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THE SUMMARY OF GAS CONDENSATE AND GAS RESERVOIR PERFORMANCE

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PREFACE

Natural gas is an emergent fuel of choice for environmentally aware due to the lower noxious emissions compared with other fossil fuels. Exploration activity by major multinational oil and gas companies is aimed increasingly to find gas in remote locations and in ever deeper ocean depths. Once a gas field has been discovered, the gas accumulation must be developed, produced, gathered, processed, and transported to the consumer. Transport of gas by pipelines to distant delivery points presents unique challenges of flow through long conduits. Processing of the gas to meet delivery specifications is required and this requires process systems design for each production facility.

This book presents a summary and basic of natural gas and gas-condensate along with gas reservoir performance. The design of a development and production of a natural gas always depends on the reservoir and well characteristics, tubing and flowline performance to the compressor and processing.

Much of the material on which this book is based was drawn from the book of H. Dale Beggs: Gas Production Operation, Production Optimization Using NODAL Analysis, Chi U. Ikoku: Natural Gas Production Engineering, and Saeid Mokhatab, William A. Poe, and James G. Speight: Handbook of Natural Gas Transmission and Processing. We, as a person, always growing and improving, and so do this book. I promise to add more theory and fundamentals of the natural gas alongside the example problem to this book. I do hope I can make a better book later.

I thank to Universitas Pembangunan Nasional “Veteran” Yogyakarta and the encouragement that I have received from many people including my colleagues and my family.

Edgie Y. Kaesti
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1 INTRODUCTION

DEVELOPMENT OF NATURAL GAS

Since its discovery in the United States at Fredonia, New York, in 1821, natural gas has been used as fuel in areas immediately surrounding the gas fields. In the early years of the natural gas industry, when gas accompanied crude oil, it had to find a market or be flared. Consequently, gas production at that time was often short-lived, and gas could be purchased for as little as 1 or 2 cents per 1000 cu ft in the field.

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 a fuel for providing space and industrial process heat, use of natural gas in making petrochemicals and fertilizers, and strong demand for low-sulfur fuels which emerged in the middle 1960s.

Natural gas, liquefied by a refrigeration cycle, can now be transported efficiently and rapidly across the oceans of the world by insulated tankers. The use of refrigeration to liquefy dry natural gas, and hence reduce its volume to the point where it becomes economically attractive to transport across oceans by tanker, was first attempted on a small scale in Hungary in 1934 and later used in the United States for moving gas in liquid form from the gas fields in Louisiana up the Mississippi River to Chicago in 1951.

The first use of a similar process on a large scale outside the United States was the liquefaction by a refrigerative cycle of some of the gas from the Hassi R’Mel gas field in Algeria and the export from 1964 onward of the resultant liquefied natural gas (LNG) by specially designed insulted tankers to Britain and France. Natural gas is in this way reduced to about one six-hundredth of its original volume and the nonmethane components are largely eliminated.

Current production from conventional sources is not sufficient to satisfy all demands for natural gas; however, there has been lack of agreement as to the extent of the gas shortage. Supplements to natural gas produced from conventional sources may provide portions of the world’s future energy. Such supplements may include gas production resulting from stimulation of tight gas reservoirs, methane gas occluded in coal, and natural gas contained in geopressured reservoirs.

Natural gas production from hydrocarbon rich shale formations, known as shale gas, is one of the most rapidly expanding trends in onshore domestic oil and gas exploration and production today. Three factors have come together in recent years to make shale gas production economically viable: advances in horizontal drilling, advances in hydraulic fracturing and perhaps most importantly, rapid increases in natural gas prices in the last several years as a result of significant supply and demand pressures. These technologies and practices, along with the increasing gas prices of the last few years, have provided how shale gas can be economically recovered.

CHARACTERISTICS OF NATURAL GAS

Natural gas is a mixture of hydrocarbon gases with some impurities, mainly nitrogen (N_2), hydrogen sulfide (H_2S), and carbon dioxide (CO_2). Gases containing significant amounts of H_2S or CO_2 or both are called sour or acid gases. The hydrocarbon gases are methane, ethane, propane, butanes, pentanes, and small amounts of hexanes, heptanes, and some heavier fractions.

Natural gas is normally considered to be a mixture of straight chain or paraffin hydrocarbon compounds. However, occasionally cyclic and aromatic compounds occur in natural gas. The general formula for the paraffin hydrocarbons is C_nH_{2n+2}, where n is the number of carbon atoms.

NATURAL GAS ORIGIN AND COMPOSITION

Natural gas exists in nature under pressure in rock reservoirs in the Earth’s crust, either in conjunction with and dissolved in heavier hydrocarbons and water or by itself. It is produced from the reservoir similarly to or in conjunction with crude oil. Natural gas has been formed by the degradation of organic matter accumulated in the past millions of years.

Two main mechanisms (biogenic and thermogenic) are responsible for this degradation. Biogenic gas is formed at shallow depths and low temperatures by the anaerobic bacterial decomposition of sedimentary organic matter. In contrast, thermogenic gas is formed at deeper depths by (1) thermal cracking of sedimentary organic matter into hydrocarbon liquids and gas (this gas is cogenetic with oil and is called “primary” thermogenic gas) and (2) thermal cracking of oil at high temperatures into gas (“secondary” thermogenic gas) and pyrobitumen.

Biogenic gas consists almost entirely of methane. In contrast, thermogenic gas can also contain significant concentrations of ethane, propane, butanes, and heavier hydrocarbons. Knowing whether a natural gas show is biogenic gas or thermogenic gas can have critical implications for the presence of liquid hydrocarbons in a basin. Gas geochemistry readily reveals whether a gas is biogenic or thermogenic.

The principal constituent of natural gas is methane. Other constituents are paraffinic hydrocarbons such as ethane, propane, and the butanes. Many natural gases contain nitrogen as well as carbon dioxide and hydrogen sulfide. Trace quantities of argon, hydrogen, and helium may also be present.

The actual composition of a natural gas can vary over wide ranges. Even two gas wells producing from the same reservoir may have different compositions. The composition of the gas produced from a given reservoir may change with time if liquids condense in the reservoir as pressure declines. This occurs in a so-called retrograde condensate reservoir. Table 1-1 shows typical hydrocarbon compositions of the gas produced from different types of reservoirs.

Some aromatics such as benzene, toluene, and xylenes can also be present, raising safety issues due to their toxicity. Natural gas can contain other contaminants too. Acid contaminants such as mercaptans—R-SH, carbonyl sulfide (COS), and carbon disulfide (CS_2)—may be present in small quantities. Mercury can also be present either as a metal in vapor phase or as an organometallic compound in liquid fractions. Concentration levels are generally very small, but even at very small concentration levels, mercury can be detrimental due its toxicity and its corrosive properties (reaction with aluminium alloys).

Natural gas is considered “dry” when it is almost pure methane, having had most of the other commonly associated hydrocarbons removed. When other hydrocarbons are present, the natural gas is “wet”.

NATURAL GAS SOURCES

Natural gas produced from geological formations comes in a wide array of compositions. Alternative to conventional sources of natural gas is importation of liquefied natural gas, substitute natural gas, coal gasification, and gas from shale reservoirs. The technology required for handling and transporting these gases once they are produced is essentially the same as for natural gases.

Liquefied natural gas is essentially methane that is liquefied at atmospheric pressure by cooling it to -260°F. The phase change reduces the volume by 623:1, and approximately 15% of the energy consumed in the phase change.

Synthetic gas from coal has been investigated in several pilot plants in the United States, but the commercial viability has not been demonstrated. The gas derived from coal is usually low in heating value as compared to natural gas.

Substitute natural gas (SNG) can be made from liquid petroleum feedstock such as naphtha, crude oil, propane, and butane. Facilities exist for this process, but the cost is extremely high in comparison to natural gas at its present price.

Gas from shale formations is a potential source of gaseous fuel that could be extracted from an area around the world. Massive fracturing, advanced recovery techniques, and a higher price for the gas will have to occur before this source contributes a substantial amount of energy to the world.

In order to recover gas from very low permeability formations in commercial quantities, some method is required for increasing the flow capacity of the wells. One method is to fracture the formation with a nuclear blast, but so far this technique has not proved feasible. The other method is massive hydraulic fracturing, which is the subject of much research of the present time.

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.

Table 1-1

Typical Natural Gas Compositions

(Gas Production Operations, H. Dale Beggs)

Component	Symbol	Mol Percent		
		Associated Gas	Wet Gas	Dry Gas
Methane	C_1	27.52	59.52	97.17
Ethane	C_2	16.34	5.36	1.89
Propane	C_3	29.18	4.71	0.29
i-Butane	i-C_4	5.37	2.03	0.13
n-Butane	n-C_4	17.18	2.39	0.12
i-Pentane	i-C_5	2.18	1.80	0.07
n-Pentane	n-C_5	1.72	1.61	0.05
Hexane	C_6	0.47	2.60	0.04

Heptanes Plus	C_{7+}	0.04	19.98	0.24
		100.00	100.00	100.00

QUALITY OF NATURAL GAS

The amount of energy that is obtained from the burning of a volume of natural gas is measured in British thermal units (Btu). The value of natural gas is calculated by its Btu content. The energy content of natural gas is variable and depends on its accumulations, which are influenced by the amount and types of energy gases they contain: the more non-combustible gases in a natural gas, the lower the Btu value. In addition, the volume mass of energy gases that are present in a natural gas accumulation also influences the Btu value of natural gas. The more carbon atoms in a hydrocarbon gas, the higher its Btu value. Btu analyses of natural gas are done at each stage of the supply chain. Gas chromatographic process analysers are used to conduct fractional analysis of the natural gas streams, separating natural gas into identifiable components. The components and their concentrations are converted into a gross heating value in Btu-cubic foot.

Normally, natural gas as it is when extracted is not suitable for pipeline transportation or commercial use before being processed. Pipelines set their specifications for the quality of natural gas.

In any case, natural gas must be processed to remove unwanted water vapor, solids, or other contaminants and to get those hydrocarbons that have a higher value as separate products.

TRANSPORTATION

Gas, because of the storage difficulties, needs to be transported immediately to its destination after production from a reservoir. There are several options for transporting natural gas energy from oil and gas fields to market. These include pipelines, liquefied natural gas (LNG), compressed natural gas (CNG), gas to solids (GTS), i.e., hydrates, gas to power (GTP), i.e., electricity, and gas to liquids (GTL), with a wide range of possible products, including clean fuels, plastic precursors, or methanol and gas to commodity (GTC), such as aluminium, glass, cement, or iron. The following section examines some of these technical methods by which natural gas energy can be transported and covers many of the essential points needed.

2 NATURAL GAS PROPERTIES

THE IDEAL GAS

The understanding of the behavior of gases with respect to pressure and temperature changes is made clearer by first considering the behavior of gases at conditions near standard conditions of pressure and temperature, that is p = 14.7 psia = 100 kPa and T = 60°F = 520°R = 288°K.

At this condition the gas said to behave ideally, and most of the early work with gases was conducted at conditions approaching these conditions. An ideal gas is defined as one in which: the volume occupied by the molecules is small compared to the total gas volume; all molecular collisions are elastic; and there are no attractive or repulsive forces among the molecules.

THE IDEAL GAS LAW

The three gas laws from Boyle’s, Charles’/Gay Lussac’s and Avogadro’s can be combined to express a relationship among pressure, volume, and temperature, called the ideal gas law.

The equation of state for an ideal gas may be derived from a combination of Boyle’s, Charles’/Gay Lussac’s, and Avogadro’s Law as:

$$\mathrm{p\,V = nRT}\ (\mathbf{2.1})$$

where:

p = absolute pressure, psia

V = volume, cu ft

T = absolute temperature, °R

n = number of pound-moles, where 1 lb-mol is the molecular weight of the gas (lb)

R = the universal gas constant

The numerical value of the constant R depends on the units used to express temperature, pressure, and volume. As an example, suppose that pressure is expressed in psia, volume in cubic feet, temperature in degrees Rankin, and moles in pound moles. Avogadro's Law states that 1 lb-mole of any ideal gas occupies 379.4 cu ft at 60°F and 14.7 psia. Therefore,

$$\mathrm{R = \frac{pV}{nT} = \frac{(14.7\ psia)(379.4\ cu\ ft)}{(1\ lb\ mole)(520°R)}}$$

$$\mathrm{= 10.732\,\frac{psia\ cu\ ft}{lb\ mole\ °R}}$$

Table 2-1 gives numerical values of R for various systems of units.

Table 2-1

Values of Gas Constant R in Various Units

(Gas Production Operations, H. Dale Beggs)

Units	R
atm, cc/g-mole, °K	82.06
BTU/lb-mole, °R	1.987
psia, cu ft/lb-mole, °R	10.73
lb/sq ft abs, cu ft/lb-mole, °R	1544
atm, cu ft/lb-mole, °R	0.730
mm Hg, liters/g-mole, °K	62.37
in. Hg, cu ft/lb-mole, °R	21.85
cal/g-mole, °K	1.987
kPa, m^3/kg-mole, °K	8.314
J/kg-mole, °K	8314

THE REAL GAS

The volume of a real gas is usually less than what the volume of an ideal gas would be, and hence a real gas is said to be super compressible. Several assumptions were made in formulating the equation of state for ideal gases. Since these assumptions are not correct for gases at pressure and temperatures that deviate from ideal or standard conditions, corrections must be made to account for the deviation from the ideal behavior. The most widely used correction method in the petroleum industry is the gas compressibility factor, more commonly called the Z-factor. It is defined as the ratio of the actual volume occupied by a mass of gas at some pressure and temperature to the volume the gas would occupy if it behaved ideally. That is,

$$\mathrm{Z} = \frac{\mathrm{V_{actual}}}{\mathrm{V_{ideal}}} \quad \text{or} \quad \mathrm{V_{actual}} = \mathrm{Z\,V_{ideal}}$$

The equation of state is:

$$\mathrm{p\,V_{ideal}} = \mathrm{nRT} \quad \text{or} \quad \mathrm{p}\frac{\mathrm{V_{actual}}}{\mathrm{Z}} = \mathrm{nRT}$$

Therefore, the equation of state for any gas becomes:

$$\mathrm{p\,V} = \mathrm{ZnRT}\ (\mathbf{2.2})$$

where, for an ideal gas, $Z = 1$.

The compressibility factor varies with changes in gas composition, temperature, and pressure. Z, which is dimensionless, is the gas deviation factor. The Z-factor can be interpreted as a term by which the pressure must be corrected to account for the departure from the ideal gas equation.

The theory of corresponding states dictates that the Z factor can be uniquely defined as a function of reduced pressure and reduced temperature. The reduced pressure and reduced temperature are defined as:

$$\mathrm{P_r} = \frac{\mathrm{P}}{\mathrm{P_c}} \text{ and } \mathrm{T_r} = \frac{\mathrm{T}}{\mathrm{T_c}}\ (\mathbf{2.3})$$

where P_r and T_r are reduced pressure and reduced temperature, respectively, and P_c and T_c are critical pressure and critical temperature of the gas, respectively.

The values of critical pressure and critical temperature can be estimated from the following equations if the composition of the gas and the critical properties of the individual components are known:

$$\mathrm{P_c} = \sum_{\mathrm{i}}^{\mathrm{n}} \mathrm{P_{ci\,yi}} \text{ and } \mathrm{T_c} = \sum_{\mathrm{i}}^{\mathrm{n}} \mathrm{T_{ci\,yi}} \quad (\mathbf{2.4})$$

where P_{ci} and T_{ci} are the critical pressure and critical temperature of component i, respectively; and y_i is the mole fraction of component i. Once critical properties of the mixture are calculated as stated in Equation 2.4, we can use Equation 2.3 to calculate the reduced properties of the mixture.

GAS FORMATION VOLUME FACTOR

The formation volume factor for gas is defined as the ratio of volume of 1 mol of gas at a given pressure and temperature to the volume of 1 mole of gas at standard conditions. In most operations involving gas production, the flow rates and quantities produced are measured at standard conditions such as scf/day or scf. Reservoir engineering and pipeline flow calculations require the volumes at in situ conditions of pressure and temperature, and therefore a convenient conversion factor from standard conditions to in situ condition is needed. The conversion factor is called the gas formation volume factor and is defined as the actual volume occupied by the gas at some pressure and temperature divided by the volume that the gas would occupy at standard conditions. That is,

$$B_g = \frac{V_{p,T}}{V_{sc}} = \frac{\frac{Z\,n\,RT}{p}}{\frac{Z_{sc}\,n\,R\,T_{sc}}{p_{sc}}} = \frac{Z\,T\,p_{sc}}{Z_{sc}\,T_{sc}\,p}\ \frac{\text{vol}}{\text{std vol}}\ (\mathbf{2.5})$$

when P_{sc} is 1 atmosphere (14.7 psia or 101.325 kPa) and T_{sc} is 60°F (519.67°R or 288.71°K). In some cases, it is more convenient to define the value of B_g in bbl/SCF. The equation can be written as:

$$B_g = 0.005\ \frac{Z\,T}{P}\ (\mathbf{2.5-1})$$

where T is in °R and P is in psia.

GAS DENSITY

Gas density is defined as mass per unit volume and so can also be derived and calculated from the real gas law:

$$\rho_g = \frac{m}{V} = \frac{p\,M}{Z\,R\,T}\ (\mathbf{2.6})$$

Knowing that the molecular weight of gas is the product of specific gravity and molecular weight of air and that the value of R is 10.73 in field units [8.314 in SI units], we can write the equation for density as:

$$\rho_g = 2.7\frac{p\,\gamma_g}{Z\,T}\ \ \mathbf{(2.6-1)}$$

where ρ_g is in lbm/ft^3, p is in psia, and T is in °R.

GAS COMPRESSIBILITY

The isothermal gas compressibility, which is given the symbol c_g, is a useful concept is used extensively in determining the compressible properties of the reservoir. Gas usually is the most compressible medium in the reservoir. Isothermal compressibility of gas is the measure of the change in volume per unit volume with pressure change at constant temperature. However, care should be taken so that it is not confused with the gas deviation factor, Z, which is sometimes called the super compressibility factor. In equation form:

$$C_g = -\frac{1}{V_g}\left(\frac{\partial V_g}{\partial p}\right)_T\ \ \mathbf{(2.7)}$$

where V and p is volume and pressure, respectively, and T is the absolute temperature. Whereas, for nonideal gas, compressibility is defined as:

$$c_g = \frac{1}{p} - \frac{1}{Z}\left(\frac{\partial Z}{\partial p}\right)_T\ \ \mathbf{(2.7-1)}$$

If the relationship between the Z factor and the pressure at a given temperature is known, we can calculate the compressibility of gas. Since we already know the relationship between Z and p, we can numerically calculate the derivative and, hence, the value of the compressibility.

GAS VISCOSITY

Just as the compressibility of natural gas is much higher than that of oil, water, or rock, the viscosity of natural gas is usually several orders of magnitude lower than oil or water. This makes gas much more mobile in the reservoir than either oil or water.

The viscosity of a fluid is a measure of the fluid's ability to flow, or the ratio of the shearing force to the shearing rate. The viscosity is usually expressed in centipoises or poises but can be converted to other units for unit compatibility.

$$1\ \text{poise} = 100\ \text{centipoises} = 6.72\ \text{x}\ 10^{-2}\,\frac{\text{lbm}}{\text{ft sec}} = 2.09\ \text{x}\ 10^{-3}\,\frac{\text{lbf sec}}{\text{ft}^2} = 0.1\,\frac{\text{kg}}{\text{m sec}}$$

Reliable correlation charts are available to estimate gas viscosity, and the viscosity of gas mixtures at one atmosphere and reservoir temperature can be determined from the gas mixture composition:

$$\mu_{ga} = \frac{\sum_{i=1}^{N} yi\ \mu i\,\sqrt{M_{gi}}}{\sum_{i=1}^{N} yi\,\sqrt{M_{gi}}}\quad \mathbf{(2.8)}$$

where μ_{ga} is the viscosity of the gas mixture at the desired temperature and atmospheric pressure, yi is the mole fraction of the ith component, µi is the viscosity of the ith component of the gas mixture at the desired temperature and atmospheric pressure, M_{gi} is the molecular weight of the ith component of the gas mixture, and N is the number of components in the gas mixture. This viscosity is then multiplied by the viscosity ratio to obtain the viscosity at reservoir temperature and pressure.

GAS-CONDENSATE SYSTEMS

As the exploration for natural gas is extended to deeper horizons, more reservoirs containing gas condensates are discovered. The gas may be in the gaseous phase at initial reservoir conditions but may condense to form some liquid at some point in the path to the separator.

Phase Behavior

Phase behavior is simple for single component systems but becomes more complicated as more components are added to the system.

The phase behavior of a fluid can be described by determining its response to pressure and temperature changes. In a liquid, the molecules are very close together, but in a gas, the molecules are widely separated. Certain forces exist that tend to either confine or disperse the molecules.

Confining forces are primarily pressure and molecular attraction. Dispersing forces are kinetic energy and molecular repulsion. The relative magnitudes of the confining and dispersing forces dictate whether the fluid is a liquid or a gas.

An increase in temperature increases the kinetic energy of the molecules and thus the dispersing forces, while an increase in pressure increases the confining forces. When more than one fluid is present, the difference in molecule size and energy has an influence on the phase change.

Type of Gas Reservoirs

Reservoir that yields natural gas can be classified into essentially four categories. These are:

1. Dry gas. The fluid exists as a gas both in the reservoir and the piping system. The only liquid associated with the gas from a dry gas reservoir is water.
2. Wet gas. The fluid initially exists as a gas in the reservoir and remains in the gaseous phase as pressure declines at reservoir temperature. However, in being produced to the surface, the temperature also drops, causing condensation in the piping system and separator.
3. Retrograde condensate gas. The fluid exists as a gas at initial reservoir conditions. As reservoir pressure declines at reservoir temperature, the dew point line is crossed and liquid forms in the reservoir, piping system and separator.

4. Associated gas. Many oil reservoirs exist at the bubble point pressure of the fluid system at initial conditions. Free gas can be produced from the gas cap of such a system. Gas which is initially dissolved in the oil can also be produced as free gas at the surface. The phase diagram of such a system will depend on the properties of the oil associated with the gas.

3 GAS-CONDENSATE RESERVOIRS

The importance of gas-condensate reservoirs has increased considerably in the last decades because of the increased demand for all types of hydrocarbon energy sources and because, as deeper drilling occurs, more and more condensate reservoirs are being discovered.

Gas-condensate reservoirs may occur at pressures below 2000 psi and temperatures below 100°F and probably can occur at any higher fluid pressures and temperatures. Most known gas-condensate reservoirs are in the range of 3000 to 6000 psi and 200 to 400°F. These pressure and temperature ranges, together with wide composition ranges, provide a great variety of conditions for the physical behavior of gas-condensate deposits.

Condensate reservoirs include both wet gas and retrograde condensate types. In both types, the fluid exists as a single-phase gas at initial reservoir conditions, the distinction being that liquid is formed in the reservoir only for the retrograde type.

A rough classification can be made based on the performance of the reservoir at initial conditions. If initial producing gas-oil-ratio (GOR) exceeds about 15000 scf/STB, and pressure and temperature do not exceed 8000 psia and 225°F, respectively, it is likely that no liquid will form in the reservoir.

Where producing gas-oil ratios exceed 6000 but not 15000 scf/SYB, the reservoir may experience retrograde behavior. Under these conditions, it is important that a representative reservoir fluid sample be obtained and a pressure-volume-temperature (pVT) analysis be made. This will permit planning for the most efficient and profitable development of the reservoir. Where the initial gas-oil ratio is between 3000 and 6000 scf/STB, the reservoir may contain either a volatile oil or a retrograde gas condensate.

Below an initial producing gas-oil ratio of 3000 scf/STB, the reservoir will contain oil, volatile or otherwise. It is theoretically possible to have a retrograde gas condensate reservoir with an initial producing gas-oil ratio as low as 2000 scf/STB, but this would take a unique combination of very high discovery pressure (exceeding 8000 psia), modest temperatures, and high concentrations of intermediates, C_2 through C_6.

Table 3-1 shows the mole compositions of a typical dry gas, single-phase wet gas, retrograde gas condensate, and a volatile oil reservoir.

Figure 3-1 illustrated a pressure-temperature phase diagram for a reservoir fluid. The development of this diagram assumes that volume and the total composition of the fluid are constants. The figure is useful as a guide to relationships among the several reservoir fluid types since both single-phase gas reservoirs and oil reservoirs are represented, with only pressure and temperature allowed to change. However, it is useful for descriptive purpose.

Table 3-1

Mole Composition of Typical Hydrocarbon Reservoir Fluids

(Gas Production Operations, H. Dale Beggs)

Component	**Dry Gas**	**Single Phase Wet Gas**	**Retrograde Gas Condensate**	**Volatile Oil**
C_1	96	90	75	60
C_2	2	3	7	8
C_3	1	2	4.5	4
C_4	0.5	2	3	4
C_5	0.5	1	2	3
C_6	-	0.5	2.5	4
C_{7+}	-	1.5	6	17
	100	100	100	100
Mol weight C_{7+}	-	115	125	180
GOR, scf/STB	High	26000	7000	2000
Tank gravity, °API	-	60	55	50
Liquid Color	-	Water White to Light Yellow	Light Yellow to Yellow	Amber to Darker Colors

Single-phase gas reservoirs are shown by point A to the right of the cricondentherm. Pressure depletion with production at constant reservoir temperature results in the gas remaining as gas. However, cooling and pressure drop in the wellbore and surface facilities allow the condensing of hydrocarbons along line A to A_2.

Retrograde gas condensate reservoirs exist at pressures sufficient to be at or above the upper boundary of the two-phase envelope and at a temperature between the critical and cricondentherm values. Frequently, retrograde gas condensate reservoirs are found to be on, or very close to, the dew point line at the time of discovery. Apparently, this is due to the presence of a large percentage of C_2 to C_6. It is also quite common to find a small volatile oil rim in the reservoir. By definition, in this latter instance, the gas cap would be exactly at the dew point. Should the observed dew point in the laboratory duplicate the discovery pressure within a few percent, an oil rim would probably be present.

Figure 3-2 presents descriptive phase diagrams for a gas cap gas and oil zone fluid for the two cases of a retrograde gas cap, and a nonretrograde gas cap. Notice the superimposing of the diagrams at the time of discovery, since phase equilibrium exists.

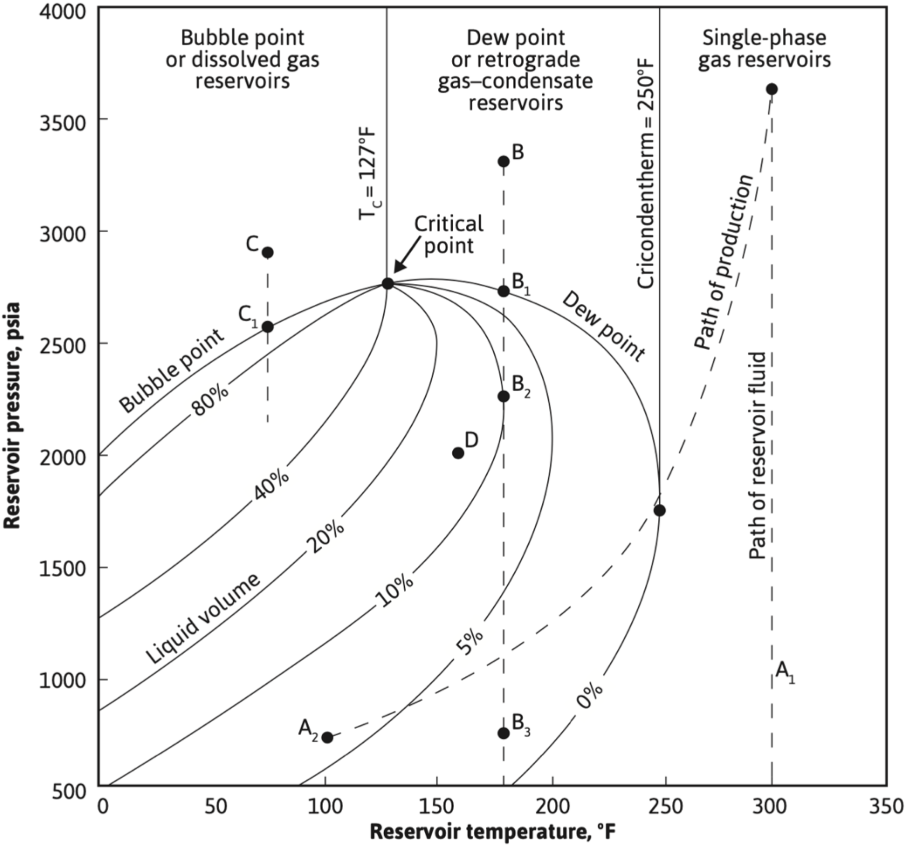

Figure 3-1. Pressure-temperature phase diagram of a reservoir fluid.

(Applied Petroleum Reservoir Engineering, B. C. Craft and M. F. Hawkins)

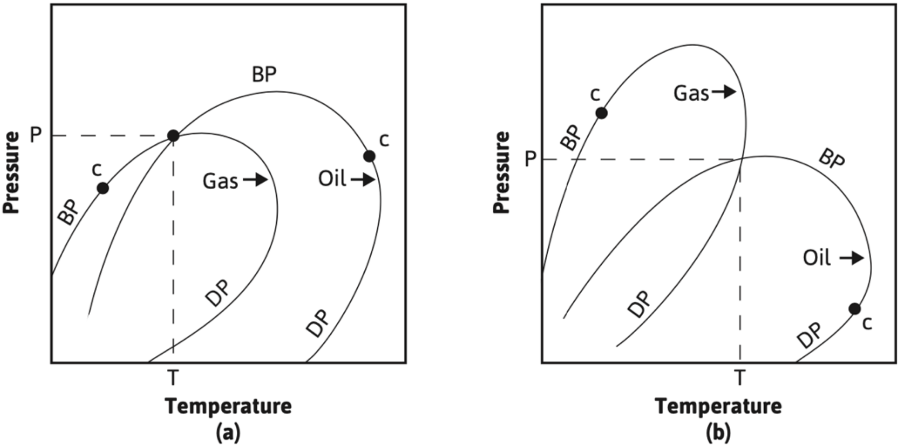

Figure 3-2. Phase diagrams of a gas cap gas and oil zone liquid for (a) retrograde gas cap gas and (b) nonretrograde gas cap gas.

(Applied Petroleum Reservoir Engineering, B. C. Craft and M. F. Hawkins)

WELL TESTING AND SAMPLING

Proper testing of gas-condensate wells is essential for ascertaining the state of the hydrocarbon system at reservoir conditions and for planning the best production and recovery program for the reservoir.

Tests are made on gas condensate wells for a number of specific purposes: to obtain representative samples for laboratory analysis, for identifying the composition and properties of the reservoir fluids; to make field determinations of gas and liquid properties; and to determine formation and well characteristics, including productivity, producibility, and injectivity. The first consideration for selecting wells for gas-condensate fluid samples is that the well be far enough removed from the “black-oil ring” (if present) to minimize any chance that the liquid oil phase will enter the well during the test period. A second and highly important consideration is the selection of wells with productivities as high as possible, so that minimum pressure drawdown will occur in actually acquiring the reservoir fluid samples.

CALCULATION OF INITIAL IN-PLACE GAS AND CONDENSATE

The initial amounts of both the gas and the condensate in a reservoir can be calculated on a unit volume basis by two methods. The more accurate method requires a compositional analysis of the reservoir fluid, but an estimate can be made if limited data are available. A procedure and example calculation for each case are presented.

Compositional Analysis Not Available

The initial in-place gas and oil (condensate) for gas-condensate reservoirs, both retrograde and nonretrograde, may be calculated from generally available field data by recombining the produced gas and oil in the correct ratio to find the average specific gravity (air = 1.00) of the total well fluid, which is presumably being produced initially from a one-phase reservoir.

The method may also be used to calculate the initial oil and gas in gas caps.

R = initial surface gas-oil ratio of the production, scf of dry or residue gas per barrel of oil,

γ_o = specific gravity of the tank oil (water = 1.00)

M_o = molecular weight of the tank oil, and

γ_g = average specific gravity of the gas produced from the surface separator(s), air = 1.00.

Standard conditions are 14.7 psia and 60°F, at which conditions the molecular volume is 379.4 scf/mole. Then, based on one barrel of tank oil and R standard cubic feet of separator or residue gas, the mass of total well fluid m_w is:

$$m_w = \frac{28.97\ R\ \gamma_g}{379.4} + 350\ \gamma_o$$

$$= 0.07636\ R\ \gamma_g + 350\ \gamma_o\ (\mathbf{3.1})$$

The total moles of fluid in one barrel of oil with R cubic feet of gas is:

$$n_t = \frac{R}{379.4} + \frac{350\ \gamma_o}{M_o}$$

$$= 0.002636\ R + 350\frac{\gamma_o}{M_o}\ (\mathbf{3.2})$$

Hence the molecular weight of the total well fluid M_W is:

$$M_w = \frac{m_w}{n_t} = \frac{0.07636\, R\, \gamma_g + 350\, \gamma_o}{0.002636 + R + 350\, \gamma_o / M_o}$$

And the specific gravity of the well fluid is $M_W/28.97$, or:

$$\gamma_m = \frac{R\, \gamma_g + 4584\, \gamma_o}{R + 132800\, \gamma_o / M_o} \quad (\mathbf{3.3})$$

If the molecular weight of the tank oil is not known, it may be estimated using the following formula developed by Cragoe:

$$M_o = \frac{44.29\, \gamma_o}{1.03 - \gamma_o} = \frac{6084}{API - 5.9} \quad (\mathbf{3.4})$$

Compositional Analysis Available

If the compositional analysis of the separator gas and liquid is available, a compositional analysis of the total well fluid, from which a more accurate Z-factor can be calculated, can be obtained by recombining the gas and liquid phases in the correct proportions.

RECOVERY ESTIMATES

Once the initial hydrocarbons in place are determined, it is then necessary to calculate the amounts of gas and condensate that can be recovered, assuming a certain abandonment pressure. As pressure drops below the dew point, liquids will condense in the reservoir and will, in most cases, be unrecoverable.

This cause the gas produced to contain fewer heavy components as the reservoir is depleted. An estimate of recoveries by pressure depletion must be made before the feasibility of maintaining pressure by cycling can be established.

Three different methods for predicting depletion performance for a volumetric reservoir are: laboratory simulation, flash calculations, and empirical correlations. The most accurate is the laboratory simulation method, and this method should be used if possible.

Laboratory Simulation Method

The laboratory simulation procedure assumes that the separation process occurring in the reservoir is a differential process; that is, no liquid phase is produced from the reservoir.

The process consists of starting with a reservoir fluid sample at or above its dew point pressure and at reservoir temperature. Gas is removed to decrease the pressure in reasonable increments, down to the assumed abandonment pressure. Each increment of gas removed is analyzed to determine its composition, and the volume remove is measured.

The liquid recovery from the gas increments produced from the cell may be measured by passing the gas through small-scale separators, or it may be calculated from the composition for usual field separation methods or for gasoline plants methods. Liquid recovery of the pentanes plus will be somewhat greater in gasoline plants than by field separation, but much greater for the propanes and butanes, commonly called liquefied petroleum gas (LPG).

GAS CYCLING

Incentive exists to cycle gas-condensate reservoirs in those instances in which natural depletion of the resource will result in substantial loss of liquid hydrocarbons. This occurs in water drive fields where wet gas is trapped or in volumetric-type reservoirs where retrograde behavior exists. Liquid hydrocarbons formed during pressure depletion are not normally revaporized at lower reservoir pressures and thus are lost. Where the reservoir rock has favorable characteristics, cycling with dry gas should permit recovery of part of the liquids that would otherwise be lost.

Liquid recovery is determined in the reservoir by displacement efficiencies, which are a product of the vertical, areal, and pore-to-pore fractional recoveries. Recoveries from cycling projects depend on the volume of reservoir contacted by the dry gas and on the fraction of wet gas displaced in the contacted volume.

Areal Sweep Efficiency (E_A)

Areal sweep efficiency is the area enclosed by the leading edge of the dry gas front divided by the total area of the reservoir. E_A can be estimated using analog models or by observing well performance in an actual project.

Vertical Sweep Efficiency (E_V)

Vertical sweep efficiency is the pore space invaded by the injected gas, divided by the hydrocarbon pore space enclosed by the projection (through full reservoir thickness) of the leading edge of the dry-gas front.

Vertical sweep efficiencies can be as high as 90% under favorable conditions. However, invasion is significantly affected by large variations in reservoir flow properties: strictly lateral variations in horizontal permeability of a single bed comprising a reservoir that does not have any variations vertically at any location; strictly layering effects, by which several strata may comprise the reservoir, each being uniform as to properties but differing appreciably in permeability from all the others; or combinations of these extreme cases.

Displacement Efficiency (E_D)

Displacement efficiency is the volume of wet hydrocarbons swept out of individual pores or small groups of pores, divided by the volume of hydrocarbons in the same pores at the start of cycling; note that both volumes must be calculated the same conditions of pressure and temperature.

Displacement efficiency is controlled mainly by the miscibility of the driving and driven fluids and their mobilities.

Reservoir Cycling Efficiency (E_R)

Reservoir cycling efficiency is the overall recovery factor defined as the wet hydrocarbons recovered divided by the wet hydrocarbons initially in place in the reservoir. It is the product of the three previously defined efficiencies, that is

$$\mathrm{E_R = E_A\, E_V\, E_D}$$

Feasibility of Gas Cycling

In choosing between pressure depletion and pressure maintenance as operating methods for a gas-condensate reservoir, detailed analyses must be made for predicting optimum economics. Cycling and gas-processing procedures require sizeable plant expenditures. Possible processing methods, whether reservoir fluids are cycled or not, include stabilization, compression, absorption, and fractionation. The latter two recover appreciably more condensibles from wet gas than do the former. If the removal of ethane from a gas stream is desirable, for economic or other reasons, fractionation can accomplish this.

When the reservoir characteristics appear favorable for recovery of condensible hydrocarbons, it must then be considered whether cycling would be economic. The primary comparison is between value of the estimated additional recovery of liquid products by cycling and the actual cycling costs, taking into account deferment of gas income and other factors.

Economic analyses of cycling and noncycling are required; these must be carried out in detail for maximum dependability, using information factors and assumptions pertinent to each particular case.

4 GAS PRODUCTION OPTIMIZATION

RESERVOIR PERFORMANCE

One of the most important components in the total well system is the reservoir. The flow into the well, depends on the drawdown or pressure drop in the reservoir, $p_R – p_{wf}$. The relationship between flow rate and pressure drop occurring in the porous medium can be very complex and depends on parameters such as rock properties, fluid properties, flow regime, fluid saturations in the rock, compressibility of the flowing fluids, formation damage or stimulation, turbulence, and drive mechanism. It also depends on the reservoir pressure itself and, depending on the drive mechanism, thus may decrease with time or cumulative production.

The flow from the reservoir into the well has been called “inflow performance” by Gilbert and a plot of producing rate versus bottomhole flowing pressure is called an “inflow performance relationship” or IPR.

The IPR for a gas well will not be linear because the inflow rate is a function of the square of p_{wf}. For dry-gas and wet-gas reservoirs, in which no liquid condenses in the reservoir, gas saturation and, therefore, permeability to gas will remain constant as p_R declines. If turbulent flow exists, the pressure drop due to turbulence will increase with flow rate, causing a deterioration in the inflow performance.

If no liquid forms in the reservoir, the effect of depletion will not cause a decrease in relative gas permeability, k_{rg}, but turbulence may increase due to higher actual velocity required to maintain a constant-mass flow rate.

In the case of a retrograde condensate-gas reservoir, that is, where T_R is between the critical temperature and the cricondentherm, if the pressure anywhere in the reservoir drops below the dewpoint pressure, p_d, liquid will form, and decrease k_{rg}. This can occur from either reducing p_{wf} below p_d or as p_R declines below p_d from depletion. Prediction of retrograde-gas reservoir behaviour or water-drive gas reservoir behaviour is very complex and, in most cases, requires the use of a reservoir model. Fortunately, since the condense liquid will occupy the small pore spaces first, the reduction of k_{rg} may be small.

PREDICTING PRESENT TIME IPR’s FOR GAS WELLS

Darcy’s equation for radial gas flow including permeability alteration and turbulence was derived as follows:

$$q_{sc} = \frac{703 \text{ x } 10^{-6}\ k_g\ h\left(p_R^2 - p_{wf}^2\right)}{\mu_g\ Z\ T\ \left(\ln\left(0.472\,\frac{r_e}{r_w}\right) + S'\right)} \quad (\mathbf{4.1})$$

The skin factor S’ includes the effects of both turbulence and actual formation damage as:

$$S' = S + Dq$$

Where S is skin factor due to permeability change, and D is turbulence coefficient. Solving for $p_R^2 - p_{wf}^2$ and collecting terms yields:

$$p_R^2 - p_{wf}^2 = Aq_{sc} + Bq_{sc}^2 \; (\mathbf{4.2})$$

where:

$$A = \frac{1422\, \mu_g\, Z\, T\, \left(\ln\left(0.472\, \frac{r_e}{r_w}\right) + S\right)}{k_g\, h}$$

$$B = \frac{3.161 \text{ x } 10^{-12}\, \beta\, \gamma_g\, Z\, T}{h^2\, r_w} = \frac{1422\, \mu_g\, Z\, T}{k_g\, h}\, D$$

This definition of B includes the assumption that r_e is much greater than r_w. The effects of turbulence can also be accounted for by including an exponent in the pressure term of Darcy's equation above. This results in the familiar back-pressure form of the equation.

$$q_{sc} = C\left(p_R^2 - p_{wf}^2\right)^n \; (\mathbf{4.3})$$

Use of the Back Pressure Equation

Examination of equation above reveals that only two flow tests would be required to evaluate C and n when p_R is known. However, due to the possibility of errors in measuring values of q_{sc} and p_{wf} it is customary to use at least four flow test and to determine n by constructing the best straight line through the four tests.

Many regulatory agencies require multi rate tests to establish allowable production rates. A plot of $p_R^2 - p_{wf}^2$ versus q_{sc} on log-log coordinates will result in a straight line having a slope of 1/n and an intercept of $C = q_{sc}$ at a value of $p_R^2 - p_{wf}^2$ equal to one.

There are essentially three types of multipoint or back-pressure test that can be used to evaluate C and n. These are the flow-after-flow, the isochronal and the modified isochronal. The test requiring the least amount of time is the modified isochronal test. It should be recalled that at least one fully stabilized test is required to evaluate C even for the modified test. A procedure for conducting a modified isochronal test on a gas well consists of:

1. Start at a shut-in condition ($p_{ws1} = p_R$), open the well on a constant flow rate and measure p_{wf} at specific time periods. The total flow period may be less than the stabilization time for the well.
2. Shut the well in for the same period at which it was allowed to flow. The bottomhole pressure will not necessarily build back up to p_R but the static pressure at the end of the shut-in period (p_{ws2}) is assumed to be the reservoir pressure for the second flow period.
3. Repeat steps 1 and 2 until the data are obtained for at least two flow rates. A plot of $p_{ws}^2 - p_{wf}^2$ versus q_{sc} on log-log coordinates will produce a straight line of slope equal to 1/n for each time at which p_{wf} was measured. A value for C can

be calculated from the stabilized test, which is usually conducted after the transient tests are run.

Jones, Blount, and Glaze Method

The method of plotting test data, which was proposed by Jones, Blount, and Glaze can be applied to gas-well testing to determine real- or present-time inflow performance relationships. The analysis procedure allows determination of turbulence or non-Darcy effects on completion efficiency irrespective of skin effect and laminar flow. The procedure also evaluates the laminar flow coefficient A, and if k_g h is known, an estimate of skin effect can be made.

The data required are either two or more stabilized flow tests. At least one stabilized flow test is required to obtain a stabilized value of the laminar coefficient A. No transient tests are required to evaluate the completion efficiency if this method is applied.

Jones, et al., also suggested methods to estimate the improvement in inflow performance that would result from reperforating a well to lengthen the completion interval or increase the perforating density and presented guidelines to determine if the turbulent effects were excessive.

Equation $\mathrm{p_R^2 - p_{wf}^2 = Aq_{sc} + Bq_{sc}}$ (4.2) can be written as:

$$\frac{\mathrm{p_R^2 - p_{wf}^2}}{\mathrm{q_{sc}}} = \mathrm{A + Bq_{sc}} \ (\mathbf{4.4})$$

Where A and B are the laminar and turbulent coefficients respectively and are defined in Equation 4.2. From Equation 4.4, it is apparent that a plot of $(p_R^2 - p_{wf}^2)/q_{sc}$ or $(\Delta p^2/q_{sc})$ versus q_{sc} on Cartesian coordinates will yield a line, which has a slope of B, and an intercept of $A = \Delta p^2/q_{sc}$ as q_{sc} approaches zero. These plots apply to both linear and radial flow, but the definitions of A and B would depend on the type of flow.

To have some qualitative measure of the importance of the turbulent contribution to the total drawdown, Jones, et al. suggested comparison of the value of A calculated at the AOF of the well (A') to the stabilized value of A. The value of A' can be calculated from:

$$\mathrm{A'} = \mathrm{A} + \mathrm{B(AOF)}\ (\mathbf{4.5})$$

where

$$\mathrm{AOF} = \frac{-\mathrm{A} + (\mathrm{A}^2 + 4\mathrm{B}\ \mathrm{p}_\mathrm{R}^2)^{0.5}}{2\mathrm{B}}\ (\mathbf{4.6})$$

Jones, et al. suggested that if the ratio of A' to A was greater than 2 or 3, then it is likely that some restriction in the completion exists. They also suggested that the formation thickness h used in the definition of B could be replaced by the length of the completed zone h_p, since most of the turbulent pressure drop occurs very near the wellbore. The effect of changing completion zone length on B and, therefore, on inflow performance can be estimated from:

$$B_2 = B_1 \left(\frac{h_{p1}}{h_{p2}}\right)^2 \quad (\mathbf{4.7})$$

where:

B_2 = turbulence coefficient after recompletion,

B_1 = turbulence coefficient before recompletion,

h_{p2} = new completion length, and

h_{p1} = old completion length.

PREDICTING FUTURE IPR's FOR GAS WELLS

As reservoir pressure declines from depletion in a gas reservoir, the change in the IPR is not as significant as it is for an oil reservoir. This is due primarily to the fact that effective permeability to gas remains fairly constant since the gas saturation remains constant. This is true for either a dry or wet gas reservoir, but not for a retrograde condensate reservoir. The factors that will change as pressure changes can be seen by referring to the definition of C. The only terms depending on pressure are the gas viscosity, m_g and the gas compressibility factor, Z.

If no changes are made in r_e, S or h, the values of C, or A and B can be adjusted for reservoir pressure changes as follows:

$$A_f = A_p \frac{(\mu\, Z)_F}{(\mu\, Z)_p} \quad (\mathbf{4.8})$$

$$C_F = C_p\ (\mu\, Z)_p / (\mu\, Z)_F$$

$$B_F = B_p\ Z_F / Z_p$$

INFLOW PERFORMANCE SUMMARY FOR GAS WELLS

The inflow-performance equation for gas wells is not as sensitive to pressure as that for oil wells because the gas saturation and therefore the permeability to gas remain fairly constant except for the case of retrograde condensate reservoirs. The following methods were presented for accounting for various effects.

1. Drawdown effects: Back-pressure equation, Jones, Blount and Glaze equation, and Darcy radial-flow equation.
2. Formation damage or stimulation: Back-pressure equation (S is included in the coefficient C), Jones, Blount, and Glaze equation (S is included in the coefficient A), and Darcy (S is included in the equation).
3. Turbulence effects: Back-pressure equation (the value of the exponent n is an indication of turbulence), Jones, Blount and Glaze (the coefficient B or the value of A'/A indicates the effects of turbulence), and Darcy (the turbulence coefficient D is an indication of tubulence).
4. Depletion-the values of C or A and B can be adjusted for changes in m_g and Z-factor with pressure change.
5. Perforation effects: Locke equation and McLeod equation.

5 BASIC CONCEPTS OF NATURAL GAS PROCESSING

INTRODUCTION

Raw natural gas after transmission through the field-gathering network must be processed before it can be moved into long-distance pipeline systems for use by consumers. The objective of gas processing is to separate natural gas, condensate, noncondensable, acid gases, and water from a gas-producing well and condition these fluids for sale or disposal. The typical process operation modules are shown in Figure 5-1. Each module consists of a single piece or a group of equipment performing a specific function. All the modules shown will not necessarily be present in every gas plant. In some cases, little processing is needed; however, most natural gas requires processing equipment at the gas processing plant to remove impurities, water, and excess hydrocarbon liquid and to control delivery pressure. The unit operations used in each application may not be arranged in the sequence shown in Figure 5-1, although this sequence is typical.

Unfortunately, at the individual module level the design may be sound, and the operation correct but could result in a poor gas processing facility. The reason is that each module has varying characteristics under varying loads, which can result in a type of internal incompatibility. For instance, a given unit module may require a particular inlet composition to produce the desired output. If a previous unit does not maintain this, the downstream unit may not operate satisfactorily. Thus, the fault might not lie so much with that unit but with total plant design, even though the unit module is usually blamed.

The individual unit modules of Figure 5-1 are briefly reviewed here with greater details to follow in subsequent chapters.

PROCESS MODULES

The first unit module is the physical separation of the distinct phases, which are typically gas, liquid hydrocarbons, liquid water, and/or solids. Phase separation of the production stream is usually performed in an inlet separator. Inlet gas receiving is complicated by the fact that transmission lines supplying the plant typically operate with two or three phases present and consequently liquid slugging is common. Slugs are normally formed from elevational changes in the inlet supply pipes, changes in gas supply flow rates, and changes in pressure and temperature during transmission. Slug flow may even be encountered in horizontal pipes under steady-state conditions if the flow regime is not properly selected.

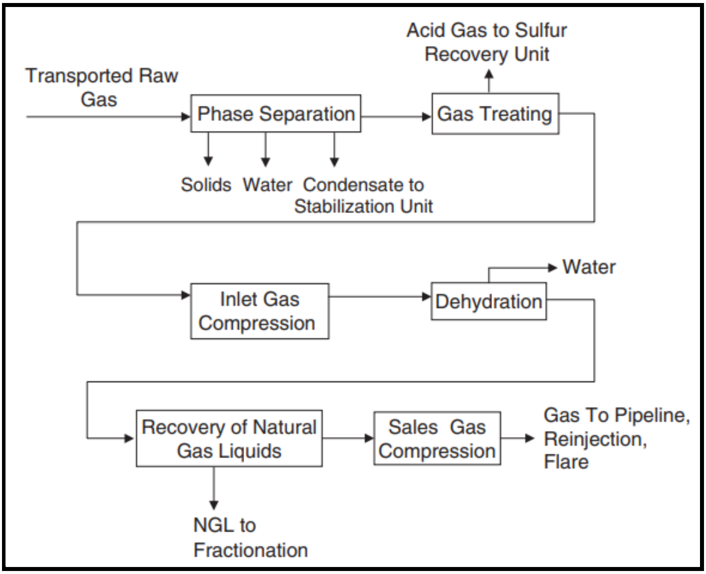

Figure 5-1. Simplified typical onshore treatment process. (Handbook of Natural Gas Transmission and Processing, Saeid Mokhatab, William A. Poe and James G. Speight).

The arrival of “slugs” at production or processing equipment impacts the operation of production facilities negatively, causing both mechanical problems (due to high velocities and momentum) and process problems (increasing liquid levels, causing surges and trips). In some cases, operators can minimize liquid accumulation by managing fields and pipelines in such a way as to create a suitable fluid flow regime (i.e., mist flow regime) in which the gas velocity is high enough to keep liquids dispersed continuously. While it is desirable to design the flow lines to avoid slugging, in practice this can be difficult while maintaining the ability to turn down the pipeline flow rate. In these cases, consideration should be given to providing suitable process equipment to diminish the effect of slugging. Gas pipelines have typically used slug catchers to dissipate the energy of the liquid slugs, to minimize turbulence, to ensure that the gas and liquid flow rates are low enough so that the stratified flow regime and subsequently gravity segregation can occur. The slug catcher is designed to separate gas, hydrocarbon condensate, and inlet water. The gas stream is sent to the inlet separators. The separators usually contain vane elements to aid in the coalescence of liquids. They may also include filters to remove particulates and may be followed by suction scrubbers if compressors are needed to bring low-pressure gas up to high pressure for further processing operations. The liquids that collect in the slug catcher flow to a three-phase separator from which the two liquid phases, hydrocarbon condensate and water/methanol or water/glycol phases, are outputs. Overhead gas from the three-phase separator is recompressed where necessary for use as fuel gas.

Hydrocarbon condensate recovered from natural gas may be shipped without further processing but is typically stabilized to produce a safe-transportable liquid. Unstabilized condensates contain a large percentage of methane and ethane, which will vaporize easily in storage tanks. Stabilization is the full removal of light fractions from the condensate, usually achieved by distillation.

Stabilized liquid will generally have a vapor pressure specification (Reid vapor pressure of <10 psi) – vapour pressure at 100°F. Reid vapor pressure is a standard indicator of volatility and a key quality control factor, particularly when considering condensate storage – as the product will be injected into a pipeline or transport pressure vessel, which has definite pressure limitations.

The next step in natural gas processing is acid gas treating. In addition to heavy hydrocarbons and water vapor, natural gas often contains other contaminants that may have to be removed. Carbon dioxide (CO_2), hydrogen sulfide (H_2S), and other sulfur-containing species such as mercaptans are compounds that require complete or partial removal. These compounds are collectively known as “acid gases.” H_2S when combined with water forms a weak sulfuric acid, whereas CO_2 and water form carbonic acid, thus the term “acid gas.” Natural gas with H_2S or other sulfur compounds present is called “sour gas,” whereas gas with only CO_2 is called “sweet.” Both H_2S and CO_2 are very undesirable, as they cause corrosion and present a major safety risk.

Depending on the pressure at the plant gate, the next step in processing will either be inlet compression to an “interstage” pressure, typically 300-400 psig, or be dew point control and natural gas liquid recovery. Water dew point control is required to meet specifications and to control hydrate formation. Gas hydrate formation is a major concern for engineers in pipeline and natural gas transportation industries as it causes choking/plugging of pipelines and other related problems. Methods of preventing hydrate formation in the plant include lowering the hydrate formation temperature with chemical inhibition or dehydration to remove the water.

Hydrocarbon dew point or hydrocarbon liquid recovery involves cooling the gas and condensing out the liquids. Hydrocarbon dew point control can be either dehydration followed by cooling/condensation or by a combination of inhibition/cooling/condensation processes. Refrigeration is performed either by auto refrigeration due to a pressure drop across a valve or by an external mechanical refrigeration process. The temperature to which the gas is cooled depends on whether it is necessary to meet a sales gas hydrocarbon dew point specification or whether substantial liquid recovery is desired. Three situations motivate maximum condensate recovery.

The first is the desire to maximize condensate production when processing associated gas. The second situation occurs when processing retrograde condensate gas; here the objective is to recover the condensate and reinject the gas into the formation. Third, in some markets, the natural gas liquids (NGLs) produced from the condensate may be more valuable as liquid products than as sales gas components, i.e., their recovery will yield a better profit. Whether to leave maximum NGLs in the gas stream (but still attaining sales hydrocarbon dew point specification) or to recover them as liquids is purely an economic decision made by comparing their value as heat versus the equivalent value as liquid chemical feedstock. If the equivalent liquid value is lower than the gas, NGLs should be left in the gas to the extent as possible. However, if the equivalent liquid value is higher than the gas value, then liquid recovery should be maximized.

If gas is produced at lower pressures than typical sales pipeline pressure (approximately 700-1000 psig), it is compressed to sales gas pressure. Transport of sales gas is done at high pressure to reduce pipeline diameter. Pipelines may operate at very high pressures (above 1000 psig) to keep the gas in the dense phase thus preventing condensation and two-phase flow. Compression typically requires two to three stages to attain sales gas pressure. As stated previously, processing may be done after the first or second stage, prior to sales compression.

Where there is no available gas pipeline, separated associated gas may be flared. The ability to flare depends on regulations as well as the field location. Increasingly in such cases, separated gas is being conserved by compression and reinjection into producing formations for eventual recovery and sales. Also, in gas condensate reservoirs, the gas is often reinjected, or “cycled,” to enable higher net recovery of valuable liquid hydrocarbons from the reservoir.

SCOPE OF NATURAL GAS PROCESSING

The important factors that usually determine the extent of gas processing include the processing objectives, the type or source of the gas, and the location and size of the gas fields.

Processing Objectives

If the natural gas is transported by pipeline, the processing installation must be designed to meet either transport or final specifications. Processing of a gas stream may have one of the following three basic objectives:

1. To produce a sales gas stream that meets specifications of the type shown in Table 5-1. These specifications are mainly intended to meet pipeline requirements and the needs of industrial and domestic consumers.
2. To maximize NGLs production by producing a lean gas stripped of most of the hydrocarbons other than methane.
3. To deliver a commercial gas. Such gas must be distinguished by a certain range of gross heating value lying.

Table 5-1

Natural Gas Specifications in the Saleable Gas Stream (Processing Sour Gas. Guidelines for Handling Sour Gas. B. G. Goar and T. O. Arrington).

Characteristic	Specification
Water content	4-7 lb/MMscf (max)
Hydrogen Sulfide content	¼ grain/100 scf (max)
Gross heating value	950 Btu/scf (min)
Hydrocarbon dew point	15°F at 800 psig (max)
Mercaptan content	0.2 grain/100 scf (max)
Total sulfur content	1-5 grain/100 scf (max)
Carbon dioxide content	1-3 mole percent (max)
Oxygen content	0-0.4 mole percent (max)
Sand, dust, gums, and free liquid	Commercially free
Typical delivery temperature	120°F
Typical delivery pressure	714.7 psia

Effect of Gas Type in Field Processing

The gas composition of the field is the most important issue in choosing a processing scheme. In other words, depending on the type of reservoir and the composition of the produced gas, the gas processing plant may contain extensive facilities for the processing of the associated liquefiable hydrocarbons.

Typically, associated gas is very rich in liquefiable hydrocarbons and must undergo NGL and condensate recovery to meet hydrocarbon dew point or minimum heating value requirements.

The gas processing scheme will also be dictated by the format of the sales contract and its specifications. The contract may be totally different for each customer depending on the composition and amount of gas, plant recoveries, and the contractual preferences of the customer.

Location of the Gas Field

The productivity of a gas reservoir can vary greatly and depend primarily on type, location, and age. Because the location and output of the wells can vary widely, then not surprisingly, the systems that have been designed to collect and process this output also vary widely. There are at least two aspects of location that are important: remoteness and local temperature variation. Temperature affects the tendency for hydrate formation in the gas gathering network.

Offshore platforms and “outbacks” are examples of remote locations. Even these locales are not strictly comparable because one is sea-based vs dry land based. For the sea-based facility, the produced fluid from each wellhead flows via a flow line into a manifold and from there to the process facilities located on the platform deck. Ship platforms are extremely limited with respect to size and allowable weight and only those operations absolutely needed are performed. Facilities on the offshore platform will generally process the gas to produce a low water content hydrocarbon stream for export to shore through the subsea pipelines. This process ensures minimal corrosion, as well as minimizing the potential for hydrate formation in the raw gas pipeline. A dry-land outback facility has essentially unlimited area available and can support operations not practical or desirable offshore, such as treating or processing involving fire hazards (Manning and Thompson, 1991).

6 CONDENSATE STABILIZATION

Hydrocarbon condensate recovered from natural gas may be shipped without further processing but is stabilized often for blending into the crude oil stream and thereby sold as crude oil. In the case of raw condensate, there are no specifications for the product other than the process requirements. The process of increasing the number of intermediates (C_3 to C_5) and heavy (C_6^+) components in the condensate is called “condensate stabilization.”

This process is performed primarily to reduce the vapor pressure of the condensate liquids so that a vapor phase is not produced upon flashing the liquid to atmospheric storage tanks. In other word, the scope of this process is to separate the very light hydrocarbon gases, methane, and ethane, from the heavier hydrocarbon components (C_3^+).

Stabilized liquid, however, generally has a vapor pressure specification, as the product will be injected into a pipeline or transport pressure vessel, which has definite pressure limitations. Condensates may contain a relatively high percentage of intermediate components and can be separated easily from entrained water due to its lower viscosity and greater density difference with water. Thus, some sort of condensate stabilization should be considered for each gas well production facility.

STABILIZATION PROCESSES

Stabilization of condensate streams can be accomplished through either flash vaporization or by fractionation.

Flash Vaporization

Stabilization by flash vaporization is a simple operation employing only two or three flash tanks. This process is similar to stage separation utilizing the equilibrium principles between vapor and condensate phases. Equilibrium vaporization occurs when the vapor and condensate phases are in equilibrium at the temperature and pressure of separation.

Figure 6-1 shows a typical scheme of condensate stabilization through the flash vaporization process. As shown, condensate from the inlet separator after passing through the exchanger enters to the high-pressure flash tank, where the pressure is maintained at 600 psia. A pressure drops of 300 psia is obtained here, which assists flashing of large amounts of lighter ends, which join the sour vapor stream after recompression.

The vapor can either be processed further and put into the sales gas or be recycled into the reservoir and used as gas lift to produce more crude oils. The bottom liquid from the high-pressure tank flows to the middle pressure flash tank operated at 300 psia. Additional methane and ethane are released in this tank. The bottom product is withdrawn again to the low-pressure tank operated at 65 psia. To ensure efficient separation, condensate is degassed in the stripper vessel at the lowest possible pressure prior to storage. This reduces excess flashing of condensate in the storage tank and reduces the inert gas blanket pressure required in it.

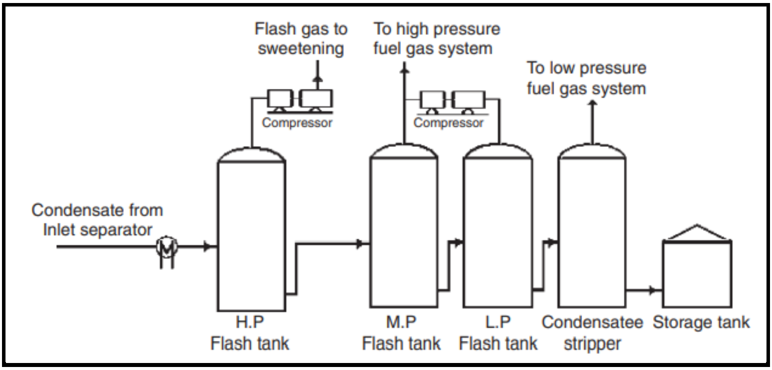

Figure 6-1. Schematic of condensate stabilization through ash vaporization process. H.P., high pressure; M>P., middle pressure; L.P., low pressure.

(Handbook of Natural Gas Transmission and Processing, Saeid Mokhatab, William A. Poe and James G. Speight).

Note that flash vaporization as a condensate stabilization method is old technology and is not used in a modern gas plant. However, variations of flash technology might also be found on oil production facilities stabilizing crude oil.

Stabilization by Fractionation

Stabilization by fractionation is a detailed process, very popular in the industry and precise enough to produce liquids of suitable vapor pressure. During the operation, light fractions such as methane-ethane-propane and most of the butanes are removed and recovered. The finished product from the bottom of the column is composed mainly of pentanes and heavier hydrocarbons, with small amounts of butane.

The process makes a cut between the lightest liquid component (pentane) and the heaviest gas (butane). The bottom product is thus a liquid free of all gaseous components able to be stored safely at atmospheric pressure. Stabilization by fractionation is a modern operation and economically attractive next to flash vaporization. It is a single tower process, as only one specification product is required. The bottom product of the column can meet any kind of rigid specifications with the proper operating conditions.

CONDENSATE STORAGE

Condensate is stored between production and shipping operations in condensate storage tanks, which are usually of floating roof type (external and internal). If the condensate does not meet the specifications, the off-specification condensate may be routed to an off-specification condensate storage fixed roof tank (vertical and horizontal) until it is recycled to the condensate stabilization unit by the relevant recycle pump if the latter is available at the plant.

The primary quality criterion for the condensate is its RVP, which is affected by atmospheric pressure (plant elevation) and maximum ambient temperature. To store the condensate in floating roof storage tanks, it is very crucial to control the RVP at the desired level (especially in warm seasons).

Emissions from condensate storage tanks are normally categorized as occurring from breathing losses (standing storage losses) or working losses. The term breathing loss refers to those emissions that result without any corresponding change in the liquid level within the tank.

Most likely, these types of emissions results from hydrocarbon vapours that are released from the tank by expansion or contraction caused by changes in either temperature or pressure. Working loss represents those emissions that occur due to changes in the liquid level caused by either filling or emptying the tank itself.

For floating roof tanks, breathing losses are a result of evaporative losses through rim seals, deck fittings, and deck seam losses. Withdrawal losses occur as the level drops, and thus the floating roof is lowered. Some liquid remains on the inner tank wall surface and evaporates when the tank is emptied. For an internal floating roof tank that has a column-supported fixed roof, some liquid also clings to the columns and evaporates. Evaporative loss occurs until the tank is filled, and the exposed surfaces are again covered.

The working pressure required to prevent breathing and thereby save standing storage losses depends on the vapor pressure of the product, the temperature variations of the liquid surface and the vapor space, and the setting of the vacuum vent.

7 NATURAL GAS COMPRESSION

Compression is used in all aspects of the natural gas industry, including gas lift, reinjection of gas for pressure maintenance, gas gathering, gas processing operations (circulation of gas through the process or system), transmission and distribution systems, and reducing the gas volume for shipment by tankers or for storage.

In recent years, there has been a trend toward increasing pipeline-operating pressures. The benefits of operating at higher pressures include the ability to transmit larger volumes of gas through a given size of pipeline, lower transmission losses due to friction, and the capability to transmit gas over long distances without additional boosting stations.

In gas transmission, two basic types of compressors are used: reciprocating and centrifugal compressors. Reciprocating compressors are usually driven by either electric motors or gas engines, whereas centrifugal compressors use gas turbines or electric motors as drivers.

The key variables for equipment selections are life cycle cost, capital cost, maintenance costs, including overhaul and spare parts, fuel, or energy costs. The units level of utilization, as well as demand fluctuations, plays an important role. While both gas engines and gas turbines can use pipeline gas as a fuel, an electric motor must rely on the availability of electric power. Due to the number of variables involved, the task of choosing the optimum driver can be quite involved, and a comparison between the different types of drivers should be done before a final selection is made.

An economic feasibility study is of fundamental importance to determine the best selection for the economic life of a project. Furthermore, it must be decided whether the compression task should be divided into multiple compressor trains, operating in series or in parallel.

RECIPROCATING COMPRESSORS

A reciprocating compressor is a positive displacement machine in which the compressing and displacing element is a piston moving linearly within a cylinder. The reciprocating compressor uses automatic spring-loaded valves that open when the proper differential pressure exists across the valve.

Figure 8-1 describes the action of a reciprocating compressor using a theoretical pressure–volume (PV) diagram. In position A, the suction valve is open, and gas will flow into the cylinder (from point 1 to point 2 on the PV diagram) until the end of the reverse stroke at point 2, which is the start of compression. At position B, the piston has travelled the full stroke within the cylinder and the cylinder is full of gas at suction pressure. Valves remain closed. The piston begins to move to the left, closing the suction valve. In moving from position B to position C, the piston moves toward the cylinder head, reducing the volume of gas with an accompanying rise in pressure. The PV diagram shows compression from point 2 to point 3. The piston continues to move to the end of the stroke (near the cylinder head) until the cylinder pressure is equal to the discharge pressure and the discharge valve opens (just beyond point 3). After the piston reaches point 4, the discharge valve will close, leaving the clearance space filled with gas at discharge pressure (moving from position C to position D). As the piston reverses its travel, the gas remaining within the cylinder expands (from point 4 to point 1) until it equals suction pressure, and the piston is again in position A.

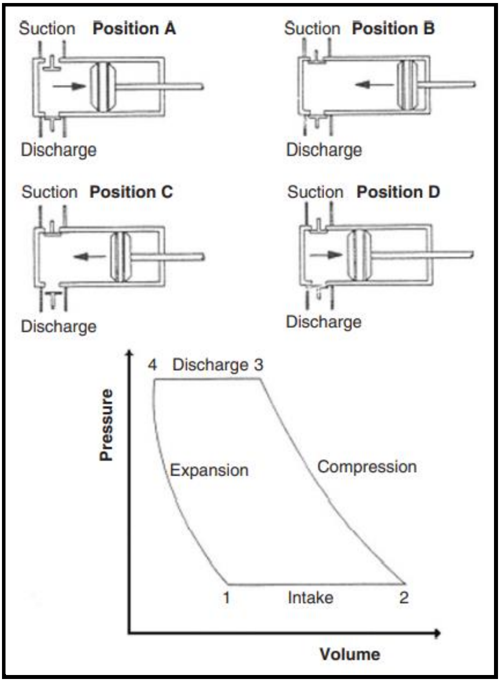

Figure 7-1. Reciprocating compressor compression cycle. (Handbook of Natural Gas Transmission and Processing, Saeid Mokhatab, William A. Poe and James G. Speight).

The flow to and from reciprocating compressors is subject to significant pressure fluctuations due to the reciprocating compression process. Therefore, pulsation dampeners have to be installed upstream and downstream of the compressor to avoid damages to other equipment. The pressure losses (several percent of the static flow pressure) of these dampeners have to be accounted for in the station design.

Reciprocating compressors are widely utilized in the gas processing industries because they are flexible in throughput and discharge pressure range. Reciprocating compressors are classified as either “high speed” or “slow speed.” Typically, high-speed compressors operate at speeds of 900 to 1200 rpm and slow-speed units at speeds of 200 to 600 rpm. High-speed units are normally “separable,” i.e., the compressor frame and driver are separated by a coupling or gearbox. For an “integral” unit, power cylinders are mounted on the same frame as the compressor cylinders, and power pistons are attached to the same drive shaft as the compressor cylinders. Low-speed units are typically integral in design.

CENTRIFUGAL COMPRESSORS

The essential components of a centrifugal compressor that accomplish the tasks specified earlier can be shown in Figure 7-2 below. The gas entering the inlet nozzle of the compressor is guided to the inlet of the impeller. An impeller consists of several rotating vanes that impart mechanical energy to the gas. The gas will leave the impeller with an increased velocity and increased static pressure. In the diffuser, part of the velocity is converted into static pressure. Diffusers can be vaned, vaneless, or volute type. If the compressor has more than one impeller, the gas will be again brought in front of the next impeller through the return channel and the return vanes.

If the compressor has only one impeller, or after the diffuser of the last impeller in a multistage compressor, the gas enters the discharge system.

The discharge system can either make use of a volute, which can further convert velocity into static pressure, or a simple cavity that collects the gas before it exits the compressor through the discharge flange.

The rotating part of the compressor consists of all the impellers. It runs on two radial bearings (on all modern compressors, these are hydrodynamic tilt pad bearings), while the axial thrust generated by the impellers is balanced by a balance piston, and the resulting force is balanced by a hydrodynamic tilt pad thrust bearing. To keep the gas from escaping at the shaft ends, dry gas seals are used. The entire assembly is contained in a casing (usually barrel type).

A compressor stage is defined as one impeller, with the subsequent diffuser and (if applicable) return channel. A compressor body may hold one or several (up to 8 or 10) stages. A compressor train may consist of one or multiple compressor bodies. It sometimes also includes a gearbox. Pipeline compressors are typically single body trains, with one or two stages.

The different working principles cause differences in the operating characteristics of the centrifugal compressors compared to those of the reciprocating unit. Centrifugal compressors are used in a wide variety of applications in chemical plants, refineries, onshore and offshore gas lift and gas injection applications, gas gathering, and in the transmission of natural gas.

Centrifugal compressors can be used for outlet pressures as high as 10,000 psia, thus overlapping with reciprocating compressors over a portion of the flow rate/pressure domain. Centrifugal compressors are usually either turbine or electric motor driven. Typical operating speeds for centrifugal compressors in gas transmission applications are about 14,000 rpm for 5000-hp units and 8000 rpm for 20,000-hp units.

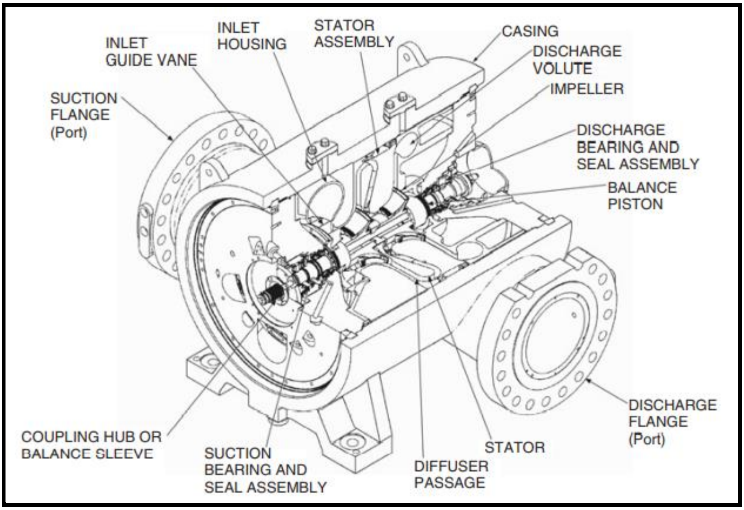

Figure 7-2. Typical centrifugal compressor cutaway

(Gas Processors Suppliers Association Engineering Data Book)

COMPARISON BETWEEN COMPRESSORS

Differences between reciprocating and centrifugal compressors are summarized as follow based on the reference from Gas Processors Suppliers Association. Advantages of a reciprocating compressor over a centrifugal machine include:

1. Ideal for low volume flow and high-pressure ratios.
2. High efficiency at high-pressure ratios.
3. Relatively low capital cost in small units (less than 3000 hp).
4. Less sensitive to changes in composition and density.

Advantages of a centrifugal compressor over a reciprocating machine include:

1. Ideal for high volume flow and low head.
2. Simple construction with only one moving part.
3. High efficiency over normal operating range.
4. Low maintenance cost and high availability.
5. Greater volume capacity per unit of plot area.
6. No vibrations and pulsations generated.

COMPRESSOR SELECTION

The design philosophy for choosing a compressor should include the following considerations:

1. Good efficiency over a wide range of operating conditions.
2. Maximum flexibility of configuration.
3. Low maintenance cost.

4. Low life cycle cost.
5. Acceptable capital cost.
6. High availability.

However, additional requirements and features will depend on each project and on specific experiences of the pipeline operator. In fact, compressor selection consists of the purchaser defining the operating parameters for which the machine will be designed.

In many cases, the decision whether to use a reciprocating compressor or a centrifugal compressor, as well as the type of driver, will already have been made based on operator strategy, emissions requirements, general life cycle cost assumptions, and so on. However, a hydraulic analysis should be made for each compressor selection to ensure the best choice. In fact, compressor selection can be made for an operating point that will be the most likely or most frequent operating point of the machine. Selections based on a single operating point have to be evaluated carefully to provide sufficient speed margin (typically 3 to 10%) and surge margin to cover other, potentially important situations.

A compressor performance map (for centrifugal compressors, this would be preferably a head vs flow map) can be generated based on the selection and is used to evaluate the compressor for other operating conditions by determining the head and flow required for these other operating conditions.

In many applications, multiple operating points are available, e.g., based on hydraulic pipeline studies or reservoir studies. Some of these points may be frequent operating points, while some may just occur during upset conditions. With this knowledge, the selection can be optimized for a desired target, such as lowest fuel consumption.

Selections can also be made based on a “rated” point, which defines the most onerous operating conditions (highest volumetric flow rate; lowest molecular weight; highest head or pressure ratio; highest inlet temperature). In this situation, however, the result may be an oversized machine that does not perform well at the usual operating conditions.

Once a selection is made, the manufacturer is able to provide parameters such as efficiency, speed, and power requirements and, based on this and the knowledge of the ambient conditions (prevailing temperatures, elevation), can size the drivers. At this point, the casing arrangement, and the number of units necessary or desirable (flexibility requirements, growth scenarios and sparing considerations will play an important role in this decision) can be discussed.

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