Oil Recovery Methods

Oil recovery methods are illustrated in Table (1) below. Primary recovery, production depends on the natural energy of the reservoir itself. Secondary recovery, when natural drive energy is depleted or too small for economic oil recovery, energy must be added to the reservoir to permit additional oil recovery. That additional energy is usually in the form of injected water or gas. Tertiary recovery, when secondary recovery is no longer economic, supplemental energy of a different kind permits additional oil recovery. Enhanced fluid flow conditions within the reservoir are usually induced by addition of heat, chemical interaction between the injected fluid and the reservoir oil, mass transfer, and/or changing of oil properties in such a way that the process facilitates oil movement through the reservoir. Tertiary recovery processes generally include thermal, chemical, gas miscible and microbial. They are also often referred to as enhanced oil recovery (EOR) processes.

Improved oil recovery (IOR) refers to any practice used to increase oil recovery. This can include EOR and secondary recovery processes such as water flooding and gas pressure maintenance, as well as practices to increase sweep such as

drilling, horizontal wells and polymers for mobility control or improved conformance.

Table 1 Summary of Reservoir Types

	Type A single phase gas	Type B gas condensate	Type C under-saturated oil	Type D saturated oil
Typical primary recovery mechanism	Volumetric gas drive	Volumetric gas drive	Depletion drive, water drive	Volumetric gas drive, depletion drive, water drive
Initial reservoir conditions	Single phase: Gas	Single phase: Gas	Single phase: Oil	Two phase: Oil and gas
Reservoir behavior as pressure declines	Reservoir fluid remains as gas.	Liquid condenses in the reservoir.	Gas vaporizes in reservoir.	Saturated oil releases additional gas.
Produced hydrocarbons	Primarily gas	Gas and condensate	Oil and gas	Oil and gas

Table 2 oil recovery methods.

<table>
<tr><td colspan="3" rowspan="2">Primary Recovery
(oil recovery less than 30%)</td><td>Natural flow</td><td>- Rock and liquid expansion drive.
- Depletion drive.
- Gas-cap drive.
- Water drive.
- Gravity drainage drive.
- Combination drive.</td></tr>
<tr><td>Artificial lift</td><td>- Pump
- Gas lift
- Other</td></tr>
<tr><td rowspan="5">Improved Oil Recovery - IOR</td><td colspan="2" rowspan="2">Secondary Oil Recovery
(oil recovery: 30-50%)</td><td>Water flood</td><td></td></tr>
<tr><td>Pressure Maintenance</td><td>Water/Gas Reinjection</td></tr>
<tr><td rowspan="3">Enhanced Oil Recovery - EOR</td><td rowspan="3">Tertiary Oil Recovery
(oil recovery more than 50% and up to 80%)</td><td>Thermal</td><td>- Combustion
- Steam soak/cyclic
- Huff-and-puff
- Steam drive/flood
- Hot water drive
- Electromagnetic</td></tr>
<tr><td>Gas miscible/ immiscible</td><td>- CO_2
- Nitrogen
- Flue gas
- Hydrocarbon</td></tr>
<tr><td>Chemical & other</td><td>- Alkaline
- Micellar-Polymer
- Microbial/foam</td></tr>
</table>

Reservoir Primary Recovery Mechanisms

The recovery of oil by any of the natural drive mechanisms is called primary recovery. The term refers to the production of hydrocarbons from a reservoir without the use of any process (such as fluid injection) to supplement the natural energy of the reservoir.

For a proper understanding of reservoir behavior and predicting future performance, it is necessary to have knowledge of the driving mechanisms that control the behavior of fluids within reservoirs. The overall performance of oil reservoirs is largely determined by the nature of the energy, i.e., driving mechanism, available for moving the oil to the wellbore. There are basically six driving mechanisms that provide the natural energy necessary for oil recovery:

- Rock and liquid expansion drive.
- Depletion drive.
- Gas-cap drive.
- Water drive.
- Gravity drainage drive.
- Combination drive.

Rock and Liquid Expansion

When an oil reservoir initially exists at a pressure higher than its bubble-point pressure, the reservoir is called an undersaturated-oil reservoir. At pressures above the bubble-point pressure, crude oil, connate- water, and rock are the only materials present. As the reservoir pressure declines, the rock and fluids expand due to their individual compressibilities. The reservoir rock compressibility is the result of two factors:

- Expansion of the individual rock grains.
- Formation compaction.

As the expansion of the fluids and reduction in the pore volume occur with decreasing reservoir pressure, the crude oil and water will be forced out of the pore space to the wellbore. Because liquids and rocks are only slightly compressible, the reservoir will experience a rapid pressure decline. The oil reservoir under this driving mechanism is characterized by a constant gas-oil ratio that is equal to the gas solubility at the bubble point pressure.

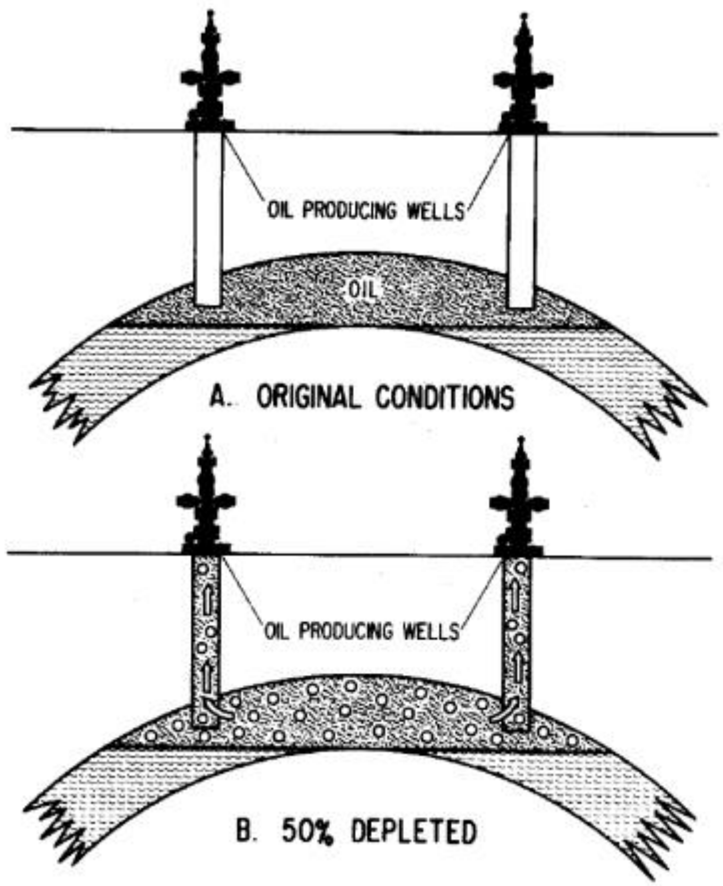
This driving mechanism is considered the least efficient driving force and usually results in the recovery of only a small percentage of the total oil-in-place.

The Depletion-Drive Mechanism

This driving form may also be referred to by the following various terms:

- Solution gas drive.
- Dissolved gas drive.
- Internal gas drive.

In this type of reservoir, the principal source of energy is a result of gas liberation from the crude oil and the subsequent expansion of the solution gas as the reservoir pressure is reduced. As pressure falls below the bubble-point pressure, gas bubbles are liberated within the microscopic pore spaces. These bubbles expand and force the crude oil out of the pore space.

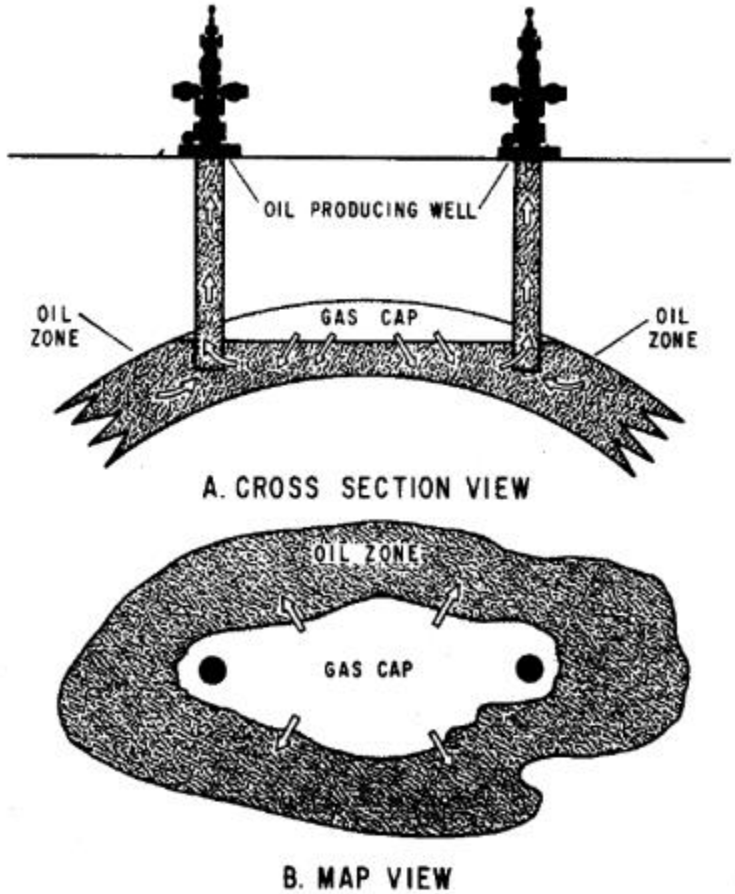


Gas-Cap Drive

Gas-cap-drive reservoirs can be identified by the presence of a gas cap with little or no water drive. Due to the ability of the gas cap to expand, these reservoirs are characterized by a slow decline in the reservoir pressure. The natural energy available to produce the crude oil comes from the following two sources:

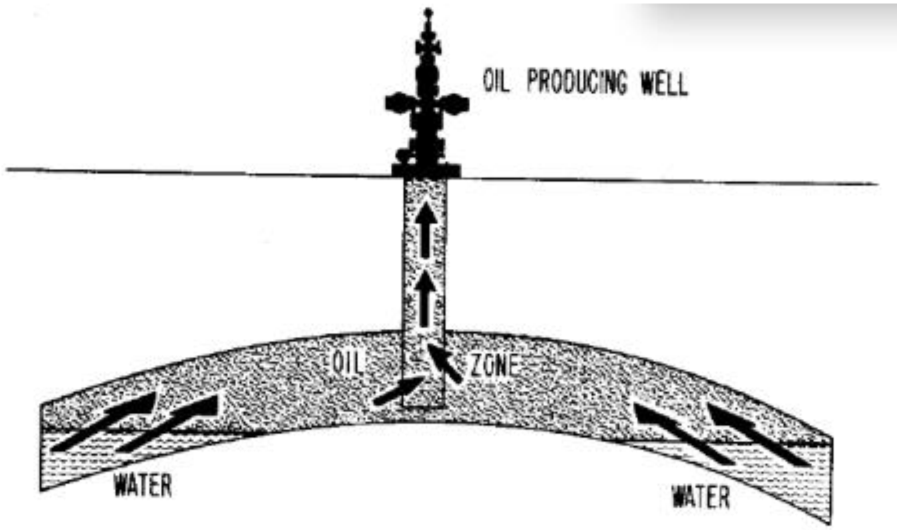
• Expansion of the gas-cap gas.

• Expansion of the solution gas as it is liberated.

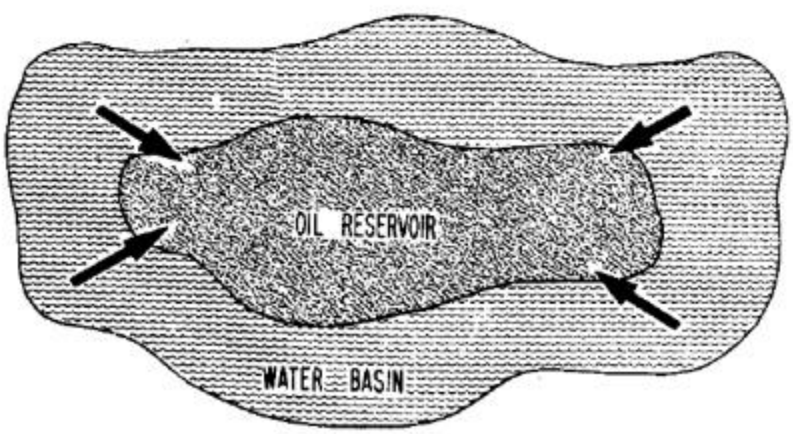


The Water-Drive Mechanism

Many reservoirs are bounded on a portion or all of their peripheries by **water bearing rocks called aquifers**. Although water is considered incompressible, the total compressed volume is quite large when such great quantities of total water volume are involved. Even the great volume of rock in which the water exist is influenced by water pressure. As oil is produced, pressure declines at the point where oil is withdrawn from the reservoir. Water then moves in to replace the oil as it is produced because of expansion of the minutely compressed water; a reservoir producing in this manner is termed a water drive reservoir. Many of the most important reservoir in the world are producing by energy supplied by water drives.



A. CROSS SECTION

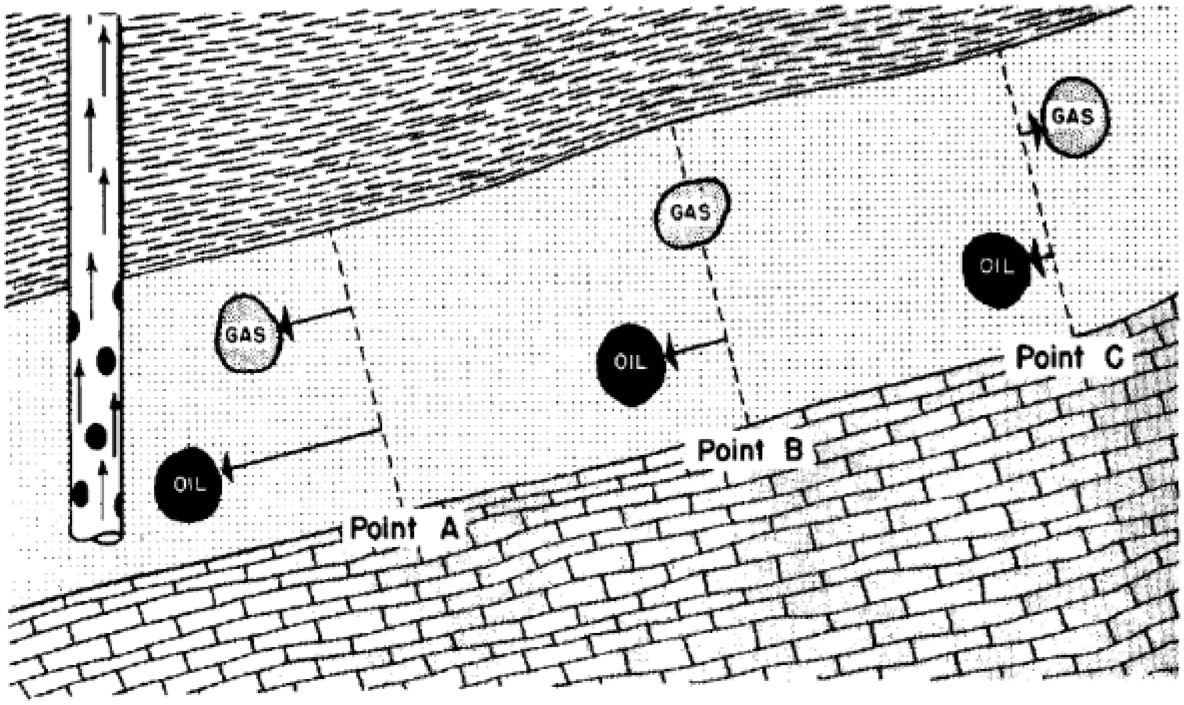


B. MAP VIEW

The Gravity-Drainage-Drive Mechanism

The mechanism of gravity drainage occurs in petroleum reservoirs as a result of differences in densities of the reservoir fluids. The effects of gravitational forces can be simply illustrated by placing a quantity of crude oil and a quantity of water in a jar and agitating the contents. After agitation, the jar is placed at rest, and the denser fluid (normally water) will settle to the bottom of the jar, while the less dense fluid (normally oil) will rest on top of the denser fluid. The fluids have separated as a result of the gravitational forces acting on them.

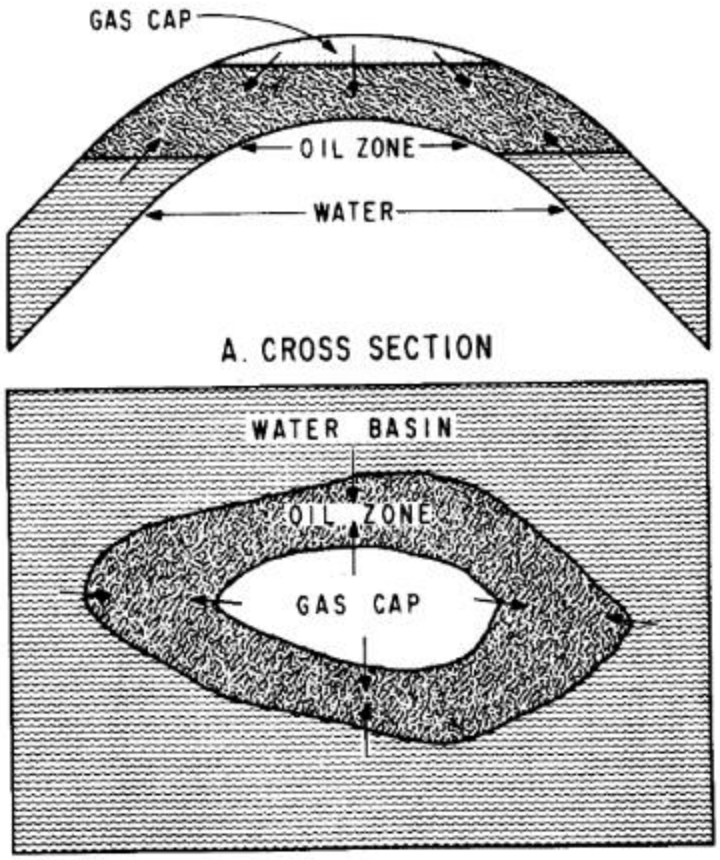
The fluids in petroleum reservoirs have all been subjected to the forces of gravity, as evidenced by the relative positions of the fluids, i.e., gas on top, oil underlying the gas, and water underlying oil. Due to the long periods of time involved in the petroleum accumulation-and-migration process, it is generally assumed that the reservoir fluids are in equilibrium. If the reservoir fluids are in equilibrium, then the gas-oil and oil-water contacts should be essentially horizontal. Although it is difficult to determine precisely the reservoir fluid contacts, best available data indicate that, in most reservoirs, the fluid contacts actually are essentially horizontal.



Gravitational segregation showing relative movement of gas and oil along the structure at various distance from a producing well.

The Combination-Drive Mechanism

Reservoirs are seldom found to fit exactly one type of drive classification. The most common type of drive encountered, is a combination drive see Figure below. Production problems are exceedingly complicated because of the infinite number of combinations characterizing the various reservoirs occurring naturally.



B. MAP VIEW

Reserve Estimation Methods

Estimates of oil and/or gas reserves are inherently uncertain. The degree of uncertainty in estimates of reserves depends mainly on:

- The degree of geologic complexity.
- Maturity of the property.
- The quality and quantity of geologic and engineering data.
- The operating environment.

• The skill, experience and integrity of the estimators.

Procedures to estimate and classify reserves (ECR) have been described as deterministic or probabilistic.

Reserve Estimation Methods

The oil and gas reserves estimation methods can be grouped into the following categories:

1. Analogy,

2. Volumetric,

3. Decline analysis,

4. Material balance calculations for oil reservoirs, (Material Balance).

5. Material balance calculations for gas reservoirs, (Material Balance).

6. Reservoir simulation.

Volumetric Methods

The volumetric method involves calculating:

(a) the amount of oil and gas initially in place by a combination of volumetric (geologic) mapping, petrophysical analysis, and reservoir engineering.

(b) the fractions of oil, gas, and associated products initially in place that are expected to be recovered commercially-i.e., the recovery efficiencies-using analytical methods and/or analogy. Procedures to estimate oil and gas initially in place and recovery efficiency.

a. Oil Reservoirs

For an oil reservoir, or for the oil column of an oil reservoir with a gas cap, oil initially in place (OIIP) may be calculated as:

$$OIIP = N_i = \frac{7758\phi_o(1 - S_{wo})A_o h_{no}}{B_{oi}} \qquad eq.(2.1)$$

where:

Ni = oil initially in place, STB.

7758 = (unit conversion constant) barrels in an acre foot (1 acre=4046.85642 m2 ≅4047 m2 =43560 ft2 *ft of h * 1 STB 5.615 ft3)=7758STB.

ϕo = average porosity in the oil zone, fraction.

Swo = average water saturation in the oil zone, fraction.

Ao = area of the oil zone, acres.

hno = average net oil pay, feet.

Boi = average initial formation volume factor, bbl/STB.

Porosity, water saturation, and oil formation volume factor should be volumeweighted averages in the oil zone. Solution gas dissolved in the oil at initial reservoir conditions may be calculated as:

$$G_{Si} = N_i R_{si} \qquad eq.(2.2)$$

where:

GSi = solution gas initially in place, scf.

Rsi = average initial solution gas/oil ratio, scf/STB.

b. Gas Reservoirs

For a non-associated gas reservoir, or for a gas cap, free gas initially in place may be calculated as:

$$G_{Fi} = \frac{43560\phi_g(1 - S_{wg})A_g h_{ng}}{B_{gi}} \qquad eq.(2.3)$$

where:

GFi = free gas initially in place, scf.

43560 = (unit conversion constant) cubic feet in an acre foot.

ϕg = average porosity in the free gas zone, fraction.

Swg = average water saturation in the free gas zone, fraction.

Ag = area of gas cap or gas reservoir, acres.

hng = average net thickness of gas cap or gas reservoir, feet.

Bgi = average initial formation volume factor, ft3/scf.

Condensate (also called distillate) in the vapor phase at initial reservoir conditions(but measured as a liquid at surface conditions) may be calculated as:

$$C_i = C_{Fi} R_{ci} \qquad eq. (2.4)$$

where:

Ci = condensate (distillate) initially in place, STB.

Rci = initial condensate/gas ratio (CGR),

STB condensate/MMscf.

CFi = free gas initially in place, MMscf.