LECTURE 2
OIL RECOVERY FROM OIL RESERVOIRS

1. *The concept of oil recovery factor, its components*

Oil recovery - is the degree of oil extraction from the reservoir. It is one of the key factors of oil deposits operation and, in general, the process of their development.

Oil recovery is characterized by oil recovery coefficient. There are ***ultimate, current and projected*** oil recovery coefficients.

The term "current oil recovery factor" (and often say current oil recovery) is the relationship between extracted quantity of oil from the reservoir at a certain date to its balance reserves.

$$\eta = \frac{Q_{extracted}}{Q_{OIIP}}. \tag{2.1}$$

The ultimate oil recovery – is the ratio of recovered oil reserves (extracted quantities of oil for the entire period of field development) to balance reserves.

Projected oil recovery factor differs from the ultimate (current) that is planned and estimated in the calculation and design of oil field development.

According to the experimental and statistical field data, it is estimated that the final oil recovery ratios, depending on the modes of operation of deposits, may acquire the values given in Table 2.1.

Table 2.1 – Recovery Factors for Oil Reservoirs

Drive Mechanism	Average Oil Recovery Factors, % of OOIP	
	Range	Average
Solution-gas drive	5 – 30	15
Gas-cap drive	15 – 50	30
Water drive	30 – 60	40
Gravity-drainage drive	3 - 15	9

OOIP – original oil in place

Estimating Oil Recovery Factors

- Solution-gas drive - API study

$$E_R = 41.8\left[\left(\frac{\phi\left(1-S_{wi}\right)}{B_{ob}}\right)^{0.1611}\left(\frac{k}{\mu_{ob}}\right)^{0.0979}\left(S_{wi}\right)^{0.3722}\left(\frac{p_b}{p_a}\right)^{0.1741}\right]$$

- Water drive - API study

$$E_R = 54.9\left[\left(\frac{\phi\left(1-S_{wi}\right)}{B_{oi}}\right)^{0.0422}\left(\frac{k\mu_w}{\mu_{oi}}\right)^{0.0770}\left(S_{wi}\right)^{-0.1903}\left(\frac{p_i}{p_a}\right)^{-0.2159}\right]$$

- Water drive - Guthrie-Greenberger study

$$E_R = 0.272\log_{10} k + 0.256\, S_{wi} - 0.136\log_{10}\mu_o - 1.538\,\phi - 0.0003\, h + 0.114$$

These correlations work best for **sandstone reservoirs**.

Nomenclature

E_R = Oil recovery efficiency (recovery factor), [% (for API study); fraction (for G-G study)]

ϕ = Reservoir porosity, fraction

S_{wi} = Interstitial water saturation, fraction

B_{ob} = Formation volume factor of oil at bubblepoint, RB/STB

k = Reservoir permeability, [darcy (for API study); md (For G-G study)]

μ_{ob} = Oil viscosity at bubblepoint pressure, cp

p_b = Bubblepoint pressure of oil, psig

p_a = Abandonment reservoir pressure, psig

Suitable Characteristics for Oil Recovery

• Solution-gas drive oil reservoirs – Low oil density – Low oil viscosity – High oil bubblepoint pressure	• Water drive oil reservoirs • Large aquifer • Low oil viscosity • High relative oil permeability • Little reservoir heterogeneity and stratification
• Gas-cap drive oil reservoirs – Favorable oil properties – Relatively large ratio of gas cap to oil zone – High reservoir dip angle – Thick oil column	• Gravity drainage oil reservoirs • High reservoir dip angle • Favorable permeability distribution • Large fluid density difference • Large segregation area • Low withdrawal

As pressure drive mechanisms are characterized by high ultimate oil recovery coefficients and high oil rates, that is why they should be implemented from the initial period of field development. Volumetric expansion drive always transforms into other different drive mechanisms.

Due to the physical nature of oil displacement and the actual fluid inflow to the wells system *oil recovery factor* for pressure drive mechanisms can be calculated as a multiplication of the oil displacement coefficient from the reservoir by sweep efficiency coefficient:

$$\eta = \eta_{dicplacement} \cdot \eta_{sweepefficiency} \qquad (2.2)$$

Displacement efficiency is the ratio of the volume of oil that is displaced from the reservoir area occupied by displacement agent (water, gas), to the initial oil reserves in that area.

$$\eta_{displacement} = 1 - \frac{S_{o.residual}}{S_{o.initial}}, \qquad (2.3)$$

where $S_{o.residual}$ – residual oil saturation of the porous medium in the area occupied by water;

$S_{o.init.}$ – the initial oil saturation of the porous medium.

Sweep efficiency is the ratio of volume covered by displacement, to the total volume of oil saturated rock.

$$\eta_{sweepefficiency} = \frac{V_{watered.}}{V_{drain.}}. \qquad (2.4)$$

2. *Ultimate oil recovery factor prediction*

Prediction of the final coefficient of oil recovery is carried out by two main methods:

- according to the results of laboratory tests on reservoir models;

- by analytical dependencies obtained from the results of laboratory studies or field data on the completed deposits.

Laboratory tests

It is known that the coefficient of oil recovery is defined as the product of the coefficients of displacement and coverage (by volume) of the formation.

The *sweep eficiency* coefficients are difficult to study in the laboratory, although there are some achievements. In most cases, their values are taken as a result of the development of adjacent fields with similar geological and physical conditions. At the same time, the displacement coefficients are mainly determined under laboratory conditions by setting up oil displacement experiments on reservoir models.

The use of laboratory test results in field practice is only possible if the processes studied in the experiments are similar to the in-situ ones.

This similarity is ensured by the equality of the complexes that make up the model and the nature that determine the process. On the basis of the similarity conditions, the parameters of models and experiments for the design of experiments should be selected. Usually approximate modeling methods are used here. When performing fluid filtration experiments, they try to keep the displacement rates, which, if possible in the oil field, pressure drops are close to the natural ones.

Oil output is affected by at least 18 different parameters; capillary pressure is considered a complex parameter.

For hydrophilic rocks, an agent is considered ideal, which, when displacing oil, creates with it an interfacial tension whose value goes to zero and the wetting angle to 90 °.

When modeling the processes of oil displacement, the geometric similarity of the pore space of the model and nature, the identity of the nature of their surface should be achieved. In the experiments, the rock and reservoir pressure, reservoir temperature should be observed.

The rock samples used to build the reservoir models must be prepared accordingly. The rock samples raised when drilling wells on hydrocarbon solutions are also suitable for models.

The equipment used for the experiments should allow the conditions of the experiments to be approximated as closely as possible to the reservoir conditions of the deposits for which they are being investigated. It should enable experiments with different pressures and temperatures (corresponding to reservoirs), create models of reservoirs of different lengths, control the saturation of the model with different fluids, obtain the required accuracy when studying the displacement characteristics, as well as obtain other necessary information.

The results of laboratory determination of the coefficient of oil displacement are recorded in a special journal, which records the sequence number of the experiment, the geometric dimensions of the reservoir model, its porosity, permeability, volumes of oil, water or gas in the model at the beginning and end of the experiment, as well as in the process of conducting it. According to the log data subsequently calculate the coefficients of oil displacement at different stages of the process.

One of the most important characteristics of the process of formation of fluids flow or motion in reservoir rocks along with the displacement factor is phase permeability. The data about it are necessary for substantiation of conditioning boundaries of petrophysical properties of rocks, for field evaluation of transitional oil and gas zones of reservoirs, in gas-hydrodynamic calculations of technological indices of development, for the choice of methods of action on the reservoirs with the aim of increasing oil recovery, etc.

Analytical dependencies of the prediction of the final oil recovery factor.

As hydrocarbon reservoir matures and production data become available, Decline Curve Analysis and Material Balance methods become the predominant methods for estimating reserves. In Decline Curve Analysis production data are extrapolated using semi-empirical equations and reserves are estimated by this extrapolation. Here the main assumption is that the trend established in the past will govern the future in a uniform manner. Therefore, the method should only be applied to the wells with uniform, lengthy production history. Two commonly-used extrapolation formulae for the production rate q(t) are

$$\text{Exponential:} q(t) = q_i \exp(-D_i t). \qquad (2.5)$$

$$\text{Hyperbolic:} q(t) = q_i (1+bD_i t)-1/b. \qquad (2.6)$$

q_i, D_i and b are constants.

Figure 2.1 shows example of hyperbolic decline curve that is fitted into the production data. Theoretically the method is applicable only to the single well computations; however, in practice, production extrapolations done for a group of wells often provide acceptable approximations. The choice of proper decline equation is essential for the reserve estimation.

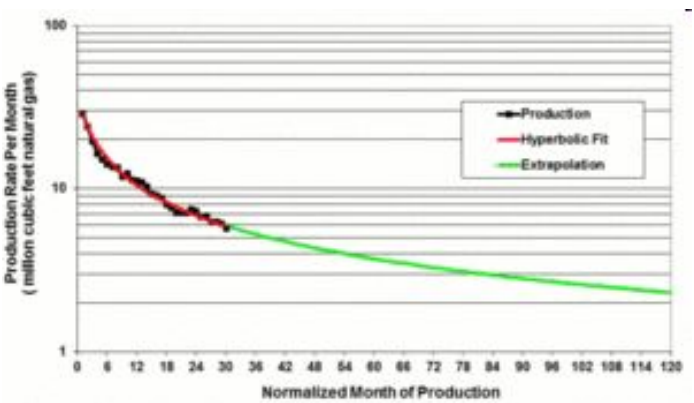


Figure 2.1 - Example showing decline curve and extrapolation of decline to estimate recovery.

Figure 2.2 demonstrates exponential and hyperbolic decline curves that start with the same initial production. It can be seen that for the first two years all decline curves fit nearly exactly and produce significantly different forecast for the later time. Therefore, the requirement of lengthy uniform decline is fundamentally important for the successful application of the method.

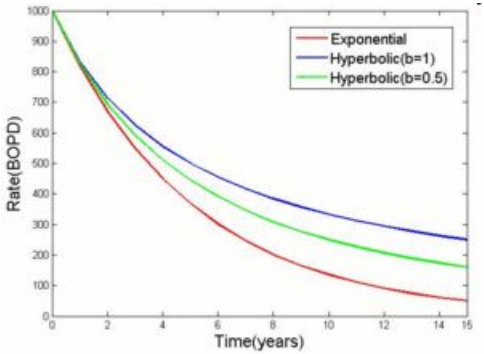


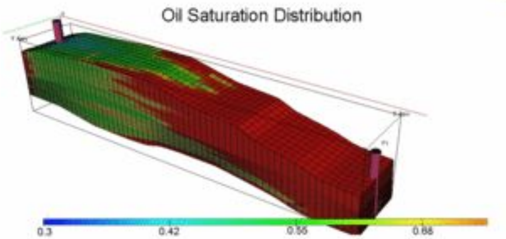
Figure 2.2 - Hyperbolic and Exponential Decline Curves

Another widely used technique for the estimation of recoverable hydrocarbons in place is a *Material Balance method*. Here the whole reservoir is treated as a closed tank where material (mass) is conserved. The reserve estimate is obtained from the measurements of fluid production and the resulting change in reservoir pressure caused by the production. The fluid properties, production and pressure data are averaged throughout the reservoir and mass conservation equation is solved analytically for the averaged system. The method is more reliable than Volumetric methods.

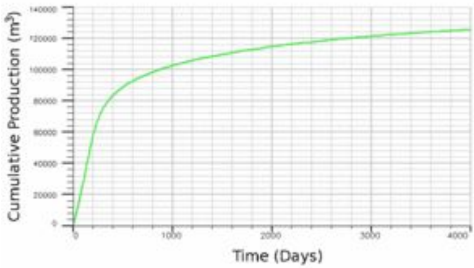
A natural extension of Material Balance method is numerical *Reservoir Simulation*. In essence, reservoir simulator is a software that numerically solves mass and energy conservation equations for the whole reservoir that is represented as a 3D grid. Grid blocks usually have non- uniform geologic properties such as porosity and permeability. The fluid flow between different grid blocks is assumed to be governed by Darcy law.

Modern reservoir simulators can handle muticomponent, mulitiphase fluids in presence of complex thermal effects.

Depending on the problem, imposed grid can vary from 10^4 to 10^8 grid blocks. The governing discretized conservation equations are nonlinear; hence, iterations are needed to obtain solution. The grid size and severe nonlinearities affect simulation time significantly; typical simulation time for realistic reservoir model can vary from hours to several days. Common outputs of reservoir simulation modelling are saturation distribution and production curves (Figure 2.3).



a)



b)

Figure 2.3 Example of Reservoir Simulation Results: Oil Saturation Distribution a) and Cumulative Oil Production Rate b). (Source: R. Zaydullin)

3. Characterization and distribution of residual oil in the reservoir. Classification and conditions of application of oil recovery enhancement methods

At present, there is no generally accepted thought about the nature of residual oil distribution in water cut reservoirs. This problem is purely fundamental. However, residual oil reserves in the non-drained reservoirs and the interlayers not covered with water are well studied.

According to expert estimates, residual oil reserves (100%) according to their types are quantitatively distributed as follows:

- oil remaining in low-permeable layers and areas not covered with water - 27%;
- oil in stagnant zones of homogeneous layers - 19%;
- oil remaining in the lenses and near the impervious screens not exposed by the wells - 24%;
- capillary-retained and film oil - 30%.

Residual oil, which is not covered by the flooding process due to the high macro-heterogeneity of the reservoirs and the stagnant zones created by the fluid flows in the reservoirs, accounts for 70% of all residual reserves, is the main reserve for increasing oil recovery. It is possible to increase the oil recovery of the formation due to this part of the oil as a result of the improvement of existing systems and technologies of development and the so-called hydrodynamic methods of increasing the oil recovery of the reservoirs. The other part remains in the flooded reservoirs due to their micro-heterogeneity and can be removed only as a result of different physical and physical-chemical processes and phenomena acting on it.

About the composition of residual oil. Changes in the properties of oil in the development process can occur both in the direction of the weighting and in the direction of facilitating the oil produced. Oil weighting is associated with a decrease in reservoir pressure during development and the loss of light fractions of oil during degassing, as well as the oxidation of oil in the interaction with the pumped water, due to the displacement of suspended oil deposits from the periphery of the contour zones. Oil properties vary very much within small, small areas of the same productive formation.

Residual oil holding forces and the ability to overcome them. Residual oil reserves, due to the macro-heterogeneity of the reservoirs, are caused by the low or zero oil filtration rate in weakly permeable zones, layers, interlayers and lenses, and this is more caused by pollution, clogging of the bottomhole zones during drilling and drilling.

The main forces acting in a layer saturated with two or more mobile phases are surface, viscous, gravitational and elastic forces.

Surface or capillary forces generate pressure of the order of 0.01–0.3 MPa at the boundary of the liquid phases. The magnitude of the surface forces is determined by the wettability of the rock and the microhomogeneity of the porous medium, the size of pores and pore channels.

Viscous forces (hydrodynamic resistance) are proportional to the viscosity of the oil. In very slow processes of transformation of layers saturation by oil and water is insignificant (since there are no deviations from Darcy's law).

Gravitational forces create a constant pressure gradient numerically equal to the difference in the density of oil, gas and water. The magnitude of this gradient can be 0.1 - 10 MPa / m. Its action leads to the floating of water in oil or gas in oil.

The elastic forces of the reservoirs, which are manifested by the reduction of reservoir pressure, cause the reduction of cracks and, therefore, contribute to the residual oil saturation.

Control questions

1. What is meant by the term oil extraction and what are the types of oil recovery coefficient?
2. How does the coefficient of oil extraction vary depending on the drive mechanism of the oil field development?
3. What is meant by the displacement efficiency?
4. What is meant by the sweep efficiency?
5. What are the methods of prediction oil recovery factor in practice?
6. What are laboratory tests of oil recovery factor?
7. What is the analytical method for predicting oil recovery factor?

8. How are the residual oil reserves distributed in the reservoir?

9. What are the properties of the residual oil and the forces that hold it in the reservoir?