10'	3.02	5.24
36" × 15'	4.13	7.45
42" × 7-1/2'	3.53	5.80
42" × 10'	4.29	7.32
42" × 15'	5.80	10.36
48" × 7-1/2'	4.81	7.79
48" × 10'	5.80	9.78
48" × 15'	7.79	13.76
54" × 7-1/2'	6.33	10.12
54" × 10'	7.60	12.65
54" × 15'	10.12	17.70
60" × 7-1/2'	8.08	12.73
60" × 10'	9.63	15.83
60" × 15'	12.73	22.03
60" × 20'	15.31	27.20

Settling Volumes of Standard Vertical Low-Pressure Separators (125 psi working pressure)

Size (D × H)	V_L (bbl)	
	Oil/Gas Separators	Oil/Gas/Water Separators
24" × 5'	0.65	1.10
24" × 7-1/2'	1.01	1.82
30" × 10'	2.06	3.75
36" × 5'	1.61	2.63
36" × 7-1/2'	2.43	4.26
36" × 10'	3.04	5.48
48" × 10'	5.67	10.06
48" × 15'	7.86	14.44
60" × 10'	9.23	16.08
60" × 15'	12.65	12.93
60" × 20'	15.51	18.64

Settling Volumes of Standard Horizontal High- Pressure Separators (230 psi to 2,000 psi working pressure)

Size (D × L)	V_L (bbl)		
	1/2 Full	1/3 Full	1/4 Full
12-3/4" × 5'	0.38	0.22	0.15
12-3/4" × 7-1/2'	0.55	0.32	0.21
12-3/4" × 10'	0.72	0.42	0.28
16" × 5'	0.61	0.35	0.24
16" × 7-1/2'	0.88	0.50	0.34
16" × 10'	1.14	0.66	0.44
20" × 5'	0.98	0.55	0.38
20" × 7-1/2'	1.39	0.79	0.54
20" × 10'	1.80	1.03	0.70

Size (D × L)	V_L (bbl)		
	1/2 Full	1/3 Full	1/4 Full
24" × 5'	1.45	0.83	0.55
24" × 7-1/2'	2.04	1.18	0.78
24" × 10'	2.63	1.52	1.01
24" × 15'	3.81	2.21	1.47
30" × 5'	2.43	1.39	0.91
30" × 7-1/2'	3.40	1.96	1.29
30" × 10'	4.37	2.52	1.67
30" × 15'	6.30	3.65	2.42
36" × 7-1/2'	4.99	2.87	1.90
36" × 10'	6.38	3.68	2.45
36" × 15'	9.17	5.30	3.54
36" × 20'	11.96	6.92	4.63
42" × 7-1/2'	6.93	3.98	2.61
42" × 10'	8.83	5.09	3.35
42" × 15'	12.62	7.30	4.83
42" × 20'	16.41	9.51	6.32
48" × 7-1/2'	9.28	5.32	3.51
48" × 10'	11.77	6.77	4.49
48" × 15'	16.74	9.67	6.43
48" × 20'	21.71	12.57	8.38
54" × 7-1/2'	12.02	6.87	4.49
54" × 10'	15.17	8.71	5.73
54" × 15'	12.49	12.40	8.20
54" × 20'	27.81	16.08	10.68
60" × 7-1/2'	15.05	8.60	5.66
60" × 10'	18.93	10.86	7.17
60" × 15'	26.68	15.38	10.21
60" × 20'	34.44	19.90	13.24

Settling Volumes of Standard Horizontal Low-Pressure Separators (125 psi working pressure)

Size ($D \times L$)	V_L (bbl)		
	1/2 Full	1/3 Full	1/4 Full
24" × 5'	1.55	0.89	0.59
24" × 7-1/2'	2.22	1.28	0.86
24" × 10'	2.89	1.67	1.12
30" × 5'	2.48	1.43	0.94
30" × 7-1/2'	3.54	2.04	1.36
30" × 10'	4.59	2.66	1.77
36" × 10'	6.71	3.88	2.59
36" × 15'	9.76	5.66	3.79
48" × 10'	12.24	7.07	4.71
48" × 15'	17.72	10.26	6.85
60" × 10'	19.50	11.24	7.47
60" × 15'	28.06	16.23	10.82
60" × 20'	36.63	21.21	14.16

Settling Volumes of Standard Spherical High-Pressure Separators (230 psi to 3,000 psi working pressure)

Size OD	V_L (bbl)
24"	0.15
30"	0.30
36"	0.54
42"	0.88
48"	1.33
60"	2.20

Settling Volumes of Standard Spherical Low-Pressure Separators (1.25 psi)

Size OD	V_L (bbl)
41"	0.77
46"	1.02
64"	1.60