NEW INFLOW PERFORMANCE RELATIONSHIP MODEL FOR A SOLUTION GAS DRIVE RESERVOIR

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A PROJECT REPORT SUBMITTED TO THE DEPARTMENT OF PERTOLEUM ENGINEERING IN PARTIAL FULFILMENT OF THE REQUIREMENTS FOR THE AWARD OF BACHELOR OF ENGINEERING DEGREE (B.ENG) IN PETROLEUM ENGINEERING IN THE DEPARTMENT OF PETROLEUM ENGINEERING, FACULTY OF ENGINEERING, UNIVERSITY OF BENIN, BENIN CITY

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CERTIFICATION

This is to certify that this project titled “New Inflow Performance Relationship for A solution Gas Drive Reservoir” was carried out by EGBUBINE BRIGHT CHIAMAKA with matriculation number ENG1503968 in the Department of Petroleum Engineering, University of Benin, Benin City, Edo state, Nigeria.

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DEDICATION

To God almighty, the most merciful, to whom I owe all my accomplishments. To the sweetest and most deserving Parents on earth Mr. Joseph and Mrs. Joy Egbubine, whose prayers and support where significant to its completion. Also my caring siblings, Miss Chiwendu and Master Joseph and Master Daniel, who made various scarifies to ensuring the completion of the Project.

This project is also dedicated to Dr. Mrs. O.A Solomu friends and well-wishers who worked painstakingly and tirelessly in imbibing spiritual, moral and financial support throughout my duration in school.

God Bless you All

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To the immortal, indefatigable and indomitable God and Savior Jesus Christ be all the praise and adorations. He has been exceedingly gracious and merciful in all that He has done. I say thank you, Abba Father.

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Nomenclature

P_i	Initial Reservoir Pressure
P	Reservoir pressure
Δp	Change in reservoir pressure = $p_i - p$
P_b	Bubble point pressure
N	Initial (original) oil in place
N_p	Cumulative oil produced
G_p	Cumulative gas produced
W_p	Cumulative water produced
R_p	Cumulative gas – oil ratio
GOR	Instantaneous gas – oil ratio
R_{si}	Initial gas solubility
R_s	Gas Solubility
B_{oi}	Initial oil formation volume factor
B_o	Oil formation volume factor
B_{gi}	Initial gas formation volume factor
B_g	Gas formation volume factor
B_w	Water formation volume factor
ϕ_o, ϕ_g, ϕ_w PVT	related properties which are functions of pressure
Den	Denominator
W_e	Cumulative water influx
W_i	Initial volume of water in the aquifer
m	Ratio of initial reservoir volume to initial reservoir oil volume
c_w	Water compressibility
c_f	Formation (rock) compressibility
c_o	Oil compressibility
S_{wc}	Connate water saturation
S_o	Oil saturation
S_o	Oil saturation at the beginning of pressure step
S_{oi}	Initial oil saturation
ΔS_o	Change in oil saturation

S_{wi}	Initial water saturation
S_w	Water saturation
$(S_L)_2$	Liquid saturation at the second pressure step
S_g	Gas saturation
P_*	Average reservoir pressure at the beginning of pressure step
P_1	Average reservoir pressure at the first pressure step
P_2	Average reservoir pressure at the second pressure step
G_{p1}	Cumulative gas produced at first pressure step
G_{p2}	Cumulative gas produced at second pressure step
N_{p1}	Cumulative oil produced at first pressure step
N_{p2}	Cumulative oil produced at second pressure step
R_{p2}	Cumulative gas – oil ratio at second pressure step
R_1	Instantaneous gas – oil ratio computed at pressure p_1
R_2	Instantaneous gas – oil ratio computed at pressure p_2
ΔG_p	Change in cumulative gas produced
ΔN_p	Change in cumulative oil produced

N_r	Oil remaining in the reservoir
G_r	Gas remaining in the reservoir
$(GOR)_{avg}$	Average instantaneous gas – oil ratio
GLR_i	Initial gas – liquid ratio
V	Pore volume
$X(p)$, $Y(p)$, $Z(p)$	Pressure dependent terms
K_{rg}	Gas relative permeability
k_{ro}	Oil relative permeability
μ_o	Oil viscosity
μ_g	Gas viscosity
P_{avg}	Average reservoir pressure
$Q_{o(avg)}$	Average oil flow-rate
Q_e	Equivalent oil flow-rate
q_e	Equivalent oil flow-rate
q_{max}	Maximum oil flow-rate

P_{wf}	Bottom-hole flowing pressure
q_b	Bubble point flow-rate
q	Flow-rate
Q_o	Oil flow-rate
J^*	Starting productivity index
Δt	Change in time
t	Time
F	Underground withdrawal
E_o	Expansion of oil
E_g	Expansion of the gas – cap gas

ABSTRACT

The Inflow Performance Relationship (IPR) describes the behavior of the well's flowing pressure and quantifies its production rate. Different IPR correlations exist today in the petroleum industry with the most commonly used models are that of Vogel's and Fetkovich's.

In this work, a new model to predict the IPR curve was developed, using a new correlation that accurately describes the behavior of a well flow-rate as a function of the average reservoir pressure. This new correlation was obtained using actual field cases. After the development of the new model, its validity was tested by comparing its accuracy with that of the most common IPR models such as Vogel, Fetkovich, and Wiggins.

The results of this comparison showed that: the new developed model gave the best accuracy with an absolute error of **5.54 %**, while the other common models are ranked, according to their accuracy in the following order to be Fetkovich, Vogel, and Wiggins, with absolute errors of **6.73 %**, **23.18 %**, and **32.3 %** respectively.

CHAPTER ONE

Introduction

1.1 Problem Statement

Solution gas drive also known as Dissolved gas drive or Internal gas drive reservoirs are characterized by a rapid and continuous decline of reservoir pressure. This reservoir pressure behavior is attributed to the fact that no extraneous fluids or gas caps are available to provide a replacement of the gas and oil withdrawals (Tarek, 2001). This rapid and continuous decline of reservoir pressure causes a direct decline of reservoir performance at early stages of the life of the reservoir. Moreover, the principal source of energy which is gas liberation from the crude oil and the subsequent expansion of the solution gas as the reservoir pressure is reduced are inadequate to produce such reservoirs to their full capacities (Tarek, 2001). Ultimate oil recovery from natural flow of a solution gas drive reservoir (less than 5% to about 30%) makes it one of the least efficient primary recovery mechanisms (Tarek, 2001). The low recovery from this type of reservoir suggests that large quantities of oil remain in the reservoir and, therefore, solution gas drive reservoirs are considered the best candidates for secondary recovery applications.

Artificial lift technologies such as continuous gas lift, gas lift with velocity strings and positive displacement pumping method is therefore employed at later phases of the reservoir in order to increase the ultimate recovery. The main challenge is to know when to change existing production mechanism to a new one for optimum recovery. A production design has therefore been made in an attempt to solving this problem with respect to constraints such as maximum production rate, maximum drawdown, and available gas lift.

The flowing bottom-hole pressure required to lift the fluids up to the surface may be influenced by size of the tubing string (Lyons, 1996) and for that matter the time when tubing strings should be replaced as a function of cumulative production is necessary.

1.2 Method of Conducting the Project

Excel VBA to analyze various methods for analyzing Inflow performance relationship on a solution gas drive reservoir model. After getting the simulated data set, with the aid of sensitivity analysis select the most accurate. Then create a New IPR model from the selected by tweaking its equation to obtain a new equation. Then apply the new equation on the same reservoir model to obtain a new data set. Then compare and contrast both equations.

1.3 Aim and Objectives

Examine a production data (flowing pressure and actual flow-rate) of a standard Reservoir model by comparing the commonly used models Vogel's, Fetkovich's and Wiggin's using Excel Visual Basic for Application.

I. Test some of the available IPR methods on a Field production data.

II. Perform Sensitivity analysis test via Error calculation to select the most accurate IPR model.

III. Develop a new IPR model from the selected model and compare both models.

1.4 Outline of this Project

The project consists of five (5) chapters. Chapter 1 defines the problem at hand, the method which the project follows and objectives. Chapter 2 presents a literature review of the topic as well as the technical terms that make up the topic. Chapter 3 introduces a thorough review on Inflow Performance Relationship model and commonly known models. Chapter 4 focuses on the application of some to the common models on an actual field data and development of our new model from the most accurate model amongst the common model Chapter 5 gives a summary and conclusions stemming from this project and provides recommendations for future research work in this area. This work focuses on applying our newly developed model, in this case cost, to help a well to optimally meet its recommended flow capacity which enhances economic evaluation in solving a real life problem.

CHAPTER TWO

Literature Review

The Inflow Performance Relationship (IPR) describes the behaviour of a well's flowing pressure and production rate, which is an important tool in understanding the reservoir or well behaviour and quantifying the production rate. The IPR is often required for designing well completion, optimizing well production, nodal analysis calculations, and designing artificial lift. Different IPR correlations exist today in the petroleum industry with the most commonly used models being that of Vogel's and Fetkovich's (Mohammed et al, 2009).

2.1 Reservoir Natural Drive Mechanisms

Natural drive mechanisms refer to the energy in the reservoir that allows the fluid to flow through the porous network and into the wells. In its simplest definition, reservoir energy is always related to some kind of expansion (Cosentino, 2001). For a proper understanding of reservoir behaviour and predicting future performance, it is necessary to have knowledge of the driving mechanisms that control the behaviour of fluids within reservoirs. Several types of expansions take place inside and outside the reservoir, as a consequence of fluid withdrawals. Inside the reservoir, the expansion of hydrocarbons, connate water and the rock itself provides energy for the fluid to flow. Outside the producing zone, the expansion of a gas cap and/or of an aquifer may also supply significant amount of energy to the reservoir. In this case, the expansion of an external phase causes its influx into the reservoir and will ultimately result in a displacement process (Cosentino, 2001). There are basically six driving mechanisms that provide the natural energy necessary for oil recovery:

1. Rock and liquid expansion drive
2. Depletion drive
3. Gas cap drive
4. Water drive
5. Gravity drainage drive
6. Combination drive

The figures 2.1 and 2.2 below compare various characteristics of the drive mechanisms.

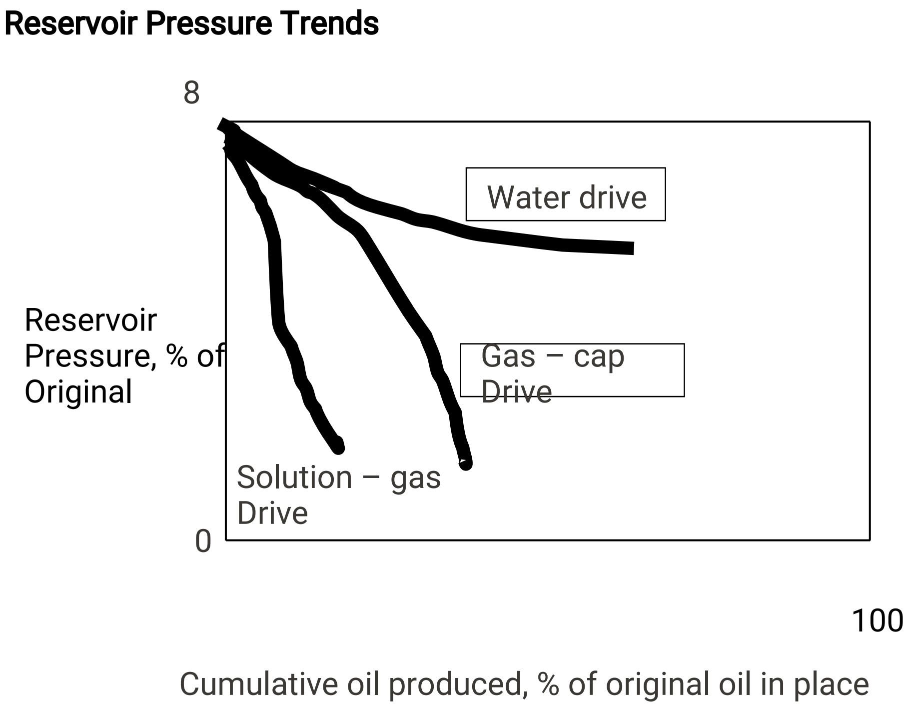


Figure 1: Typical pressure trends of some drive mechanisms

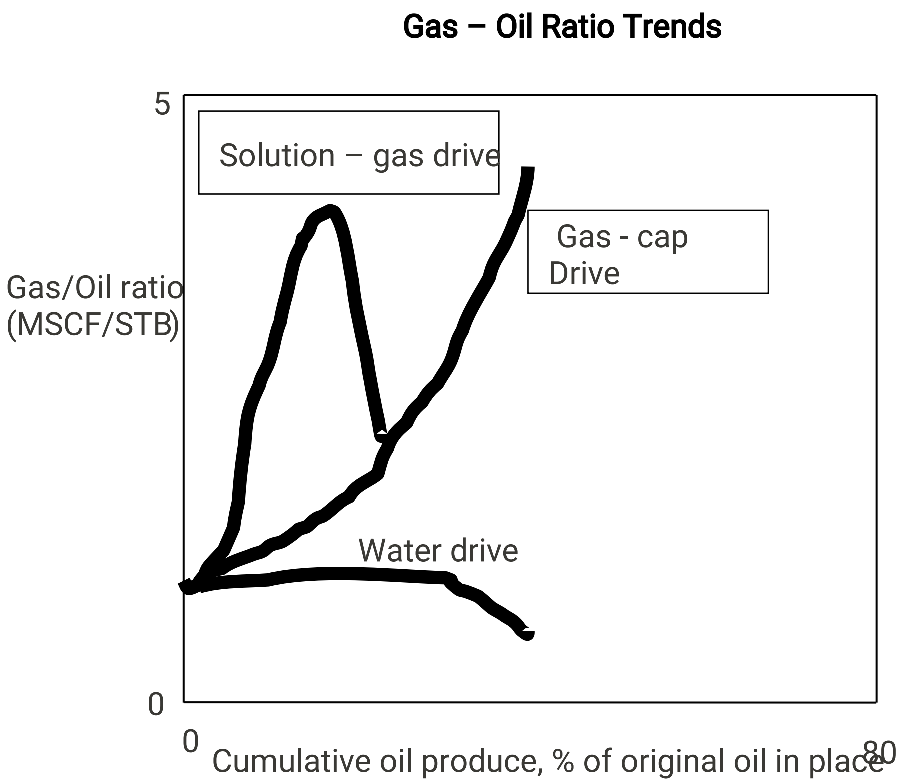


Figure 2: Typical Gas – Oil Ratio Trends of Some Drive Mechanisms

The attention of this project is on the Depletion drive mechanism also known as the solution gas drive mechanism which is reviewed as follows.

2.2 Solution – Gas Drive Reservoir

This driving form may also be referred to by the following various terms: Solution gas drive, Dissolved gas drive or internal gas drive. A solution gas drive reservoir is one in which the principal drive mechanism is the expansion of the oil and its originally dissolved gas. The increase in fluid volumes during the process is equivalent to the production (Dake, 1978). A solution – gas drive reservoir is mostly closed from any outside source of energy, such as water encroachment. Its pressure is initially above bubble-point pressure, and, therefore, no free gas exists. The only source of material to replace the produced fluids is the expansion of the fluids remaining in the reservoir (Beggs, 2003). Some small but usually negligible expansion of the connate water and rock may also occur.

When the reservoir falls below the saturation pressure, gas is liberated from the hydrocarbon liquid phase. Expansion of the gas phase contributes to the displacement of the residual liquid phase. Initially the liberated gas will expand but not flow, until its saturation reaches a threshold value, called critical gas saturation (Cosentino, 2001). Typical values of the critical saturation ranges between 2 and 10% (Cosentino, 2001). When this value is reached, gas starts to flow with a velocity proportional to its saturation. The more the pressure drops, the faster the gas is liberated and produced, thus lowering further the pressure, in a sort of chain reaction that quickly leads to the depletion of the reservoir (Cosentino, 2001).

At the surface, solution gas drive reservoirs are characterized in general by rapidly increasing in Gas – Oil Ratios (GORs) and decreasing oil rates. Generally no or little water is produced. The ideal behaviour of a field under solution gas drive is depletion is illustrated in figure 2.3. The GOR curve has a peculiar shape, in that it tends to remain constant and equal to the initial R_{si} while the reservoir pressure is below the bubble point, then it tends to decline slightly until the critical gas saturation is reached. This decline corresponds to the existence of some gas in the reservoir that cannot be mobilized (Cosentino, 2001). After the critical saturation is reached, the GOR increases rapidly and finally declines towards the end of the field life, when the reservoir approaches the depletion pressure.

The most important parameter in solution – gas drive reservoirs is gas – oil relative permeability (Cosentino, 2001). Actually, the increase in the GOR curve is related to the increased gas permeability with respect to oil, as its saturation increases. The lower the critical gas saturation, the more rapid the gas will be mobilized and produced, thus accelerating the depletion and impairing the final recovery (Cosentino, 2001).

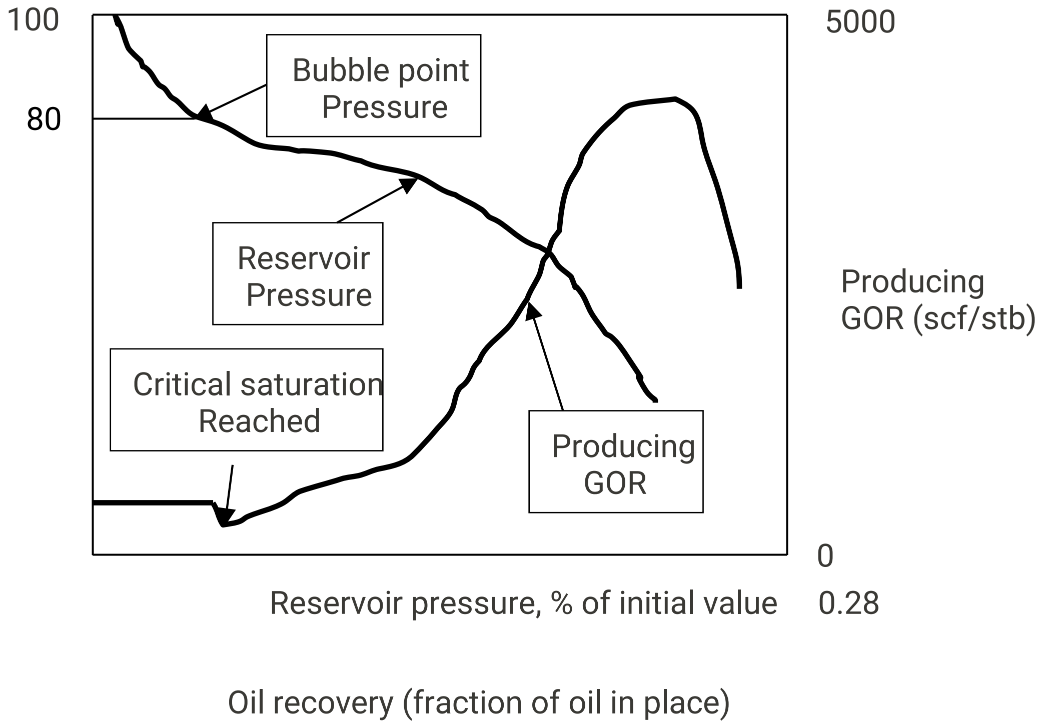


Figure 3: Ideal production behavior of a solution gas drive reservoir

2.3 Material Balance for some Drive Mechanisms

Material balance has long been regarded as one of the basic tools of reservoir engineers for interpreting and predicting reservoir performance (Dake, 2001). In the most elementary form the material balance equation states that the initial volume in place equals the sum of the volume remaining and the volume produced (Lyons, 1996). The zero dimensional material balance is derived and subsequently applied in this report, using mainly the interpretative technique of Havlena and Odeh, to gain an understanding of reservoir drive mechanisms under primary recovery conditions (Dake, 2001).

$$N_p(B_o + \left(R_p - R_{s)}B_g\right) = NB_{oi}$$

$$\left[\frac{(B_o - B_{oi}) + (R_{si} - R_s)B_g}{B_{oi}}\right] + m\left(\frac{B_g}{B_{gi}} - 1\right) + (1+m)\left(C_o\frac{(C_w - S_{wc} + C_f)}{1 - S_{wc}}\right)\Delta p + (w_e - w_p)B_w \qquad (2.1)$$

According to Tarek, 2001, the basic assumptions in the material balance equation are as follows:

- **Constant temperature:** Pressure - volume changes in the reservoir are assumed to occur without any temperature changes.
- **Pressure equilibrium:** All parts of the reservoir have the same pressure, and fluid properties are therefore constant throughout.
- **Constant production data:** All production data should be recorded with respect to the same time period.
- **Constant reservoir volume:** Reservoir volume is assumed to be constant except for those conditions of rock and water expansion of water influx that are specifically considered in the equation.

2.3.1 Solution – Gas Drive

A schematic representation of material balance equations for solution gas reservoirs, when the change in pore volume is negligible is shown in figure 2.4 (Lyons, 1996). Above the bubble point, the drive energy is due to the expansion of the under saturated, single phase oil, the connate water expansion and the pore compaction, while below, the complex solution gas drive process is activated once gas has been liberated from the oil (Dake, 2001).

Oil Oil

For $P > P_b$ $\boxed{N B_{oi}} = \boxed{(N - N_p)\,B_o}$

P_i $P_i > P > P_b$

Oil Oil Free Gas

For $P<$ $\boxed{N B_{oi}} = \boxed{(N - N_p)\,B_o}\boxed{[NR_{si} - (N - N_p)R_s - G_p]\,B_g}$ P_b

P_i

$P_i < P_b$

Schematic of material balance equations for solution – gas drive reservoir
(**Source:** Lyon, 1996)

Two main phases of a solution gas drive reservoir are identified. These are depletion above the bubble point and depletion below the bubble point.

Depletion above bubble point (Under saturated)

For a solution gas drive reservoir it is assumed that there is no initial gas cap, thus m = 0, and that the aquifer is relatively small in volume and the water influx is negligible. Furthermore, above the bubble point, $R_s = R_{si} = R_p$, since all the gas produced at the surface must have been dissolved in the oil in the reservoir (Dake, 2001). Under these assumptions, the material balance equation (2.1) becomes:

$$N_P B_O = NB_{oi}\left(\frac{(B_o - B_{oi})}{B_{oi}}\right) + \left(\frac{(C_w - S_{wc} + C_f)}{1-S_{wc}} * \Delta p\right) \qquad (2.2)$$

The component describing the reduction in the hydrocarbon pore volume, due to the expansion of the connate water and reduction in pore volume cannot be neglected for an under saturated oil reservoir since the compressibility c_w and c_f are generally of the same order of magnitude as the compressibility of the oil (Dake, 2001) where the oil compressibility is given by:

$$C_o = \frac{(B_o - B_{oi})}{B_{oi} * \Delta p} \qquad (2.3)$$

Substituting eqn. (2.3) into eqn. (2.2) gives

$$N_P B_O = NB_{oi} + \left(C_o \frac{(C_w - S_{wc} + C_f)}{1 - S_{wc}} \right) \Delta p \qquad (2.4)$$

Since there are only two fluids in the reservoir, that is , oil and water, then the sum of the fluid saturations must be 100% of the pore volume, or is the effective, saturation – weighted compressibility of the reservoir system.

$$S_{wc} + S_o = 1 \qquad (2.5)$$

$$N_p B_O = NB_{oi} + \left(\frac{(C_o S_o - S_{wc} C_w + C_f)}{1 - S_{wc}} \right) \Delta p \qquad (2.6)$$

$$\text{Or} \quad N_p B_o = NB_{oi} C_o \Delta p \qquad (2.7)$$

$$C_O = \frac{1}{1 - S_{wc}} (C_o S_o - S_{wc} C_w + C_f) \qquad (2.80)$$

2.3.2 Gas Cap Drive

For a reservoir in which gas cap drive is the predominant mechanism it is still assumed that the natural water influx is negligible ($W_e = 0$) and, in the presence of so much high compressibility gas, that the effect of water and pore compressibility is also negligible (Dake, 2001). Under these circumstances, the material balance eqn. (2.1), can be written as

$$N_p(B_o + \left(R_p - R_s\right)B_g) = NB_{oi}\left[\frac{(B_o - B_{oi}) + (R_{si} - R_s)B_g}{B_{oi}}\right] + m\left(\frac{B_g}{B_{gi}} - 1\right) \qquad (2.9)$$

Using the technique of Havlena and Odeh with negligible water influx, the material balance equation can be reduced to the form

$$F = N(E_o + ME_g) \qquad (2.10)$$

2.3.3 Water Drive

A drop in the reservoir pressure, due to the production of fluids, causes the aquifer water to expand and flow into the reservoir. Applying compressibility definition to the aquifer, then

Water Influx = Aquifer Compressibility × Initial Volume of Water × Pressure Drop or

$$W_e = (C_w + C_f)\, W_i\, \Delta p \qquad (2.11)$$

Using the technique of Havlena and Odeh (assuming that $B_w = 1$), the full material balance can be expressed as

$$F = N\left(E_o + ME_g + E_{fw}\right) + W_e \qquad (2.12)$$

If the reservoir has no initial gas cap and coupled with the fact that water and pore compressibility are small and also the water influx helps to maintain the reservoir pressure (making Δp appearing in the $E_{f,w}$ term reduced), eqn. (2.12) reduces to

$$F = NE_o + W_e \qquad (2.13)$$

2.4 Predicting Primary Recovery in Solution – Gas Drive Reservoirs

Several methods for predicting performance of solution-gas behaviour relating pressure decline to gas-oil ratio and oil recovery have appeared in literature (Lyons, 1996). These methods include Tracy's method, Tarner's method and Muskat's method. The following assumptions are generally made: uniformity of the reservoir at all times regarding porosity, fluid saturations, and relative permeability; uniform pressure throughout the reservoir in both the gas and oil zones (which means the gas and oil volume factors, the gas and oil viscosities, and the solution gas will be the same throughout the reservoir); negligible gravity segregation forces; equilibrium at all times between the gas and the oil phases; a gas liberation mechanism which is the same as that used to determine the fluid properties, and no water encroachment and negligible water production (Lyons, 1996).

2.4.1 Tracy's Method

Neglecting the formation and water compressibility as well as any form of injection, the general material balance equation as expressed by eqn. 2.1 can be reduced to (Tarek, 2001)

$$N = \frac{N_pB_o+\left(G_p-N_pR_s\right)B_g-\left(W_e-W_pB_w\right)}{\left(B_o-B_{oi}\right)+\left(R_{si}-R_s\right)B_g+mB_{oi}\left[\frac{B_g}{B_{gi}}-1\right]} \qquad (2.14)$$

Where $G_p = R_pN_p$

Tracy (1955) suggested that the above relationship can be rearranged into a more usable form as:

$$N = N_p \Phi_z + G_p \Phi_g + \left(W_p B_w - W_e\right) \Phi_w \tag{2.15}$$

Where ϕ_o, ϕ_g and ϕ_w are considered PVT related properties that are functions of pressure and defined by:

$$\phi_o = \frac{B_o - R_s B_g}{Den} \tag{2.16}$$

$$\phi_g = \frac{B_g}{Den} \tag{2.17}$$

$$\phi_w = \frac{1}{Den} \tag{2.18}$$

$$Den = \left(B_o - B_{oi}\right) + \left(R_{si} - R_s\right) B_g + mB_{oi}\left[\frac{B_g}{B_{gi}} - 1\right] \tag{2.19}$$

Figure 2.5 gives a graphical presentation of the behaviour of Tracy’s PVT functions with changing pressure (Tarek, 2001).

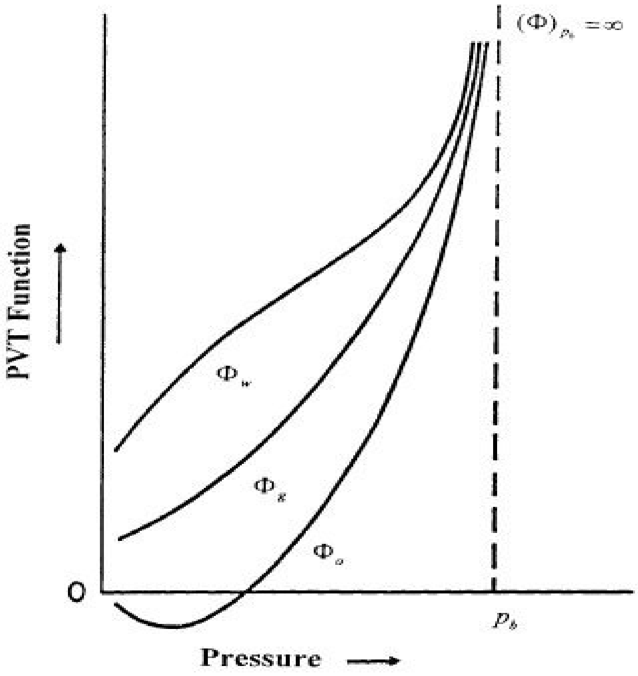


Figure 4 Tracy's PVT functions (Source: **Tarek, 2001)**

For a solution gas drive reservoir, equations (2.15) and (2.19) reduce to the following equations respectively:

$$N = N_p\phi_o + G_p\phi_g \qquad (2.20)$$

And

$$Den = (B_o - B_{oi}) + (R_{si} - R_s)B_g \qquad (2.21)$$

Tracy's calculations are performed in series of pressure drops that proceed from known reservoir condition at the previous reservoir pressure p^* to the new assumed lower pressure p. The calculated results at the new reservoir pressure become "known" at the next assumed lower pressure (Tarek, 2001).

2.4.2 Tarner's Method

This is a trial and error procedure based on the simultaneous solution of the material balance equation and the instantaneous gas-oil ratio equation (Lyons, 1996). For a pressure drop from p_1 to p_2, the procedure involves a stepwise calculation of cumulative oil produced $(Np)_2$ and of cumulative gas produced $(Gp)_2$. The stepwise procedure as enumerated in Lyons, 1996 is as follows:

- During the pressure drop from p_1 to p_2, assume that the cumulative oil production increases from $(Np)_l$ to $(Np)_2$. At the bubble point pressure, Np should be set equal to zero.
- By means of the material-balance equation for $W_p = 0$, compute the cumulative gas produced $(GP)_2$ at pressure p_2 as:

$$(G_p)_2 = (N_p)_2(R_p)_2 = N\left([R_{si}-R_s]-\frac{B_{oi}-B_o}{B_g}\right)- (N_p)_2\left(\frac{B_o}{B_g}-R_s\right) \qquad (2.22)$$

- Compute the fractional total liquid saturation $(S_L)_2$ at pressure p_2 as:

$$(S_L)_2 = S_w + (1-S_w)\frac{B_o}{B_{oi}}[1-\frac{(N_p)_2}{N}] \qquad (2.23)$$

- Determine the k_{rg}/k_{ro} ratio corresponding to the total liquid saturation (SL)2 and

Compute the instantaneous gas – oil ratio at p2 as:

$$R_2 = R_s + \left(\frac{k_{rg}}{k_{ro}}\right)\left(\frac{\mu_o B_o}{\mu_g B_g}\right) \tag{2.34}$$

- Compute the cumulative gas produced at pressure p_2 as:

$$(G_p)_2 = (G_p)_1 + \frac{R_1+R_2}{2}\left[(N_p)_2 - (N_p)_1\right] \tag{2.35}$$

- Where R_1 is the instantaneous gas – oil ratio computed at pressure p_1.

2.4.3 Muskat's Method

Muskat expresses the material balance in terms of finite pressure differences in small increments. The changes in variables that affect production are evaluated at any stage of depletion or pressure (Lyons, 1996). Assumption is made that values of the variables will hold for a small drop in pressure, and the incremental recovery can be calculated for the small pressure drop (Lyons, 1996). Knowing PVT data and the gas- oil relative permeability at any liquid saturation, the unit recovery by pressure depletion can be computed from a differential form of the material balance equation as:

$$\frac{ds_o}{dp} = \frac{\frac{S_o B_g}{B_o}\frac{dR_S}{dp}+\frac{S_o}{B_o}\frac{k_{rg}}{k_{ro}}\frac{\mu_o}{\mu_g}\frac{dB_o}{dp}+(1\text{-}S_o\text{-}S_w)B_g\frac{d(\frac{1}{B_g})}{dp}}{1+\frac{k_{rg}\mu_o}{k_{ro}\mu_g}} \qquad (2.36)$$

From the change in saturation at any pressure, the reservoir saturation at that time can be related to the change in oil production and the instantaneous gas – oil ratio (Lyons, 1996).

Using $(\Delta S_o/\Delta p)$ which is mostly the average, the oil saturation S_o is computed as:

$$S_o = S_o * -(p^* - p)\left(\frac{\Delta S_o}{\Delta p}\right)_{avg} \qquad (2.37)$$

The cumulative oil production is then calculated as:

$$N_p = N\left[1-\left(\frac{B_{oi}}{B_o}\right)\left(\frac{S_o}{1-S_{wi}}\right)\right] \qquad (2.38)$$

And the cumulative gas production is computed as:

$$G_p = G_p + \Delta G_p \qquad (2.39)$$

Where

$$\Delta G_p = (GOR)_{avg}\Delta N_p \qquad (2.40)$$

2.5 Artificial Lift Methods

Most oil reservoirs are of the volumetric type where the driving mechanism is the expansion of solution gas when reservoir pressure declines because of fluid production. Oil reservoirs will eventually not be able to produce fluids at economical rates unless natural driving mechanisms (e.g., aquifer and/or gas cap) or pressure maintenance mechanisms (e.g., water flooding or gas injection) are present to maintain reservoir energy (Boyun et al., 2007). When reservoir pressure is insufficient to sustain the flow of oil to the surface at adequate rates, natural flow must be aided by artificial lift. There are two basic forms of artificial lift: continuous gas lift and bottomhole pumping (Golan and Whitson, 1995). Both methods supplement the natural drive energy of the reservoir and increase the flow by reducing backpressure at the wellbore caused by flowing fluids in the tubing (Golan and Whitson, 1995). Approximately 50% of wells worldwide need artificial lift systems (Boyun et al., 2007).

The commonly used artificial lift methods include the following:

a. Sucker rod pumping
b. Continuous Gas lift
c. Intermittent Gas Lift
d. Electrical submersible pumping
e. Hydraulic piston pumping
f. Hydraulic jet pumping
g. Plunger lift
h. Progressing cavity pumping

In naturally flowing wells, the well flowrate capacity is usually higher than the recommended or desired flow rate and the well production is controlled by the use of a choke. There are some naturally flowing wells that although able to produce steadily the desired flow rate, cannot start production without some help. Those wells need a kick-off operation after a shutdown in order to produce a steady flow rate. In this case an artificial lift method can be used whenever necessary to kick-off the well (Prado, 2008).

In certain cases, the bottom hole flowing pressure may be sufficient only to produce the well at flow rates smaller than the recommended or desired flow rate. In some cases the bottom hole flowing pressure may not be capable to produce any flow rate at all and the well is called a dead well. In those two cases artificial lift methods can be used to achieve the recommended flow rate (Prado, 2008).

Finally, there are conditions when the bottom hole flowing pressure is able to produce the fluids to the surface but the production is unsteady. In those cases artificial lift methods can be used to stabilize the well (Prado, 2008).

Artificial lift is the area of petroleum engineering related to the use of technologies to promote an increase in the production rate of flowing oil or gas wells, to put wells back into production or to stabilize production by using an external horsepower source. The external source helps the bottom hole flowing pressure to overcome the pressure drops in the system downstream of the perforations or to use methods that reduce the pressure drop in the production system by improving the multiphase flow conditions in the well. In any case either energy or products will be consumed at the surface (costs) to obtain higher flow rates from the well (income). The main purpose of artificial lift is to increase the profit of the operation (Prado, 2008).

2.5.1 Gas Lift

Gas lift technology increases oil production rate by injection of compressed gas into the lower section of tubing through the casing–tubing annulus and an orifice installed in the tubing string (Boyun et al., 2007). Upon entering the tubing, the compressed gas affects liquid flow in two ways: (a) the energy of expansion propels (pushes) the oil to the surface and (b) the gas aerates the oil so that the effective density of the fluid is less and, thus, easier to get to the surface (Boyun et al., 2007). Gas lift technology is a simple and flexible method seen as an extension of natural flow. It mostly requires a source of high pressure gas and casing and lines must withstand injection pressure (Prado, 2008).

A continuous gas lift operation is a steady-state flow of the aerated fluid from the bottom (or near bottom) of the well to the surface. In continuous gas lift, a small volume of high-pressure gas is introduced into the tubing to aerate or lighten the fluid column. This allows the flowing bottom-hole pressure with the aid of the expanding injection gas to deliver liquid to the surface. To accomplish this efficiently, it is desirable to design a system that will permit injection through a single valve at the greatest depth possible with the available injection pressure (Boyun et al., 2007). Intermittent gas lift operation is characterized by a start-and-stop flow from the bottom (or near bottom) of the well to the surface. This is unsteady state flow (Boyun et al., 2007). The type of gas lift operation used, continuous or intermittent, is also governed by the volume of fluids to be produced, the available lift gas as to both volume and pressure, and the well reservoir's conditions such as the case when the high instantaneous BHP drawdown encountered with intermittent flow would cause excessive sand production, or coning, and/or gas into the wellbore (Boyun et al., 2007). A complete gas lift system consists of a gas compression station, a gas injection manifold with injection chokes and time cycle surface controllers, tubing string with installations of unloading valves and operating valve, and a down-hole chamber (Boyun et al., 2007). Figure 2.5 shows the configuration of a typical gas lift well.

Gas Lift with Velocity Strings

Velocity strings are a commonly applied remedy to liquid loading in gas wells (Oudeman, 2007). By installing a small diameter string inside the tubing, the flow area is reduced which increases the velocity and restores liquid transport to surface. The disadvantage of the velocity string is the increase in frictional pressure drop, constraining production. Hence an optimal velocity string has to be selected such that liquid loading is delayed over a long period with a minimal impact on production (Oudeman, 2007). This requires accurate methods to predict pressure drop in the velocity string as well as tubing-velocity string annulus (Oudeman, 2007).

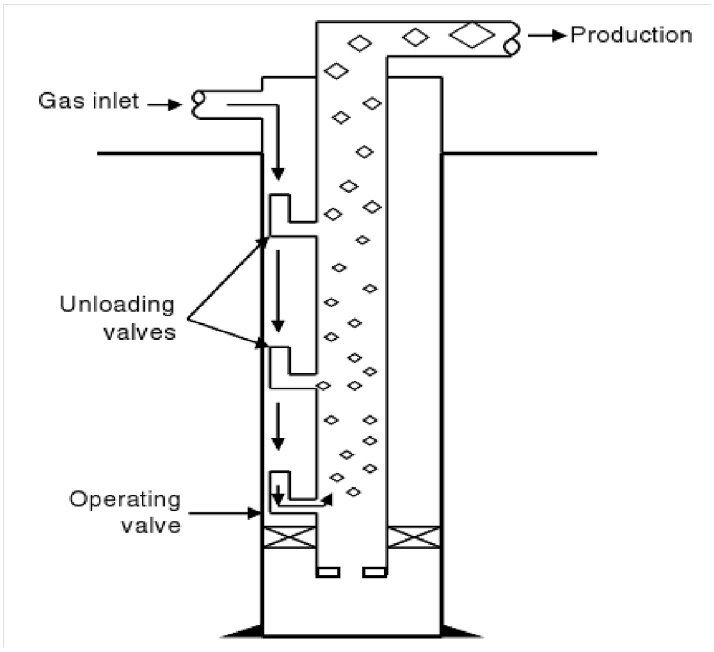


Figure 5 Configuration of a typical gas lift well (Source: Boyun et al., 2007)

2.5.2 Bottomhole Pumping

Bottomhole pumping provides mechanical energy to lift oil from bottom hole to surface. It raises the pressure in a liquid by transforming mechanical work into potential energy, that is, pressure. Liquid enters the pump at a given pressure, called discharge pressure. Pump pressure usually refers to the difference between the discharge and the suction pressures (Golan and Whitson, 1995). Pump pressure corresponds to the gain in potential energy of the liquid. This gain represents only a fraction of the total work used to drive a pump. It is efficient, simple, and easy for field people to operate. It can pump a well down to very low pressure to maximize oil production rate (Boyun et al., 2007). The efficiency of a pump depends on how efficiently it can transform the driving forces into fluid potential energy (Golan and Whitson, 1995).

Pumps are generally classified according to the physical principle used to transform driving forces into pressure (Golan and Whitson, 1995). The main classes of conventional pumps are: positive – displacement and dynamic – displacement pumps. Positive – displacement pumps develop pressure by moving a piston or cam to reduce the volume of a compression chamber. This compression raises the pressure of liquid in the chamber (Golan and Whitson, 1995). Dynamic – displacement pumps develop pressure by a sequence of accelerations and decelerations of the pumped liquid (Golan and Whitson, 1995).

Positive – Displacement Pumps

1. *Sucker Rod Pump:* a positive – displacement pump that compresses liquid by the reciprocating motion of a piston. The piston is actuated by a string of sucker rods that extend from the bottom hole pump to the pumping unit at the surface (Golan and Whitson, 1995).

2. *Reciprocating Hydraulic Pump:* a positive – displacement pump with a reciprocating piston. The piston is actuated by a reciprocating hydraulic motor coupled and assembled with the pump. The down hole motor is driven by a power fluid injected at high pressure from the surface (Golan and Whitson, 1995).

Centrifugal submersible pump and jet pump are examples of dynamic – displacement pumps.

Chapter THREE

Research Design and Methodology

3.1 Inflow Performance Relationship (IPR)

Since the reservoir originally exists at its bubble point pressure, fluid flowing in the reservoir goes to multiphase conditions immediately at the start of production when the pressure is lower than the bubble point. This means the linear IPR will not be valid. As the pressure inside the reservoir goes below the bubble point value, gas comes out of solution reducing the oil saturation and relative permeability, and increasing oil viscosity. Also the formation volume factor is always greater than one due to the gas in solution (Prado, 2008). The oil productivity is reduced since now the driving force for fluid movement is spent moving the liquid and the gas phases (Prado, 2008). The constant productivity index (PI) concept is no longer valid. Since IPR under multiphase flow conditions cannot be easily calculated, Fetkovich's empirical correlation is employed to estimate the IPR.

The Inflow Performance Relationship (IPR) describes the behavior of the well's flowing pressure and production rate, which is an important tool in understanding the reservoir/well behavior and quantifying the production rate. The IPR is often required for designing well completion, optimizing well production, nodal analysis calculations, and designing artificial lift. Different IPR correlations exist today in the petroleum industry with the most commonly used models are that of Vogel's and Fetkovich's. In addition to few analytical correlations, that usually suffers from limited applicability.

In this work, a new model to predict the IPR curve was developed, using a new correlation that accurately describes the behavior the oil mobility as a function of the average reservoir pressure. This new correlation was obtained using actual field cases in addition to several simulated tests.

After the development of the new model, its validity was tested by comparing its accuracy with that of the most common IPR models such as Vogel, Fetkovich, Wiggins, and Sukarno models. Twelve field cases were used for this comparison. The results of this comparison showed that: the new developed model gave the best accuracy with an average absolute error of **5.54** %, while the other common models are ranked, according to their accuracy in the following order to be Fetkovich, Vogel, and Wiggins, with average absolute errors of 6.73 %, 23.1 %, 13.7 %, and 32.3 respectively.

The new developed IPR model is simple in application, covers wide range of reservoir parameters, and requires only one test point. Therefore, it provides a considerable advantage compared to the multipoint test method of Fetkovich. Moreover, due to its accuracy and simplicity, the new IPR provides a considerable advantage compared to the widely used method of Vogel.

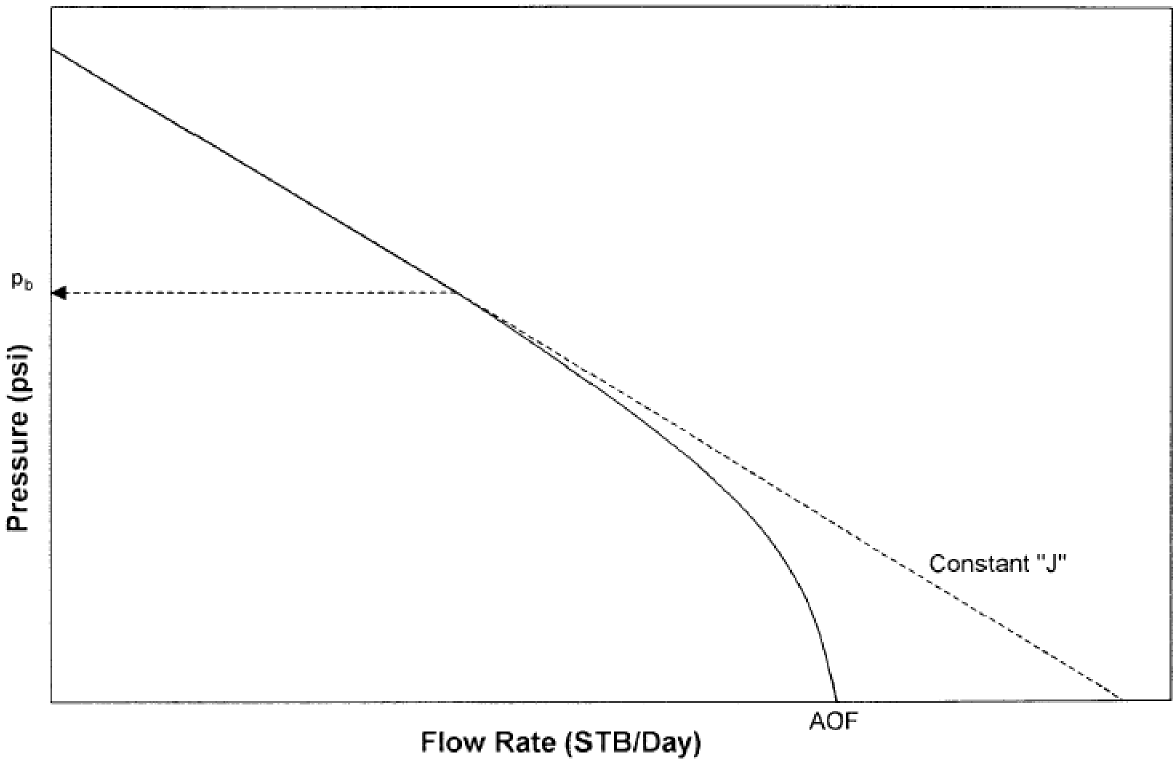


Figure 6 Pot Pressure (psi) against Flow Rate (STB/Day)

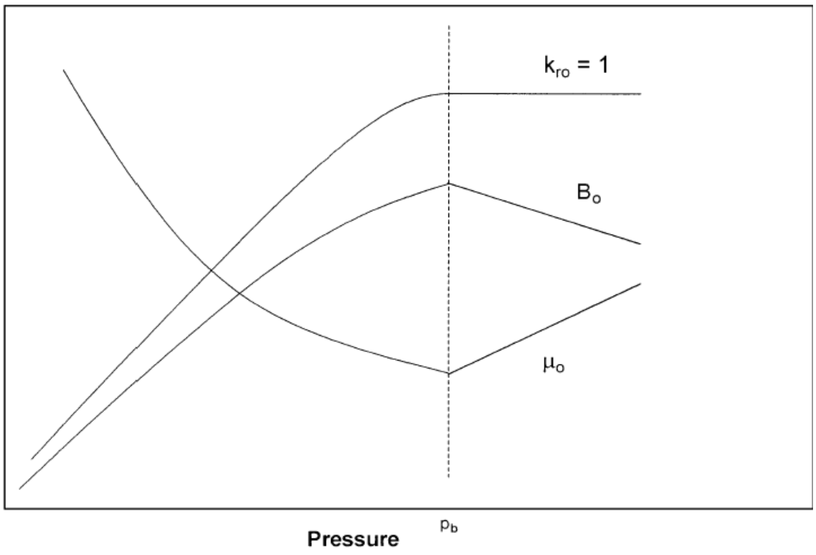


Figure 7 Plot of dependent parameters (μ_o,B_o, k_{ro}) against Pressure (psi)

The relationship between variables affecting the productivity index and in turn the inflow performance are essentially those that are pressure dependent parameters (μ_o,B_o, k_{ro}).

3.2 Commonly known IPR Models

3.2.1 Vogel's Equation.

In 1968, Vogel used a computer program based on Weller's assumptions in 1966 for solution gas drive reservoirs to predict inflow performance curves. Vogel used twenty-one reservoir data sets to develop the following IPR:

$$\frac{q_O}{q_{max}} = \left[1\text{-}0.2\left(\frac{p_{wf}}{p_r}\right)\text{-}0.8\left(\frac{p_{wf}}{p_r}\right)^2\right] \qquad (2.41)$$

$$q_o = q_{max}\left[1\text{-}0.2\left(\frac{p_{wf}}{p_r}\right)\text{-}0.8\left(\frac{p_{wf}}{p_r}\right)^2\right] \qquad (2.42)$$

Standing (1971) improved upon Vogel's equation and developed an equation that can be used to predict the future IPR of the well given the productivity index measured at a given average pressure as given by

$$q_o = \frac{J^* p_f}{1.8}\left[1\text{-}0.2\left(\frac{p_{wf}}{p_r}\right)\text{-}0.8\left(\frac{p_{wf}}{p_r}\right)^2\right] \qquad (2.43)$$

Where

$$q_{max} = \frac{J^* p_f}{1.8} \qquad (2.44)$$

Vogel's correlation gave a good match with the actual well inflow performance at early stages of production but deviates at later stages of the reservoir life. Therefore, this will affect the prediction of inflow performance curves in case of solution gas drive reservoirs, because at later stages of production the amount of the free gas that comes out of the oil will be greater than the amount at the early stages of production.

3.2.2 Fetkovich’s Correlation

Fetkovich’s correlation is usually the one that is more conservative always under predicting flow capacity in comparison to the other IPR equations (Prado, 2008). In 1973, Fetkovich4 developed an IPR based on the data from multi-rate tests “forty different oil wells from six fields.” In addition, the general treatment of the inflow performance for the solution gas drive under pseudo-steady state conditions was used. Fetkovich is also a simpler equation which in some cases can simplify some of the calculations. Even being the most conservative of the IPRs, because it is not a model and just a correlation, it can over predict flow capacities for some reservoirs that are severely affected by the presence of free gas in the porous media. Fetkovich’s correlation is given by equation.
A series of back pressure test were performed by Fetkovich (1973) for reservoirs above the critical gas saturation and found out that the oil well back pressure curves follow the same general form as that used for expressing the rate–pressure relationship for gas wells as given by

$$q_o = c\,(p_r^2 - p_{wf}^2)^n \qquad (2.45)$$

The backpressure equation parameter (n) of Fetkovich IPR equation does not take into consideration the change in the average reservoir pressure.

3.2.3 Wiggins's Method

In 1993, Wiggins6 developed a generalized empirical three phase IPR similar to Vogel3 correlation to overcome the problem of applying his developed analytical model in 1991. This correlation is:

$$\frac{q_o}{q_{max}} = 1 - 0.519167\left(\frac{p_{wf}}{p_r}\right) - 0.481092\left(\frac{p_{wf}}{p_r}\right)^2 \qquad (2.46)$$

$$q_o = q_{max}\left[1 - 0.519167\left(\frac{p_{wf}}{p_r}\right) - 0.481092\left(\frac{p_{wf}}{p_r}\right)^2\right] \qquad (2.47)$$

3.2.4 Sukarno and Wisnogroho's Method

In 1995, Sukarno and Wisnogroho7 developed the following IPR equation based on simulation results that attempts to account for the flow-efficiency variation caused by rate-dependent skin:

$$\frac{q_o}{q_{max}|_{S=0}} = FE\left[1 - 0.1489\left(\frac{p_{wf}}{p_r}\right) - 0.4416\left(\frac{p_{wf}}{p_r}\right)^2 - 0.4093\left(\frac{p_{wf}}{p_r}\right)^3\right] \qquad (2.48)$$

Where

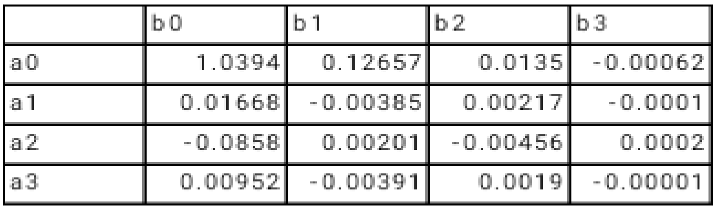
$$FE = a_0 + a_1\left(\frac{p_{wf}}{p_r}\right) + a_2\left(\frac{p_{wf}}{p_r}\right)^2 + a_3\left(\frac{p_{wf}}{p_r}\right)^3 \qquad (2.49)$$

$$a_i = b_{oi} + (b_{1i}*s) + (b_{2i}*S^2) + (b_{3i} * S^3) \qquad (2.50)$$

Express Sukarno and Wisnogroho's

Where:

S is the skin factor, and a_0, a_1, a_2, a_3, b_{0i}, b_{1i}, b_{2i} and b_{3i} are the fitting coefficients that are shown below



	b0	b1	b2	b3
a0	1.0394	0.12657	0.0135	-0.00062
a1	0.01668	-0.00385	0.00217	-0.0001
a2	-0.0858	0.00201	-0.00456	0.0002
a3	0.00952	-0.00391	0.0019	-0.00001

3.2.5 Klins and Majcher's Method

In 1992 based on Vogel’s work, Klins and Majcher5 developed the following IPR correlation that takes into account the change in bubble-point pressure and reservoir pressure due to the depletion in solution gas drive reservoirs.

$$\frac{q_o}{q_{max}|_{S=0}} = \left[1\text{-}0.295\left(\frac{p_{wf}}{p_r}\right)\text{-}0.705\left(\frac{p_{wf}}{p_r}\right)^{N_1}\right] \qquad (2.51)$$

Where, N_1 is defined by the following equation:

$$N_1 = \left(0.28+0.72\frac{P_r}{p_b}\right) * \left(1.235+0.001p_b\right) \qquad (2.52)$$

3.2.6 Beggs and Brill Correlation

The Beggs and Brill program (Prado, 2008) is a spreadsheet program developed to obtain the IPR and OPR curves. The Beggs and Brill correlation enables the calculation of the pressure gradient as a function of other production variables like pipe diameter, GLR and gas and oil flow rates. This correlation considers Slip and flow regime. It is applicable to inclined wells with or without water cut. It also predicts pressure drop for upward and downward fluid flow with accuracy.

3.3 Methodology to use the New IPR Model

Step 1: From the test data plot graph of square of change in pressure differential against flow rate on a semi log graph.

Step 2: From the graph obtain the flow exponential (n), which is the inverse of the slope;

$$n = \frac{1}{slope} \qquad (2.53)$$

$$n = \frac{\log x_2 - \log x_1}{\log y_2 - \log y_1} \quad (2.54)$$

$$n = \frac{\log \left(\frac{x_2}{x_1}\right)}{\log \left(\frac{y_2}{y_1}\right)} \quad (2.55)$$

Step 3: Inputting the values of flow exponent into a data set i.e. at boundary condition (p_{wf} =0 pisg or 14.73 psia).

Step 4: Repeat step 3 on another data set from the available data

Step 5: Simultaneously solve for the flow coefficient i.e. two equations two unknown (flow-rate and flow coefficient).

Step 6: On an Excel VBA spreadsheet iterate the values on flow coefficient and flow exponential to obtain a more accurate value of a lesser Error percentage.

NB: consider the literature range of values of the flow coefficient and flow exponential of a solution gas drive reservoir.

3.4 List of properties that found did not affect the IPR behavior:

a. Water Gravity, γ_w
b. Water Viscosity, μ_w
c. Critical water saturation, S_{wcr}
d. Residual oil saturation in Water, S_{orw}
e. Relative permeability to water at S_{orw}, k_r at (S_{orw})
f. Oil-Water relative permeability exponent, OWEXP
g. Water relative permeability exponent, WEXP
h. Porosity

3.5 Properties that did not affect the dimensionless IPR behavior:

a. Temperature
b. Oil gravity
c. Gas gravity
d. Vertical permeability
e. Horizontal permeability
f. Drainage radius
g. Formation thickness

3.6 Mobility-Reservoir Pressure Relationship

Production rate and pressure results from four simulation cases were used to develop the inflow performance curves. Table 2 presents the ranges of reservoir, rock, and fluid parameters used in the four simulation cases. The saturation and pressure information was also used to develop the mobility function profiles. The general simulation assumptions that were used in building the reservoir model can be summarized as follows:

a. 3D radial flow into the well bore
b. The reservoir initially at the bubble point pressure
c. Vertical well at the center of the formation
d. The well is completed through the whole formation thickness.
e. Homogeneous, bounded reservoir
f. Isothermal conditions exist
g. No initial O.W.C. exist
h. Capillary pressure is neglected
i. Interfacial tension effects and non-Darcy flow effects are not considered

3.7 Application and Importance of study

Accordingly based on the literature survey in this work, it is necessary to:

a. Develop a new, more general, simple, and consistent method to correlate inflow performance trends for solution gas drive oil reservoirs. This new method takes into consideration the behavior of the well flowing pressure as function with the average reservoir pressure without the direct knowledge of this behavior.
b. Determine the applicability and accuracy of the proposed new model by applying it on different field cases with a comparison with some of the most known and used IPR equations, considering a wide range of fluid, rock, and reservoir characteristics.
c. Test some of the available IPR methods on field data.

CHAPTER FOUR

Result and Discussion

4.1 The New Developed IPR Model

In this work, several inflow performance reservoir models were used to analysis a particular reservoir model on Excel VBA. Thereafter, various oil flow-rate production data was obtained for each IPR models. A sensitivity test was done via error calculation also with the aid of Excel VBA to select the most accurate IPR model for the reservoir model in consideration. Then a new IPR equation was derived from the preferred equation to describe accurately the behavior of the well’s flowing pressure and production rate, which assisted in perfectly understanding the reservoir/well behavior and quantifying the production rate.

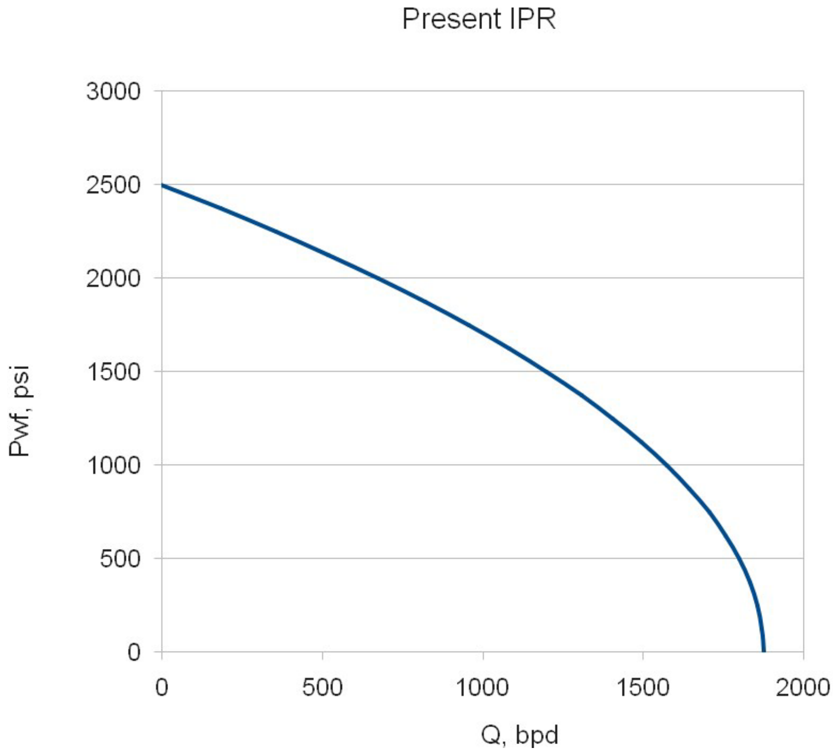
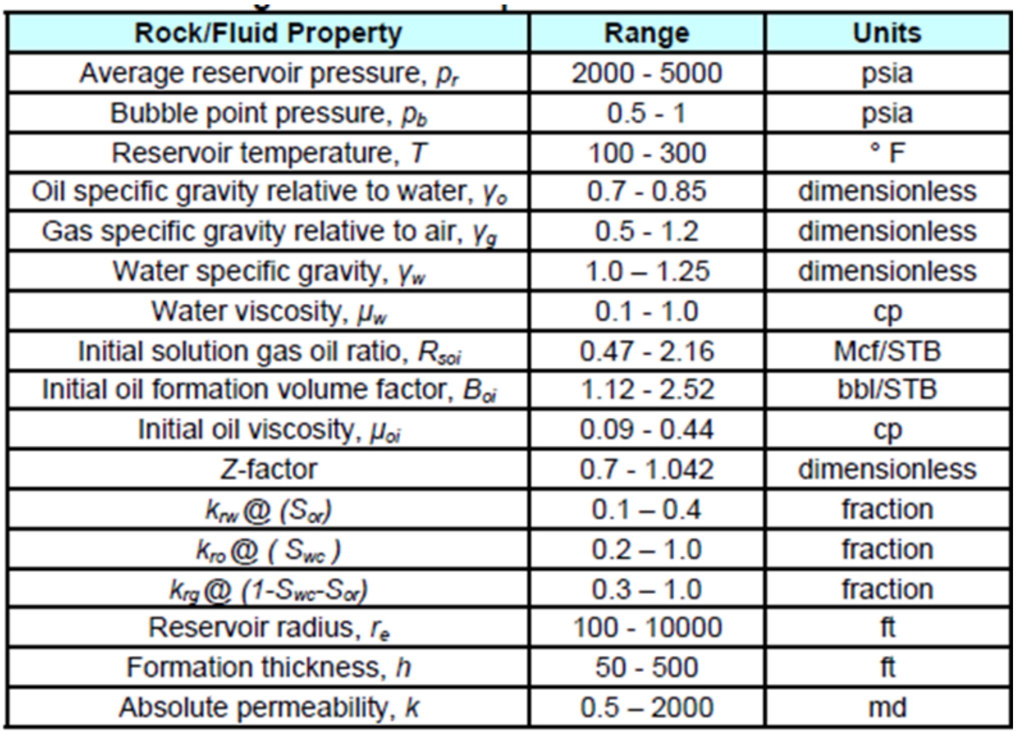


Figure 8 Present Sample IPR of reservoir at initial conditions

Figure 9Ranges of data used in the development relationship

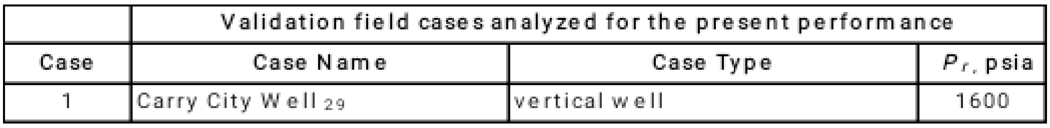


Rock/Fluid Property	Range	Units
Average reservoir pressure, p_r	2000 - 5000	psia
Bubble point pressure, p_b	0.5 - 1	psia
Reservoir temperature, T	100 - 300	° F
Oil specific gravity relative to water, γ_o	0.7 - 0.85	dimensionless
Gas specific gravity relative to air, γ_g	0.5 - 1.2	dimensionless
Water specific gravity, γ_w	1.0 – 1.25	dimensionless
Water viscosity, μ_w	0.1 - 1.0	cp
Initial solution gas oil ratio, R_{soi}	0.47 - 2.16	Mcf/STB
Initial oil formation volume factor, B_{oi}	1.12 - 2.52	bbl/STB
Initial oil viscosity, μ_{oi}	0.09 - 0.44	cp
Z-factor	0.7 - 1.042	dimensionless
k_{rw} @ (S_{or})	0.1 – 0.4	fraction
k_{ro} @ (S_{wc})	0.2 – 1.0	fraction
k_{rg} @ $(1\text{-}S_{wc}\text{-}S_{or})$	0.3 – 1.0	fraction
Reservoir radius, r_e	100 - 10000	ft
Formation thickness, h	50 - 500	ft
Absolute permeability, k	0.5 – 2000	md

Field Case Study: Carry City Well

Frederic Gallice and Michael L. Wiggins presented multi-rate-test data for a well producing from the Hunton Lime in the Carry City Field, Oklahoma. The test showed that the well was producing at random rates, rather than in an increasing or decreasing rate sequence. The average reservoir pressure was 1600 psia, with an estimated bubble-point pressure of 2530 psia and an assumed skin value of zero. The multi-rate test of this well is summarized in Table 7.

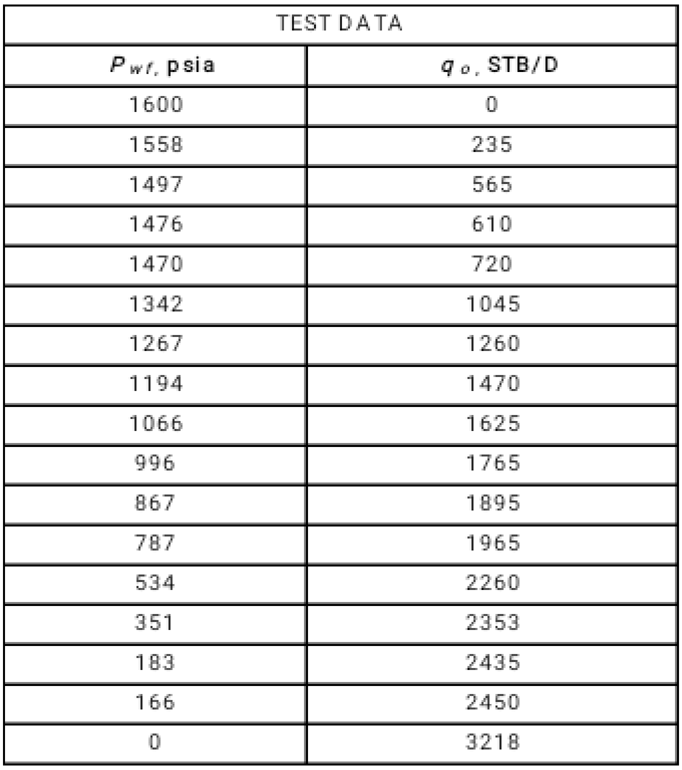
Table 3 presents the predictions of the well's performance for the test information at a flowing bottom hole pressure of 1194 psia, which representing a 25 % of the pressure drawdown. As can be observed, the maximum well deliverability varies from 2550 to 4265 STB/D. The largest flow rate was calculated with Wiggins's IPR, while the smallest rate was obtained using Fetkovich model. **Fig.14** shows the resultant IPR curves for the different methods of calculations such as Vogel, Fetkovich, Wiggins, and Sukarno in comparison with the actual field data and the new developed IPR model. It is clear from this figure that the method of the new developed IPR model is succeed to estimate the actual well performance. In addition, it can be clearly concluded from this figure that the methods of the new developed IPR model and Fetkovich’s model are nearly estimate the maximum oil flow rate for this well more accurately than the other models, and as indicated, the other methods overestimate the actual performance.



	Validation field cases analyzed for the present performance		
Case	Case Name	Case Type	P_r, psia
1	Carry City Well$_{29}$	vertical well	1600

Table 1 Average Reservoir pressure of the actual well

Test data-field well



TEST DATA	
P_{wf}, psia	q_o, STB/D
1600	0
1558	235
1497	565
1476	610
1470	720
1342	1045
1267	1260
1194	1470
1066	1625
996	1765
867	1895
787	1965
534	2260
351	2353
183	2435
166	2450
0	3218

Table 2 Test Data of the Reservoir model

4.3 Application of Methodology to use the New IPR Model

Step 1: From the graph of square of change in pressure differential against flow rate on a semi log graph, the value of slope obtained was 1.1962.

Step 2: From the graph obtain the flow exponential (n), which is the inverse of the slope;

$$n = \frac{1}{slope} \tag{2.56}$$

$$n = \frac{1}{1.1962} \tag{2.57}$$

$$n = 0.836 \tag{2.58}$$

Step 3: Inputting the values of flow exponent into a data set to obtain its flow coefficient i.e. at boundary condition (p_{wf} =0 pisg or 14.73 psia)

$$q_o = C\left(p_r^2 - p_{wf}^2\right)^n \tag{2.59}$$

$$q_o = C(p_r^2 - p_{wf}^2)^{0.836} \tag{2.60}$$

$$q_o = C(1600^2 - 14.73^2)^{0.836} \tag{2.61}$$

Step 4: Repeat step 3 on another data set from the available data.

$$q_o = C\left(p_r^2 - p_{wf}^2\right)^n \tag{2.62}$$

$$q_o = C(p_r^2 - p_{wf}^2)^{0.836} \tag{2.63}$$

$$q_o = C(1600^2 - 1558^2)^{0.836} \tag{2.64}$$

Step 5: Simultaneously solve for the flow coefficient i.e. two equations two unknown (flow-rate and flow coefficient).

$$C = 0.0111 \tag{2.65}$$

Step 6: On an Excel VBA spreadsheet iterate the values on flow coefficient and flow exponential to obtain a more accurate value of a lesser Error percentage.

$$C = 0.0103 \text{ and } n = 0.8502 \tag{2.66}$$

NB: The literature range of values of the flow coefficient and flow exponential of a solution gas drive reservoir were considered.

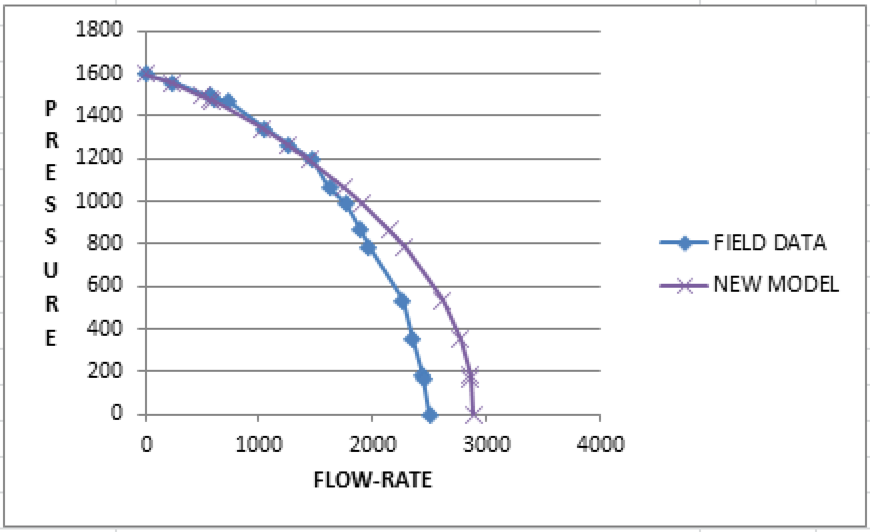


Figure 10 Plot Comparing Field Data against New IPR model

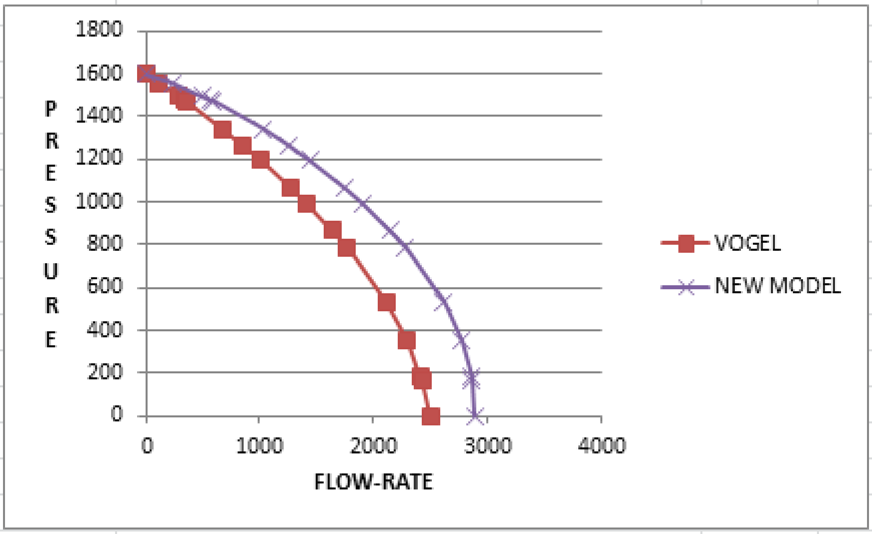


Figure 11 Plot Comparing Vogel's model against New IPR model

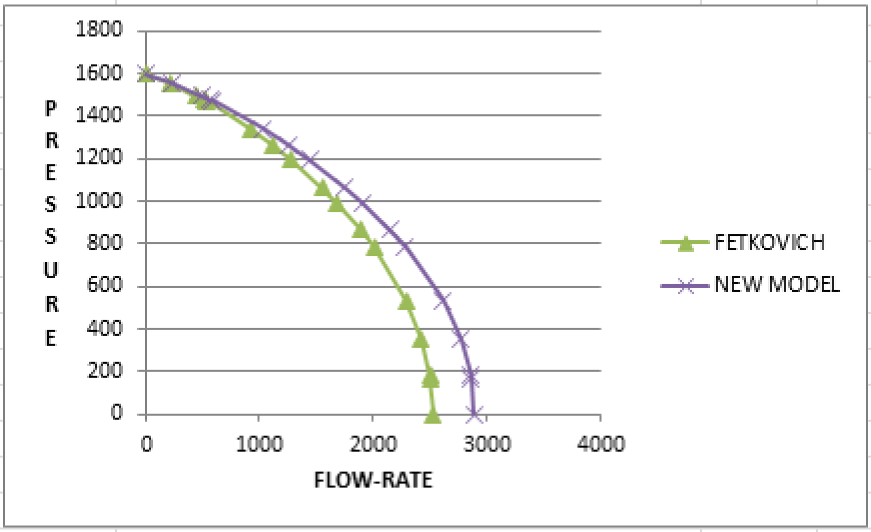


Figure 12 Plot Comparing Fetkovich against New IPR model

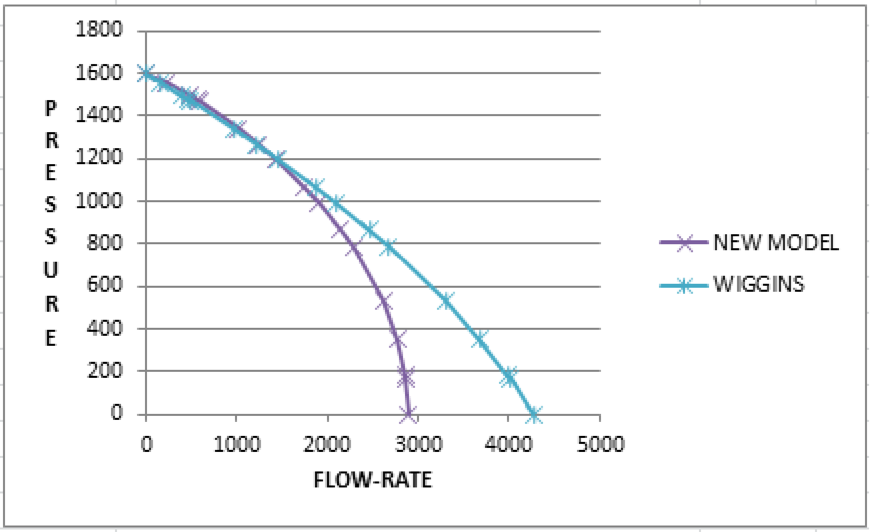


Figure 13 Plot Comparing wiggins model against New IPR model

Prediction Of the Performance of case 1 @ 25% of pressurer drawdown					
Test Points		The New IPR Model	Vogel's Method	Fetkovich Method	Wiggins Method
Pwf (psia)	Qo (bbl/day)	Qo (bbl/day)	Qo (bbl/day)	Qo (bbl/day)	Qo (bbl/day)
1600	0	0	0	0	0
1558	235	233	150	213	164
1497	565	491	362	444	398
1476	610	572	434	516	477
1470	720	594	454	536	499
1342	1045	1026	867	920	965
1267	1260	1247	1094	115	1225
1194	1470	1443	1304	1288	1470
1066	1625	1751	1647	1559	1879
996	1765	1901	1820	1690	2091
867	1895	2145	2114	1905	2462
787	1965	2278	2279	2021	2679
534	2260	2608	2717	2309	3297
351	2353	2765	2954	2447	3680
183	2435	2851	3111	2522	3985
166	2450	2857	3124	2527	4013
0	2500	2883	3243	2550	4265

Table 3 Prediction of the performance of case

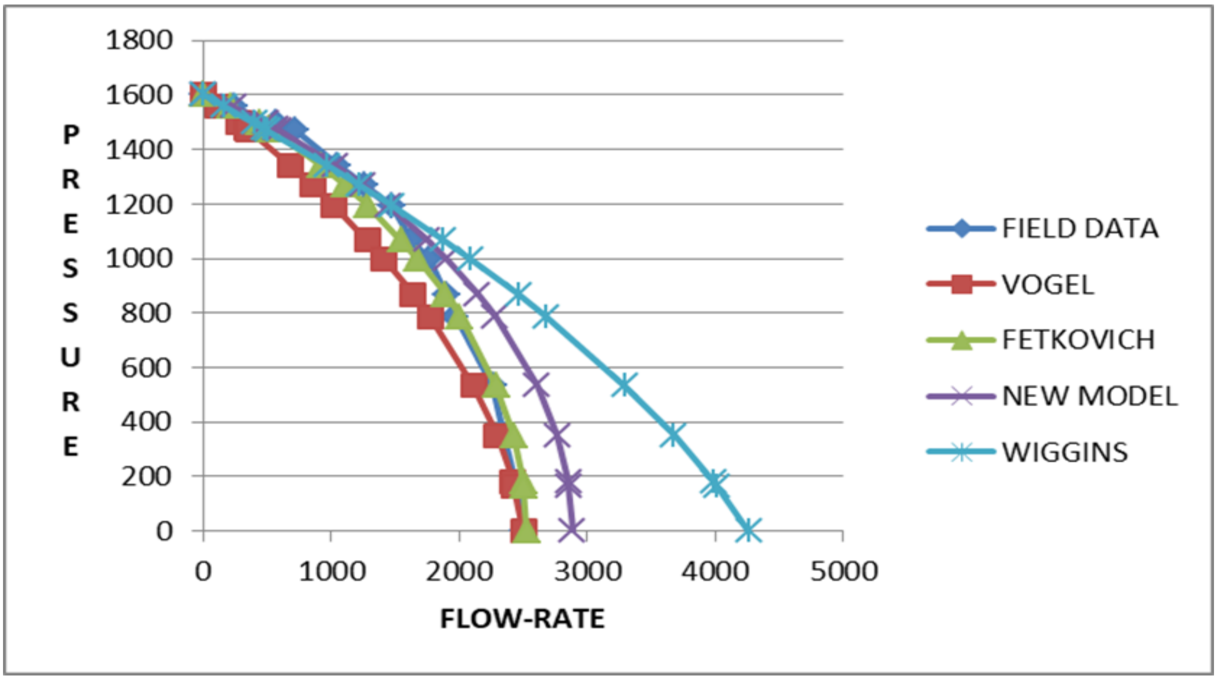
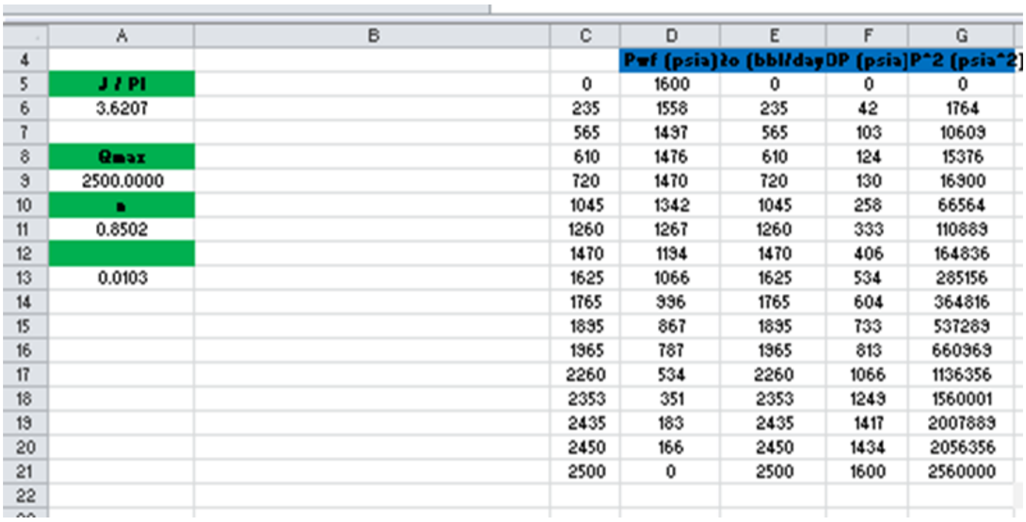


Figure 14 the predicted inflow curves by the different used methods in comparison to the actual field data.



	A	B	C	D	E	F	G
4				Pwf (psia)	Qo (bbl/day	DP (psia)	P^2 (psia^2]
5	J / PI		0	1600	0	0	0
6	3.6207		235	1558	235	42	1764
7			565	1497	565	103	10609
8	Qmax		610	1476	610	124	15376
9	2500.0000		720	1470	720	130	16900
10	n		1045	1342	1045	258	66564
11	0.8502		1260	1267	1260	333	110889
12			1470	1194	1470	406	164836
13	0.0103		1625	1066	1625	534	285156
14			1765	996	1765	604	364816
15			1895	867	1895	733	537289
16			1965	787	1965	813	660969
17			2260	534	2260	1066	1136356
18			2353	351	2353	1249	1560001
19			2435	183	2435	1417	2007889
20			2450	166	2450	1434	2056356
21			2500	0	2500	1600	2560000
22							

Table 4 Excel spreadsheet of Values used to calculate Productive index

4.4 Validation of the New IPR model

To verify and validate the new developed IPR model, the new model was applied on the test data set collected and analyzed from the well field case in consideration. The field case uses actual field data which representing different producing conditions. In order to test the accuracy and reliability of the new developed IPR model, which is also a multi-point method, it will be compared to the standard inflow performance relationship model currently available in the industry. These methods are those of Vogel (single point method), Fetkovich (multi-point method), Wiggins (single point method), and Sukarno (single point method) for the present inflow performance.

The Analysis showed that Fetkovich correlation was the most accurate from the standard models, with the newly develop proving more accurate than the standard fetkovich IPR model.

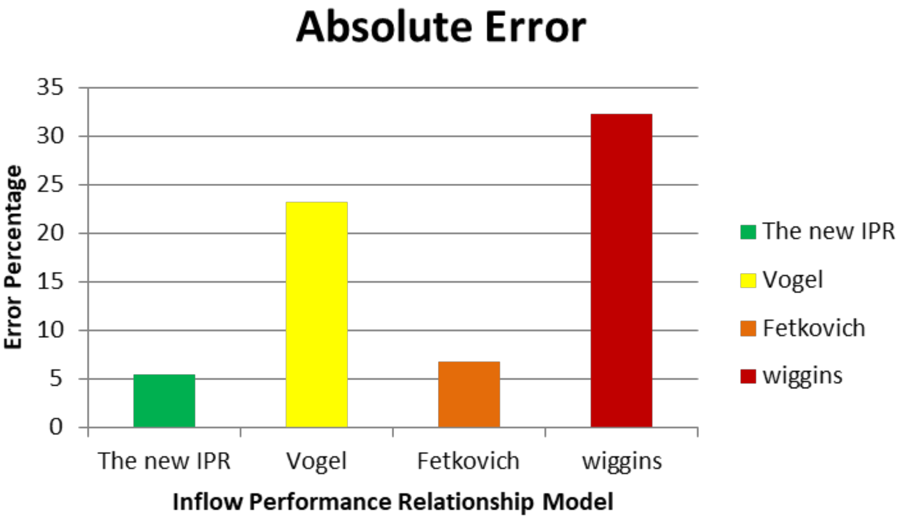
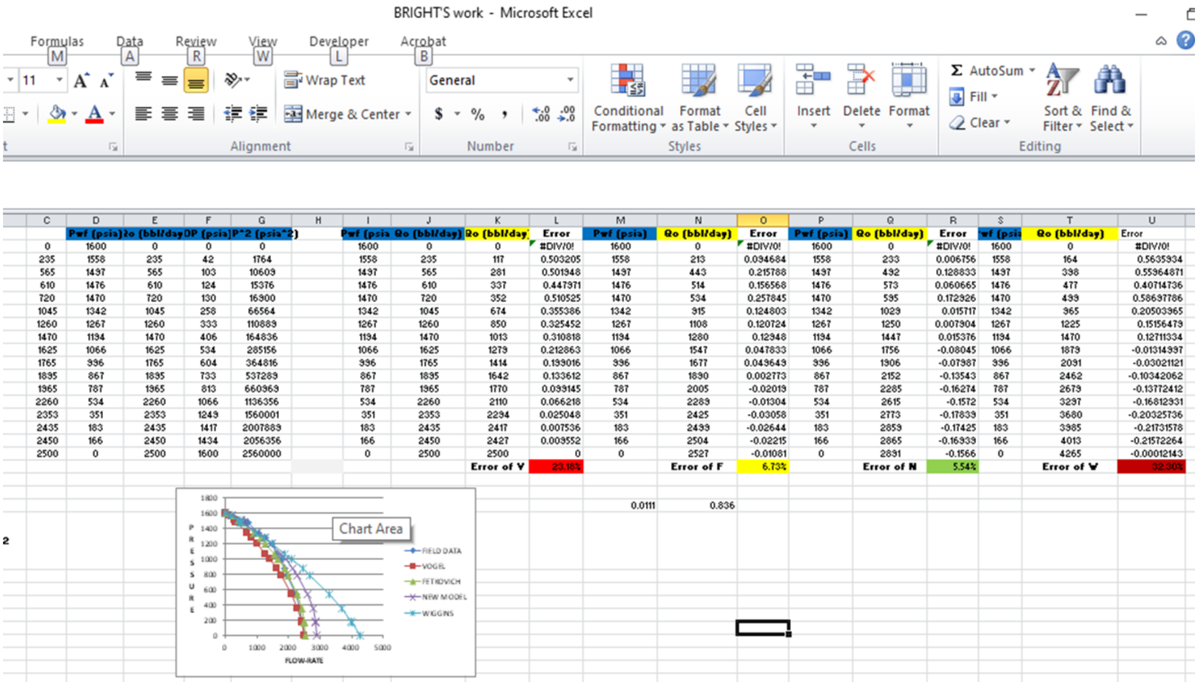


Figure 14 Plot of Error percentage against commonly known IPR method

The results of this comparison showed that: the new developed model gave the best accuracy with an absolute error of **5.54** %, while the other common models are ranked, according to their accuracy in the following order to be Fetkovich, Vogel, and Wiggins, with absolute errors of 6.73 %, 23.18 %, and 32.3 % respectively.



C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U
	Pwf (psia)	o (bbl/day	DP (psia)	P^2 (psia^2)		Pwf (psia	Qo (bbl/day)	Qo (bbl/day	Error	Pwf (psia)	Qo (bbl/day)	Error	Pwf (psia)	Qo (bbl/day)	Error	wf (psi	Qo (bbl/day)	Error
0	1600	0	0	0		1600	0	0	#DIV/0!	1600	0	#DIV/0!	1600	0	#DIV/0!	1600	0	#DIV/0!
235	1558	235	42	1764		1558	235	117	0.503205	1558	213	0.094684	1558	233	0.006756	1558	164	0.5635934
565	1497	565	103	10609		1497	565	281	0.501948	1497	443	0.215788	1497	492	0.128833	1497	398	0.55964871
610	1476	610	124	15376		1476	610	337	0.447971	1476	514	0.156568	1476	573	0.060665	1476	477	0.40714736
720	1470	720	130	16900		1470	720	352	0.510525	1470	534	0.257845	1470	595	0.172926	1470	499	0.58697786
1045	1342	1045	258	66564		1342	1045	674	0.355386	1342	915	0.124803	1342	1029	0.015717	1342	965	0.20503965
1260	1267	1260	333	110889		1267	1260	850	0.325452	1267	1108	0.120724	1267	1250	0.007904	1267	1225	0.15156479
1470	1194	1470	406	164836		1194	1470	1013	0.310818	1194	1280	0.12948	1194	1447	0.015376	1194	1470	0.12711334
1625	1066	1625	534	285156		1066	1625	1279	0.212863	1066	1547	0.047833	1066	1756	-0.08045	1066	1879	-0.01314997
1765	996	1765	604	364816		996	1765	1414	0.199016	996	1677	0.049649	996	1906	-0.07987	996	2091	-0.03021121
1895	867	1895	733	537289		867	1895	1642	0.133612	867	1890	0.002773	867	2152	-0.13543	867	2462	-0.10342062
1965	787	1965	813	660969		787	1965	1770	0.099145	787	2005	-0.02019	787	2285	-0.16274	787	2679	-0.13772412
2260	534	2260	1066	1136356		534	2260	2110	0.066218	534	2289	-0.01304	534	2615	-0.1572	534	3297	-0.16812931
2353	351	2353	1249	1560001		351	2353	2294	0.025048	351	2425	-0.03058	351	2773	-0.17839	351	3680	-0.20325736
2435	183	2435	1417	2007889		183	2435	2417	0.007536	183	2499	-0.02644	183	2859	-0.17425	183	3985	-0.21731578
2450	166	2450	1434	2056356		166	2450	2427	0.009552	166	2504	-0.02215	166	2865	-0.16939	166	4013	-0.21572264
2500	0	2500	1600	2560000		0	2500	2500	0	0	2527	-0.01081	0	2891	-0.1566	0	4265	-0.00012143
								Error of V	23.18%		Error of F	6.73%		Error of N	5.54%		Error of W	32.30%
										0.0111	0.836							

Table 5   GENERAL EXCEL SPREADSHEET

4.5 Field Case Summary for the Inflow Performance

The method of the new developed IPR model provided the most reliable estimates of the actual well data analyzed. It has the lowest value of the absolute error percent, which is **5.54%** in comparison with that of Fetkovich's method, which has a reasonable absolute error percent of **6.73 %** but is still higher than the method of the new developed IPR model. The other methods (Vogel and Wiggins) provided less accurate values for the pressure-rate estimates of the actual well data that used in this analysis.

The method of the new developed IPR model tends to do a better job of predicting well performance than the other methods, and this it may be due to assume an accurate relationship between the oil mobility function and the average reservoir pressure (i.e., the Reciprocal Relationship). Overall, the single-point methods of Vogel, Wiggins, provided great absolute errors percent in the well case 1 as 23.18% and 32.30 % respectively.

CHAPTER FIVE

SUMMARY

As indicated, the empirical correlations suffer from the limitation of their application range as they depend largely on the data used in their generation, and its lack of accuracy. In addition, they are not explicitly function of reservoir rock and fluid data, which are different from one reservoir to another. On the other hand, the analytical correlations suffer from their difficulty to be applied due to its requirement to the oil mobility profiles and its derivatives in addition to the assumptions used in their development. As discussed, the main parameter that affects the productivity index and in turn the inflow performance curves is the oil mobility function ($K_{ro}/\mu B_o$) and its relation to the average reservoir pressure. Therefore, the aspect of conducting the flow tests should be considered in selecting the IPR method. It is evident that test costs have to be taken into consideration.

The relationship between the oil mobility function and the average reservoir pressure should be accurately determined. In addition, the most common equation that represents a basic start point for the development of any IPR equation.

Most of the previously empirical derived IPR equations did not take into their consideration the whole effect of the oil mobility function, this in turn largely reduce the accuracy, power, and utility of these equations. Even though the models that took into their consideration the effect of this function, such as the models of Fetkovich and Wiggins, assumed the relationships between this function and p_r, as the linear form and the third polynomial form for Fetkovich and Wiggins, respectively. In fact, these linear and polynomial for me do not accurately describe the general behavior of the oil mobility function with the average reservoir pressure with an accurate manner. On the other hand, some of analytical derived IPR equations did not considered the effect of this function, except the models of Wiggins. Wiggins's model is so complicated because it requires the oil mobility represented in its derivate as a function of the average reservoir pressure, this is greatly difficult in application.

Finally, the range of applicability will also influence the selecting of the IPR methods to predict the well performance.

CONCLUSION

In this work, we reviewed the most commonly used IPR models, also, we developed new IPR model. The new IPR was compared to the most commonly used models using field data (An actual field). Based on this work, we can conclude the following:

a. The validity of the new IPR model was tested through its application on an actual case in comparison with the behavior of the most common methods that are used in the industry. The results of this validation showed that the new IPR model ranked the first model that succeeded to predict the behavior of the IPR curve for the examined field cases, while the other models of Fetkovich, Sukarno, Vogel, and Wiggins ranked the second, the third, the forth, and the fifth, respectively
b. The new IPR model also requires three test point and is as accurate or more than Fetkovich's model which requires three test points
c. The new developed IPR outperformed all available IPR models except at low pressures (Less than 1000 psia).

RECOMMENDATION

The following recommendations are suggested:

Determine the applicability and accuracy of the proposed new model by applying it on different field cases with a comparison to some of the commonly known IPR equations, considering a wide range of average reservoir pressure from the respective wells in consideration.

Economic evaluation should be included to solve a real life problem. The costs of carrying out the commonly known IPR models and the newly developed IPR model for the purpose of generate an optimal production pattern of the reservoir.

More wells can be included to simulate a more practical situation and the performance with time analyzed.

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