Petroleum Production Engineering II

About the lecturer:

- Asst. lecturer Ahmed Razzaq Sahal is a Senior Petroleum Engineer in Iraq Oil Ministry at the Field Division.

- M.S. from the University of Baghdad, and B.S. from University of Technology — all degrees in Petroleum Engineering.

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About the Course:

- Theoretical 3 hr/ week.

- Tutorial 2 hr/ week.

- Units 6.

The syllabus:

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

2- Productivity index and Inflow performance relationship (IPR).

3- Productivity index test, Vogel method, Standing method, Couto method, Fetkovich method, Al-Saadoon method.

4- Mathematical and physical principles for pressure drop calculations.

5- Flow pattern and its relation with pressure drop, Poettmann and Carpenter method, Dukler method, working charts.

6- Analysis of choke performance, prediction of restricted and unrestricted production.

7- Derivation and solutions of diffusivity equation, application of Horner solution, multi - rates test, build - up test, draw - down test.

8- Effect of skin factor on well testing, analysis of tests that affected by barrier, bounded reservoirs.

9- Gas lift operations.

10- Stimulation operations (acidizing and fracturing).

Lecture One

1.1 Petroleum Production System

The role of a production engineer is to maximize oil and gas production in a cost-effective manner. Familiarization and understanding of oil and gas production systems are essential to the engineers. This lecture provides graduating production engineers with some basic knowledge about production systems. More engineering principles are discussed in or shown in Fig. 1.1, a complete oil or gas production system consists of a reservoir, well, flow-line, separators, pumps, and transportation pipelines. The reservoir supplies wellbore with crude oil or gas. The well provides a path for the production fluid to flow from bottom hole to surface and offers a means to control the fluid production rate. The flow-line leads the produced fluid to separators. The separators remove gas and water from the crude oil. Pumps and compressors are used to transport oil and gas through pipelines to sales points.

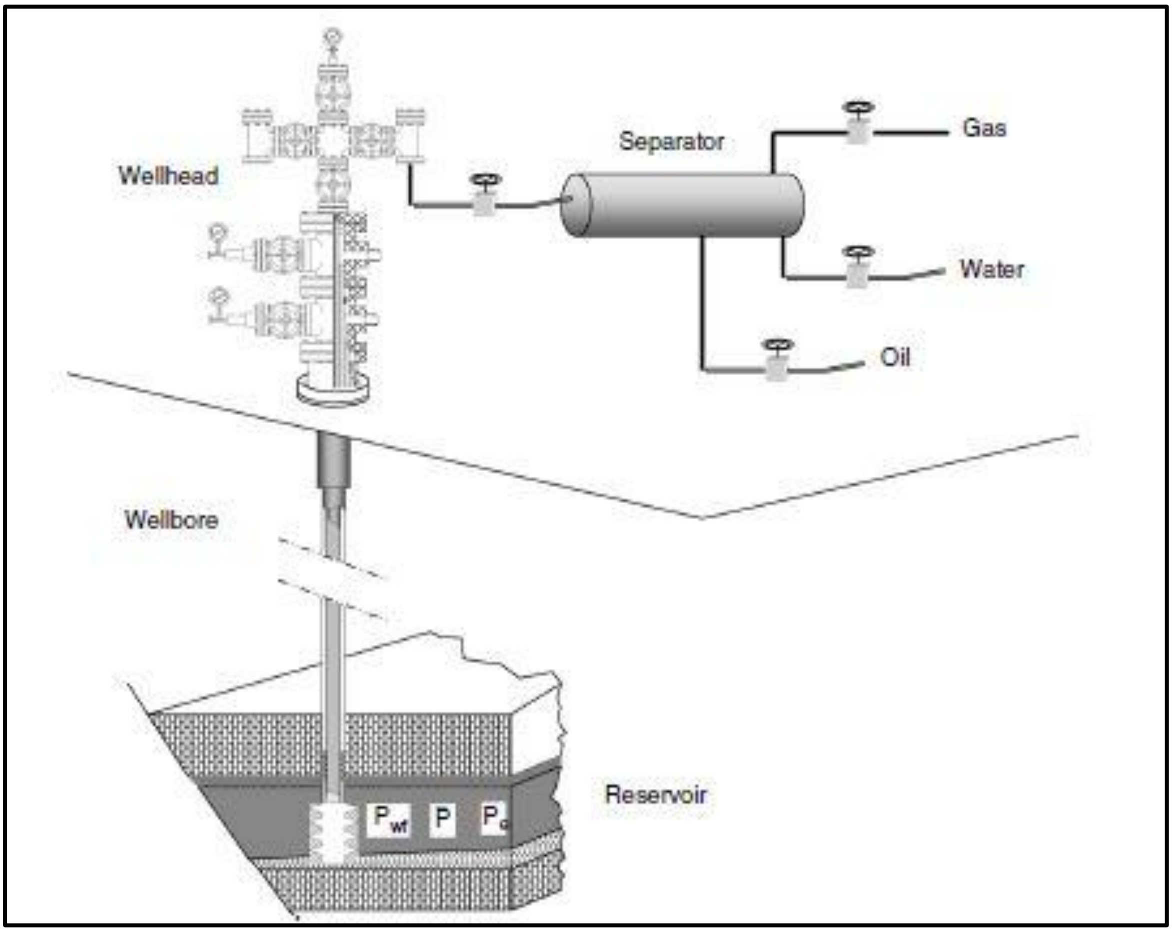

Figure 1.1: A sketch of a petroleum production system

1.2 Systems Analysis Approach

The systems analysis approach, often called "NODAL Analysis" has been applied for many years to analyze the performance of systems composed of interacting components. Electrical circuits, complex pipeline networks and centrifugal pumping systems are all analyzed using this method. Its application to well producing systems was first proposed by Gilbert in 1954 and discussed by Nind in 1964 and Brown in 1978.

The procedure consists of selecting a division point or node in the well and dividing the system at this point. The locations of the most commonly used nodes are shown in Figure 1.2.

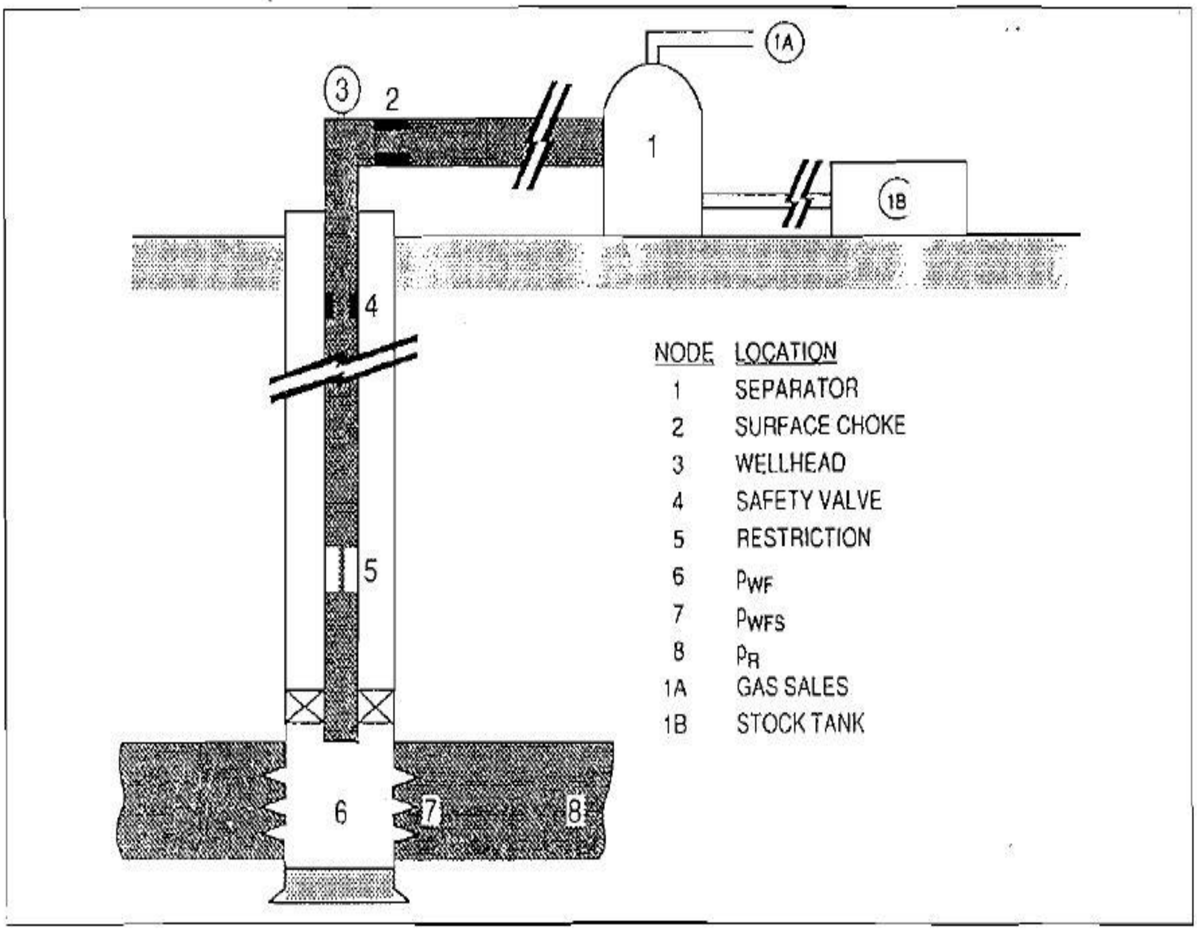

Figure 1.2: Location various nodes.

All of the components upstream of the node comprise the inflow section, while the outflow section consists of all of the components downstream of the node. A relationship between flow rate and pressure drop must be available for each component in the system. The flow rate through the system can be determined once the following requirements are satisfied:

1. Flow into the node equals flow out of the node.
2. Only one pressure can exist at a node.

At a particular time in the life of the well, there are always two pressures that remain fixed and are not functions of flow rate. One of these pressures is the average reservoir pressure P_r, and the other is the system outlet pressure. The outlet pressure is usually the separator pressure P_{sep} but if the well is controlled by a surface choke the fixed outlet pressure may be the wellhead pressure P_{wh}.

Once the node is selected, the node pressure is calculated from both directions starting at the fixed pressures:

In flow to the node:

$$P_r - \Delta P \text{ (upstream components)} = P_{node}$$

Outflow from the nodes:

$$P_{sep} - \Delta P \text{ (downstream components)} = P_{node}$$

The pressure drop, ΔP in any component, varies with flow rate, q. Therefore, a plot of node pressure versus flow rate will produce two curves, the intersection of which will give the conditions satisfying requirements 1 and 2, given previously. The procedure is illustrated graphically in Figure 1.3.

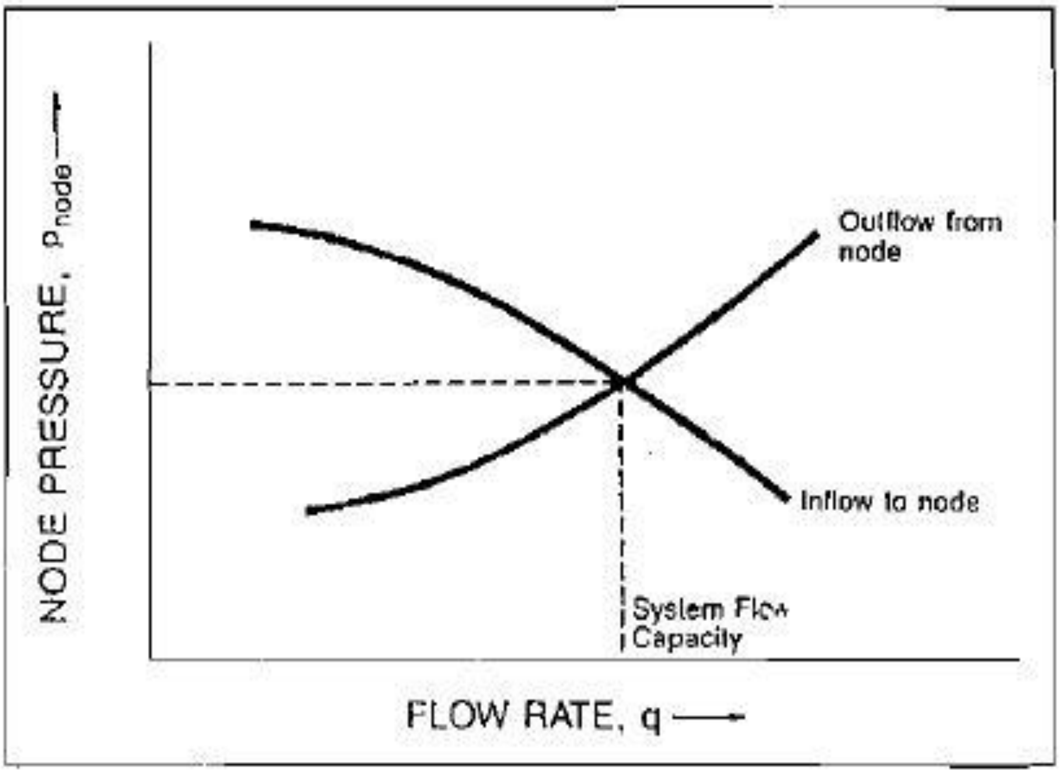

Figure 1.3: determination of flow capacity.

1.3 Type of Reservoir

Hydrocarbon accumulations in geological traps can be classified as reservoir, field, and pool. A ‘‘reservoir’’ is a porous and permeable underground formation containing an individual bank of hydrocarbons confined by impermeable rock or water barriers and is characterized by a single natural pressure system. A ‘‘field’’ is an area that consists of one or more reservoirs all related to the same structural feature. A ‘‘pool’’ contains one or more reservoirs in isolated structures.

Depending on the initial reservoir condition in the phase diagram (Figure 1.4), hydrocarbon accumulations are classified as oil, gas condensate, and gas reservoirs. An oil that is at a pressure above its bubble-point pressure is called an ‘‘under-saturated oil’’ because it can dissolve more gas at the given temperature. An oil that is at its bubble-point pressure is called a ‘‘saturated oil’’ because it can dissolve more gas at the given temperature. Single (liquid)-phase flow prevails in an under-saturated oil reservoir, whereas two-phase (liquid oil and free gas) flow exists in a saturated oil reservoir.

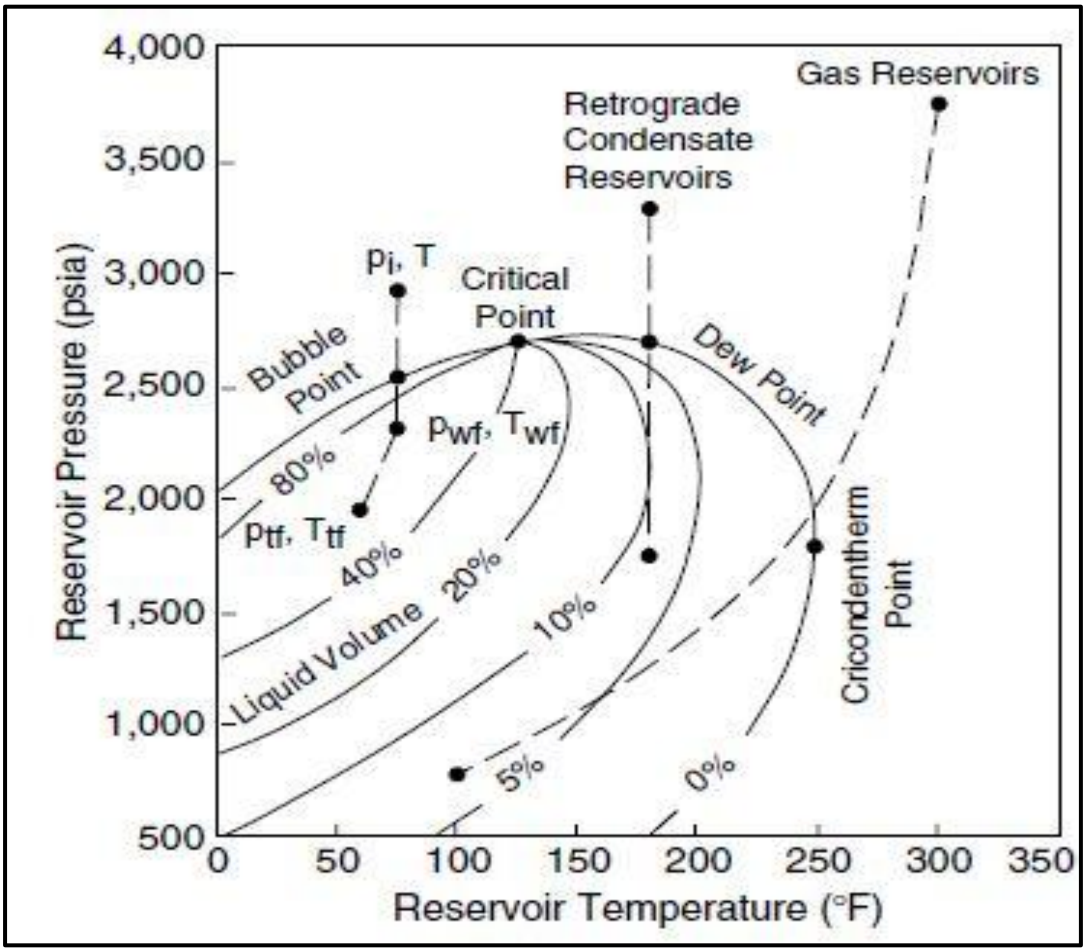

Figure 1.4: A typical hydrocarbon phase diagram

Wells in the same reservoir can fall into categories of oil, condensate, and gas wells depending on the producing gas–oil ratio (GOR).Gas wells are wells with producing GOR being greater than 100,000 scf/stb; condensate wells are those with producing GOR being less than 100,000 scf/stb but greater than 5,000 scf/stb; and wells with producing GOR being less than 5,000 scf/stb are classified as oil wells.

Oil reservoirs can be classified on the basis of boundary types, which determines driving mechanism, and which are as follows:

- Water-drive reservoir
- Gas-cap drive reservoir
- Dissolved-gas drive reservoir

In water-drive reservoirs, the oil zone is connected by a continuous path to the surface groundwater system (aquifer). The pressure caused by the ‘‘column’’ of water to the surface forces the oil (and gas) to the top of the reservoir against the impermeable barrier that restricts the oil and gas (the trap boundary). This pressure will force the oil and gas toward the wellbore. With the same oil production, reservoir pressure will be maintained longer (relative to other mechanisms of drive) when there is an active water drive. Edgewater drive reservoir is the most preferable type of reservoir compared to bottom-water drive. The reservoir pressure can remain at its initial value above bubble-point pressure so that single-phase liquid flow exists in the reservoir for maximum well productivity. A steady-state flow condition can prevail in a edge-water drive reservoir for a long time before water breakthrough into the well. Bottom-water drive reservoir (Figure 1.5) is less preferable because of water-coning problems that can affect oil production economics due to water treatment and disposal issues.

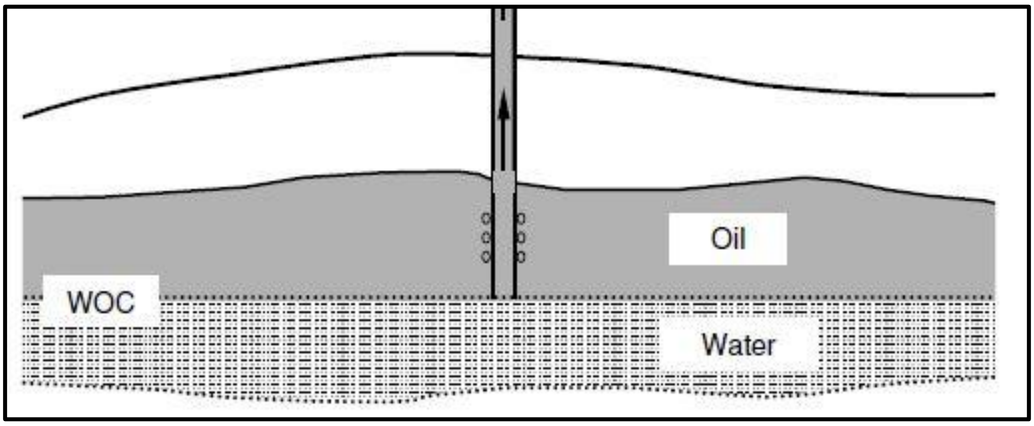

Figure 1.5: A sketch of a water-drive reservoir.

In a gas-cap drive reservoir, gas-cap drive is the drive mechanism where the gas in the reservoir has come out of solution and rises to the top of the reservoir to form a gas cap (Figure 1.6). Thus, the oil below the gas cap can be produced. If the gas in the gas cap is taken out of the reservoir early in the production process, the reservoir pressure will decrease rapidly. Sometimes an oil reservoir is subjected to both water and gas-cap drive.

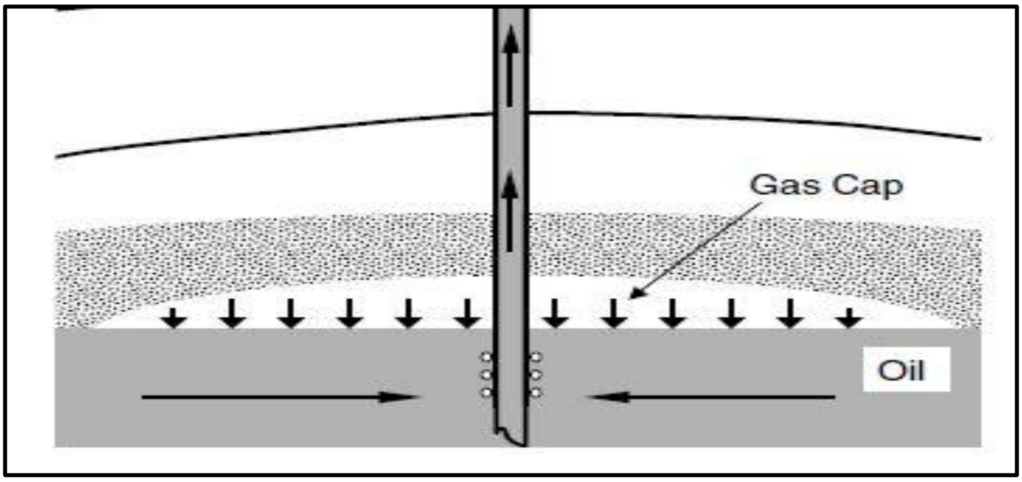

Figure 1.6: A sketch of a gas-cap drive reservoir

A dissolved-gas drive reservoir (Figure 1.7) is also called a ‘‘solution-gas drive reservoir’’ and ‘‘volumetric reservoir.’’ The oil reservoir has a fixed oil volume surrounded by no flow boundaries (faults or pinch-outs). Dissolved-gas drive is the drive mechanism where the reservoir gas is held in solution in the oil (and water). The reservoir gas is actually in a liquid form in a dissolved solution with the liquids (at atmospheric conditions) from the reservoir. Compared to the water- and gas-drive reservoirs, expansion of solution (dissolved) gas in the oil provides a weak driving mechanism in a volumetric reservoir. In the regions where the oil pressure drops to below the bubble-point pressure, gas escapes from the oil and oil–gas two-phase flow exists. To improve oil recovery in the solution-gas reservoir, early pressure maintenance is usually preferred.

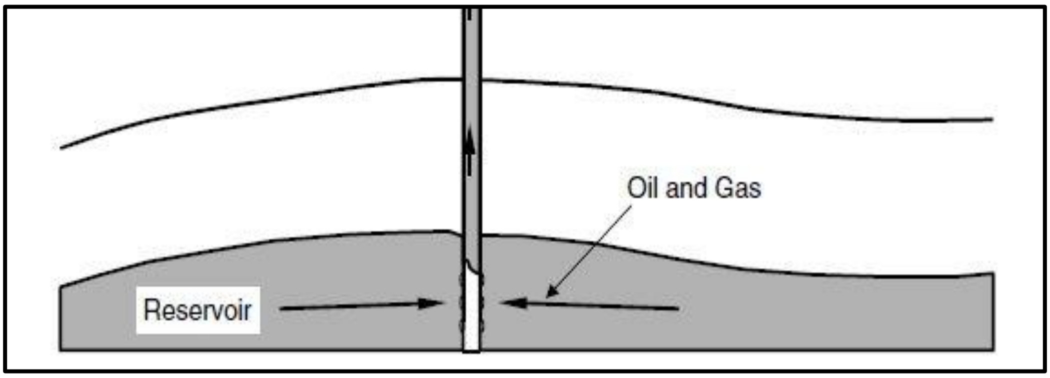

Figure 1.7: A sketch of a dissolved-gas drive reservoir.

1.4 Reservoir geometry

The shape of a reservoir has a significant effect on its flow behavior. Most reservoirs have irregular boundaries and a rigorous mathematical description of their geometry is often possible only with the use of numerical simulators. However, for many engineering purposes, the actual flow geometry may be represented by one of the following flow geometries:

- Radial flow.
- Linear flow.
- Spherical and hemispherical flow.

Radial flow

In the absence of severe reservoir heterogeneities, flow into or away from a wellbore will follow radial flow lines a substantial distance from the wellbore. Because fluids move toward the well from all directions and coverage at the wellbore, the term radial flow is used to characterize the flow of fluid into the wellbore. Figure 1.8 shows idealized flow lines and iso-potential lines for a radial flow system.

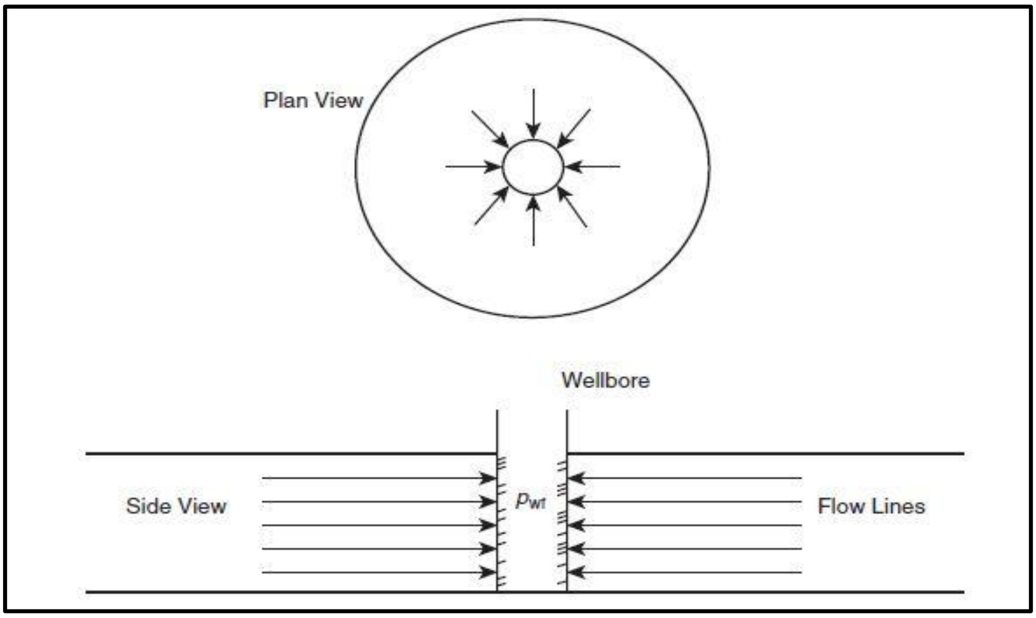

Figure 1.8: Ideal radial flow into a wellbore.

Linear flow

Linear flow occurs when flow paths are parallel and the fluid flows in a single direction. In addition, the cross-sectional area to flow must be constant. Figure 1.9 shows an idealized linear flow system. A common application of linear flow equations is the fluid flow into vertical hydraulic fractures as illustrated in Figure 1.10.

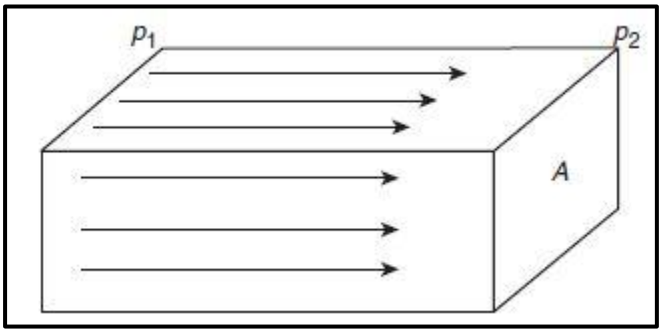

Figure 1.9: Linear flow.

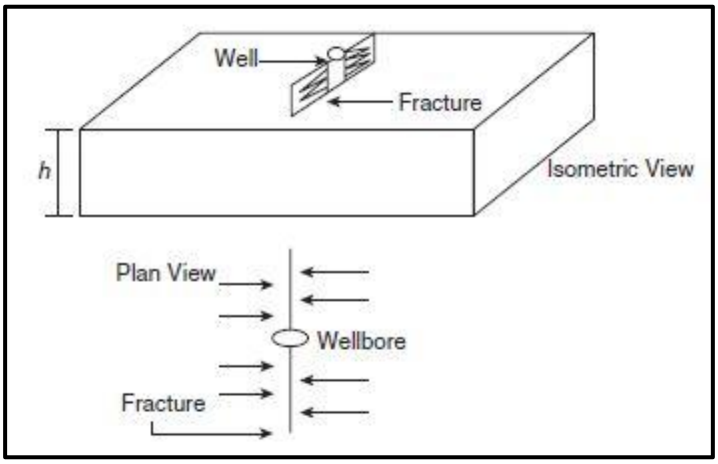

Figure 1.10: Ideal linear flow into vertical fracture.

Spherical and hemispherical flow

Depending upon the type of wellbore completion configuration, it is possible to have spherical or hemispherical flow near the wellbore. A well with a limited perforated interval could result in spherical flow in the vicinity of the perforations as illustrated in Figure 1.11. A well which only partially penetrates the pay zone, as shown in Figure 1.12, could result in hemispherical flow. The condition could arise where coning of bottom water is important.

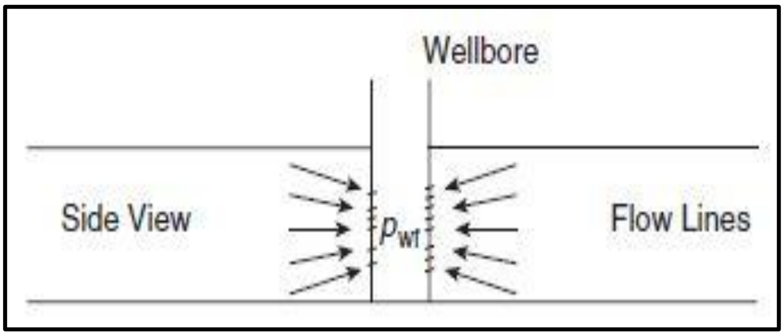

Figure 1.11: Spherical flow due to limited entry.

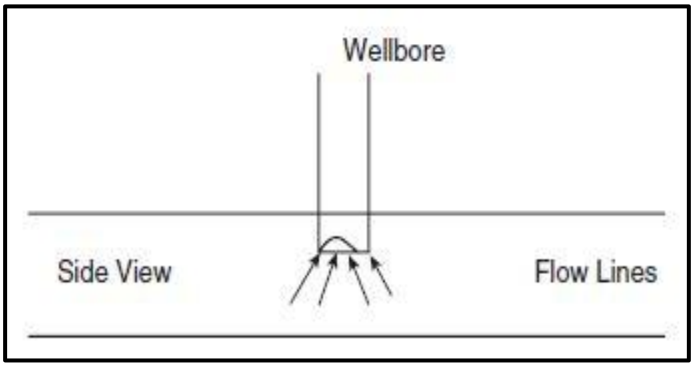

Figure 1.12: Hemispherical flow in a partially penetrating well.

1.5 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. These three flow regimes are:

- Steady-state flow
- Unsteady-state flow
- Pseudo-steady-state flow.

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:

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

This 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.

Unsteady-state flow

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:

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

Pseudo-steady-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 pseudo-steady-state flow. Mathematically, this definition states that the rate of change of pressure with respect to time at every position is constant, or:

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

It should be pointed out that pseudo-steady-state flow is commonly referred to as semi-steady-state flow and quasi-steady-state flow.

Figure 1.13 shows a schematic comparison of the pressure declines as a function of time of the three flow regimes.

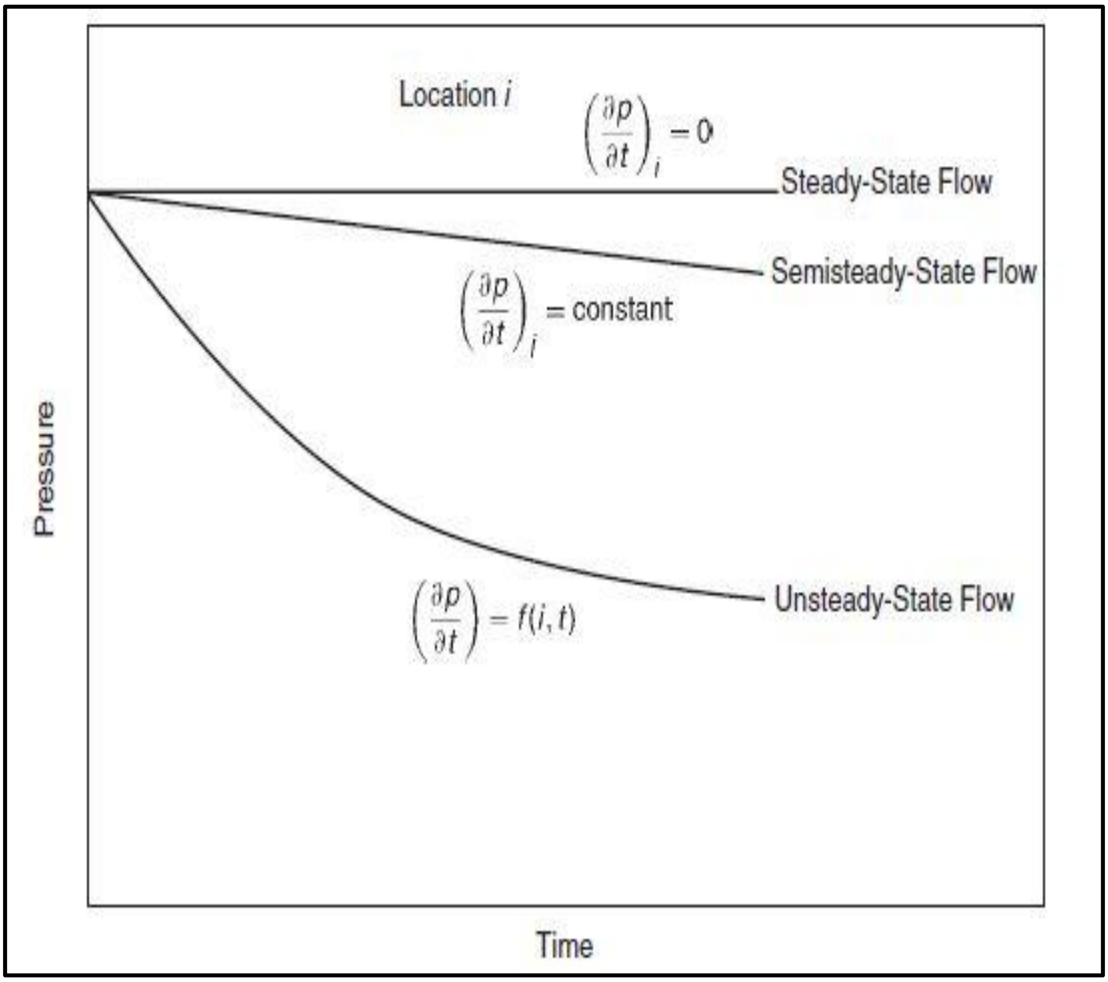

Figure 1.13: Flow regimes.