CHAPTER III

RELATED THEORIES

The following theories related to this study and the reservoir simulation are discussed in this chapter:

(i) Nodal analysis

(ii) Material balance

(iii) Reservoir drive mechanisms

(iv) Gas lift theory

3.1 Nodal Analysis

The system analysis approach called Nodal Analysis will be applied to this research. Nodal Analysis is the determination of the production capacity for any combination of interactive system components and the identification of locations of excessive flow resistance or pressure drop for remedial action.

The three major components of a well's production system are as follows:

1) Flow through the porous medium (reservoirs)
2) Vertical, inclined or horizontal tubing flow
3) Horizontal flowline or pipeline flow

Figure 3.1 illustrates both the location of various nodes in the system and possible pressure losses in the system.

The nodes for nodal analysis can be either at separator, surface choke, wellhead, safety valve, restriction, P_{wf}, P_{wfs}, and P_r. The pressures that are keys to the optimization of a well are:

1) **The drainage boundary pressure (P_e)** or **the average reservoir pressure (P_r).** P_e or P_r is the highest pressure in the system and is the reservoir energy that causes production to occur.
2) **The flowing bottom-hole pressure (P_{wf})** which is immediately downstream of a well's completion is also a key parameter in determining the magnitude of flow from the reservoir. At a given reservoir pressure, the higher the P_{wf}, the smaller the drawdown and the lower the production rate from the reservoir.
3) **The wellhead (tubing) pressure (P_{wh})** is the pressure measured at the wellhead. The setting of the wellhead pressure using a choke plays another key role in the

pressure loss taken through the system, the back pressure on the reservoir and ultimately the productivity of the well.

4) **The separator pressure (P_{sep}).** The separator pressure, in situations where sub-critical flow occurs through a wellhead choke, does affect the productivity of the well; otherwise, it does not affect productivity.
5) **The stock tank or sales line pressure (P_{ST}).** The stock tank pressure is the lowest pressure in the well's system, if there is no pump or compressor.

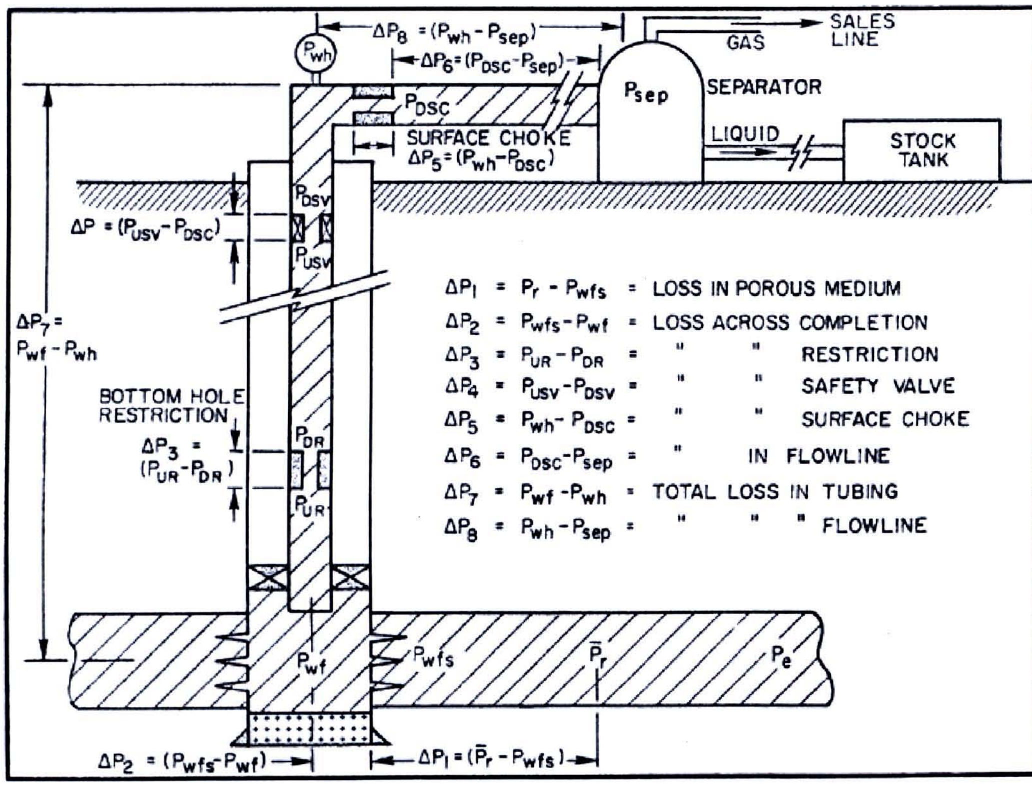

Figure 3.1 Possible Pressure Losses in a Complete System (after Beggs) [15].

In nodal analysis, the pressures listed above are related through the inflow and outflow equations. Examples of general inflow and outflow equation for node placed anywhere are:

Inflow to the node:

$$P_r - \Delta P_{(upstream\_components)} = P_{node} \tag{3.1}$$

Outflow from the node:

$$P_{sep} + \Delta P_{(downstream\_components)} = P_{node} \tag{3.2}$$

3.1.1 Inflow Performance Relationship (IPR)

Inflow Performance Relationship (IPR) is an equation that defines the manner by which the flowing bottom-hole pressure and the surface production rate are related. On the other hand, an IPR equation describes reservoir fluid inflow into the wellbore and constitutes a major component of the nodal analysis technique for well performance optimization. Although the term "back pressure curve" is used by some to refer to the gas well analogue, the bottom-hole pressure versus wellhead gas rate equation is also referred to as IPR.

There are different methods to determine IPR; however, IPR equation for oil and gas wells can be generally expressed in the form of [16]

$$q = J\, f\,(P_e,\, P_{wf}) \qquad P \text{ for oil and } P^2 \text{ for gas wells} \tag{3.3}$$

where

$$J_o = C\, f\,(k_o,\, h,\, \mu_o,\, B_o,\, r_e,\, r_w,\, S) \tag{3.4}$$

and

$$J_g = C\, f\,(k_g,\, h,\, \mu_g,\, Z,\, T,\, r_e,\, r_w,\, S) \tag{3.5}$$

In these equations,

q	= production rate (stb/d for oil, scf/d for gas)
$f(.....)$	= function of (variables)
J	= productivity index (J_o for oil in stb/d/psi and J_g for gas in scf/d/psi^2)
C	= conversion constant for oil or gas wells
P_e or P_r	= static average pressure measured at the drainage radius, r_e (psia).
P_{wf}	= bottom-hole flowing pressure measured at the wellbore radius, r_w (psia)
k_o, k_g	= permeability for oil and gas (md)
μ_o, μ_g	= viscosity for oil and gas (cp)
h	= net pay thickness (ft)
B_o	= oil formation volume factor (bbl/stb)
r_e, r_w	= drainage radius and wellbore radius (ft)
S	= total skin factor (dimensionless)
Z	= gas compressibility factor (dimensionless)
T	= temperature (deg. R)

The simplest relation of IPR is the straight-line for undersaturated oil wells producing above the bubble point or J is a constant (Figure 3.2).

$$q_o = J_o \,(P_r - P_{wf}) \tag{3.6}$$

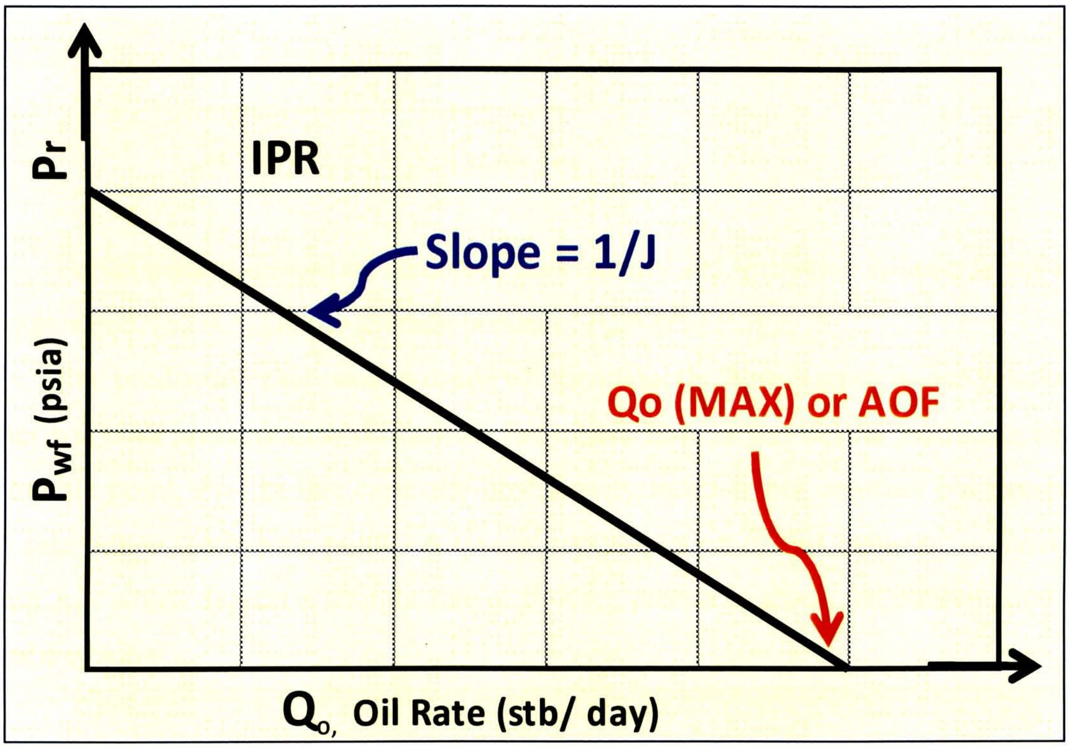

Figure 3.2 Straight-line IPR of an Undersaturated Oil Well Producing above Bubble Point [17]

The maximum rate of flow, $q_{o(MAX)}$ or absolute open flow (AOF), corresponds to P_{wf} equals to zero. Although, in practice, this may not be a condition at which the well can produce, it is useful definition, particularly for comparing the performance or potential of different wells in the same field.

3.1.2 Productivity Index

The productivity index is the ratio of the producing rate of a well to its drawdown at that particular rate. It is related to the formation capacity to produce fluids under a pressure difference between the static and the bottom-hole flowing pressure. The productivity index, J, is a famous term used to describe well deliverability, represents only one point on the inflow performance curve. By re-arranging (3.6), the productivity index is defined as

$$J_o = \frac{q_o}{(P_r - P_{wf})} \tag{3.7}$$

Most reservoirs exhibit at least partial decline and the industry standard is to use the pseudo-steady-state assumption in productivity calculation. To define the productivity index in terms of reservoir parameters

$$J_o = \frac{2\pi kh}{\left[\ln(\frac{r_e}{r_w}) - 0.75 + S\right](\mu_o B_o)_{avg}} \tag{3.8}$$

For an undersaturated oil reservoir, the viscosity and formation volume factor is an average value, $(\mu_o\ B_o)_{avg}$ at the average pressure, $P_{av} = (P_r + P_{wf})/2$.

The production rate usually drops off significantly from a straight-line relation at higher wellbore pressure drawdown with two-phase flow or the well is producing below the bubble point, P_b. In this case, the productivity index is not constant but decreases with rate below the bubble point. A typical representation of this behavior is shown in Figure 3.3, which depicts a straight line at flowing pressures above the bubble point and curvature below.

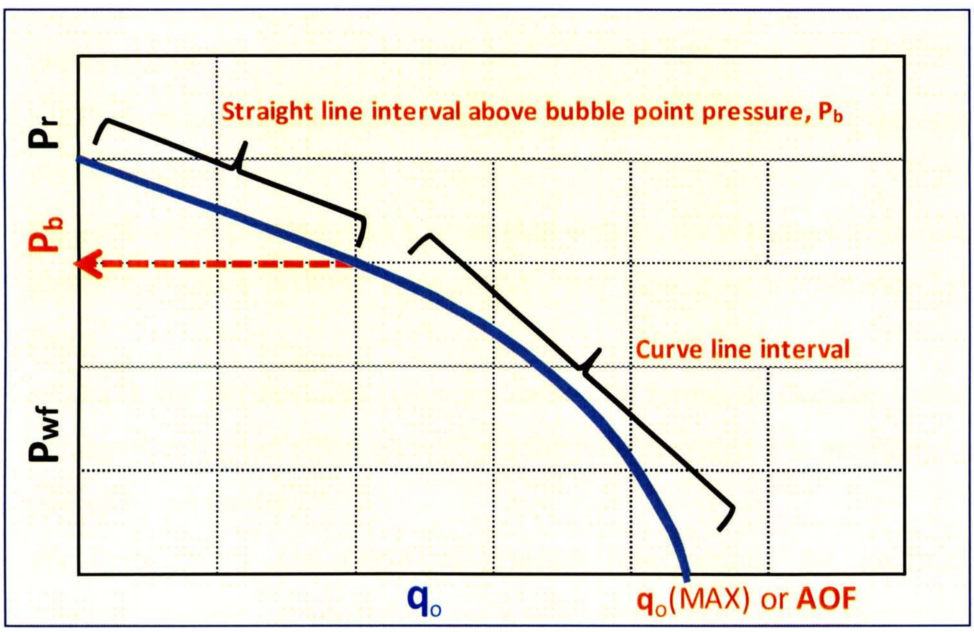

Figure 3.3 Typical IPR of an Undersaturated Oil Well Producing Below Bubble Point [17].

3.1.3 Key variables that affect IPR

1) **Flow capacity (*kh*).** From (3.8), the flow capacity (*kh*) is directly proportional to the productivity index (*J*) or production rate from a well. Both *k* (permeability) and *h* (net pay thickness) have significant influence on IPR's – the higher the values, the higher the production rate.
2) **Total Skin (*S*).** Skin around the wellbore has significant effect on IPR's. Skin removal by stimulating or fracturing can be evaluated using nodal analysis.
3) **Completion Type**. Although completion type is a factor rather than a variable, the type of completion significantly affects the IPR. Whether the well is cased and perforated or open hole makes a big difference to the wells reservoir-wellbore communication. Completion type affects flow efficiency which is computed using skin factor. The better the completion efficiency, the smaller the skin factor. The higher flow efficiency and the higher expected rate from the well.
4) **Perforation**. The effect of perforations on the IPR is usually expressed as a skin factor which depends on the perforation geometry and perforation quality. The most important parameters are:

   i) Perforation length (penetration) – longer perforations are more productive.

   ii) Perforation diameter – wider perforation will show a reduced frictional pressure loss

   iii) Perforation density (shot density) – the more shots per foot, the better the performance.

   iv) Perforation phasing – for a given shot density, the phasing that provides the greatest distance between perforations, and thus least interference between them.

   v) Depth and permeability reduction caused by formation damage – formation damage has limited effect on well productivity provided it is penetrated or by-passed by perforation.

   vi) Permeability and depth of crushed zone around the perforation – perforation clean up procedure such as underbalanced perforation should be designed to remove this impaired crushed zone prior to production.

   vii) Drawdown and properties of the produced fluids - high gas and very high oil flow rates through the perforation lead to extra pressure losses from non-Darcy flow effects.

5) **Other variables**. Relative permeability changes as fluid saturation changes, formation volume factors (shrinkage or expansion), and turbulence are other variables that affect IPR.

Composite IPR for Commingled Reservoirs

Nind [18] concluded that the composite IPR for three commingled reservoirs is the sum of each individual IPR curve. Figure 3.4 and Figure 3.5 illustrate a typical performance of commingled production system and describes the behavior of the IPR curve in a stratified three-layered reservoir with permeabilities of 1, 10, and 100 md. Initially, the IPR curve of Zone A which has the highest reservoir pressure will be the same as the composite IPR since Zone B and Zone C which have lower reservoir pressure cannot be produced. With increase in flow rate or decrease in the bottom-hole flowing pressure until a certain point, Zone B and Zone C can be produced, resulting in a change in the composite IPR.

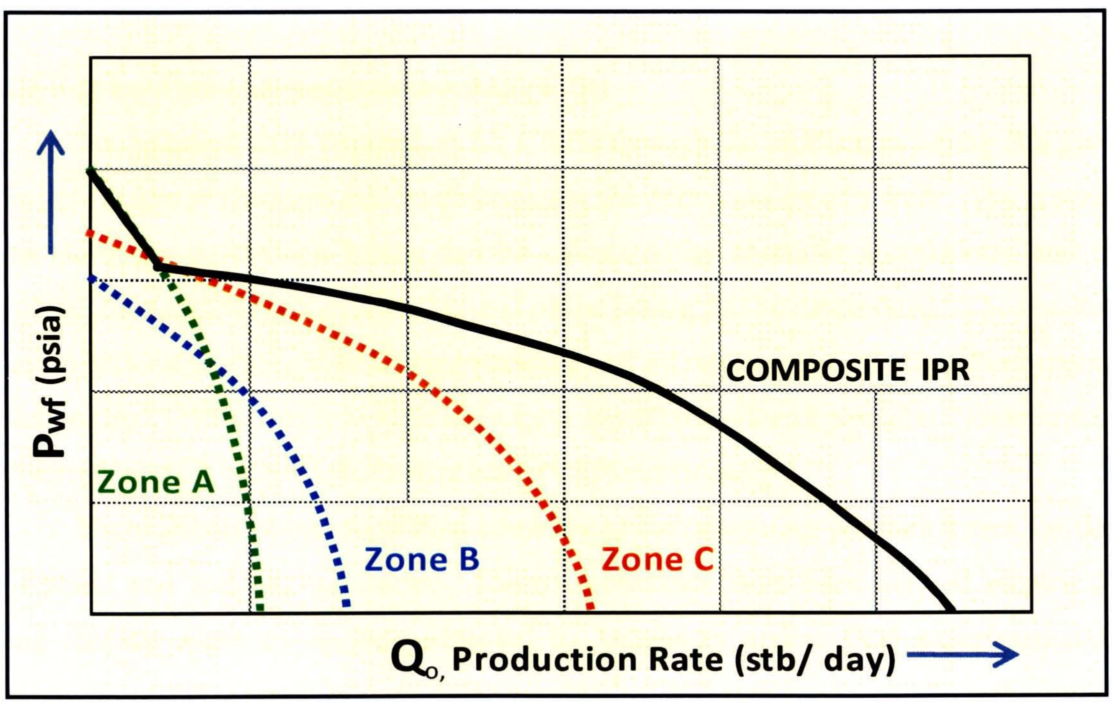

Figure 3.4 The Composite IPR Curve Calculated in Conventional Way as the Sum of Three Individual IPR Curves [18]

Figure 3.5 also exhibits an improved productivity index with increasing production rate at the lower rates, but a deteriorated productivity index at the higher rate.

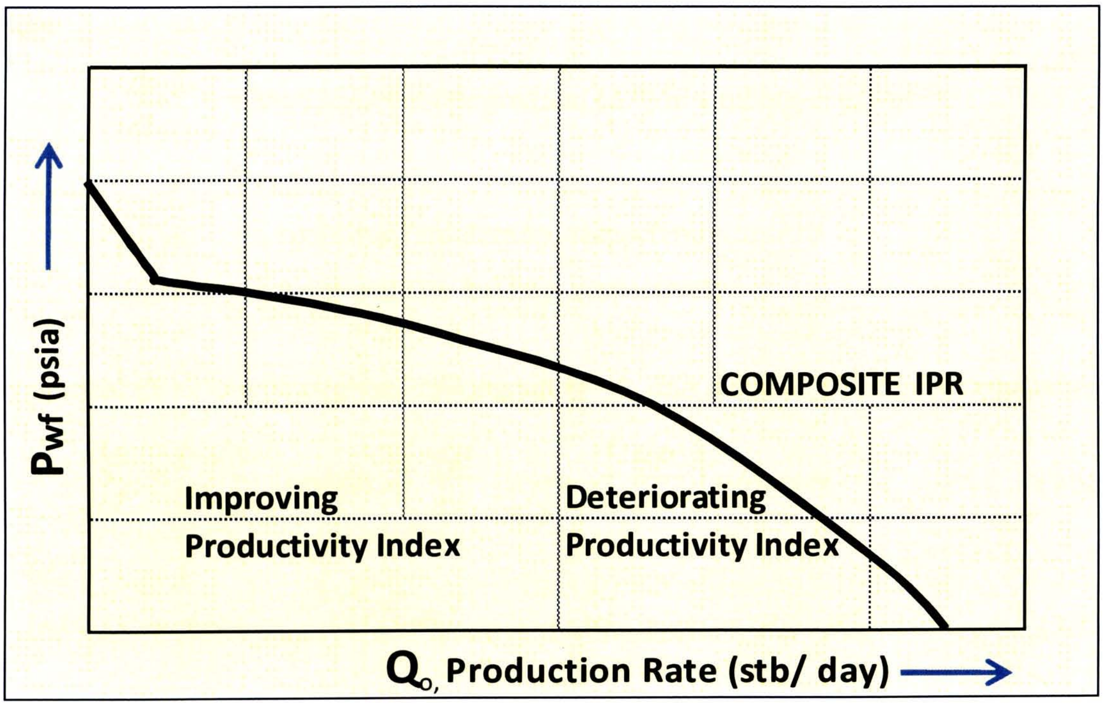

Figure 3.5 The Composite IPR Curve in Relationship with Productivity Index [18]

3.1.4 Tubing Performance Relationship (TPR)

The pressure drop required to lift a fluid through the production tubing at a given flow rate is one of the main factors determining the deliverability of a well. The pressure drop along the production tubing can be calculated by charts or correlations, and the resulting flowing pressure at the other end of the tubing can be determined. The resulting relation between bottom-hole flowing pressure and oil rate is called "Tubing Performance Relationship" (TPR), and it is valid only for a specified wellhead pressure. Sometimes, it is referred as the Vertical Lift Performance (VLP) relationship.

There are numerous fluid flow correlations for computing pressure losses for flow in vertical and inclined wellbores. These correlations have been derived empirically using statistic methods on data obtained by laboratory and/or field experimentation. Starting from the general energy balance equation and making necessary substitutions from thermodynamic principles, the general pressure gradient equation is derived as

$$\frac{dp}{dL} = \frac{g}{g_c}\rho \sin\Phi + \frac{f\rho v^2}{2 g_c d} + \frac{\rho v dv}{g_c dL} \tag{3.9}$$

where:

$\frac{dp}{dL}$ = the total pressure gradient (ΔP) in a tubing component

$\rho = \rho_L H_L + \rho_G H_G$

ρ_L, ρ_G = Liquid and Gas density, respectively

H_L, H_G = Liquid and Gas hold up, respectively

For vertical flow, Φ= 90 degrees, making sin Φ= 1, $dL= dZ$ and (3.9) can be reduced to

$$\frac{dp}{dZ} = \left(\frac{dp}{dZ}\right)_{elevation} + \left(\frac{dp}{dZ}\right)_{fricion} + \left(\frac{dp}{dZ}\right)_{acceleration} \tag{3.10}$$

or

$$(\Delta P)_{\mathrm{total}} = (\Delta P)_{\mathrm{elevation}} + (\Delta P)_{\mathrm{friction}} + (\Delta P)_{\mathrm{acceleration}} = P_{wf} - P_{wh} \tag{3.11}$$

This equation is used to account for three components of pressure losses in wellbore fluid flow which are:

1) The elevation component of the total pressure drop, $(\Delta P)_{elevation}$ or the hydrostatic pressure due to gravity and the elevation change between wellhead and the intake of the tubing
2) The frictional component of the total pressure drop, $(\Delta P)_{friction}$ which includes irreversible pressure losses due to viscous drag and slippage.
3) The acceleration component of the total pressure drop, $(\Delta P)_{acceleration}$ due to acceleration of an expanding fluid. This term is usually insignificant when compared with the other losses and therefore neglected in most design calculations.

Figure 3.6 illustrates the three components of pressure in a TPR curve for single-phase liquid, dry gas, and a two-phase gas/oil mixture.

In case of single-phase liquid (e.g. undersaturated oil or water), the density is assumed constant. Therefore, the hydrostatic pressure gradient (pressure loss per unit length) is a constant. Friction loss, on the other hand, is rate-dependent, characterized by two flow regimes – laminar and turbulent – separated by a transition zone. The rate dependence of friction-related pressure loss differs with the flow regime. At low rates, the flow is laminar and the pressure gradient changes linearly with rate or flow velocity.

At high rates, the flow is turbulent and the pressure gradient increases more than linearly with increasing flow rate. In gas wells, there is interdependence between flow rate, flow velocity, density and pressure. In general, increasing gas rate results in increasing total pressure loss. In multiphase mixtures, friction-related and hydrostatic pressure losses vary with rate in a much more complicated manner than for gas. Increasing rate may change the governing pressure loss mechanism from predominantly gravitational to predominantly friction. The result of this shift is a change of trend in the TPR curve.

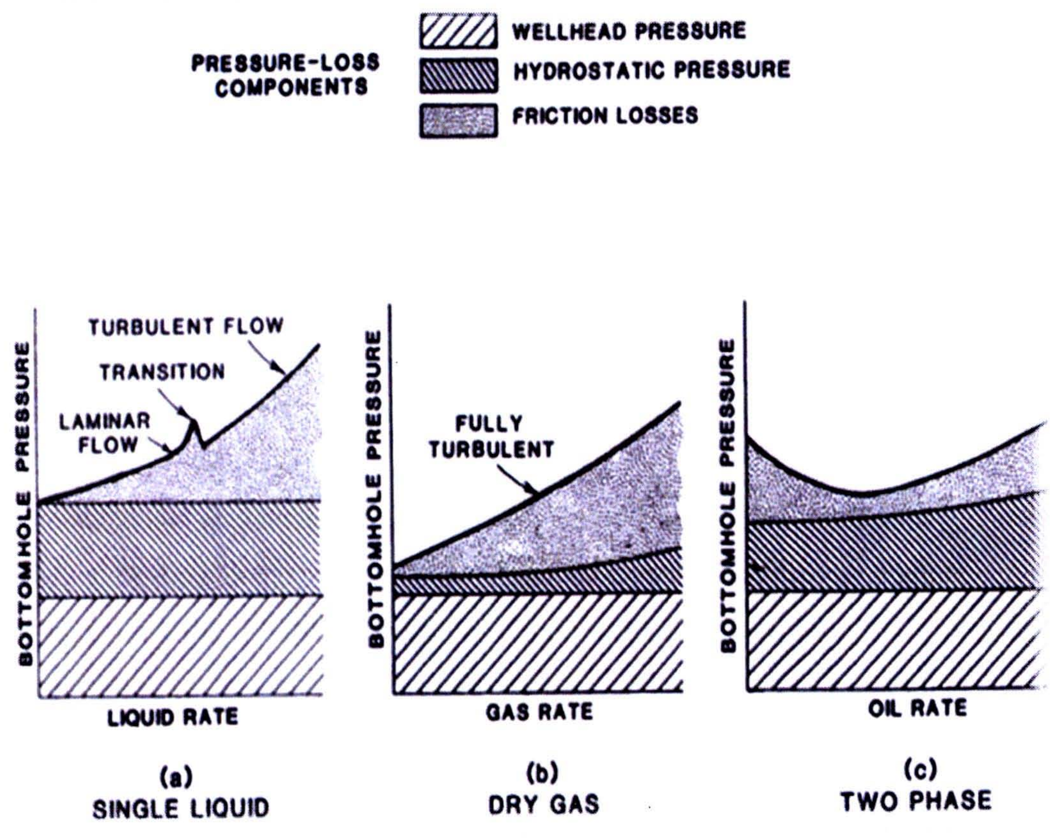

Figure 3.6 Components of Pressure Losses in Tubing [17]

3.1.5 Key Variables that Affect TPR

The variables that affect TPR are discussed as follows:

1) **Wellhead Pressure (P_{wh}).** The setting wellhead pressure using the choke plays another key role in the pressure loss occurring through the system since it affects

back pressure on the reservoir and ultimately the productivity of the well. The wellhead pressure serves as a back-pressure to well productivity. The higher the wellhead pressure, the lower the rate from particular well assuming that reservoir energy and reserves are available. Increasing the wellhead pressure by reducing the choke opening will shift the TPR curve upward, resulting in a decrease in rate.

2) **Gas-Liquid Ratio (GLR).** Effect of changing the GLR is not as straight forward as for the case of changing the well head pressure. It has different effects on two components of pressure loss in the tubing – friction and hydrostatic. Increasing GLR lightens the mixture density and therefore reduces the pressure loss due to hydrostatic forces. Larger quantities of gas will however, usually result in larger pressure losses due to friction. An increase in GLR tends to shift TPR to the right, resulting in an increase in natural flow rate. The trend continues up to a certain GLR where the trend is then reversed. One of methods that is used to increase GLR by injecting gas from the surface to lower section of tubing is so-called a conventional gas lift.
3) **Water-Gas or Water-Oil Ratio or % WC.** Water-Gas and Water-Oil Ratio have major influence on the gravitational component of the wellbore pressure drop. Because the density of water is higher than that of either of oil or gas, the presence of water in the wellbore drastically affects well performance and productivity. Increasing water cut (% WC) in the flowing wellbore fluid creates a higher flowing bottomhole pressure, which impedes flow from the reservoir, and lowers well productivity and the well will completely load up. It is analogous to large tubing size case. Some form of artificial lift will be required to produce such a well at decent rates for water cut exceeding 50%.
4) **Tubing Sizes.** There is an optimum tubing size for each well. The larger the tubing size, the higher the flow rate through it due to reduced frictional pressure drop. However, if the tubing is too large for the well, the liquid loading can result pre-maturely and force production to cease. This is due to the fact that, the upward (gas) flow velocity has decreased so much (due to tubing diameter increase), that it is no longer sufficient to efficiently lift the liquid to surface, i.e. slip phenomena commence and liquid loading begins. Tubing sizes significantly affect tubing performance and hence well productivity.

5) **Separator Pressure (P_{sep}).** The separator pressure is often the main component in the surface pressure losses. It exerts a restrictive "back pressure" on the well production which limits the total pressure drop available for fluid inflow from the reservoir and onward transportation to the surface. In situations where sub-critical flow occurs through the wellhead choke, P_{sep} does affect the productivity of the well; otherwise, does not affect productivity.
6) **The Stock Tank or Sales Line Pressure (P_{ST}).** The stock tank is the lowest pressure in the well's system, if there is no pump or compressor. If there is a pump (liquid) or a compressor (gas case) in the system, the P_{ST} is not the lowest pressure in the system. In the instance, where either the liquid pump or gas compressor exists in the system, then the intake pressure to the pump or compressor may be lower than the sales line pressure.
7) **Changing the Production Components.** The prediction of the gas well performance in the future is critical under existing as well as modified conditions. For example, for a gas-condensate reservoir, we would like to know when the gas well will start loading under existing conditions so that appropriate production components can be changed before the actual loading occurs. These alterations include changing choke size, changing the tubing size or reducing the well head pressure. Based on the production scenarios under existing as well as altered conditions, a proper method can be selected for continued gas production.

3.1.6 Natural Flow

It is possible to calculate and plot both inflow and tubing performance relations. At a specific rate, the wellbore flowing pressure and tubing intake pressure are equal, the flow system is in equilibrium and flow is stable. The intersection of the IPR and TPR curves determines the rate of stable flow that can be expected from the particular well. The equilibrium rate and pressure constitute what is called the "natural flow point". The equilibrium rate is called the "natural flow rate". Figure 3.7 illustrates typical IPR and TPR for the natural flow condition.

Natural flow rate and pressure change with reservoir depletion, depending on the variation in IPR and TPR resulting from changes in the reservoir pressure and flow characteristics. Usually, the change of natural flow is toward a lower rate. However, it is possible to change equipment or operating criteria to maintain a desired rate of production. Lowering the wellhead pressure by choke manipulation or lowering separator pressure is perhaps the simplest and most common adjustment.

Introducing artificial lift or treating wells by stimulation are more complicated and costly alternatives for maintaining a desired rate of production. One form of artificial lifts commonly used to improve the well performance is the conventional gas lift – which can be either continuous or intermittent. The details of the continuous and intermittent gas lift will be discussed in section 3.4.1 and 3.4.2, respectively.

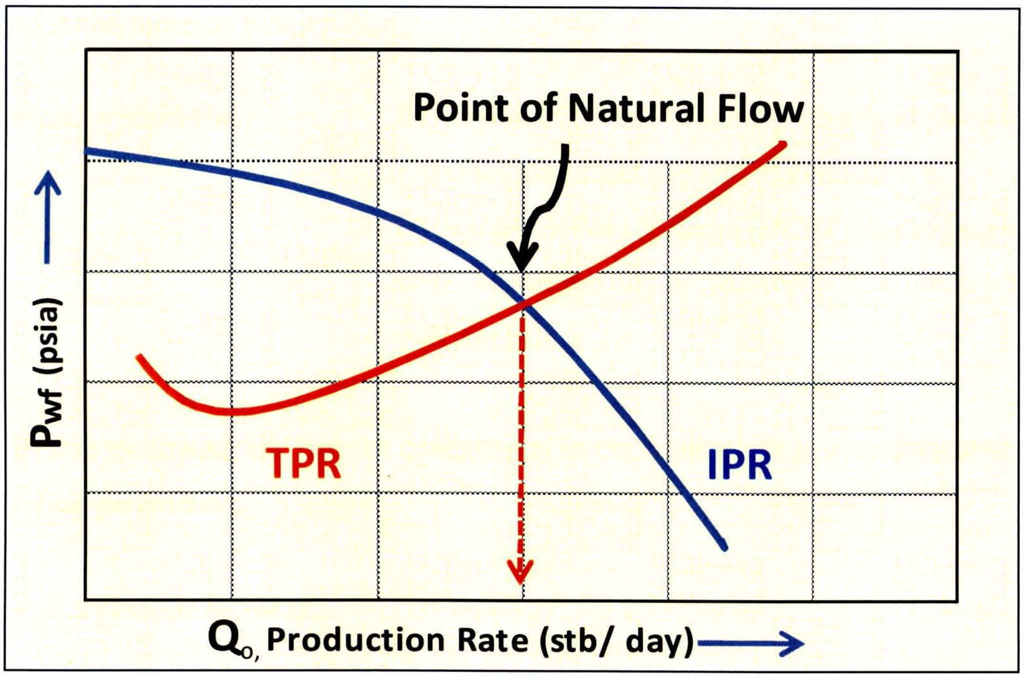

Figure 3.7 Natural Flow Condition [16]

3.2 Material Balance

The material balance equation has long been regarded as one of the basic tools of reservoir engineers for interpreting and predicting reservoir performance. In this chapter, the material balance is derived and subsequently applied, using mainly the interpretative technique of Havlena and Odeh [21, 22] to gain an understanding of reservoir drive mechanisms under primary recovery conditions. Finally, some uncertainties associated with estimation of in situ pore compressibility, a basic component in the material balance equation, are qualitatively discussed. Although the classical material balance techniques have now largely been superseded by numerical simulators, which are essentially multidimensional, multi-phase, dynamic material balance programs, the classical approach is well worth studying since it provides a valuable insight into the behavior of hydrocarbon reservoirs.

The general form of material balance equation is derived as a volume balance which equates the cumulative observed production, expressed as an underground withdrawal, to the expansion of the fluids in the reservoir resulting from a finite pressure drop. If the total observed surface production of oil and gas is expressed in terms of an underground withdrawal, evaluated at a lower pressure, p, which means effectively taking all the surface production back down to the reservoir at this lower pressure can be expressed in the terms as below:

Underground withdrawal = Expansion of oil and originally dissolved gas (rb) + Expansion of gas cap (rb) + Reduction in Hydrocarbon Pore Volume (*HCPV*) due to connate water expansion and decrease in pore volume (rb) + Water influx

Before evaluating the various components in the equation, it is necessary to define the following parameters:

$N = V\,\emptyset\,(1-S_{wc})/\,B_{oi}$ in stb (3.12)

m = initial reservoir volume of the gas cap / initial reservoir volume of the oil (a constant being defined under initial conditions)

N_p = cumulative oil production in stb

R_p = cumulative GOR in scf/stb

3.2.1 Expansion of Oil and Originally Dissolved Gas

Liquid expansion:

The stock tank oil initially in place, N (stb) occupies a reservoir volume of NB_{oi} (rb), at the initial pressure, while at the lower pressure p, the reservoir volume occupied by the oil will be NB_o, where B_o is the oil formation volume factor at the lower pressure. The difference gives the liquid expansion as:

$N(B_o - B_{oi})$ (rb) (3.13)

Liberated gas expansion:

If the initial oil is in equilibrium with the gas cap at saturation or bubble point pressure, reducing the pressure below *pi* will result in the liberation of solutions gas. The total amount of solution gas in the oil is NR_{si} (scf). Therefore, the gas volume liberated during the pressure drop Δp, expressed in reservoir barrels at the lower pressure is:

$$N(R_{si} - R_s)B_g \qquad \text{(rb)} \tag{3.14}$$

3.2.2 Expansion of Gas-cap Gas

The total volume of gas-cap gas is mNB_{oi} (rb), which in scf may be expressed as

$$G = \frac{mNB_{oi}}{B_{gi}} \qquad \text{(scf)} \tag{3.15}$$

This amount of gas at the reduced pressure p will occupy a reservoir volume

$$mNB_{oi}\frac{B_g}{B_{gi}} \qquad \text{(rb)} \tag{3.16}$$

Therefore, the expansion of the gas cap is

$$mNB_{oi}\left(\frac{B_g}{B_{gi}} - 1\right) \qquad \text{(rb)} \tag{3.17}$$

3.2.3 Change in HCPV due to Connate Water Expansion and Pore Volume Reduction

The total volume change due to these combined effects can be mathematically expressed as

$$d(HCPV) = dV_w + dV_f \tag{3.18}$$

Or as a reduction in hydrocarbon pore volume as

$$d(HCPV) = -(c_w V_w + c_f V_f)\Delta p \tag{3.19}$$

where V_f is the total pore volume $= \dfrac{(HCPV)}{(1-S_{wc})}$

and V_w is the connate water volume = $V_f \times S_{wc}$ $= \dfrac{(HCPV)S_{wc}}{(1-S_{wc})}$

Since the total *HCPV*, including the gas cap is

$$(1+m)NB_{oi} \qquad \text{(rb)} \qquad (3.20)$$

Then the HCPV reduction can be expressed as

$$-d(HCPV) = (1+m)NB_{oi}\left(\frac{c_w S_{wc} + c_f}{1 - S_{wc}}\right)\Delta p \qquad \text{(rb)} \qquad (3.21)$$

This reduction in the volume that can be occupied by the hydrocarbons at the lower pressure, p, must correspond to an equivalent amount of fluid production expelled from the reservoir and hence should be added to the fluid expansion terms.

3.2.4 Underground Withdrawal

The observed surface production during the pressure drop Δp is N_p (stb) of oil and N_pR_p (scf) of gas. At reservoir conditions, this volume of oil plus dissolved gas is N_pB_o (rb). All that is known about the total gas production is that, the lower pressure, N_pR_s (scf) will be dissolved in N_p (stb) of oil. The remaining produced gas, $N_p(R_p - R_s)$ (scf) is therefore, the total amount of liberated and gas-cap gas produced during the pressure drop Δp and will occupy a volume $N_p(R_p - R_s)B_g$ (rb) at the lower pressure. The total underground withdrawal term is therefore

$$N_p(B_o + (R_p - R_s)B_g) \qquad \text{(rb)} \qquad (3.22)$$

Therefore, equating this withdrawal to the sum of the volume changes in the reservoir, equations (3.13), (3.14), (3.17) and (3.21), gives the general expression for the material balance as

$$N_p[B_o+(R_p-R_s)B_g] =$$

$$NB_{oi}\left[\frac{(B_o-B_{oi})+(R_{si}-R_s)B_g}{B_{oi}} + m\left(\frac{B_g}{B_{gi}-1}\right) + (1+m)\left(\frac{c_wS_{wc}+c_f}{1-S_{wc}}\right)\Delta p\right] + (W_e-W_p)B_w \qquad (3.23)$$

in which the final term $(W_e - W_p)B_w$ is the net water influx into the reservoir. This term has been intuitively added to the right hand side of the balance since any such influx must expel an equivalent amount of production from the reservoir thus increasing the left hand side of the equation by the same amount.

where:

B_o	=	oil formation volume factor
B_g	=	gas formation volume factor
B_w	=	water formation volume factor
c_w	=	water compressibility
c_f	=	rock pore volume compressibility
m	=	the ratio of gas cap pore volume to oil pore volume
N_p	=	cumulative oil production
N	=	initial oil in place
p	=	average reservoir pressure; subscript i= initial
R_s	=	solution gas-oil ratio
R_p	=	cumulative production gas-oil ratio
S_w	=	water saturation
W_e	=	cumulative water influx from the into the reservoir
W_p	=	cumulative amount of aquifer water produced

3.2.5 The Material Balance Expressed as a Linear Equation

The material balance equation can be developed further to be expressed as a linear equation. Havlena and Odeh [21, 22] presented two interesting papers which described the technique of interpreting the material balance as the equation of the straight line and also illustrating the application to reservoir case histories. The way Havlena and Odeh [21, 22] presented requires the definition of the following terms:

Underground withdrawal

$$F = N_p\,[B_o + (R_p - R_s)\,B_g\,] + W_p\,B_w \qquad \text{(rb)} \qquad (3.24)$$

Expansion of oil and its originally dissolved gas

$$E_o = (B_o - B_{oi}) + (R_{si} - R_s)\,B_g \qquad \text{(rb/stb)} \tag{3.25}$$

Expansion of gas-cap gas

$$Eg = B_{oi}\left(\frac{B_g}{B_{gi} - 1}\right) \tag{3.26}$$

Expansion of connate water and reduction in the pore volume

$$E_{f,w} = (1+m)B_{oi}\left(\frac{c_w S_w + c_f}{1 - S_w}\right)\Delta p \tag{3.27}$$

Using these terms, the material balance equation can be written as

$$F = N\,(E_o + mE_g + E_{f,w}) + W_e B_w \tag{3.28}$$

Havlena and Odeh [21, 22] have shown in many cases that the above equation can be interpreted as a linear function. For instance, in the case of a reservoir which has no gas cap, negligible water influx and for which the connate water and rock compressibility term is neglected, the equation can be reduced to

$$F = N\,E_o \tag{3.29}$$

in which the observed production, evaluated as an underground withdrawal, should plot as a linear function of the expansion of oil plus its originally dissolved gas, the latter being calculated from a knowledge of the PVT parameters at the current reservoir pressure. This interpretation technique is useful, in that, if a simple linear relationship is expected for a reservoir and yet the actual plot turns out to be non linear, then this deviation can itself be diagnostic in determining the actual drive mechanisms in the reservoir.

3.3 Reservoir Drive Mechanisms

Producing oil and gas needs energy. Usually some of this required energy is supplied by nature. The hydrocarbon fluids are under pressure because of their depth. The gas and water in petroleum reservoirs under pressure are the two main sources that help move the oil to the well bore and sometimes up to the surface. Depending on the original characteristics of hydrocarbon reservoirs, the type of driving energy is different. Generally there are five important drive mechanisms (or combinations) which are

(i) Solution gas drive

(ii) Gas cap drive

(iii) Water drive

(iv) Gravity drainage

(v) Combination or mixed drive

3.3.1 Solution Gas Drive

This drive mechanism requires the reservoir rock to be completely surrounded by impermeable barriers. As the production occurs the reservoir pressure drops, and this causes emerging and expansion of the dissolved gases in the oil and water providing most of the reservoirs drive energy. The process is shown schematically in Figure 3.8. A solution gas drive reservoir is initially either considered to be undersaturated or saturated depending on its pressure:

- Undersaturated: Reservoir pressure > bubble point of oil.
- Saturated: Reservoir pressure ≤ bubble point of oil.

For an undersaturated reservoir, no free gas exists until the reservoir pressure falls below the bubble point. In this regime reservoir drive energy is provided only by the bulk expansion of the reservoir rock and liquids (water and oil).

For a saturated reservoir, any oil production results in a drop in reservoir pressure that causes gas to come out of solution and expand. When the gas comes out of solution the oil (and water) shrinks slightly. However, the volume of the gas, and its subsequent expansion more than makes up for this. Thus gas expansion is the primary reservoir drive for reservoirs below the bubble point.

Solution gas drive reservoirs show a particular characteristic pressure, GOR (or R) and fluid production history as shown in Figure 3.9. If the reservoir is initially undersaturated, the reservoir pressure p_i can drop by a great deal (several hundred psi over a few months).

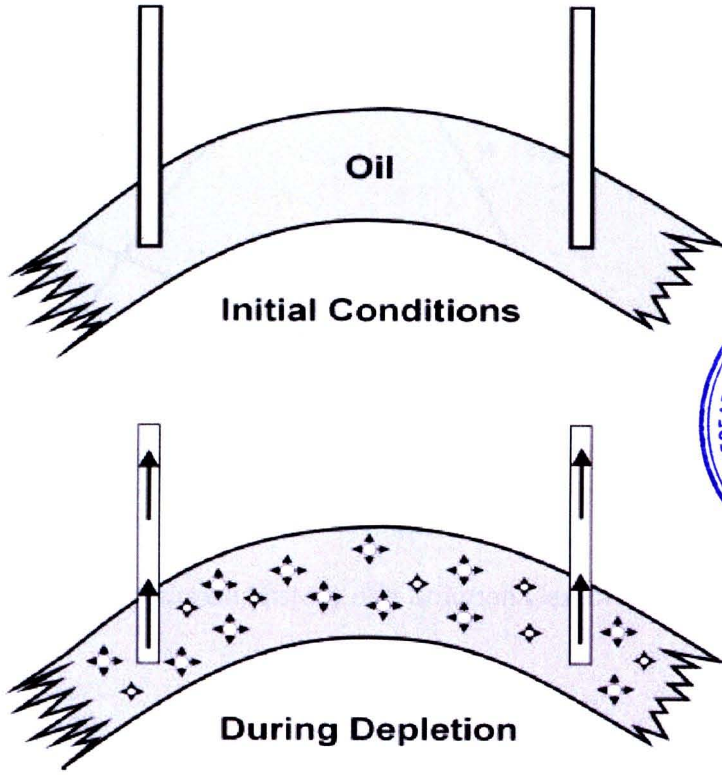

Figure 3.8 Solution Gas Drive Reservoir [21]

This is because of the small compressibility of the rock water and oil, compared to that of gas. In this undersaturated phase, gas is only exsolved from the fluids in the well bore, and consequently the GOR is low and constant. When the reservoir reaches the bubble point pressure p_b, the pressure declines less quickly due to the formation of gas bubbles in the reservoir that expand taking up the volume exited by produced oil and hence protecting against pressure drops. When this happens, the GOR rises dramatically. Further fall in reservoir pressure, as production continues, can; however, lead to a decrease in GOR again when reservoir pressures are such that the gas expands less in the borehole. When the GOR initially rises, the oil production falls and artificial lift systems are then instituted. The efficiency of solution gas drive depends on the amount of gas in solution, the rock and fluid properties and the geological structure of the reservoir. Recovery based on solution gas drive is low, in the order of 10-15 % of the original oil in place (OOIP).

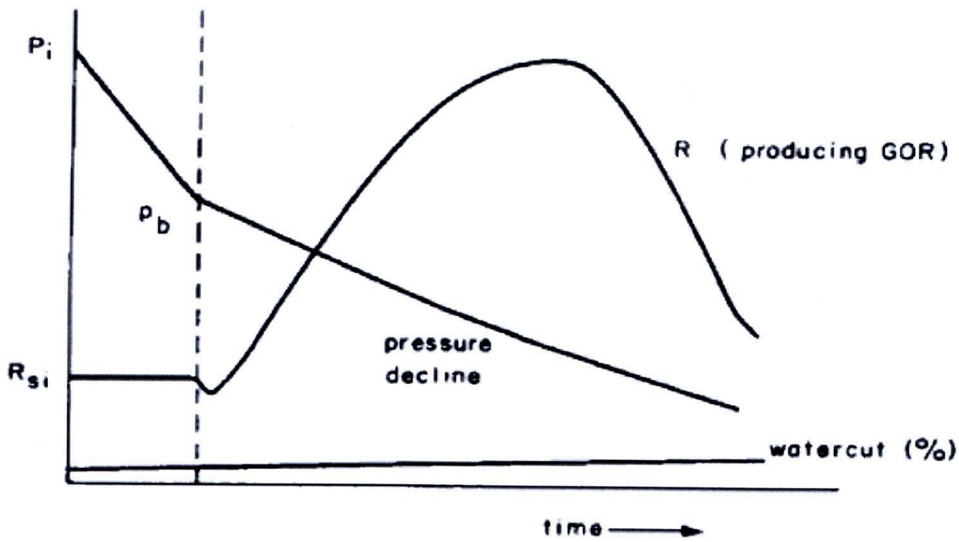

Figure 3.9 Schematic of Production History of a Solution Gas Drive Reservoir [22]

3.3.2 Gas Cap Drive

Sometimes, the pressure in the reservoir is below the bubble point initially; so there is more gas in the reservoir than the oil can retain in solution. This extra gas, because of density difference, accumulates at the top of the reservoir and forms a cap.

The process is shown schematically in Figure 3.10. This kind of reservoirs is called gas cap drive reservoirs. In gas cap drive reservoirs, wells are drilled into the oil zone of the formation. As oil production causes a reduction in pressure, the gas in gas cap expands and pushes oil into the well bores. Expansion the gas cap is limited by the desired pressure level in the reservoir and by gas production after gas comes into production wells.

From Figure 3.11, the GOR (or R) rises only slowly in the early stages of production from such a reservoir because the pressure of the gas cap prevents gas from coming out of solution in the oil and water. As production continues, the gas cap expands pushing the gas-oil contact (GOC) downwards (Figure 3.10). Eventually the GOC will reach the production wells and the GOR will increase by large amounts (Figures 3.11). The slower reduction in pressure experienced by gas cap reservoirs compared to solution drive reservoirs results in the oil production rates being much higher throughout the life of the reservoir, and needing artificial lift much later than for solution drive reservoirs. The actual rate of pressure decrease is related to the size of the gas cap. Moreover, gas cap reservoirs produce very little or no water.

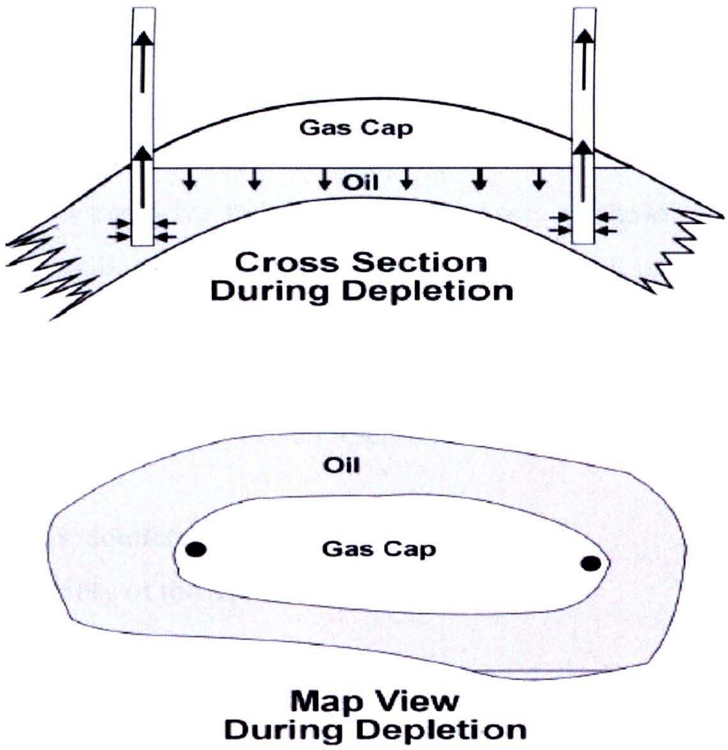

Figure 3.10 Gas-Cap Drive Reservoir [21]

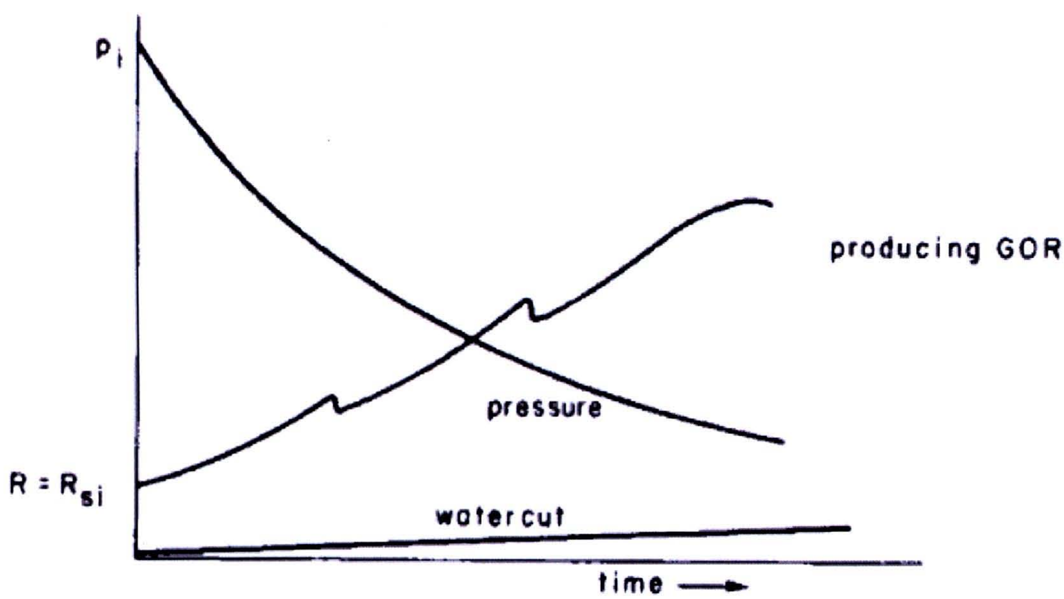

Figure 3.11 Schematic of Production History of a Typical Gas-Cap Drive Reservoir [22]

3.3.3 Water Drive

Most oil or gas reservoirs have water aquifers. When this water aquifer is an active one, continuously fed by incoming water, this water will expand as pressure of the oil/gas zone is reduced because of production causing an extra driving energy. This kind of reservoirs is called water drive reservoirs. The process is shown schematically in Figure 3.12. The expanding water also moves and displaces oil or gas in an upward direction from lower parts of the reservoir, so the pore spaces partially by oil or gas produced are filled by water. The oil and gas are progressively pushed towards the well bore. The pressure history of a water driven reservoir depends critically upon:

(i) The size of the aquifer.
(ii) The permeability of the aquifer.
(iii) The reservoir production rate.

If the production rate is low, and the size and permeability of the aquifer is high, then the reservoir pressure will remain high because all produced oil is replaced efficiently with water. If the production rate is too high then the extracted oil may not be able to be replaced by water in the same timescale, especially if the aquifer is small or low permeability. In this case the reservoir pressure will fall (Figure 3.13).

The GOR remains very constant in a strongly water driven reservoir as the pressure decrease is small and constant, whereas if the pressure decrease is higher (weakly water driven reservoir) the GOR increases due to gas exsolving from the oil and water in the reservoir. Likewise the oil production from a strongly water driven reservoir remains fairly constant until water breakthrough occurs. Recovery efficiency of 70 to 80 % of the original oil in place (OOIP) is possible in some water drive oil reservoirs.

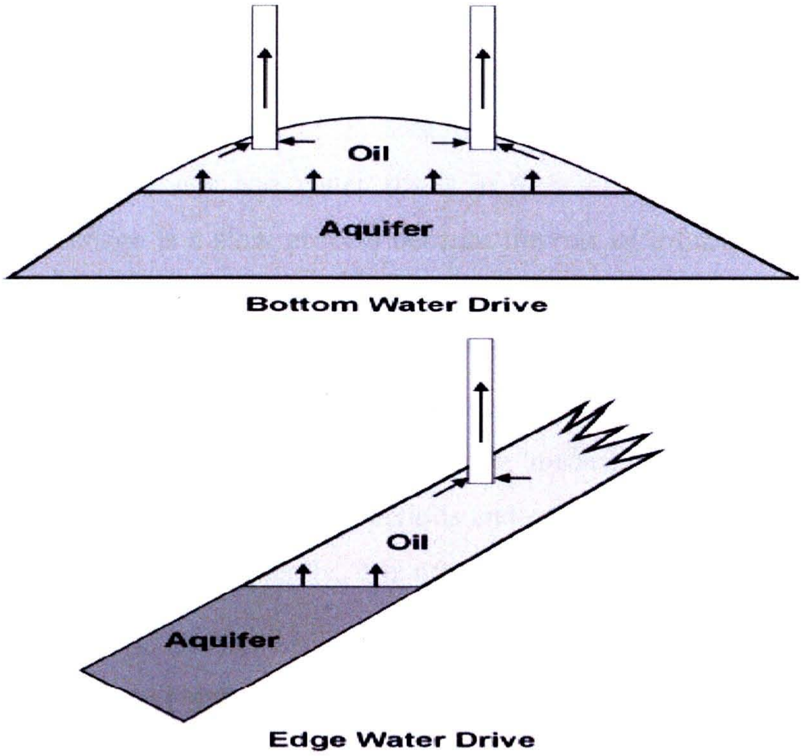

Figure 3.12 Water Drive Reservoir [21]

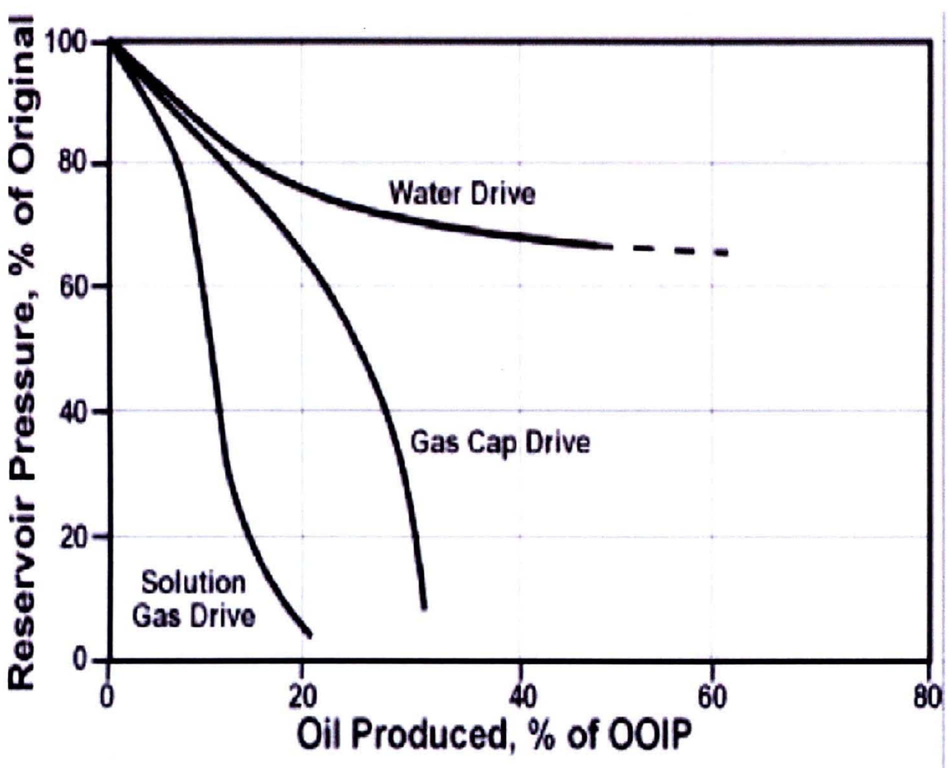

Figure 3.13 Reservoir Pressure Trends for Drive Mechanisms [21]

3.3.4 Gravity Drainage

Gravity drainage may be a primary producing mechanism in thick reservoirs that have a good vertical communication or in steeply dipping reservoirs. The density differences between oil and gas and water result in their natural segregation in the reservoir. Gravity drainage is a slow process because the rate of oil drainage is slower than the gas migration. This process can be used as a drive mechanism, but is relatively weak, and in practice is only used in combination with other drive mechanisms. Figure 3.14 shows production by gravity drainage. The rate of production engendered by gravity drainage is very low compared with the other drive mechanisms examined so far. However, it is extremely efficient over long periods and can give rise to extremely high recoveries (50-70% OOIP). Consequently, it is often used in addition to the other drive mechanisms.

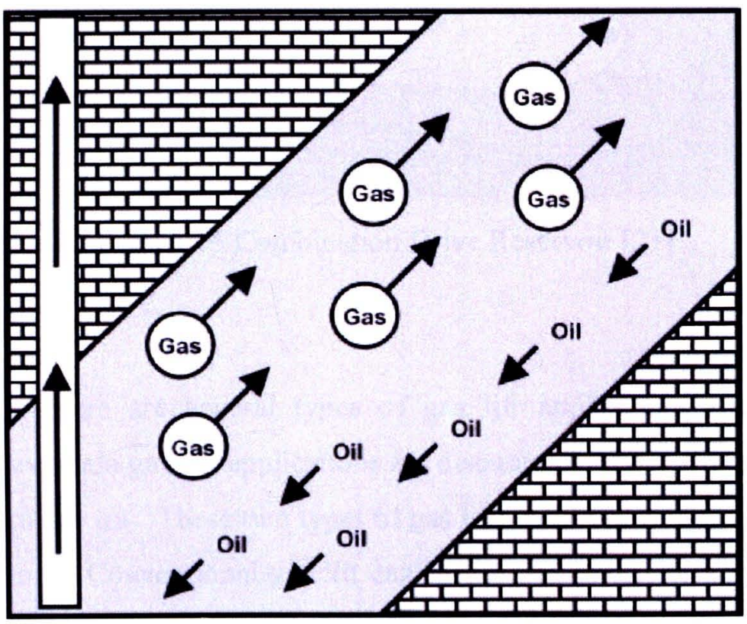

Figure 3.14 Gravity Drainage Reservoir [21]

3.3.5 Combination Drive

In practice a reservoir usually incorporates at least two main drive mechanisms For example, in the case shown in Figure 3.15, it can be seen that the management of the reservoir for different drive mechanisms can be diametrically opposed (e.g. low perforation for gas cap reservoirs compared with high perforation for water drive reservoirs). If both occur as in Figure 3.15, a compromise must be sought, and this compromise must take into account the strength of each drive present, the size of the gas cap, and the size/permeability of the aquifer.

It is the job of the reservoir manager to identify the strengths of the drives as early as possible in the life of the reservoir to optimize the reservoir performance.

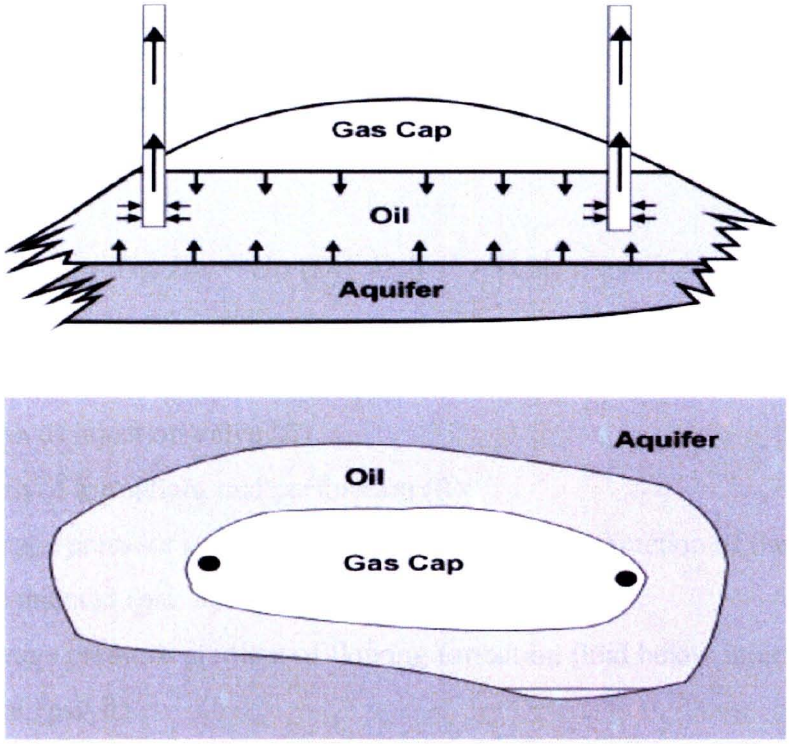

Figure 3.15 Combination Drive Reservoir [21]

3.4 Gas Lift Theory

Generally, there are several types of gas lift applications used in oil wells. However, only two main gas lift applications are discussed in this study, the conventional gas lift and in-situ gas lift. These two types of gas lift applications may result in different oil recovery factors. Conventional gas lift can be divided into two main categories, the continuous gas lift and intermittent gas lift. The continuous gas lift is used in this study for setting up the base case model.

3.4.1 Continuous Gas Lift

Gas is continuously injected into the tubing through a gas lift valve at a fixed depth. The injected gas increases gas liquid ratio (GLR) from the valve to the surface and decreases the hydrostatic pressure gradient in the tubing, thus decreasing the wellbore flowing pressure, P_{wf} even though the friction loss increases. The only difference between in-situ gas lift operation and a flowing valve is that the gas liquid ratio changes at some point in the tubing for the gas lift valve.

A simplified schematic and pressure traverse for a gas lift operation shown in Figure 3.16 indicated that if the gas is injected deeper in the well, it has the ability to decrease the gradient more effectively.

As the diagram indicates, P_{wf} is determined by the pressure traverse in the tubing above and below the injection point.

Assuming linear pressure traverse below and above injection point, P_{wf} can be expressed as

$$P_{wf} = P_{wh} + G_{av} D_{ov} + G_{bv} (D_f - D_{ov}) \qquad [17] \qquad (3.30)$$

where

P_{wh} = wellhead pressure (psia)

D_{ov} = depth of injection valve (ft)

D_f = depth of formation, mid perforation (ft)

G_{av} = average pressure gradient above injection point, a function of the gas rate injected (psi/ ft)

G_{bv} = average pressure gradient of flowing formation fluid below injection point (psi/ ft)

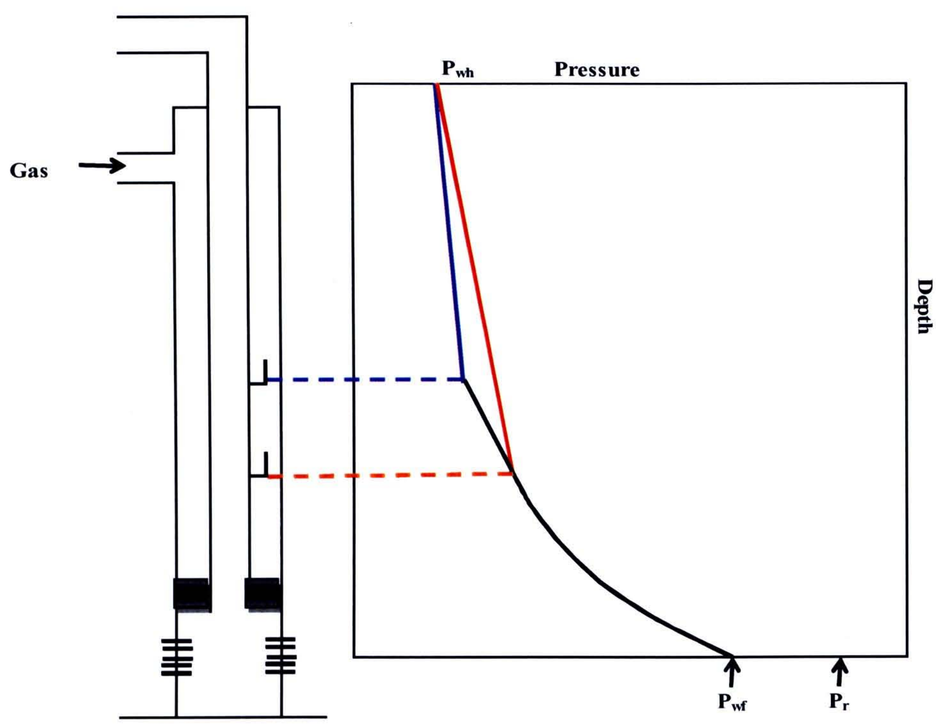

Figure 3.16 Pressure Diagram for a Gas-Lift Well [17]

Two parameters in (3.30), the injection depth and the flowing pressure gradient above the injection point, may be varied independently by the designer in a given wellhead pressure and tubing size. The ability to control the bottom-hole flowing pressure and production rate in a gas-lift well thus amounts to the ability to control the depth of injection and the flowing pressure gradient.

The depth of injection is controlled by the amount of surface gas injection pressure available. The more pressure available, the deeper the injection point can be. As seen in Figure 3.16, the deeper the injection depth, the higher the pressure in the tubing at the point of injection. Also, as the depth of injection increases, less injection gas is required to achieve the same bottom-hole flowing pressure.

The second independent parameter in the diagram, the flowing gradient in the tubing, is controlled by the gas injection rate. At a given rate and constant wellhead pressure, the tubing intake pressure varies with GLR. For each flow rate in a given tubing size, there is a particular GLR that yields minimum tubing intake pressure or minimum flowing gradient resulting in maximum liquid rate. This GLR is referred as favorable or optimal GLR. A plot of favorable GLR versus the corresponding rates in a given tubing size is given in Figure 3.17. Favorable GLR decreases as oil rate increases. The favorable GLR is seldom equal to reservoir GLR and it may be achieved by adding gas to the tubing. The amount of gas injection rate required to achieve a favorable GLR is difference between the favorable and formation GLRs.

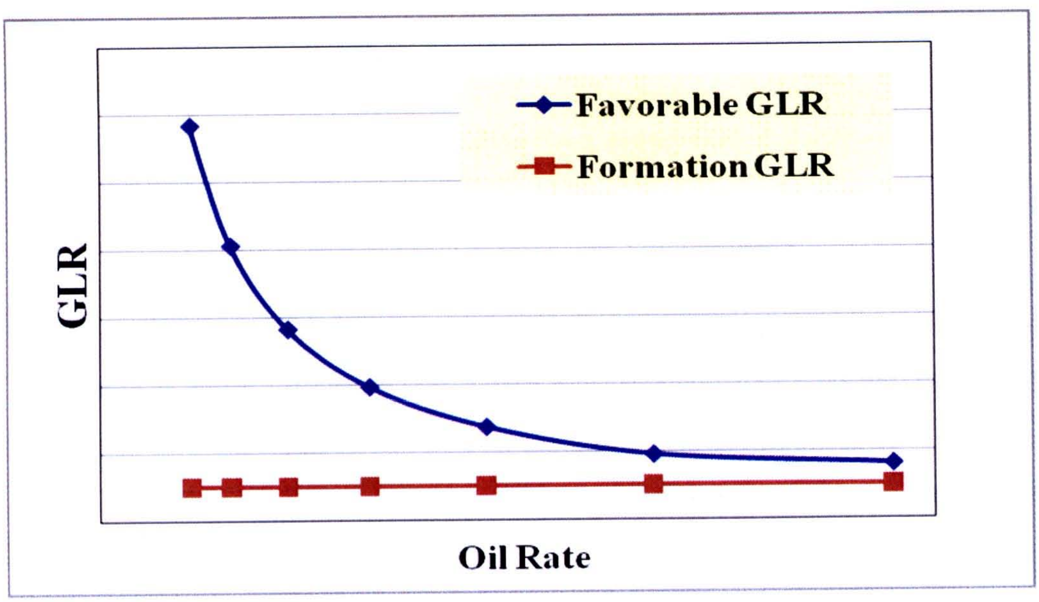

Figure 3.17 Example Plot of Favorable and Formation GLR vs. Oil Rate [17]

From Figure 3.18, increasing gas injection rate increases the gas-liquid ratio (GLR) in the tubing and up to a certain limit, decreases the flowing gradient. Beyond this limit, the flowing pressure gradient is increased by larger GLR or because the injected GLR becomes too large, the increasing in piping system pressure drop due to friction will exceed the decrease in the hydrostatic pressure in the tubing above the valve or injection point.

For a particular well, if the formation GLR is lower than the favorable GLR, injection of gas will increase the production. On the other hand, in wells where formation GLR is higher than the favorable GLR there is no gain in production by gas lift.

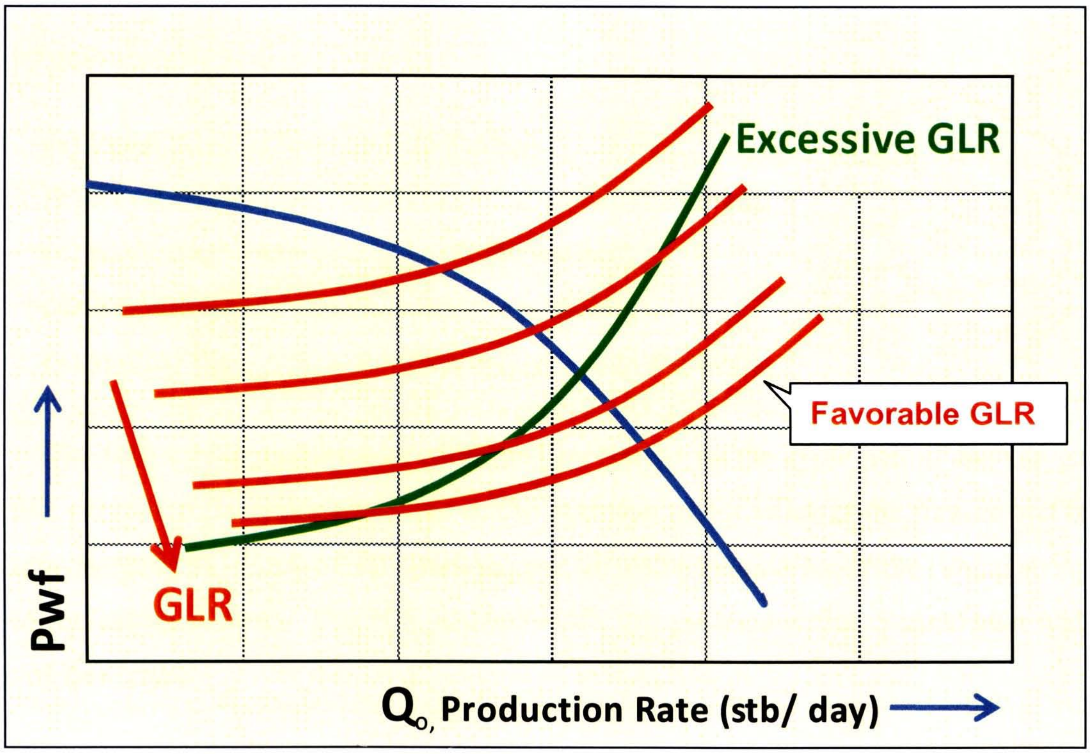

Figure 3.18 Gas-lift Well Analysis [17]

Figure 3.18 also illustrates the significance of intersection points in term of a tubing performance curve. It shows that tubing performance curves for any GLR higher or lower than the favorable GLR will intersect the IPR at a lower liquid rate.

The favorable GLR for a given liquid rate is independence of reservoir behavior. Therefore, in spite of depletion, the locus of favorable GLRs does not change. In gas injection rate required to maintain the maximum liquid rate as the reservoir depletes is the difference between the favorable GLR and formation GLR.

For solution gas-drive reservoirs, the needed gas-injection GLR increases at early stages but drops rapidly as reservoir GLR increases when reservoir pressure drops below the bubble point.

3.4.2 Intermittent Gas Lift

As the bottom-hole pressure declines, a point is reached where the well can no longer support continuous gas lift and the well is converted to intermittent gas lift. The intermittent gas lift (IGL) is an artificial lift method employed to produce oil when the reservoir is somewhat exhausted or its productivity is too low to use a higher producing method. A high-pressure gas supply provides the supplement of energy necessary to intermittently lift the reservoir's liquids (oil and water) up to the surface. The IGL cycle may be described by stages as follows:

(a) injection (gas input into the casing)
(b) elevation (gas-lift of the liquid slug inside the tubing)
(c) production (output of liquid at the surface)
(d) decompression (gas flow out of the tubing)
(e) loading (liquid flow from the reservoir into the well)

The IGL cyclic operation is controlled by setting up the cycle period and the gas injection period on the timer controller of the injection motor valve at the surface and by pressure-charging the dome of the operating gas lift-valve located inside the tubing string, near to the casing bottom. The IGL assisted wells can produce within a somewhat wide range of flow rates.

3.4.3 In-situ Gas Lift

Another method of gas lift is in-situ gas lift which is different from the continuous and intermittent gas lift. The in-situ gas lift has been developed without external gas sources. This method is applied to wells in which a gas zone(s) is available. In many cases, one or more gas zones are perforated with limited or partial perforation interval and produced along with the oil zones for production. The perforation interval may range from 1 to 3 feet with and 2" scallop guns, 6 shots per foot perforation density and 60 degrees of phasing.

Theoretically, conventional gas lift should provide better optimal GLR than in-situ gas lift; however, the in-situ gas lift may give more favorable economics in some certain scenarios.

In practice, the injection depth of gas lift in slim monobore completion is normally limited by the depth of the casing shoe which is typically set at about 4,000 ft TVD in Pattani Basin. For the in-situ gas lift, the depth of the in-situ gas zone(s) can be inferred as the injection depth which can be located deeper than 4,000 ft TVD. This could be one of the advantages of in-situ gas lift over the conventional gas lift.

Moreover, for the conventional gas lift, the maximum gas injection pressure is limited by the capacity of a gas lift compressor. The maximum gas injection pressure from typical gas lift compressors designed for the offshore application in the Gulf of Thailand is approximately 1,200 psi whereas the reservoir pressure of the in-situ gas zone(s) can be as high as 5,000 psi.

Usually, the gas injection rate required for monobore wells with conventional gas lift is about 0.5 – 1.0 MMscfd per well. Unlike the conventional gas lift, the in-situ gas lift has more difficulty in controlling or optimizing the downhole in-situ gas lift rate to achieve optimal GLR. However, the in-situ gas rate from the gas zone(s) can be controlled by limited or partial perforation or mechanical devices such as downhole choke or straddle pack-off assembly with an orifice valve. A rate greater than 1.0 MMscfd for in-situ gas zone can be achieved.

Table 3.1 Comparison between Conventional Gas Lift and In-situ Gas Lift

Parameter	**Conventional Gas Lift**	**In-Situ Gas Lift**
Injection depth	Limited by casing shoe +/- 4,000' TVD (monobore completion)	Vary with depth, could be as deep as 8,000' TVD
Injection pressure	Limited by compressor capacity +/-1,200 psi (typical model)	Vary, could be as high as 5,000 psi from a gas zone(s)
Control of gas injection rate	Can be controlled to achieve optimal GLR.	More difficult to be controlled by perforating or a mechanical device
Any limit on gas injection rate or GLR?	May be limited by the capacity, 0.5 – 1.0 MMscfd/ well.	Vary, could be higher than 1.0 MMscfd.