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EXAMINATIONS OF THE PERFORMANCE OF A GAS LIFT FOR OIL WELL PRODUCTION

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ABSTRACT

Gas lift is a method of artificial lift that uses an external source of high pressure gas for supplementing formation gas to lift the well fluids. The primary limitations for gas lift operations are the lack of formation gas or of an outside source of gas, wide well spacing and available space for compressors on offshore platforms. Generally, gas lift is not applicable to single-well installations and widely spaced wells that are not suited for a centrally located power system. Gas lift can intensify the problems associated with production of viscous crude, super-saturated brine, or an emulsion. Old casing, sour gas and long, small-internal diameter flow lines can rule out gas lift operations. Wet gas without dehydration will reduce the reliability of gas lift operations. A model relating the factors affecting potential production rate along the tubing of a gas lift oil well was developed to optimize production using analytical approach. Modified Darcy equation was employed alongside some other equation of flow such as Fanning's equation, Reynolds' equation and a host of others which resulted in the developed model equation. Data from four wells were used in applying the model equation and it was found that, $k = 9476$ for the four wells and the square of the velocity of oil flow is equal to the oil production rate and both vary directly with the difference in pressure between the reservoir and the well bore. This implies, the lower the well bore pressure the higher the oil production rate and oil velocity.

Keywords: oil well, artificial lift, gas lift.

1. INTRODUCTION

When oil is first drilled in the reservoir, it is under pressure from the natural forces that surround and trap it. If a well is drilled into the reservoir, an opening is provided at a much lower pressure through which the fluid can escape. The driving force which causes this fluid to move out of the reservoir and into the wellbore comes from the compression of the fluids that are stored in the reservoir. The actual energy that causes a well to produce oil results from a reduction in pressure between the reservoir and the producing facility on the surface [1]. If the pressures in the wellbore and the reservoir are allowed to equalize, either because of a decrease in reservoir pressure or an increase in wellbore and surface pressure, there will be no flow from the reservoir and hence no production from the well [2]. There are a number of factors which affect the producing characteristics of an oil well. These factors are often interrelated and may include such things as fluid properties of the oil itself, amount of gas and water associated with the oil, properties of the reservoir, size of the producing pipe and related subsurface equipment.

Others are the size and length of the flow line connecting the well to the production facilities. All of these factors play an important part in an oil well's performance and most carefully considered when the installation is designed [1]. An ideal production installation makes maximum use of the natural energy available from the reservoir. In many wells the natural energy associated with the oil will not produce sufficient pressure differential between the reservoir and the wellbore to cause the well to flow into the production facilities at the surface [1]. In other wells, natural energy will not drive oil to the surface in sufficient volume. The reservoirs natural energy must then be supplemented by some form of artificial lift.

There are basically four ways of producing an oil well by artificial lift. They are: gas lift, sucker rod pumping, submersible electric pumping and subsurface hydraulic pumping [3]. The choice of the artificial lift system in a given well depends on some factors, primary among them, as far as gas lift is concerned, is the availability of lift gas, either as dissolved gas in the produced oil, or from an outside source, then gas lift is often an ideal selection for artificial lift.

Gas is the form of artificial lift that most closely resembles the natural flow process. There are basically two types of gas lift systems used in the oil industry, they are continuous flow and intermittent flow [3]. The aim of this work is to optimize the productivity of a gas lift oil well through the factors affecting potential production rate using analytical method.

2. EXPERIMENTAL METHODOLOGY

Natural oil production process can be considered as a combination of two fluid flows, first in reservoir and second along the tubing. Both fluid flows, may be a one phase (liquid) or a two-phase (liquid and gas). In this study, both fluid flows are assumed naturally single phase (liquid), up to the point of gas injection in the tubing. Above gas injection point, two-phase flow takes place. An analytical approach will be used in developing the model.

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2.1. Development of model equation

Figure-1 illustrates how a free flowing well delivers or produces oil. From the sketch and also from literature it is evident that the factors that affect the rate of production of an oil well are: pressure differential, fluid viscosity, area/ diameter (size) of tubing just to mention a few [4].

In order to model the behavior of oil producing well, a single phase flow model is necessary. Darcy's equation was used as the basis of the model based on the assumption that the effects of gravity and acceleration on pressure differential are negligible. In addition, friction factor obtained from the relationship between fanning's equation and Reynolds number will be substituted into Darcy's equation to generate the new model equation. Emphasis would be on response or effects of these factors at the tubing, basically the pressure difference.

The oil production rate in rb/day can be estimated from the Darcy equation [1]:

$$q_l = J(p_r - p_{wf}) \qquad (1)$$

where,

$$J = \frac{2\pi kh}{\mu In\left(\frac{r_e}{r_{wf}}\right)} \qquad (2)$$

The model was developed taking into consideration the fact that pressure drop affects the production rate of a well and that the pressure drop depends on certain factors such as friction loss, gravity and acceleration, the model was developed.

Assuming that the flow through the well tubing is a single-phase fluid flow (oil) and that the test section (tubing) has an inner radius R and length L carrying fluid at constant density and viscosity at steady state mass flow rate and that the pressures p_o and p_l at the ends are known. For this well to be able to lift oil from the well bore to the well head, [p_r - p_{wf}] must be greater than [p_{wf} - p_{wh}].

The use of Reynolds number and the fanning equation indicate that Newtonian fluids follow the same law of flow. Fanning's equation is expressed as [5]:

$$\Delta p = \frac{4fL\rho V^2}{2gD} \qquad (3)$$

Friction factor f is found by transposing fanning's equation.

$$f = \frac{16}{\text{Re}} \qquad (4)$$

where,

$$\text{Re} = \frac{\rho Vd}{\mu} \qquad (5)$$

Substituting (5) into (4) and making μ subject of formula:

$$\mu = \frac{f\rho vd}{16} \qquad (6)$$

Substituting, equation (6) in Darcy's equation for radial flow:

$$u^2 = k(p_r - p_{wf}) \qquad (7)$$

(model equation)

Assume also that the oil to be produced contains gas, recalling the equation for two-phase fluid flow (liquid and gas) along the tubing, derived from the mechanical energy balance equation according to [3], [4] and [5].

$$\frac{dp}{dz} = \left(\frac{g\rho_m}{g_c}\right) + \left(\frac{2f\rho_m u_m{}^2}{g_c D}\right) + \left(\frac{\rho_m du_m{}^2}{2g_c dz}\right) \qquad (8)$$

The terms:

$\frac{g\rho_m}{g_c}$ = pressure drop due to gravity

$\left(\frac{2f\rho_m u_m{}^2}{g_c D}\right)$ = pressure drop due to friction

$\left(\frac{\rho_m du_m{}^2}{2g_c dz}\right)$ = pressure drop due to acceleration

Since the pressure drop due to acceleration is quite small, its contribution will be neglected ∴

$$\frac{dp}{dz} = \left(\frac{g\rho_m}{g_c}\right) + \left(\frac{2f\rho_m u_m{}^2}{g_c D}\right) \qquad (9)$$

Assuming g is negligible (zero) when pressure is sufficient to cause fluid flow through the well tubing, it implies that,

$$\frac{dp}{dz} = \left(\frac{2f\rho_m u_m{}^2}{g_c D}\right) \qquad (10)$$

$$2u_m{}^2 \rho_m fdz = dpg_c D$$

$$u_m{}^2 = \frac{dpg_c D}{2dzf\rho_m} \qquad (11)$$

$$u_m{}^2 = \left(\frac{g_c D}{2dzf\rho_m}\right)dp \qquad (12)$$

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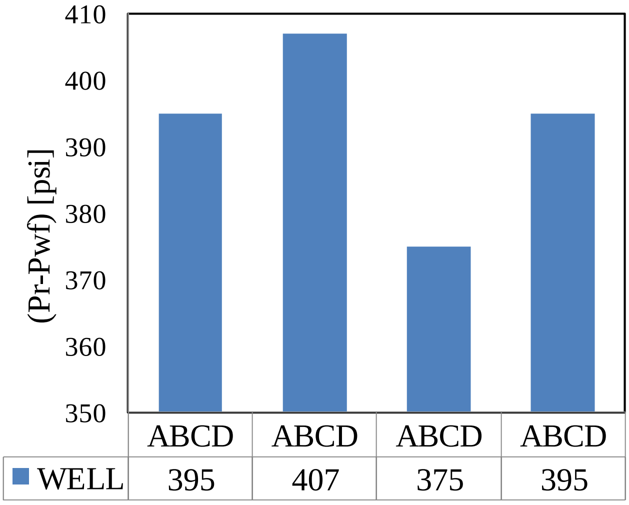
Comparing the model equation (7) with equation (12), it is evident that the square of the velocity (in this case, rate of production) is directly proportional to the pressure drop (difference).

Introducing gas lift by injecting gas at selected point in the tubing would cause a reduction of natural bottom hole pressure, which increases the pressure difference between the reservoir and bottomhole; this consequently implies that the velocity would be increased.

The goal of gas lift is to deliver the fluid to the top of the wellhead while keeping the bottomhole pressure low enough to provide high pressure drop between the reservoir and the bottomhole. Reduction of bottomhole pressure due to gas injection will normally increase liquid (oil) production rate, because gas injection will lighten the fluid column, therefore larger amount of fluid will flow along the tubing. However, injecting too much amount of gas will increase the bottomhole pressure which may decrease the oil production rate. This is because very high gas injection rate causes slippage, where gas phase moves faster than liquid, leaving the liquid phase behind. In this condition, less amount of liquid will flow along the tubing. Hence, there must be an optimum gas injection rate that yields maximum oil production rate.

3. RESULTS AND DISCUSSIONS

This section will present results of comparison of experiments with simulated results for the months of January to June 1998. The data were recorded in the afternoon around 13:00 pm for the months of January to June 1998. Below are the results for four natural flowing wells obtained from standard data of free flowing wells and also from the application of both Darcy and the model equation.



(a)

$$u_m^{\ 2} = \left(\frac{g_c D}{2dzf\rho_m}\right)dp \qquad (12)$$

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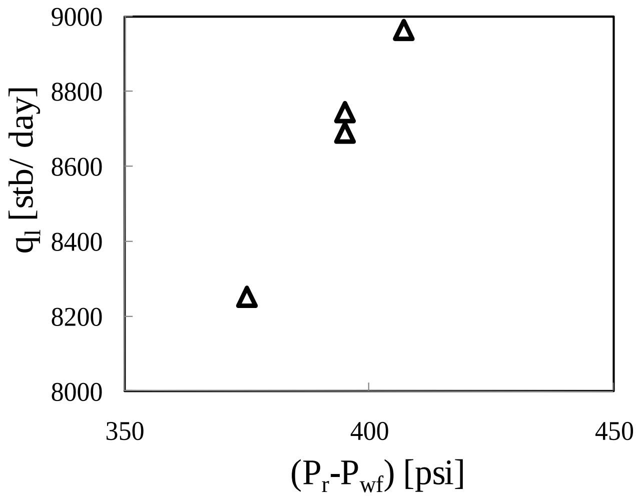
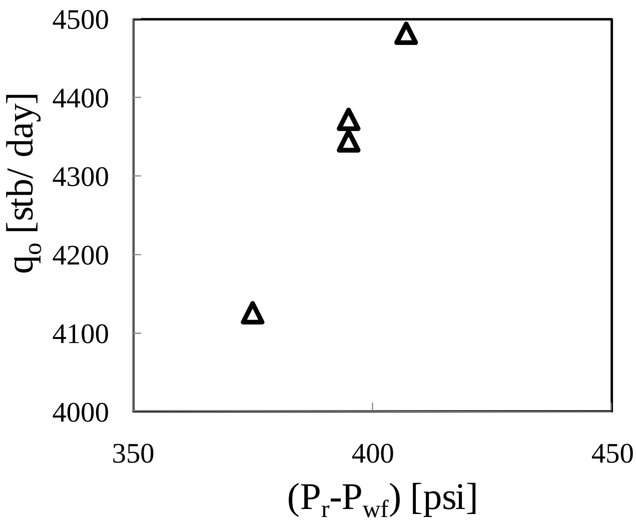


(b)



(c)

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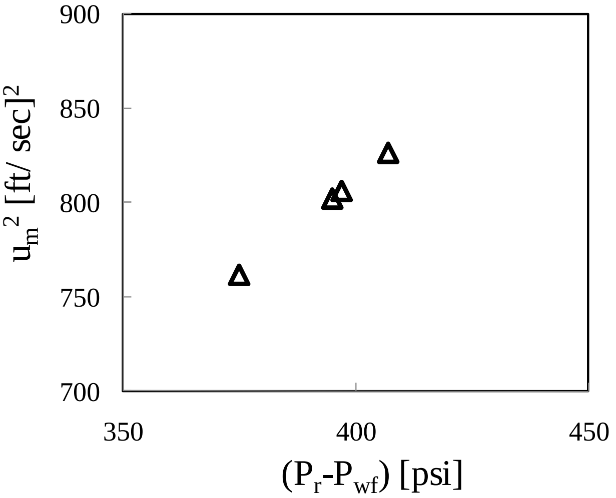

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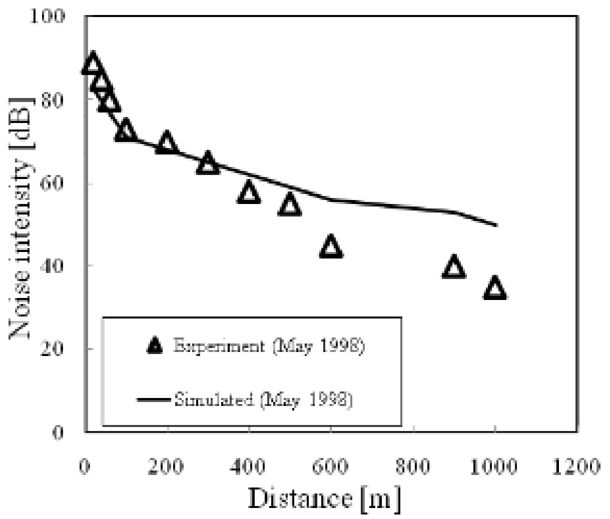
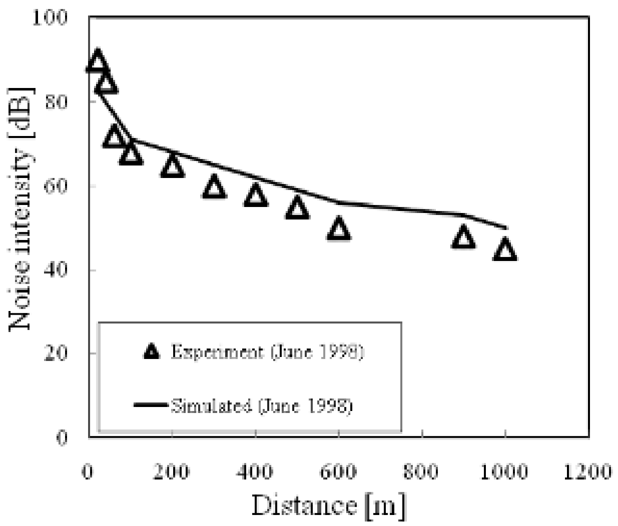


(e)



(f)

Figure-2. Comparison of experiment with simulated data for the months of February to June 1998.

An examination of comparison of measured experimental data with simulated results over a range of distance from the refinery show that all the plots exhibited same trends. It shows that irrespective of the wind speed and ambient temperature, noise intensity decreases with an increase in distance from the refinery. This is in agreement with the inverse square law, that the noise intensity is inversely proportional to area. It is interesting to observe that the simulated results better replicate experimental data for the month of June 1998, corresponding to spring season in Kaduna, Nigeria. The comparison between experiment and simulated results is very good within 20 to 100 m, irrespective of the month of the year.

Comparing the values in Table 4 with the values in Tables 3 and 2, it can be observed that well B has the highest production rate (velocity) followed by wells D, A, and then C. It could also be seen that the pressure difference $(p_r - p_{wf})$ decreases from wells B to D, to A, then C. This shows that, for a well to have a high production rate, p_{wf} has to be decreased to ensure that, $(p_r - p_{wf})$, is sufficient to lift the oil from the reservoir to the well head. The value of p_{wf} could actually be reduced by using an artificial lift method, in this case the gas lift (in which gas is injected through the well tubing). The injected gas mixes with the oil and reduces its viscosity and consequently reduces its pressure (p_{wf}) this undoubtedly, lifts the oil at a faster rate and hence increases the production rate. From the calculations made using the model equation: $u^2 = k(p_r - p_{wf})$, k is a constant, which means; $u^2 \propto (p_r - p_{wf})$. Quoting from literature, modified Darcy's equation $\left[q_l = J(p_r - p_{wf})\right]$, where J is a constant and also from the standard well data on Table 1 was given to be a constant for wells (A, B, C and D).

From the model equation $u^2 = k(p_r - p_{wf})$; on application of well data, k was found to be 9476, which was a constant for the four wells (A, B, C and D). Since k and J have been found to be constants for all the four wells, comparing both equations; that is, $\left[q_l = J(p_r - p_{wf})\right]$ and, $u^2 = k(p_r - p_{wf})$ shows that $q_l \propto (p_r - p_{wf})$ and $u^2 \propto (p_r - p_{wf})$. Now assuming $J = k = 1$, $u^2 = (p_r - p_{wf})$ and $q_l = (p_r - p_{wf})$, therefore, $u^2 = q_l = (p_r - p_{wf})$. The expression $u^2 = q_l = (p_r - p_{wf})$ can also be written as $q_l = (p_r - p_{wf})$; If p_{wf} is increased it means $(p_r - p_{wf})$ will be reduced for constant P_r; this implies that q_l will be reduced. If on the other hand, p_{wf} is decreased $(p_r - p_{wf})$ will be increased for constant P_r; this implies that q_l will be increased. Hence for optimum or maximum production rate p_{wf} should be low enough to produce a higher pressure differential $(p_r - p_{wf})$ which will be sufficient to lift or increase the oil production rate. This trend can also be observed from Table 2.

Table-1. Standard data for a natural flowing well.

	WELL A	WELL B	WELL C	WELL D	UNITS
P_r	790	815	750	795	Psi
J	11	11	11	11	11
l	6,900	7,000	7,000	7217.8	Stb/d/psi
d	2.875	2.875	2.875	2.875	inch
WOR	1	1	1	1	-
γ_g	0.65	0.65	0.65	0.65	-
γ_o	0.876	0.876	0.876	0.876	-
γ_w	1.01	1.01	1.01	1.01	-

Research consortium on pipeline network ITB (OPPINERT) [3]

Table-2. Result from application of Darcy's equation.

	WELL A	WELL B	WELL C	WELL D	UNITS
p_{wf}	395	408	375	398	psi
k	1.7726E-3	1.7726E-3	1.7726E-3	1.7726E-3	mD
q_l	8689.996	8965.0598	8250.4042	8744.966	Stb/day
q_o	4344.998	4482.530	4125.202	4372.483	Stb/day
Δp	**395**	**407**	**375**	**395**	**Psi**

Table-3. Result from model equation.

	WELL A	WELL B	WELL C	WELL D	UNIT
κ	9476	9476	9476	9476	-
u^2	374302	3856732	3553500	3761972	ft/s

Table-4. Results from the equation of two-phase fluid flow.

WELL	u_m^2	Δp	$g_c D / 2 \bar{f} \ell dz$
A	802.128	395	7.6192
B	826.497	407	7.6192
C	761.514	375	7.6192
D	806.1893	397	7.6192

Figure-2a shows that there is a good agreement between experiment and simulated result within a distance of 20 to 200 m from the refinery. Within this distance from the refinery, the frequency of vibration of machines falls above the range of normal hearing, i.e., 20,000Hz. This is in agreement with the works of [2]. The agreement between experiment and simulated result reduced as the distance from the refinery increased from about 30 to 1000 m. The variation between experiment and simulated results may be due to assumptions made at the beginning of developing the model, neglecting the variation in meteorological conditions (e.g. wind speed, temperature). It may also be due to the fact that

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experimental results depend on the prevailing meteorological conditions while simulated results are instantaneous.

It is interesting to note that within a distance of 0 to 200 m, the noise intensity level is about 82 to 67 dB respectively. This range of values of noise intensity is above the threshold of (65 dB) health impairments, by the preventive medicine [2].

The agreement between the experiment and simulated result improved in increasing order from the months of February to June, 1998 as shown in Figures 1b to 1f. The months of January to June in Nigeria represent, January and February, winter season, March and April, summer season, and May and June, spring season.

Nomenclature

M = Mass of machines (kg)
W = Wind speed (m/s)
P = power of machines (Watt)
c = Velocity of sound in air (ms^{-1})
T = Temperature (K)
V = Volume of air (m^3)
Q = Directivity factor (dB)
ρ = Density of air (Kg/m^3)
R = Specific gas constant (KJ/Kmolk)
P_r = Reference sound pressure (N/m^2)
P_c = Sound pressure rms (N/m^2)
I_0 = Threshold of hearing m/m^2
q = Rate of cooling at constant volume of air (W)
l_w = Noise intensity level (dB)
χ = Frequency of vibration (Hz)
A = Amplitude of vibration of machines
n = number of reflections
α = absorption coefficient of the source
E = Sound energy density (J/m^3)
S = Surface area (m^2)
γ = ratio of specific heats of a gas at a constant pressure to a gas at a constant volume
E_v = Vibrational energy per unit volume (J/m^3)
$V_{\max}$ = Maximum velocity of vibration (m/s)
I_d = Noise intensity from direct source (W/m^2)
I_r = Noise intensity from reverberant source (W/m^2)
I_{mv} = Noise intensity due to machine vibration (W/m^2)

5. CONCLUSIONS

The study on the examination of the factors affecting potential rate and gas injection requirement for a gas lift oil well has been successfully carried out. The results show that square of the velocity of oil flow is equal to the oil production rate according to the model equation and that both vary directly with the difference in pressure between the reservoir and the well bore. This implies that, the lower the well bore pressure the higher the oil production rate and oil velocity. This is in agreement with results from literature.

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Appendix-A

Figure-1 below illustrates how a free flowing well delivers or produces oil. From the sketch and also from literatures it is evident that the factors that affect the rate of production of an oil well are: pressure differential, fluid viscosity, area/ diameter (size) of tubing just to mention a few [4].

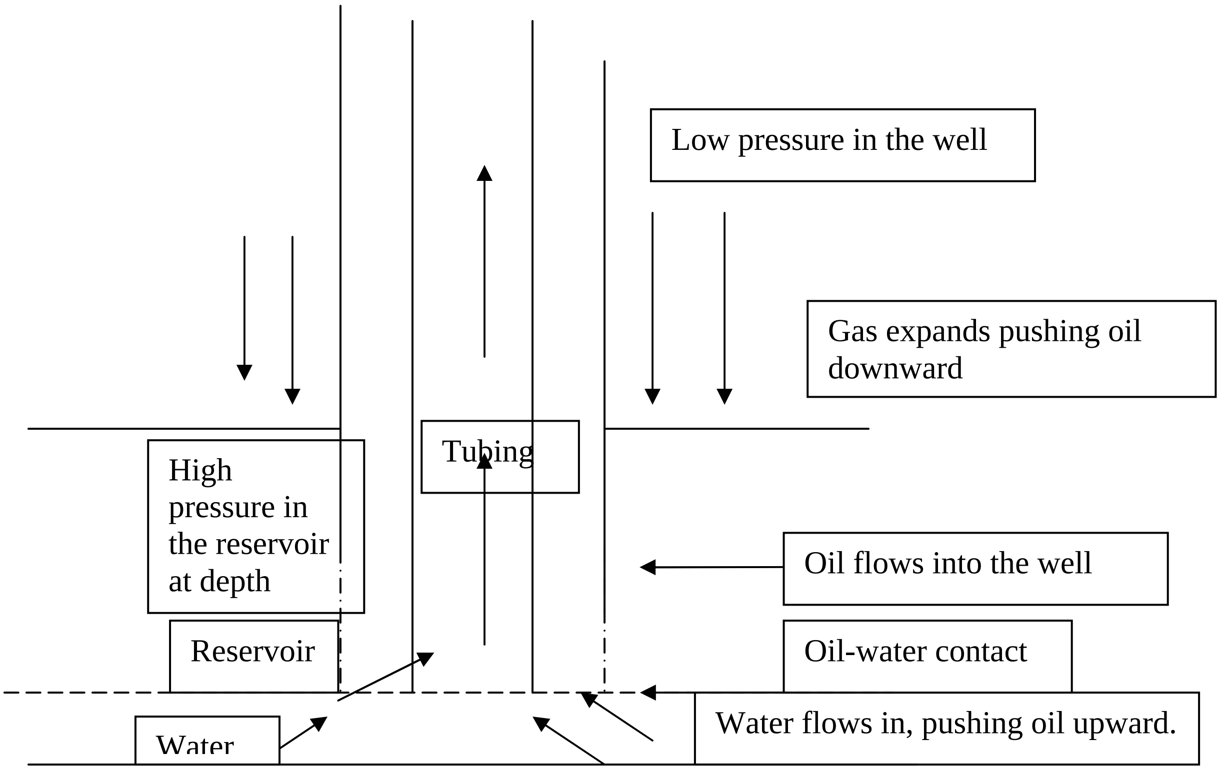

Figure-1. Sketch of a free flowing well.