ОСНОВЫ НЕФТЕГАЗОВОГО ДЕЛА

Методические указания к практическим занятиям
для студентов бакалавриата направления 21.03.01

ESSENTIALS OF OIL AND GAS ENGINEERING

Methodical instructions for conducting practical classes
for undergraduate students of educational branch 21.03.01

САНКТ-ПЕТЕРБУРГ
2020

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Кафедра разработки и эксплуатации нефтяных
и газовых месторождений

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Научный редактор доц. *Д.С. Тананыхин*

Рецензент канд. техн. наук *Р.Р. Гумеров* (ООО «Газпромнефть НТЦ»)

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Сост. *А.Н. Паляницина*

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РИЦ Санкт-Петербургского горного университета
Адрес университета и РИЦ: 199106 Санкт-Петербург, 21-я линия, 2

INTRODUCTION

The petroleum industry is involved in the global processes of exploration, extraction, refining, transporting (often with oil tankers and pipelines), and marketing petroleum products. The largest volume products of the industry are fuel oil and gasoline. Petroleum is also the raw material for many chemical products, including pharmaceuticals, solvents, fertilizers, pesticides, and plastics. The industry is usually divided into three major components: upstream, midstream and downstream. Midstream operations are usually included in the downstream category.

Introduction to Petroleum Engineering introduces people with technical backgrounds to petroleum engineering. The book presents fundamental terminology and concepts from geology, geophysics, petrophysics, drilling, production, and reservoir engineering. It covers upstream, midstream, and downstream operations. Exercises are designed to highlight and reinforce material in the chapter and encourage the reader to develop a deeper understanding of the material.

Introduction to Petroleum Engineering is suitable for science and engineering students, practicing scientists and engineers, continuing education classes, industry short courses, or self-study.

OIL AND GAS OPERATING CYCLE AND ACTIVITIES

Upstream is a term used in the oil industry which refers to the searching for, the recovery and production of crude oil and natural gas.

The upstream sector includes.

Exploration – the searching for potential onshore or offshore oil and gas reservoirs, and the drilling of exploratory wells

Production and maintenance of wells and facilities to recover and bring the crude oil and/or raw natural gas to the surface plant and to process the produced hydrocarbons.

I EXPLORATION

1. Basins / Area Assessment:

Regional Studies
Geological Modeling (Basin modeling)
Bid Evaluation
Farm in/out opportunities

2. Prospects Definition / Discovery:

seismic survey & interpretation
drilling
subsurface geology
production tests

The role of exploration is to provide the information required to exploit the best opportunities presented in the choice of areas, and to manage research operations on the acquired blocks.

An oil company may work for several years (Figure 1.1) on a prospective area before an exploration well is spudded and during this period the geological history of the area is studied and the likelihood of hydrocarbons being present quantified.

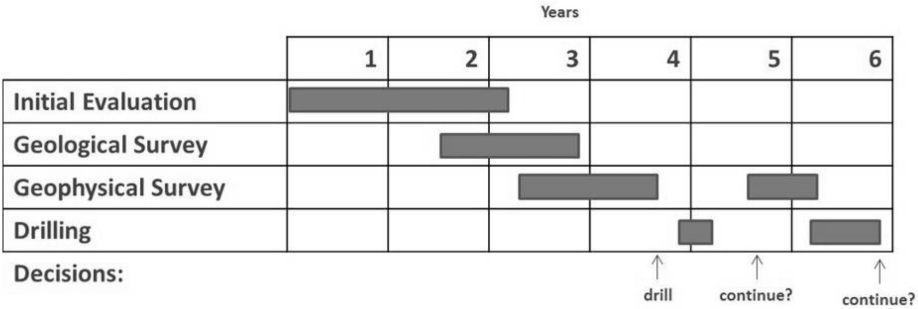


Figure 1.1. Stages of a typical exploration program

Exploration is responsible for handling the risk intrinsic in this activity, and this is generally achieved by selection of a range of options in probabilistic and economic terms.

II FIELD APPRAISAL

Reservoir Delineation & Modeling:
appraisal drilling
reservoir studies
reservoir modeling & reserves definition
feasibility studies.

Once an exploration well has found hydrocarbons, considerable effort will still be required to accurately assess the potential of the discovery and the role of appraisal is to provide cost-effective information that will be used for subsequent decisions (development).

During appraisal, more wells are drilled to collect information and samples from the reservoir and other seismic survey might also be acquired in order to better delineate the reservoir.

III DEVELOPMENT PHASE

Development:
development plan & environmental aspects
drilling & completion
surface facilities construction & installation.

The development stage takes place after successfully completing the appraisal period and before the beginning of the field production.

Field Development Plans (FDPs) provide the necessary support for field optimization, and include all activities and processes required to optimally develop a field.

In general, development activities and processes involves:
environmental impact, geophysics, geology, reservoir and production engineering, infrastructure, well design and construction, completion design, surface facilities, economics and risk assessment

In particular, the activities and people involved in the development stage:

- define a precise Field Development Plan (FDP) – geologists, geophysicists and reservoir engineers;
- decide the best production/injection well placement and design – drilling engineers, reservoir engineers, geologists;
- select the optimal production facilities required to properly process hydrocarbons before their treatment – production engineers, reservoir engineers, facilities engineers;
- choose the transport options and route to export oil and gas – logistics engineers.

A FDP must consider:

- Objectives of the development;
- Petroleum engineering data;
- Operating and maintenance objectives;
- Description of the engineering facilities;
- Cost and manpower estimates;
- Project planning budget proposal.

IV PRODUCTION

Production:

- Production management & optimization;
- Reservoir management;
- Wells interventions.

Production phase aims to the recovery of the reservoir fluids to surface followed by their processing. All production and maintenance activities are carried out to meet strict safety and environmental policies and procedures.

During the production phase it is necessary to:

- control production and injection to meet up approved plans for volumes and quality of products;
- monitor and record all data to manage the reservoir, wells and facilities.

A typical production profile is made up by three phases (Fig. 1.2):

- Build-up period;
- During this period production wells are progressively brought on flow;
- Plateau period;
- Constant production rate is maintained;
- Decline period;
- All producers show declining of production rates.

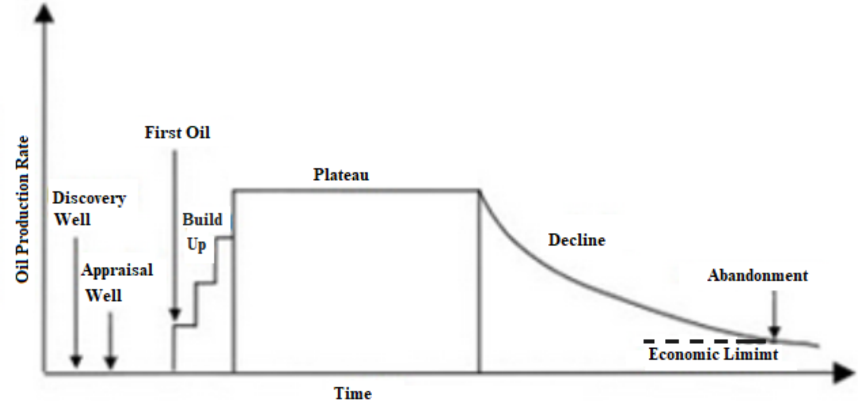


Figure 1.2. Typical field production profile

V ABANDONMENT

Well Abandonment Phase:

wells plugging
plant removal
environmental restoration.

The end of the life of the field occurs when it is no longer economic for the operator to continue production, and consequently the wells will be plugged and abandoned.

Well workovers or stimulation, artificial lift, drilling new wells, etc, may help in prolonging the field’s life, but they are undertaken if they can be economically justified by increased production.

The objective of all P&A operations is to achieve the following:

- isolate and protect all fresh and near fresh water zones;
- isolate and protect all future commercial zones;
- prevent leaks in perpetuity from or into the well;
- remove surface equipment and cut pipe to a mandated level below the surface.

1. RESERVOIR FLUID PROPERTIES

To understand and predict the volumetric behavior of oil and gas reservoirs as a function of pressure, knowledge of the physical properties of reservoir fluids must be gained. These fluid properties are usually determined by laboratory experiments performed on samples of actual reservoir fluids. In the absence of experimentally measured properties, it is necessary for the petroleum engineer to determine the properties from empirically derived correlations. The objective of this chapter is to present several of the well-established physical property correlations for the following reservoir fluids:

- Natural gases
- Crude oil systems
- Reservoir water systems

1.1 Oil and Gas Units

Two sets of units are commonly found in the petroleum literature: oil field units and metric units (SI units). Units used in the text are typically oil field units (Table 1.1). The ability to convert between oil field and SI units is an essential skills because both systems of units are frequently used.

Table 1.1

Examples of Common Unit Systems

Property	Oil Field	SI (Metric)	British
Length	ft	m	ft
Time	hr	sec	sec
Pressure	psia	Pa	lbf/ft^2
Volume flow rate	bbl/day	m^3/s	ft^3/s
Viscosity	cp	Pa·s	lbf·s/ft^2

1.2 Classification of Oil and Gas

Surface temperature and pressure are usually less than reservoir temperature and pressure. Hydrocarbon fluids that exist in a single phase at reservoir temperature and pressure often transition to two phases when they are produced to the surface where the temperature and pressure are lower. There are a variety of terms for describing hydrocarbon fluids at surface conditions. Natural gas is a hydrocarbon mixture in the gaseous state at surface conditions. Crude oil is a hydrocarbon mixture in the liquid state at surface conditions. Heavy oils do not contain much gas in solution at reservoir conditions and have a relatively large molecular weight. By contrast, light oils typically contain a large amount of gas in solution at reservoir conditions and have a relatively small molecular weight.

A summary of hydrocarbon fluid types is given in Table 1.2. *API* gravity in the table is defined in terms of oil specific gravity as

$$API=\left(\frac{141{,}5}{\gamma_0}\right)-131{,}5 \qquad (1.1)$$

The specific gravity of oil is the ratio of oil density ρ_o to freshwater density ρ_w:

$$\gamma_0=\left(\frac{\rho_o}{\rho_w}\right), \qquad (1.2)$$

Table 1.2

Rules of Thumb for Classifying Fluid Types

Fluid Type	Separator GOR (MSCF/STB)	Gravity (˚API)	Behavior in Reservoir due to Pressure Decrease
Dry gas	No surface liquids		Remains gas
Wet gas	>50	40-60	Remains gas
Condensate	3,3-50	40-60	Gas with liquid dropout
Volatile oil	2,0-3,3	>40	Liquid with significant gas
Black oil	<2,0	<45	Liquid with some gas
Heavy oil	≈0		Negligible gas formation

Data from Raymond and Leffler (2006)

The API gravity of freshwater is 10°API, which is expressed as 10 degrees API. API denotes American Petroleum Institute.

Another way to classify hydrocarbon liquids is to compare the properties of the hydrocarbon liquid to water. Two key properties are viscosity and density. Viscosity is a measure of the ability to flow, and density is the amount of material in a given volume.

Water viscosity is 1cp (centipoise) and water density is 1g/cc (gram per cubic centimeter) at 60°F. A liquid with smaller viscosity than water flows more easily than water. Gas viscosity is much less than water viscosity. Tar, on the other hand, has very high viscosity relative to water.

Table 1.3 shows a hydrocarbon liquid classification scheme using API gravity and viscosity. Water properties are included in the table for comparison. Bitumen is a hydrocarbon mixture with large molecules and high viscosity. Light oil, medium oil, and heavy oil are different types of crude oil and are less dense than water. Extra heavy oil and bitumen are denser than water. In general, crude oil will float on water, while extra heavy oil and bitumen will sink in water.

Table 1.3

Classifying Hydrocarbon Liquid Types Using API Gravity and Viscosity

Liquid type	API Gravity (˚API)	Viscosity (cp)
Light oil	>31,1	
Medium oil	22,3-31,1	
Heavy oil	10-22,3	
Water	10	1
Extra heavy oil	4-10	<10 000
Bitumen	4-10	>10 000

Example 1.1

The specific gravity of an oil sample is 0.85. What is its API gravity?

1.3 Properties of Natural Gases

A gas is defined as a homogeneous fluid of low viscosity and density that has no definite volume but expands to completely fill the vessel in which it is placed. Generally, the natural gas is a mixture of hydrocarbon and nonhydrocarbon gases. The hydrocarbon gases that are normally found in a natural gas are methanes, ethanes, propanes, butanes, pentanes, and small amounts of hexanes and heavier. The nonhydrocarbon gases (i.e., impurities) include carbon dioxide, hydrogen sulfide, and nitrogen.

Knowledge of pressure-volume-temperature (PVT) relationships and other physical and chemical properties of gases is essential for solving problems in natural gas reservoir engineering. These properties include:

- Apparent molecular weight, M_a
- Specific gravity, γ_g
- Compressibility factor, z
- Density, ρ_g
- Specific volume, v

- Isothermal gas compressibility coefficient, c_g
- Gas formation volume factor, B_g
- Gas expansion factor, E_g
- Viscosity, μ_g

The above gas properties may be obtained from direct laboratory measurements or by prediction from generalized mathematical expressions. This section reviews laws that describe the volumetric behavior of gases in terms of pressure and temperature and also documents the mathematical correlations that are widely used in determining the physical properties of natural gases.

BEHAVIOR OF IDEAL GASES

The kinetic theory of gases postulates that gases are composed of a very large number of particles called molecules. For an ideal gas, the volume of these molecules is insignificant compared with the total volume occupied by the gas. It is also assumed that these molecules have no attractive or repulsive forces between them, and that all collisions of molecules are perfectly elastic.

Based on the above kinetic theory of gases, a mathematical equation called equation-of-state can be derived to express the relationship existing between pressure p, volume V, and temperature T for a given quantity of moles of gas n. This relationship for perfect gases is called the ideal gas law and is expressed mathematically by the following equation:

$$pV=nRT, \tag{1.3}$$

where p = absolute pressure, psi
V = volume, ft^3
T = absolute temperature, °R
n = number of moles of gas, lb-mole
R = the universal gas constant which, for the above units, has the value 10,730 psia ft^3/lb-mole °R.

The number of pound-moles of gas, i.e., n, is defined as the weight of the gas m divided by the molecular weight M, or:

$$n=\frac{m}{M} \tag{1.4}$$

Combining Equation 1.3 with 1.4 gives:

$$pV = \left(\frac{m}{M}\right) RT, \tag{1.5}$$

where m = weight of gas, lb
M = molecular weight, lb/lb-mol.

Since the density is defined as the mass per unit volume of the substance, Equation 1.5 can be rearranged to estimate the gas density at any pressure and temperature:

$$\rho_g = \frac{m}{V} = \frac{pM}{RT}, \tag{1.6}$$

where ρ_g = density of the gas, lb/ft^3.

It should be pointed out that lb refers to lbs mass in any of the subsequent discussions of density in this text.

Example 1.2

Three pounds of n-butane are placed in a vessel at 120°F and 60 psia. Calculate the volume of the gas assuming an ideal gas behavior.

Example 1.3

Using the data given in the above example, calculate the density n-butane.

Petroleum engineers are usually interested in the behavior of mixtures and rarely deal with pure component gases. Because natural gas is a mixture of hydrocarbon components, the overall physical and chemical properties can be determined from the physical properties of the individual components in the mixture by using appropriate mixing rules.

The basic properties of gases are commonly expressed in terms of the apparent molecular weight, standard volume, density, specific volume, and specific gravity. These properties are defined as follows:

Apparent Molecular Weight

One of the main gas properties that is frequently of interest to engineers is the apparent molecular weight. If y_i represents the mole fraction of the *ith* component in a gas mixture, the apparent molecular weight is defined mathematically by the following equation:

$$M_a = \sum_{i=1} y_i M_i, \tag{1.7}$$

where M_a = apparent molecular weight of a gas mixture
M_i = molecular weight of the *ith* component in the mixture
y_i = mole fraction of component *i* in the mixture.

Standard Volume

In many natural gas engineering calculations, it is convenient to measure the volume occupied by l lb-mole of gas at a reference pressure and temperature. These reference conditions are usually 14.7 psia and 60°F, and are commonly referred to as standard conditions. The standard volume is then defined as the volume of gas occupied by 1 lb-mol of gas at standard conditions. Applying the above conditions to Equation 1.3 and solving for the volume, i.e., the standard volume, gives:

$$V_{sc} = \frac{(1)RT_{sc}}{P_{sc}} = \frac{(1)(10{,}73)520)}{14{,}7}, \tag{1.8}$$

or

$$Vsc = 379{,}4\ scf/lb\text{-}mol \tag{1.9}$$

where V_{sc} = standard volume, scf/lb-mol
scf = standard cubic feet
T_{sc} = standard temperature, °R
p_{sc} = standard pressure, psia

Density

The density of an ideal gas mixture is calculated by simply replacing the molecular weight of the pure component in Equation 1.6 with the apparent molecular weight of the gas mixture to give:

$$\rho_g = \frac{pM_a}{RT}, \tag{1.10}$$

where ρ_g = density of the gas mixture, lb/ft^3
M_a = apparent molecular weight

Specific Volume

The specific volume is defined as the volume occupied by a unit mass of the gas. For an ideal gas, this property can be calculated by applying Equation 1.5:

$$v = \frac{V}{m} = \frac{RT}{pM_a} = \frac{1}{\rho_g}, \qquad (1.11)$$

where v = specific volume, ft^3/lb

ρ_g = gas density, lb/ft^3

Example 1.4

A gas well is producing gas with a specific gravity of 0.65 at a rate of 1.1 MMscf/day. The average reservoir pressure and temperature are 1,500 psi and 150°F. Calculate:

a. Apparent molecular weight of the gas;
b. Gas density at reservoir conditions;
c. Flow rate in lb/day.

Example 1.5

A gas well is producing a natural gas with the following composition:

Component	y_i
CO_2	*0,05*
C_1	*0,90*
C_2	*0,03*
C_3	*0,02,*

Assuming an ideal gas behavior, calculate:

a. Apparent molecular weight;
b. Specific gravity;
c. Gas density at 2000 psia and 150°F;
d. Specific volume at 2000 psia and 150°F.

BEHAVIOR OF REAL GASES

In dealing with gases at a very low pressure, the ideal gas relationship is a convenient and generally satisfactory tool. At higher pressures, the use of the ideal gas equation-of-state may lead to errors as great as 500%, as compared to errors of 2–3% at atmospheric pressure.

Basically, the magnitude of deviations of real gases from the conditions of the ideal gas law increases with increasing pressure and temperature and varies widely with the composition of the gas. Real gases behave differently than ideal gases. The reason for this is that the perfect gas law was derived under the assumption that the volume of molecules is insignificant and that no molecular attraction or repulsion exists between them. This is not the case for real gases.

Numerous equations-of-state have been developed in the attempt to correlate the pressure-volume-temperature variables for real gases with experimental data. In order to express a more exact relationship between the variables p, V, and T, a correction factor called the *gas compressibility factor*, *gas deviation factor*, or simply the *z-factor*, must be introduced into Equation 1.3 to account for the departure of gases from ideality. The equation has the following form:

$$pV=znRT, \tag{1.15}$$

where the gas compressibility factor z is a dimensionless quantity and is defined as the ratio of the actual volume of n-moles of gas at T and P to the ideal volume of the same number of moles at the same T and P:

$$z=\frac{V_{actual}}{V_{ideal}}=\frac{V}{(nRT)/P} \tag{1.16}$$

Studies of the gas compressibility factors for natural gases of various compositions have shown that compressibility factors can be generalized with sufficient accuracies for most engineering purposes when they are expressed in terms of the following two dimensionless properties:

- Pseudo-reduced pressure
- Pseudo-reduced temperature

These dimensionless terms are defined by the following expressions:

$$P_{pr}=\frac{P}{P_{pc}} \tag{1.17}$$

$$T_{pr}=\frac{T}{T_{pc}} \tag{1.18}$$

where P - system pressure, psi

P_{pr} - pseudo-reduced pressure, dimensionless

T - system temperature, °R

T_{pr} - pseudo-reduced temperature, dimensionless

P_{pc}, T_{pc} - pseudo-critical pressure and temperature, respectively, and defined by the following relationships:

$$P_{pc}=\sum_{i=1} y_i\, P_{ci} \tag{1.19}$$

$$T_{pc}=\sum_{i=1} y_i\, T_{ci} \tag{1.20}$$

It should be pointed out that these pseudo-critical properties, i.e., P_{pc} and T_{pc}, do not represent the actual critical properties of the gas mixture. These pseudo properties are used as correlating parameters in generating gas properties.

Based on the concept of pseudo-reduced properties, Standing and Katz (1942) presented a generalized gas compressibility factor chart as shown in Figure 1.1. The chart represents compressibility factors of sweet natural gas as a function of p_{pr} and T_{pr}. This chart is generally reliable for natural gas with minor amount of nonhydrocarbons. It is one of the most widely accepted correlations in the oil and gas industry.

Example 1.6

Calculate the molar mass of each component, the molecular weight of the gas, its density under standard conditions, the relative density of the gas through the air, the compressibility factor according to Brown curves, if the dissolved gas in the volume of oil V_{liq} *has a volume* V_g *reduced to normal conditions. Table 1.4*

Table 1.4

Gas component composition

№	Gas component composition volume fractions in%								*P*, MPa	*t*, °C	$V_г$, $\cdot 10^4$, м^3	V_{liq}, м^3
	CH_4	C_2H_6	C_3H_8	C_4H_{10}	C_5H_{12}	CO_2	N_2	H_2S				
1	53,4	7,2	15,1	8,3	6,3	0,1	9,6	0	18,8	60	18,5	950
2	97,8	0,1	0,03	0,02	0,01	0,3	1,7	0,04	19,2	65	18,0	1000
3	84	5	1,6	0,7	1,8	1,1	4,2	1,6	19,7	62	19,0	1100
4	95,6	2	0,34	0,1	0,05	1,15	0,76	0	23	50	19,3	1050
5	58,8	1,8	0,6	0,23	0,12	11	21,3	6,15	16	58	19,5	1225
6	37,3	20,7	18,9	9,5	4,8	-	8,8	-	17	64	17,6	920
7	39,4	16,8	6,5	2,8	1,1	-	31,6	1,8	19,6	45	18,3	940
8	48	12,2	24	11,1	2,6	-	2,1	-	18	58	18,5	960
9	62,2	9,2	13,7	7,4	4	0,8	2,7	-	20	62	18,7	980
10	72,3	6,2	11,4	5,1	2	0,7	1,8	0,5	19	61	18,5	960

Table 1.5

Atomic masses of components

Component	H	C	O	S	N
Atomic mass	1,008	12,011	15,999	32,064	14,007

Table 1.6

Indicators of gas components

	Relation air density	Critical temperature., K	Critical pressure MPa	Density(normal conditions)
CH_4	0,555	191	4,49	0,717
C_2H_6	1,049	305	4,75	1,356
C_3H_8	1,562	370	4,25	2,019
C_4H_{10}	2,091	425	3,50	2,703
C_4H_{10}	2,066	408	374	2,668
C_5H_{12}	2,48	460	3,22	3,216
C_5H_{12}	2,490	460	3,23	3,880
C_6H_{12}	2,974	507	2,93	3,860
C_7H_{16}	3,450	540	2,65	4,470
N_2	0,967	126	3,28	1,250
H_2S	1,190	374	8,71	1,539
CO_2	1,529	304	7,15	1,976
Air	1,000	414	3,65	1.000

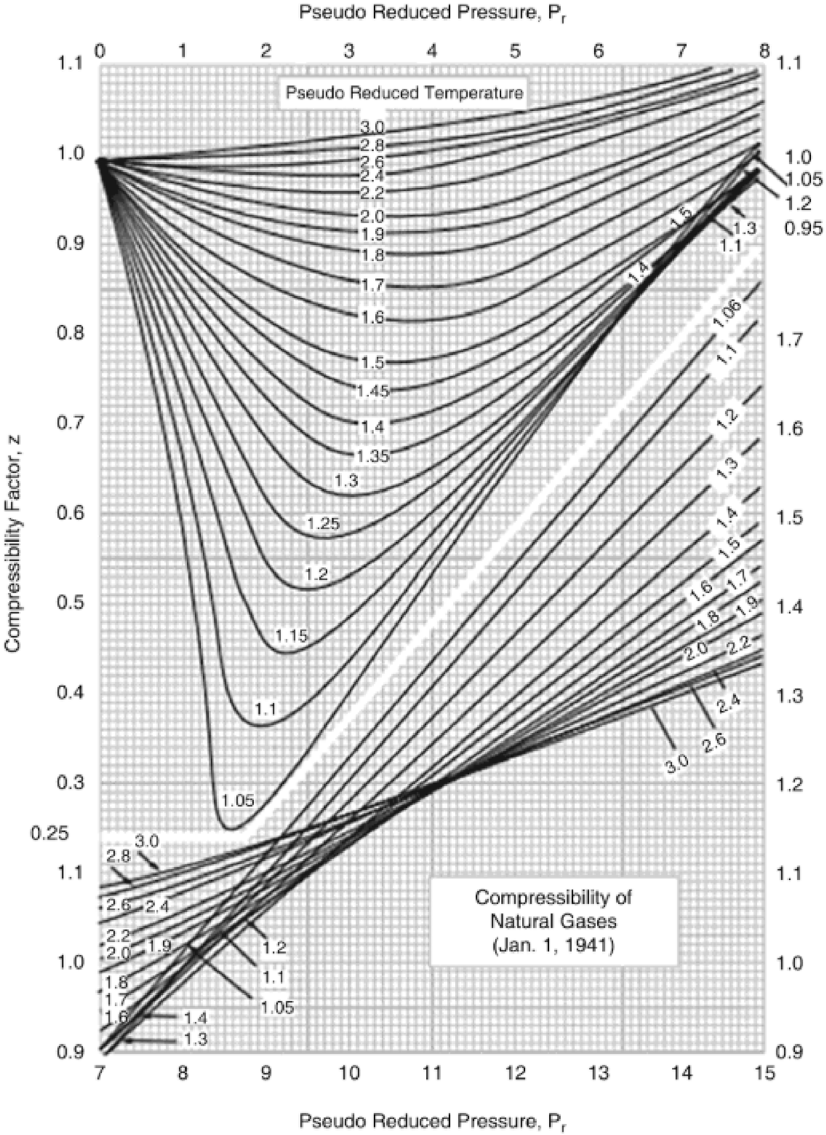


Figure 1.3. Standing and Katz compressibility factors chart. (*Courtesy of GPSA and* GPA Engineering Data Book, *EO Edition, 1987*.)

1.4 Properties of Crude Oil Systems

Petroleum (an equivalent term is crude oil) is a complex mixture consisting predominantly of hydrocarbons and containing sulfur, nitrogen, oxygen, and helium as minor constituents. The physical and chemical properties of crude oils vary considerably and are dependent on the concentration of the various types of hydrocarbons and minor constituent present.

An accurate description of physical properties of crude oils is of a considerable importance in the fields of both applied and theoretical science and especially in the solution of petroleum reservoir engineering problems. Physical properties of primary interest in petroleum engineering studies include:

- Fluid gravity;
- Specific gravity of the solution gas;
- Gas solubility;
- Bubble-point pressure;
- Oil formation volume factor;
- Isothermal compressibility coefficient of undersaturated crude oils;
- Oil density;
- Total formation volume factor;
- Crude oil viscosity;
- Surface tension.

Data on most of these fluid properties are usually determined by laboratory experiments performed on samples of actual reservoir fluids. In the absence of experimentally measured properties of crude oils, it is necessary for the petroleum engineer to determine the properties from empirically derived correlations.

Crude Oil Gravity

The crude oil density is defined as the mass of a unit volume of the crude at a specified pressure and temperature. It is usually expressed in pounds per cubic foot. The specific gravity of a crude oil is defined as the ratio of the density of the oil to that of water.

It should be pointed out that the liquid specific gravity is dimensionless, but traditionally is given the units 60°/60° to emphasize the fact that both densities are measured at standard conditions. The density of the water is approximately 62.4 lb/ft^3, or:

Although the density and specific gravity are used extensively in the petroleum industry, the API gravity is the preferred gravity scale. This gravity scale is precisely related to the specific gravity by the following expression:

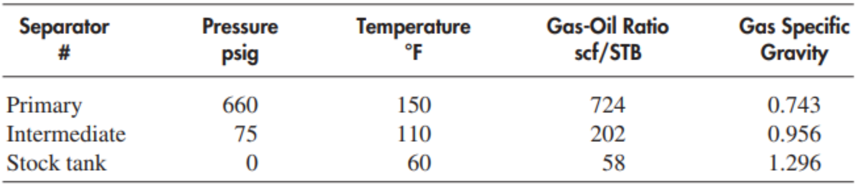
The API gravities of crude oils usually range from 47° API for the lighter crude oils to 10° API for the heavier asphaltic crude oils.

Example 1.8

Calculate the specific gravity and the API gravity of a crude oil system with a measured density of 53 lb/ft^{3}at standard conditions.

Example 1.9

Separator tests were conducted on a crude oil sample. Results of the test in terms of the separator gas-oil ration and specific gravity of the separated gas are given below:



Separator #	Pressure psig	Temperature °F	Gas-Oil Ratio scf/STB	Gas Specific Gravity
Primary	660	150	724	0.743
Intermediate	75	110	202	0.956
Stock tank	0	60	58	1.296

Calculate the specific gravity of the separated gas.

Gas Solubility

The gas solubility Rs is defined as the number of standard cubic feet of gas which will dissolve in one stock-tank barrel of crude oil at certain pressure and temperature. The solubility of a natural gas in a crude oil is a strong function of the pressure, temperature, API gravity, and gas gravity

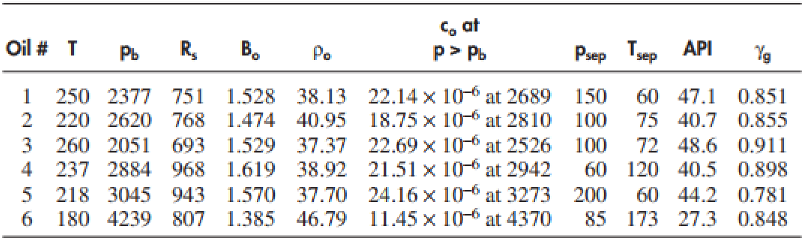
For a particular gas and crude oil to exist at a constant temperature, the solubility increases with pressure until the saturation pressure is reached. At the saturation pressure (bubble-point pressure) all the available gases are dissolved in the oil and the gas solubility reaches its maximum value. Rather than measuring the amount of gas that will dissolve in a given stock-tank crude oil as the pressure is increased, it is customary to determine the amount of gas that will come out of a sample of reservoir crude oil as pressure decreases.

A typical gas solubility curve, as a function of pressure for an undersaturated crude oil, is shown in Figure 1.2. As the pressure is reduced from the initial reservoir pressure pi, to the bubble-point pressure pb, no gas evolves from the oil and consequently the gas solubility remains constant at its maximum value of Rsb. Below the bubble-point pressure, the solution gas is liberated and the value of Rs decreases with pressure. The following five empirical correlations for estimating the gas solubility are given below:

- Standing’s correlation
- The Vasquez-Beggs correlation
- Glaso’s correlation
- Marhoun’s correlation
- The Petrosky-Farshad correlation

Example 1.10

The following experimental PVT data on six different crude oil systems are available. Results are based on two-stage surface separation.



Oil #	T	p_b	R_s	B_o	ρ_o	c_o at $p > p_b$	p_{sep}	T_{sep}	API	γ_g
1	250	2377	751	1.528	38.13	22.14×10^{-6} at 2689	150	60	47.1	0.851
2	220	2620	768	1.474	40.95	18.75×10^{-6} at 2810	100	75	40.7	0.855
3	260	2051	693	1.529	37.37	22.69×10^{-6} at 2526	100	72	48.6	0.911
4	237	2884	968	1.619	38.92	21.51×10^{-6} at 2942	60	120	40.5	0.898
5	218	3045	943	1.570	37.70	24.16×10^{-6} at 3273	200	60	44.2	0.781
6	180	4239	807	1.385	46.79	11.45×10^{-6} at 4370	85	173	27.3	0.848

where T - reservoir temperature, °F
P_b - bubble-point pressure, psig
B_o - oil formation volume factor, bbl/STB
P_{sep} - separator pressure, psig
T_{sep} - separator temperature, °F
C_o - isothermal compressibility coefficient of the oil at a specified pressure, psi

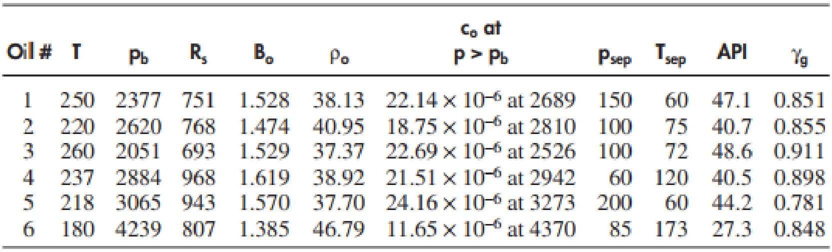
Bubble-Point Pressure

The bubble-point pressure P_b of a hydrocarbon system is defined as the highest pressure at which a bubble of gas is first liberated from the oil. This important property can be measured experimentally for a crude oil system by conducting a constant-composition expansion test. In the absence of the experimentally measured bubble-point pressure, it is necessary for the engineer to make an estimate of this crude oil property from the readily available measured producing parameters. Several graphical and mathematical correlations for determining P_b have been proposed during the last four decades. These correlations are essentially based on the assumption that the bubble-point pressure is a strong function of gas solubility R_s, gas gravity $_g$, oil gravity *API*, and temperature *T*, or:

$$P_b = f\,(R_S,\ _g, API, T) \qquad (1.22)$$

Example 1.11

The experimental data given in Example 2-17 are repeated here for convenience. Predict the bubble-point pressure by using Standing's correlation



Oil #	T	P_b	R_s	B_o	ρ_o	c_o at $p > p_b$	P_{sep}	T_{sep}	API	γ_g
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6	180	4239	807	1.385	46.79	11.65×10^{-6} at 4370	85	173	27.3	0.848

1.5 Properties of Reservoir Water

The presence of water in geologic formations means that the properties of water must be considered. Water properties are discussed in this section.

Formation Volume Factor. The effects of pressure and temperature on the volume of water very nearly cancel, so the FVF of water is approximately 1.0 RB/STB for most reservoirs.

Viscosity. The viscosity of water depends on pressure, temperature, and composition. At reservoir conditions, water will contain dissolved solids (mostly salts) as well as some dissolved hydrocarbon gases and small amounts (<1000 ppm) of other hydrocarbons. The effects of temperature and composition on water viscosity at 14.7psi (1 atm) of pressure are shown in Figure 1.4. Viscosity of pure water is near 1cp at room temperature, but it is much less at typical reservoir temperatures.

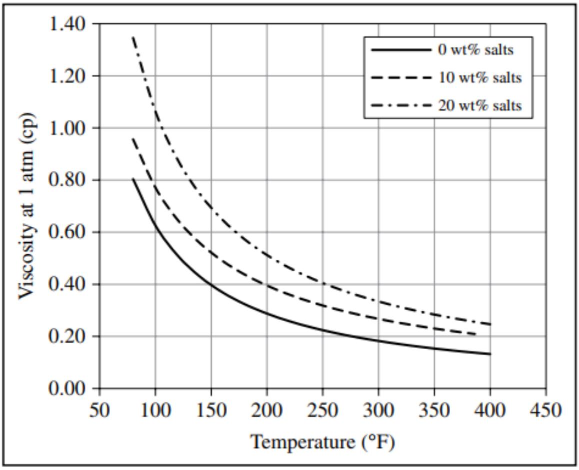


Figure 1.4. Effect of temperature and dissolved salts on viscosity of water at 14.7 psi (1 atm).

Viscosity of water increases by about 50% from 14.7psi (1atm) to 8000psi. The effect of pressure on water viscosity can be estimated using the following correlation with pressure in units of psi:

$$\frac{\mu_w}{\mu_{w,latm}} = 1{,}0 = 0{,}00004P + 3{,}1 \cdot 10^{-9}P^2$$

2. PROPERTIES OF RESERVOIR ROCK

Porosity and permeability are fundamental rock properties. Porosity is a measure of the storage capacity of the rock and permeability is a measure of rock flow capacity. Storage capacity tells us how much resource can be contained in the rock, and flow capacity tells us how fast we can produce the resource.

2.1 Porosity

Consider a handful of sand that contains sand grains and space between grains. The volume of the sand is the sum of the volume of the sand grains plus the volume of space between grains. Figure 2.1 presents a sketch of a block of rock with grains of sand filling the block and an example of Berea sandstone from Berea, Ohio. The Berea sandstone image is a microscopic view of sandstone surface that has been expanded 25 times. Rock grains and the space between grains, called pore space, are visible in the image.

What is the difference between a handful of sand and a piece of sandstone? The handful of sand consists of loose grains of sand. By contrast, grains in the sandstone are cemented together by minerals that have precipitated from the mineral-rich water that has occupied the pore space over tens of thousands, perhaps millions, of years. Furthermore, sandstone is typically composed of a variety of grain sizes. Small grains can fill pore space between larger grains and reduce the porosity of sandstone. Some rocks have pore spaces that are not connected. Our interest here is confined to connected pores that contribute to commercial storage and flow capacity.

Bulk volume is the volume of the block shown in Figure 2.1. It includes both grain volume and the volume of space between grains in the block. The bulk volume *V*B of the block is the product of area *A* in the horizontal plane and gross thickness *H*:

$$V_B = AH \qquad (2.1)$$

The volume of space between grains is called pore volume. Porosity ϕ is the ratio of pore volume V_p to bulk volume V_B:

$$\phi = \frac{V_p}{V_B} \qquad (2.2)$$

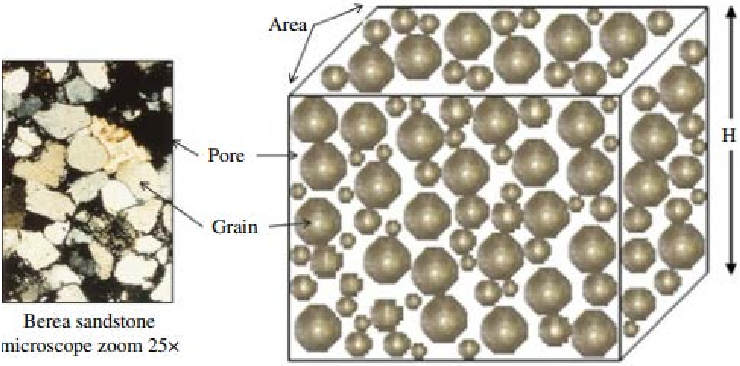


Figure 2.1. Porous medium

Consider another example. A beaker contains 500 ml of marbles. In terms of bulk volume, the marbles occupy a bulk volume of 500 ml. How much water must be added to bring the water level to the top of the marbles? If 200 ml must be added, then the pore volume is 200 ml and the porosity is 40%. What is the actual volume of the marbles? That volume, typically referred to as grain volume for rocks, would be 300 ml. In summary, bulk volume V_B is the sum of grain volume V_G and pore volume V_p:

$$V_B = V_G + V_P \tag{2.3}$$

Example 2.1

Core Porosity

A sandstone core sample is cleanly cut and carefully measured in a laboratory. The cylindrical core has a length of 3 in. and a diameter of 0.75 in. The core is dried and weighed. The dried core weighs 125g. The core is then saturated with freshwater. The water-saturated core weighs 127.95g. Determine the porosity of the sandstone core. Neglect the weight of air in the dried core and assume the density of water is 1g/cc.

2.2 Saturation

Pore spaces in reservoir rock are occupied by fluid phases, including oil, water, and gas phases. The fraction of the pore volume that is occupied by any phase is called the saturation of that phase. For example, S_o, S_w, and S_g are the saturations of oil, water, and gas phases, respectively. Saturation can be expressed as a percentage or as a fraction.

For a reservoir with oil, water, and gas phases, the sum of the saturations must satisfy the constraint

$$1 = S_o + S_w + S_g \tag{2.4}$$

since the sum of the pore space occupied by each phase must equal the total pore space. If just oil and water are present in a reservoir, then gas saturation $S_g = 0$ and

$$1 = S_o + S_w \tag{2.5}$$

Example 2.2 *Core Saturation*

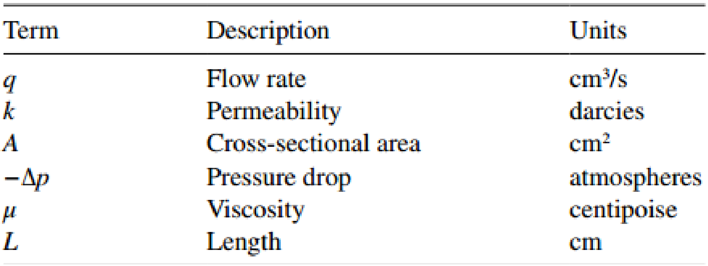
A sandstone core is completely saturated with 2.95ml water. Oil is injected into the core and 2.10ml of water is collected from the core. What are the oil and water saturations in the core?

2.3 Permeability

The concept of permeability was developed by Henry Darcy in the early 1800s while studying the flow of water through sand filters for water purification. Darcy found that flow rate is proportional to the pressure change between the inlet and outlet of the porous medium. Darcy's relationship between flow rate and pressure change, now known as Darcy's law, states that flow rate q of a fluid of viscosity μ is related to pressure drop ΔP by the equation:

$$q = -\frac{kA}{\mu L}\Delta P \tag{2.6}$$

where the terms of the physical system are defined in Figure 2.2. As defined by Darcy, the terms in Equation 2.6 have the following units:



Term	Description	Units
q	Flow rate	cm^3/s
k	Permeability	darcies
A	Cross-sectional area	cm^2
$-\Delta p$	Pressure drop	atmospheres
μ	Viscosity	centipoise
L	Length	cm

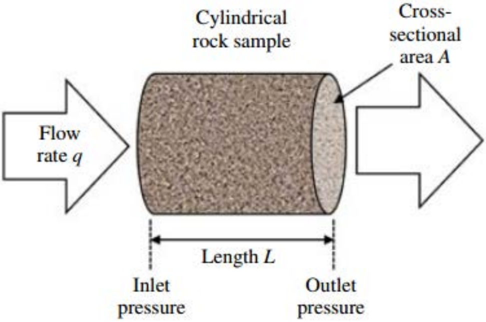
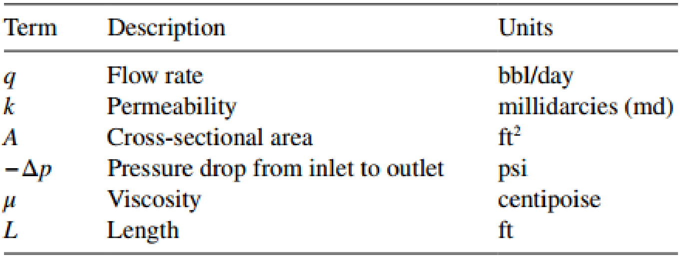


Figure 2.2 - Definition of terms for Darcy’s law

Permeability units are called darcies. Most conventional reservoir applications with sandstone and limestone use millidarcies (md) where 1darcy= 1000md. In oil field units, Equation 2.6 has the form:

$$q = -0{,}001127\frac{kA}{\mu L}\Delta P \qquad (2.7)$$

where the constant 0.001127 is the appropriate conversion factor and the units for Equation 2.7 are the following:



Term	Description	Units
q	Flow rate	bbl/day
k	Permeability	millidarcies (md)
A	Cross-sectional area	ft^2
$-\Delta p$	Pressure drop from inlet to outlet	psi
μ	Viscosity	centipoise
L	Length	ft

Permeability is qualitatively proportional to the average cross-sectional area of pores in a porous material, and its dimensions are those of area. For example, 1 darcy= 9 87×10^{-13} m^2. Coarse-grain sandstone might have a permeability of 500 md, while fine-grain sandstone might have a permeability of just a few millidarcies.

Example 2.3 *Flow Rate From Darcy’s Law*

Assume the permeability of a cylindrical rock sample (often called a core) is 150 md, the length of the core is 6 in., the diameter of *the core is 1 in., the pressure drop across the core is 20 psi, and the viscosity of brine passing through the core is 1.03 cp. Use Darcy’s law to calculate the magnitude of volumetric flow rate in bbl/day.*

3. PETROLEUM GEOLOGY

The ability to manage subsurface resources depends in part on our knowledge of the formation and evolution of the Earth. We describe the geologic history and structure of the Earth and then present concepts from petroleum geology.

3.1 Volumetric Analysis, Recovery Factor, EUR

Different calculation procedures and data sources can be used to estimate reservoir fluid volumes. Geologists determine volume using static information in a procedure called volumetric analysis. Static information is information that does not change significantly between the time the reservoir is discovered and the time production begins in the reservoir. Static information includes reservoir volume and the original saturation and pressure distributions. By contrast, engineers use dynamic information to estimate reservoir fluid volumes. Dynamic information is information that changes with respect to time such as pressure changes and fluid production. Material balance is an engineering procedure for estimating original fluid volumes from dynamic data. Reservoir fluid volume estimates obtained from different procedures and sources of data provide a means of assessing the quality of information used by different disciplines. Calculated original fluid volumes can be combined with a recovery factor (RF) to calculate estimated ultimate recovery (EUR) for a given economic limit.

In this section, we present the equations for volumetric estimates of original oil and gas in place and then define RF and EUR

Volumetric Oil in Place

The volume of original hydrocarbon in place (OHIP) in an oil reservoir is original oil in place (OOIP). It is calculated using the expression:

$$N = \frac{7758\phi A h_0 S_{oi}}{B_{oi}} \tag{3.1}$$

where 7758 is a unit conversion factor, N is OOIP (STB), ϕ is reservoir porosity (fraction), A is reservoir area (acres), h o is net thickness of oil zone (feet), S_{oi} is initial reservoir oil saturation (fraction), and B_{oi} is initial oil formation volume factor (RB/STB). Initial oil formation volume factor is the volume of oil at reservoir conditions divided by the volume of oil at stock tank conditions. Associated gas, or gas in solution, is the product of solution gas–oil ratio R_{so} and N.

Example 3.1 *Oil in Place*

An oil reservoir has average porosity= 0.15 in an area of 6400 acres with a net thickness of 100 ft, initial oil saturation of 75%, and initial oil formation volume factor of 1.3 RB/STB. Use the volumetric OIP equation to estimate OOIP.

Volumetric Gas in Place

OHIP for a gas reservoir is original free gas in place:

$$N = \frac{7758\phi A h_g S_{gi}}{B_{gi}} \tag{3.2}$$

where 7758 is a unit conversion factor, G is original gas in place (SCF), ϕ is reservoir porosity (fraction), A is reservoir area (acres), h_g is net thickness of gas zone (ft), S_g is initial reservoir gas saturation (fraction), and B_{gi} is initial gas formation volume factor (RB/SCF). Initial gas formation volume factor is the volume of gas at reservoir conditions divided by the volume of gas at standard conditions. Equation 3.2 is often expressed in terms of initial water saturation S_{wi} by writing $S_{gi} = -1\ S_{wi}$. Initial water saturation can be determined from well log or core analysis.

Example 3.2 *Gas in Place*

A well is draining a gas–water reservoir. The drainage area of the well is 160 acres and has a net thickness of 20ft. Initial properties are 15% porosity, 70% gas saturation, and gas FVF of 0.0016 RB/SCF. What was the original gas in place in the drainage area?

Recovery Factor and Estimated Ultimate Recovery

RF is the fraction of OHIP that can be produced from a reservoir. EUR is calculated from RF and OHIP as:

$$\mathrm{EUR}=\mathrm{OHIP}\cdot\mathrm{RF}=\frac{GRV\cdot\overline{\phi\cdot\mathrm{NTG}\cdot\overline{S_{hi}}}}{B_{hi}}\cdot\mathrm{RF} \tag{3.3}$$

where EUR is estimated ultimate recovery (standard conditions);
OHIP is original hydrocarbon in place (standard conditions);
RF is recovery factor (fraction) to economic limit;
GRV is gross rock volume (reservoir conditions);

φ is average porosity in net pay (reservoir conditions);
NTG is net-to-gross ratio (reservoir conditions);
S_{hi} is initial average hydrocarbon saturation in net pay (reservoir conditions);
B_{hi} is initial hydrocarbon formation volume factor in a consistent set of units.

Formation volume factor is the ratio of reservoir volume to surface volume. The product GRV·N·φ·TG is reservoir pore volume. The volume of fluid produced from a reservoir is the product of RF and original fluid in place. For example, a 30% oil RF means that 30% of the OOIP can be produced. It also implies that 70% of OOIP will remain in the reservoir. EUR is the volume of fluid produced at a specified economic limit.

Example 3.3

Suppose a reservoir is 3mi long by 6 mi wide and has an average gross thickness of 40 ft, a net-to-gross ratio of 0.7, and a porosity of 0.18. Well logs show an average water saturation of 0.30. An oil sample has a formation volume factor of 1.4 RB/STB. We can calculate original oil in place (in STB) using the following procedure.

***1.** What is the bulk volume of the reservoir (in RB)?*

***2.** Calculate the pore volume of pay in the reservoir (in RB) if porosity is 0.18 and net-to-gross ratio is 0.7.*

***3.** If the reservoir has an oil saturation of 0.7, what is the volume of oil in the reservoir (in RB)?*

***4.** Calculate original oil in place (in STB).*

Example 3.4

An oil reservoir has average porosity = 0.23 in an area of 3200 acres with a net thickness of 80 ft, an initial oil saturation of 70%, and an initial oil formation volume factor of 1.4 RB/STB. Use the volumetric OIP equation to estimate OOIP.

Example 3.5

***1**. A reservoir is 3 mi wide and 5mi long. What is the area of the reservoir in acres? **2.** The reservoir has a net thickness of 50ft and 10% porosity. The initial gas saturation is 70% with a gas formation volume factor of 0.005 RB/SCF. What is the gas in place in SCF?*

4. DRILLING

Reservoir fluids are accessed by drilling a well and then preparing the well for the production or injection of fluids. In this chapter, we discuss drilling rights and related issues, describe rotary drilling rigs and the basics of the drilling process, and survey different types of wells.

After the location is fully prepared, the drilling rig, associated equipment, housing, and materials are moved onto the location and "rigged up," or MIRU for move in and rig up. For remote areas, this move (or mobilization) may be 5–10% of the total well cost.

The first task for the drilling rig is to drill to the depth required for the surface casing, usually 500–2000 ft as specified by the agency that permitted the well. The surface casing has two functions: first, it protects water in aquifers near the surface from contamination; second, it provides mechanical support for the well. The drilling fluid for the surface hole is typically freshwater. When the required depth is reached, the surface casing is lowered into place and cemented by pumping cement down the casing and up the annulus between the casing and the surrounding formations to the surface. The last step in cementing is to push a cement plug with drilling fluid down the casing until it reaches the bottom of the casing.

After the cement has cured, a casing head is attached to the top of the surface casing, and the BOP is attached to the top of the casing head. The BOP is used to shut the well in emergencies.

To continue drilling, the drilling crew feeds the BHA and drill pipe through the top of the BOP and into the surface casing, tripping down to the top of the cement plug. The bit on the BHA must be small enough to enter the surface casing. After starting circulation of drilling mud, the crew can drill through the plug and cement and past the bottom of the surface casing.

For many wells, the next drilling objective is the depth of the target formation. While drilling to this depth, the crew will adjust the composition of the mud as needed to clean the hole and maintain pressure control. Throughout the drilling process, a company employee submits daily reports to management of drilling activities and costs. In some cases, the drilling plan may need adjustment if an unanticipated event occurs.

At some point after setting surface casing, a separate contractor arrives on location to create a continuous tabular record, or log, of the drilling process and results for a well. This contractor is the mud logging company and its employee on location is a mud logger, usually a geologist. The mud logger installs hardware and software to monitor operations as requested by the production company. The hardware usually includes computer displays of the log in the doghouse on the drilling rig, in the office of the company employee, and in the mud logger's workspace.

The mud log consists of four to six columns of information. In the first column of the table, the ROP of the bit is recorded, typically in minutes per foot. Other operating parameters (such as rotation rate, WOB, pumping rate, mud weight and viscosity, and mud composition) are included as notes in this column. In a second column, lithology (sandstone, shale, limestone, etc.) of cuttings are recorded by the on-site geologist at 10 ft intervals. The geologist also enters detailed descriptions of cuttings collected at the shale shaker in another column. This column includes notes on oil or gas shows. Composition of hydrocarbon gas that evolves from the mud is continually recorded in the last column. The organization and extent of the mud log varies from company to company. As the first source of data from the subsurface formations, the mud log is vital for drilling management, hydrocarbon exploration, and completion designs.

When drilling reaches the target depth, the drilling crew circulates mud until the hole is clean and then trips the drill pipe out of the hole. The well is ready now for the next stage of the drilling process.

Example 4.1 *Drill String*

How many stands of drill pipe are needed to prepare a drill string that is 10000ft long? A stand is three pipes, and each pipe has a length of 30ft. Assume one stand of drill collar and neglect elongation of pipe.

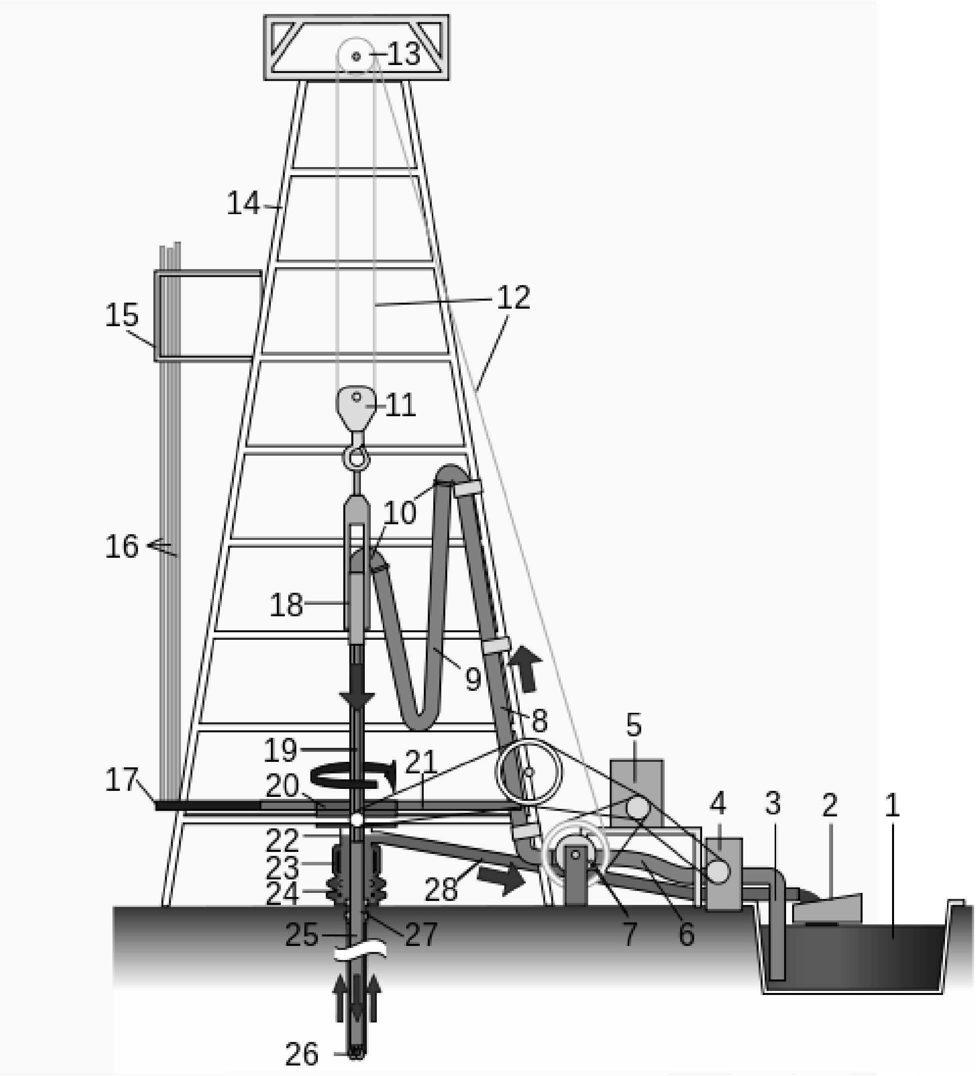


Figure 4.1. Simple diagram of a drilling rig and its basic operation

1. Mud tank
2. Shale shakers
3. Suction line (mud pump)
4. Mud pump
5. Motor or power source
6. Hose
7. Draw-works
8. Standpipe
9. Kelly hose
10 Goose-neck
11. Traveling block
12. Drill line
13. Crown block
14. Derrick
15. Racking Board (Sometimes referred to as the Monkey Board)
16. Stand (of drill pipe)
17. Setback (floor)
18. Swivel (On newer rigs this may be replaced by a top drive)
19. Kelly drive
20. Rotary table
21. Drill floor
22. Bell nipple
23. Blowout preventer (BOP) Annular type
24. Blowout preventer (BOP) Pipe ram & blind ram
25. Drill string
26. Drill bit
27. Casing head or Wellhead
28. Flow line

5. OIL FIELD DEVELOPMENT

5.1 Calculation of Oil Field Development Duration

The oil recovery factor is determined by the ratio of the balance (recoverable) oil reserves to the initial oil reserves and shows the amount of oil that can be extracted from the earth under the existing operating methods. The final oil recovery factor is the ratio of extracted oil reserves (the extracted amount of oil for the whole period of development) to the balance reserves. Since water flooding is essential in development of oil reservoirs, finding ways to increase its efficiency is a priority task. This can be achieved by optimizing the process of flooding. But in order to successfully solve this complex problem, a detailed study of the various geological factors influence on the oil field development efficiency is required.

Also, the increase of the oil recovery during flooding is successfully solved by applying methods of physic-chemical effects on reservoirs. Among the main natural factors are: the heterogeneity of the reservoirs, the relationship between the viscosities of oil and pushing fluid in reservoir conditions, the structural and mechanical properties of oil, the wettability of the rock by the saturating liquids, the structure of the pore volume, etc. The latter parameters characterize the magnitude of capillary pressure and relative permeability. Such parameters of oil fields development as density of the well grid and the rate of oil displacement in the reservoir, can vary within rather wide limits.

The reserves of extracted oil at each stage of development can be calculated with the following formula:

$$V_n = \pi(R_n^2 - R_{n-1}^2) \cdot h \cdot m,\ m^3 \tag{5.1}$$

R – radius of oil-bearing contour or operational range, m;
h – formation thickness, m;
m – formation porosity.

Number of wells in each row:

$$n_n = 2\pi R_n / 2\sigma,\ \text{pcs} \tag{5.2}$$

σ– half the distance between the wells in rows.

Total flow rate of all wells in the development stages:

- first stage:

$$Q_{p1}=q(n_1+n_2+n_3+1),\ m^3/\text{day} \qquad (5.3)$$

- second stage:

$$Q_{p2}=q(n_2+n_3+1),\ m^3/\text{day} \qquad (5.4)$$

- third stage:

$$Q_{p3}=q(n_3+1),\ m^3/\text{day} \qquad (5.5)$$

Duration of the development stages:

$$t_n=V_n/Q_{pn},\ \text{days} \qquad (5.6)$$

The oil recovery factor (ORF) at the moment depending on the water saturation of rock is found by the formula:

$$\text{ORF} = \frac{\text{CWS - IWS}}{\text{100 - IWS}}, \qquad (5.7)$$

where IWS – initial water saturation, %;
CWS – current water saturation, %.

Example 5.1.

Determine the development duration of a circular oil reservoir with the following data: the radius of the oil reservoir initial contour R_c*, radius of the development rows:* $R_1 = 0,8 \cdot R_c$*,* $R_2 = 0,6 \cdot R_c$*,* $R_3 = 0,45 \cdot R_c$*. Oil well with the radius of* $r_w = 0,0075$ *m is situated in the center of the formation. Distance between the wells in the rows* $2\delta = 300$ *m, formation thickness h. Formation porosity m. Each well is operating with the flow rate q. All rows work simultaneously.*

Example 5.2.

Parameters of the oil reservoir with a water-pressure regime are determined as a result of the core samples investigation and geophysical methods. It was found that the amount of water in the initial period of operation is equal to IWS. During the operation of the deposit, the water saturation began to increase. In six years it was equal to $CWS_6 = 4 \cdot IWS$*, in nine years –* $CWS_9 = 6 \cdot IWS$*. It is required to find* ORF_6 *and* ORF_9*.*

Table 5.1

Baseline data for calculations

Variant	R_c, *m*	*q*, m^3/day	*h, m*	*m*, %	IWS, %
1	3000	109	10	18	12
2	3100	130	11	19	13
3	2800	129	12	20	14
4	2900	127	13	21	15
5	2700	105	14	22	16
6	2600	119	15	17	3
7	2500	110	16	16	4
8	2400	112	10	20	5
9	2300	119	11	21	6
10	3000	117	12	18	7
11	3100	122	13	19	8
12	2800	124	14	20	9
13	2900	118	15	21	10
14	2700	116	16	22	11
15	2600	125	10	17	12
16	3000	118	11	16	13
17	3100	126	12	17	14
18	2800	124	13	18	15
19	2900	123	14	19	16
20	2700	121	15	24	10

6. OIL EXTRACTING

6.1 Calculation of the Permissible Tubing Running Depth

Production tubing - the pipe in a production well through which oil or gas flows from the reservoir to the surface, also known as the production string. They are designed for the production of liquid and gas, their injection into the well, suspension of pumping and process equipment, repair works. According to the design, production tubing can be smooth (unequal in strength) and with upset ends (equal in strength) (Figure 2.1). Pipes with smooth ends have a constant diameter along the length, and therefore they are weakened at the thread cutting site. Pipes with upset ends have thickened ends with threaded threads, so it does not reduction the strength of the pipe.

Axial tensile forces acting on the tubing can cause the string burst and violate the coupling. The greatest effort is experienced by the pipe at the wellhead. It can be determined by the following formula:

$$P=P_1+P_2+P_3+P_4 \tag{6.1}$$

P_1 – weight of pipes, N;

P_2, P_3, P_4 – weight of liquid, pumping rods (for deep-pumping pipes) and suspended equipment on pipes respectively, N.

Smooth pipes are unequal in strength, because the strength in the chopped part is 80-85% of the strength of the plain section. Pipes with upset ends have a thickening at the ends of the pipe. These tubes have the same strength in the body and threaded part, and therefore they are usually called "equal in strength"

For a one-size combination tubing string, the maximum depth of descent can be found by the following formula:

$$l = \frac{P}{K \cdot q_{pip}} \tag{6.2}$$

P – ultimate joint strength for unequal in strength pipes, or a load corresponding to the yield strength for the pipes of equal strength, N;

K – factor of safety (1,3...1,5);

q_{pip} – weight of 1 meter of pipe, N.

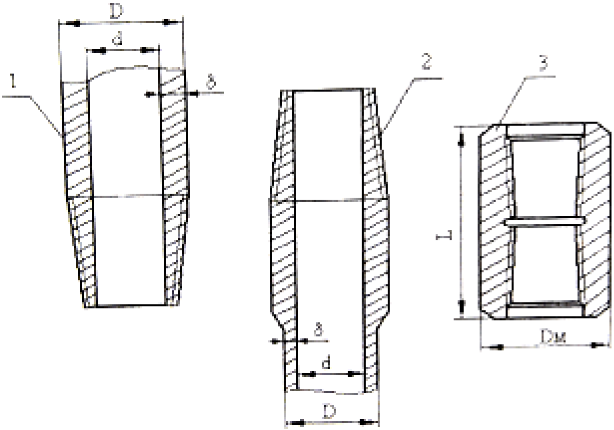


Figure 6.1.- Production tubing:
1 – unequal in strength; 2 – equal in strength; 3 – coupling;
D – outer diameter of production tubing; d – inner diameter of PT; δ – wall thickness; DM – coupling diameter; L – coupling length.

For two-size combination tubing string the length of the lower and upper sections are found by the following formula, m:

$$l = \frac{P_1}{K \cdot q_{pip}} \tag{6.3}$$

$$l = \frac{P_2}{K \cdot q_{pip}} \tag{6.4}$$

Calculation of the tubing string with upset ends is carried out along the pipe body, proceeding from the extension from its own weight:

$$P = F \cdot \sigma_{тек} \tag{6.5}$$

F – cross sectional area of pipe, m^2;
$\sigma_{тек}$ – yield strength of pipe material, Pa.

For the deep-pumping operating method, the allowable depth of descent of the production tubing will be:

$$l = \frac{P}{K \cdot (q_{pip} + q_{str} + q_l)} \tag{6.6}$$

q_{str} – weight of 1 meter of string, N (tabular data);
q_l – weight of 1 meter of liquid column, N.

Weight of 1 meter of liquid column:

$$q_l = \frac{\pi}{4} \cdot \left(d_{PT}^2 - d_{TS}^2\right) \cdot \rho_{liq} \cdot q, \qquad (6.7)$$

d_{PT} – inner diameter of production tubing, m;
d_{TS} – outer diameter of tubing string, m;
ρ_{liq} – fluid density, kg/ m^3 .

Pipe section area is given by the expression 6.8:

$$q_l = \frac{\pi}{4} \cdot \left(d_o^2 - d_i^2\right), \qquad (6.8)$$

d_o, d_i – outer diameter and inner diameter of production tubing respectively, m.

Example 6.1

Find the maximum permissible depth of descent of a two-size combination tubing based on the tensile strength condition. The initial data are given in Table 6.1. Additional data for this problem are given in Tables 6.2 and 6.3.

Table 6.1

The initial data

Variant	Oil density, kg/ m^3	Water density, kg/ m^3	Diameter of steps, d_1/d_2, mm	Steel grade
1	850	1050	73/60	D
2	870	1075	89/60	D
3	876	1110	89/73	D
4	860	ИЗО	73/60	К
5	833	1115	89/60	К
6	840	1122	89/73	К
7	845	1111	73/60	E
8	870	1127	89/60	E
9	885	1008	89/73	E
10	881	1116	73/60	L
11	867	1122	89/60	L
12	853	1090	89/73	L
13	829	1125	102/60	D
14	847	1158	102/73	К
15	884	1114	102/89	E

Continuation table 6.1

Variant	Oil density, kg/ m^3	Water density, kg/ m^3	Diameter of steps, d_1/d_2, mm	Steel grade
16	856	1147	73/60	E
17	873	1072	89/60	E
18	859	1134	89/73	L
19	862	1029	73/60	L
20	864	1196	89/60	L

Table 6.2

Additional data for task 6.1

Nominal diameter, (d_n), mm	inner diameter (d_i), mm	outer diameter, (d_o), mm	weight of 1 meter of pipe (q_p), H
60	50,3	60,3	68,4
73	62,0	73,0	91,6
89	76,0	88,9	132,2
102	88,6	101,6	152,2

Table 6.3

Additional data for task 6.1

Steel grade	Yield strength of pipe material (σ), MPa
D	380
K	500
E	550
L	650

Example 6.2

According to the task 1 find the maximum permissible depth of descent of a one-size combination tubing. Values of the ultimate joint strength are presented in Table 6.4 below.

Table 6.4

Initial data for example 6.2

Nominal diameter, (d_n), mm	Ultimate joint strength to the threaded connection of unequal in strength pipes, kN			
	D	K	E	L
60,0	208,0	274,0	301,5	356,0
73,0	294,0	387,0	426,0	505,0
89,0	446,0	585,0	645,0	762,5
102	459	608,0	664,0	785,0

6.2 Determination of Rod Column Weight

To drive the plunger of a downhole rod pump, rods of 6 - 9 m in length, 16, 19 and 22 mm in diameter are used. The rods have a thread and a part with a square cross-section for grasping with special keys when screwing and unscrewing. The rods are connected with special couplings (Figure 7.1). When assembling the stepped rod string, couplings are used, which allow connecting the rods with a diameter of 16 and 19, 19 and 22, 22 and 25 mm. Rods have to work under alternating loads, with considerable frictional forces, vibration; they carry a load from the weight of the liquid column and the load from its own weight. Depending on operating conditions, rods with different strength characteristics are used. For the manufacture of rods 40 grade steel is used, alloyed with chromium, nickel and molybdenum, followed by heat treatment and subsequent surface hardening by high-frequency currents.

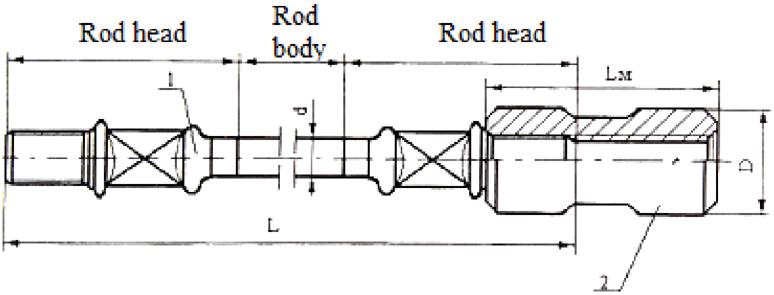


Figure. 6.2 - Pump rod and junction coupling:
1– pump rod; 2 –junction coupling; *L*–length of the rod; L_c–length of the coupling; *d*–diameter of the rod; *D*–diameter of the coupling

Weight of the rod column in the air is calculated by the formula:

$$P_{rod}=q\cdot H,\ n \qquad (6.9)$$

where *q*–weight of the 1 m rod in the air, N/m; *H* – length of the rod column, m.

Weight of the rod column in the fluid:

$$P'_{rod}=P_{rod}\cdot K_{arch},\ n \qquad (6.10)$$

where K_{arch}–coefficient, denoting loss of rod weight in the fluid:

$$K_{arch}=\frac{\rho_{rod}\cdot\rho_f}{\rho_{rod}\cdot} \qquad (6.11)$$

where ρ_{rod}–density of rod material, *kg/m*^{3}; ρ_f–density of fluid, *kg/m*^{3}.

The water content in the wellbore product can be determined by the formula:

$$\beta = \frac{Q_w}{Q_{oil}+Q_w} \tag{6.12}$$

where Q_{OIL}, Q_W– flow rate of water and oil in the well respectively, m^3/day.

Example 6.3.

Determine the weight of the rod column in the fluid at given conditions.

Table 6.5

Baseline data for calculations

Variant	Oil flow rate *m*^{3}*/day*	Water flow rate *m*^{3}*/day*	Rod diameter, mm	Density of oil, *kg/m*^{3}	Density of water, *kg/m*^{3}	Rod length, *m*
1	20	10	16	870	1120	700
2	25	15	19	885	1060	820
3	35	18	22	881	1078	980
4	40	42	25	867	1115	1020
5	120	80	16	853	1046	1300
6	150	75	19	829	1119	1350
7	220	105	22	847	1125	1430
8	300	58	25	884	1122	1500
9	285	90	16	865	1010	1560
10	178	150	19	870	1086	1250
11	75	56	25	830	1120	900
12	90	78	16	847	1110	850
13	140	135	19	835	1040	1380
14	115	74	22	857	1050	1450
15	125	53	16	862	1100	1350
16	140	110	19	871	1040	1390
17	86	75	22	853	1070	1470
18	97	25	25	892	1080	1320
19	108	86	16	887	1060	920

Density of rod material is 7850 kg/m^3.

7. ENHANCED OIL RECOVERY

7.1 Determination of the Parameters in Formation Pressure Maintenance System

The effect of the reservoir inhomogeneity on the sweep factor depends on the ratio magnitude of the mobility of water and oil:

$$M_0 = \frac{k_w}{\mu_w} \cdot \frac{\mu_w}{k_{oil}} \tag{7.1}$$

where M_0 – coefficient of mobility;
k_w and k_{oil} – water and oil relative perm abilities.

For small values of the mobility factor, the effect of inhomogeneity is manifested more for sharply inhomogeneous reservoirs (with a standard deviation of more than 1.5 for the log-normal law of permeability distribution). If, on the other hand, the coefficient of mobility $M_0 > 30$, then sweep efficiency depends to a greater extent on the degree of inhomogeneity at small values of the standard deviation. The noted feature of the relationship between reservoir heterogeneity and mobility coefficient should be taken into account when selecting objects for application of enhanced oil recovery methods. With a typical effect, for example, water pumped into the reservoir, thickened with polymers, compensates not only mobilities, but also heterogeneity as a result of adsorption of the polymer in a porous medium, which leads to a favorable redistribution of flows in the formation and an increase in oil recovery.

Time of water breakthrough to the production well is determined by the formula:

$$t = \frac{4 \cdot \sigma^2 m_1 h}{\pi (q_w \cdot q_{oil})} \cdot \ln \frac{q_w}{q_{oil}}, \text{ days} \tag{7.2}$$

where m_1 – efficient porosity considering coefficient of pore volume φ,

$$m_1 = m \cdot \varphi,$$

q_w – flow rate of water injection well, m^3/day;
q_{oil} – flow rate of oil well, $\mathrm{m^3/day}$.

For this period square of flooded area will be:

$$S = \frac{q_{oil} \cdot t}{m_1 h}, m^2 \tag{7.3}$$

Velocities of the water-oil contact, moving to the oil well in vertical C_v and horizontal C_g directions, as well as along the formation course C_c are determined by the following formulas:

$$C_v = \frac{p_1 \cdot p_2}{t(\rho_w \cdot \rho_{oil}) \cdot g}, m/s \qquad (7.4)$$

$$C_g = \frac{p_1 \cdot p_2 \cdot \mathrm{ctg}\alpha}{t(\rho_w \cdot \rho_{oil}) \cdot g}, m/s \qquad (7.5)$$

$$C_c = \frac{p_1 \cdot p_2}{t(\rho_w \cdot \rho_{oil}) \cdot g \cdot \sin\alpha}, m/s \qquad (7.6)$$

where α – formation angle dip, degrees;
t - time of water breakthrough to the production well, days.

Example 7.1. *Flow rate of water injection well in the system of formation pressure maintenance is* q_w*. Flow rate of nearest oil well is* q_{oil}*, formation thickness h, Formation porosity m. Distance between the wells in the rows 2δ = 500 m, φ = 0,5. It is required to determine time of water breakthrough to the production well and square of flooded area.*

Example 7.2. *Oil formation is exploited at water drive regime with no free gas in lifting column. Density of formation oil-* ρ_{oil}*, water - 1000 kg/*m^3*. Shut-in tubing pressure (Q = 0) -* p_1*. Formation angle dip- α.*

It is required to find velocities of the water-oil contact, moving to the oil well in vertical and horizontal directions, as well as along the formation course, noting that after t days shut-in tubing pressure lowered to $p_2 = 0{,}6 \cdot p_1$*.*

Table 7.1

Baseline data for calculations

Variant	q_{oil}, m^3/day	q_w, m^3/day	h, m	m, %	ρ_{oil}, kg/m^3	α	p_1, MPa
1	109	1000	10	18	760	20	2,5
2	130	1100	11	19	780	18	2,4
3	129	1120	12	20	820	19	2,3
4	127	980	13	21	860	20	1,9
5	105	990	14	22	880	18	2,1
6	119	1000	15	17	900	19	2,2
7	110	1100	16	16	920	20	2,5
8	112	1120	10	20	940	18	2,4
9	119	980	11	21	960	19	2,3
10	117	990	12	18	800	20	1,9
11	122	1000	13	19	830	18	2,1
12	124	1100	14	20	850	19	2,2
13	118	1120	15	21	870	20	2,5
14	116	980	16	22	890	18	2,4
15	125	990	10	17	910	19	2,3
16	118	1000	11	16	930	20	1,9
17	126	1100	12	17	950	18	2,1
18	124	1120	13	18	970	19	2,2
19	123	980	14	19	810	20	2,5
20	121	990	15	24	790	18	2,4

8. TRANSPORTATION

8.1 Calculation of Friction Losses in the Pipeline

Inner diameter of the pipeline can be calculated by the formula

$$d=D_n-2\delta \tag{8.1}$$

D_o, δ_o -outdoor nominal diameter and wall thickness.

Flow rate and the mean velocity of oil in pipeline determined by the Expression:

$$Q=\frac{Q_ч}{3600} \tag{8.2}$$

$$v=\frac{4Q}{\pi d^2} \tag{8.3}$$

Head losses due to friction in the pipe is determined by the Darcy-Weisbach’s formula

$$h=\lambda\frac{L}{d}\frac{v^2}{2g} \tag{8.4}$$

λ - coefficient of hydraulic resistance; L - length of the pipeline.

Flow regime in a pipe characterized by a Reynolds number

$$\mathrm{Re}=\frac{vd}{\nu}=\frac{4Q}{\pi d\nu} \tag{8.5}$$

ν - kinematic viscosity of oil calculated in m^2/s.

In laminar flow conditions. i.e. when Re <2320 flow resistance coefficient determined by the Stokes formula

$$\lambda=64/\mathrm{Re} \tag{8.6}$$

In turbulent flow conditions are three friction zones: hydraulically smooth pipes (λ depends only on Re), mixed friction (λ depends Re and the relative roughness of the pipe ε), quadratic friction (λ depends only on ε). The boundaries of these zones are transition Reynolds number based on the results of experiments:

$$\mathrm{Re_I} = \frac{17,5}{\varepsilon};\ \ \mathrm{Re_{II}} = \frac{531}{\varepsilon} \tag{8.7}$$

$\varepsilon = K_{\text{ý}} / d$ - relative roughness of the pipe that is determined from equivalent roughness K (Table 9.3) and diameter in mm.

Table 8.1

Equivalent roughness pipes (A.D.Altshul' data)

Type of pipe	Condition of the pipe	K, mm
Seamless steel	New clean	$\frac{0,01 - 0,02}{0,014}$
Welded steel	After several years of operation	$\frac{0,15 - 0,3}{0,2}$
Welded steel	New clean	$\frac{0,03 - 0,12}{0,5}$
Welded steel	With minor corrosion after purification	$\frac{0,1 - 0,2}{0,15}$
Welded steel	Moderately rusty	$\frac{0,3 - 0,7}{0,5}$
Welded steel	Old rusty	$\frac{0,8 - 1,5}{1}$
Welded steel	Strongly rusty or with large deposits	$\frac{2 - 4}{3}$

Note. The denominator shows the average value of the equivalent roughness.

Conditions for the existence of different friction zones:

- a hydraulically smooth tubes $2320 < \mathrm{Re} \le \mathrm{Re_I}$;

- area of mixed friction (transition zone) $\mathrm{Re_I} < \mathrm{Re} < \mathrm{Re_{II}}$;

- quadratic friction zone $\mathrm{Re} \ge \mathrm{Re_{II}}$.

Flow resistance coefficient in hydraulically smooth pipe zone is determined by the Blasius formula

$$\lambda = 0,3164 / \mathrm{Re}^{0,25} \tag{8.8}$$

For mixed friction coefficient zones recommended to calculate with the Altshul's formula

$$\lambda = 0{,}11\left(\varepsilon + \frac{68}{\mathrm{Re}}\right)^{0{,}25} \qquad (8.9)$$

The value of the coefficient in quadratic friction zone is recommended to determine with the Shifrinson's formula:

$$\lambda = 0{,}11\varepsilon^{0{,}25} \qquad (8.10)$$

Formula (8.4) can be represented in generalized form (Leibenson's formula):

$$h = \beta\frac{Q^{2-m}\nu^{m}L}{d^{5-m}} \qquad (8.11)$$

β. m – coefficients,

$$\beta = \left(\frac{4}{\pi}\right)^{2-m}\frac{A_1}{2g} \qquad (8.12)$$

Table 8.2

The values of the coefficients in Leibenson's formula

Flow regime	***m***	***A_1***	**β. s^2 / m**
Laminar	1	64	4.15
Turbulent:			
Blasius zone	0.25	0.3164	0.0246
Mixed friction zone	0.1	0.206ε0.15	0.0166ε0.15
Quadratic friction zone	0	λ	0.0827λ

Example 8.1

Find head losses in pipeline $D_н$ = 530 mm, $\delta_н$ = 9 mm, Q = 8 million tons / year, the optimal path length of 425 km. The minimum temperature soil at a depth of laying the pipeline corresponds to the mean temperature of March and is 272 K. The kinematic viscosity of the oil at this temperature is equal to 99.7·10-6 m^2/s, density 878 kg/m^3.

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CONTENT