University of Kirkuk/College of Engineering/Petroleum Department

Production Engineering II

[Inflow Performance Relationship (IPR)]

2017-2018

Syllabus:

1. Types of reservoirs and radial flow in the reservoirs.

2. Productivity index.

3. Inflow performance relationship (IPR).

4. Effect of stratification and water cut on IPR productivity index test.

5. IPR methods, Vogel method, Standing method, Couto method, Fetkovich method, Al-Saadoon method.

6. Mathematical and physical principles for pressure drop calculations.

7. Flow pattern and its relation with pressure drop.

8. Poettman and Carpenter method, Dukler method.

9. Working charts.

10. Analysis of choke performance.

11. Prediction of restricted and unrestricted production.

12. Effect of other parameters on well performance.

13. Derivation and solutions of diffusivity equation.

14. Application of Horner solution.

15. Multi-rates test.

16. Build-up test.

17. Draw-down test.

18. Effect of skin factor on well testing analysis.

الكتاب المنهجي (هندسة إنتاج النفط II)، حازم حسن العطار،رشيد هليل العاني.

References:

1. Production optimization using nodal analysis, Dale Beggs.
2. Petroleum production engineering, Boyun Guo, William C. Lyons, Ali Ghalambor.

3. Heriot watt University, production engineering technology II.
4. The technology of artificial methods, volume 1, Kermit E. Brown, H. Dale Beggs.
5. Pressure transient test, John Lee, John B. Rollins, John P. Spivey.
6. Reservoir engineering handbook , Tarek Ahmed.
7. Advance in well testing analysis, Robert, C. Earlougher,Jr.
8. Papers.
9. Other resources: internet.

Division mark

1. Final average (40%).
2. Final exam (60%).

Examinations

1. Open part.
2. Close part.

⬌ Important Terms
⬌ Flow Regimes

There are basically three types of flow regimes that must be recognized in order to describe the fluid flow behavior and reservoir pressure distribution as a function of time. There are three flow regimes:

- Steady-state flow
- Unsteady-state flow
- Pseudosteady-state flow

1) Steady-State Flow

The flow regime is identified as a steady-state flow if the pressure at every location in the reservoir remains constant, i.e., does not change with time. Mathematically, this condition is expressed as:

$$\left(\frac{\partial p}{\partial t}\right)_i = 0$$

The above equation states that the rate of change of pressure **p** with respect to time **t** at any location **i** is **zero**. In reservoirs, the steady-state flow condition can only occur when the reservoir is completely recharged and supported by strong aquifer or pressure maintenance operations.

2) Unsteady-State Flow

The unsteady-state flow (frequently called **_transient flow_**) is defined as the fluid flowing condition at which the rate of change of pressure with respect to time at any position in the reservoir is not zero or constant.

This definition suggests that the pressure derivative with respect to time is essentially a function of both position **i** and time **t**, thus

$$\left(\frac{\partial p}{\partial t}\right) = f(i, t)$$

3) Pseudosteady-State Flow

When the pressure at different locations in the reservoir is declining linearly as a function of time, i.e., at a constant declining rate, the flowing condition is characterized as the pseudosteady-state flow. Mathematically, this definition states that the rate of change of pressure with respect to time at every position is constant, or

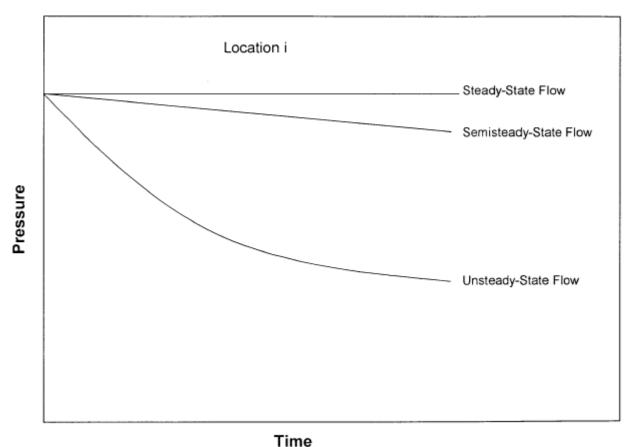$$\left(\frac{\partial p}{\partial t}\right)_i = \text{constant}$$

Fig. (1-1): Flow regimes.

Types of Reservoirs and Radial Flow in the Reservoirs

In general, reservoirs are conveniently classified on the basis of the location of the point representing the initial reservoir pressure **pi** and temperature **T** with respect to the pressure-temperature diagram of the reservoir fluid. Accordingly, reservoirs can be classified into basically two types. These are:

1. **Oil reservoirs:** If the reservoir temperature **T** is **less than** the critical temperature T_c of the reservoir fluid, the reservoir is classified as an oil reservoir.

2. **Gas reservoirs:** If the reservoir temperature is **greater than** the critical temperature of the hydrocarbon fluid, the reservoir is considered a gas reservoir.

▶ Oil Reservoirs

Depending upon initial reservoir pressure **pi**, oil reservoirs can be sub-classified into the following categories:

- **Under-saturated oil reservoir:** If the initial reservoir pressure **pi** (as represented by **point 1** on Figure (1-2), is **greater than** the bubble-point pressure **p_b** of the reservoir fluid, the reservoir is labeled an under-saturated oil reservoir.

- **Saturated oil reservoir:** When the initial reservoir pressure is **equal** to the bubble-point pressure of the reservoir fluid, as shown on Figure (1-2) by **point 2**, the reservoir is called a saturated oil reservoir.

- **Gas-cap reservoir:** If the initial reservoir pressure is **below** the bubble point pressure of the reservoir fluid, as indicated by **point 3** on Figure (1-2), the reservoir is termed a gas-cap or two-phase reservoir, in which the gas or vapor phase is underlain by an oil phase. The appropriate quality line gives the ratio of the gas-cap volume to reservoir oil volume.
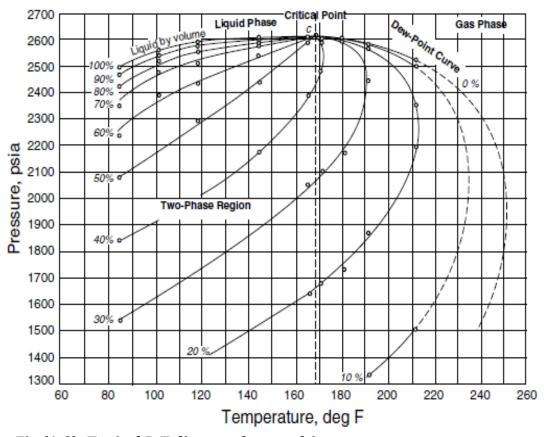

Fig.(1-2): Typical P-T diagram for a multicomponent system.

✚ Reservoir Drive Mechanisms

Ideally the hydrocarbons are recovered from the reservoir pore spaces by exploiting a drive mechanism, precluding the need for artificial method. Drive mechanisms have two classifications:

1. **Internal drive:** Using the internal energy of the reservoir configuration.
2. **External drive:** Which involves the invasion of the pore spaces by a replacement fluid, this type of drive called "**Secondary recovery or Enhanced oil recovery**".

1) Internal drive

This is known as primary recovery, which includes three drive mechanisms see Figure (1-3):

1. Depletion or internal gas drive
2. External gas cap drive
3. Water drive

1) Depletion or internal gas drive

The compressibility of oil and water is relatively small. As soon as production commences, it is accompanied by a rapid drop of pressure in the producing zone which soon reaches the bubble point of entrained gas. Initially, this gas is dispersed, but it rapidly expands and assists in dispelling the oil. Eventually, however, the gas will start to form a gas front, which, having more mobility than the oil, will increase the production gas to oil ratios. This depletion or dissolved gas drive is characterized by a rapid decline in reservoir pressure and by the recovery of only a small percentage of the oil in situation, e.g. 5 to 20% maximum see Figure (1-4).
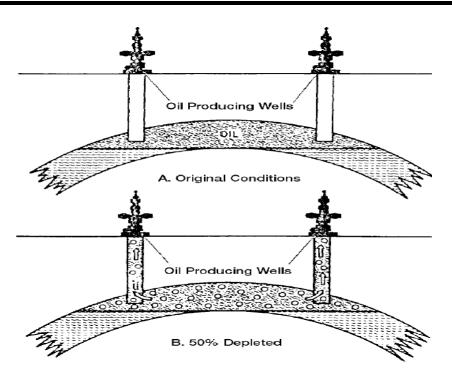
Fig. (1-4): Depletion or internal gas drive.

2) External gas cap drive

Where the oil has a gas cap, the gas cap pressure together with the pressure of gas in solution tends to maintain pressure in the reservoir much longer than depletion drive. Therefore, gas cap reservoirs have higher recovery rates e.g. 20 to 40% see Figure (1-5).
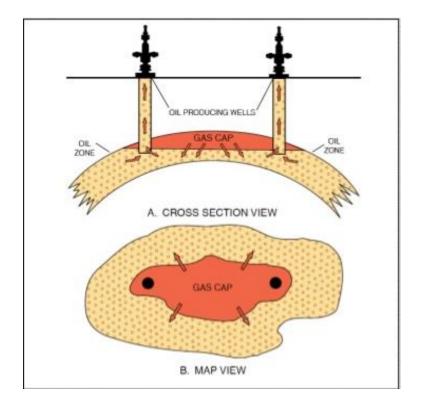
Fig. (1-5): External gas cap drive.

3) Water drive

Water drive is characterized by large local deposits of water which expand as pressure is reduced in the reservoir. Eventually, recovery will decrease due to the greater mobility of the water front which eventually breaks through to the wellbore with increased water to oil ratios. Nonetheless, water drive is the most efficient of all the drive mechanisms and can produce recovery rates as high as 60% see Figure (1-6).

All three-drive mechanisms may be present to varying degrees at the same time although one will predominate see Figure (1-7).
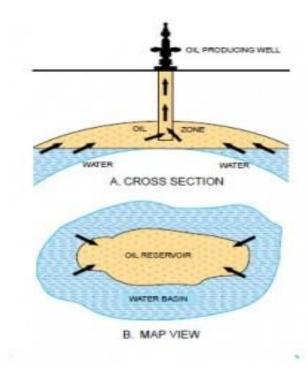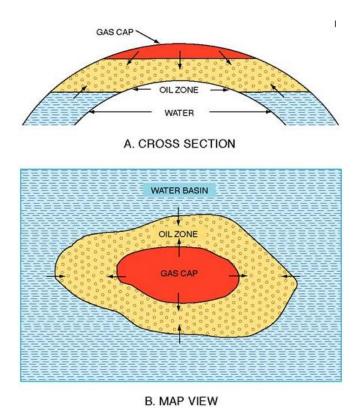
Fig. (1-6): Water Drive Mechanisms.

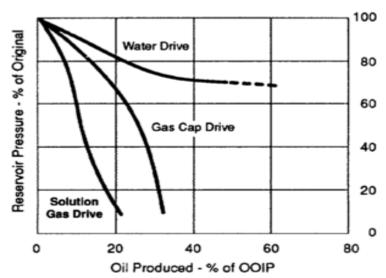**Fig. (1-7): Combined Drive Mechanisms.**

Fig. (1-8): Reservoir – Pressure Trends for Various Drive Mechanisms.

1) External drive

If fluid is injected into a well so that the volumetric rate of fluid replacement is equal to the volumetric rate of fluid extraction, then the average reservoir pressure will tend to remain constant. Injection stimulates secondary recovery.

Depending on the **type and configuration of the reservoir**, pressure can be maintained therefore by:

1. Gas injection
2. Water injection
3. Miscible and immiscible fluid injection.

In general, gas is injected into the crest, and water injection into the base or periphery of the reservoir. Particular consideration must be given to the quality of the injection fluid. They must be compatible with existing reservoir fluids, filtered to prevent formation plugging, possess a viscose significantly higher than formation water. Variation in reservoir permeability, and injection rate should also be considered. If the injection rate is excessive, the water front may advance unevenly, thus giving rise to early water breakthrough, or to unstable coning round the borehole.