بسم الله الرحمن الرحيم

Sudan University of Science and Technology

College of petroleum engineering and technology

Petroleum engineering department

Project of :

Calculations of optimum injection point for gas lift system

[Case study]

حسابات نقطة الحقن المثلى لنظام الرفع بالغاز

[دراسة حالة]

Project submitted in partial fulfillment of the requirements of the degree of b.sc in petroleum engineering

Prepared by:

1. Abdalbagi Alelaish Dafallah Ibrahim.
2. Ahmed Abdul-Jabbar Hmd Alneel.
3. Mohammed abdelrasoul Abdullah.
4. Mohanned Abdullah albasheer alfadol.

Supervisor:

Mr. Sami Mohammed Alameen

الآيه :


سُورَةُ العَلَق

بِسْمِ اللَّهِ الرَّحْمَٰنِ الرَّحِيمِ

اقْرَأْ بِاسْمِ رَبِّكَ الَّذِي خَلَقَ ﴿١﴾ خَلَقَ الْإِنسَانَ مِنْ عَلَقٍ ﴿٢﴾ اقْرَأْ وَرَبُّكَ
الْأَكْرَمُ ﴿٣﴾ الَّذِي عَلَّمَ بِالْقَلَمِ ﴿٤﴾ عَلَّمَ الْإِنسَانَ مَا لَمْ يَعْلَمْ ﴿٥﴾ كَلَّا إِنَّ
الْإِنسَانَ لَيَطْغَىٰ ﴿٦﴾ أَن رَّآهُ اسْتَغْنَىٰ ﴿٧﴾ إِنَّ إِلَىٰ رَبِّكَ الرُّجْعَىٰ ﴿٨﴾ أَرَأَيْتَ
الَّذِي يَنْهَىٰ ﴿٩﴾ عَبْدًا إِذَا صَلَّىٰ ﴿١٠﴾ أَرَأَيْتَ إِن كَانَ عَلَى الْهُدَىٰ ﴿١١﴾ أَوْ أَمَرَ
بِالتَّقْوَىٰ ﴿١٢﴾ أَرَأَيْتَ إِن كَذَّبَ وَتَوَلَّىٰ ﴿١٣﴾ أَلَمْ يَعْلَم بِأَنَّ اللَّهَ يَرَىٰ ﴿١٤﴾ كَلَّا لَئِن
لَّمْ يَنتَهِ لَنَسْفَعًا بِالنَّاصِيَةِ ﴿١٥﴾ نَاصِيَةٍ كَاذِبَةٍ خَاطِئَةٍ ﴿١٦﴾ فَلْيَدْعُ نَادِيَهُ
﴿١٧﴾ سَنَدْعُ الزَّبَانِيَةَ ﴿١٨﴾ كَلَّا لَا تُطِعْهُ وَاسْجُدْ وَاقْتَرِب ۩ ﴿١٩﴾

DEDICATION:

We would like to dedicate this

research

To the spirit of

Dr. Mohammed Naeim

And to our families, Friends and our

teachers.

ACKNOWLEDGEMENTS:

This project consumed huge amount of work research and dedication, there for we would like to extend sincere gratitude to all of those who help us.

First of all we are thank full to our project supervisor **Mr. Sami Mohammed Alameen** for his support ,and for providing necessary guidance concerning project implementation.

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Abstract:

In this project the gas lift system was applied on well (x) Block 6-Sudan by using the volumetric balanced method and by using pipe simulator, The optimum injection point was has been calculated and it was (3600 ft) by volumetric balance method and (4183 ft) by simulator software.

التجريد :

في هذا المشروع تم تطبيق نظام الرفع بالغاز علي البئر بإستخدام طريقة توازن الحجوم وباستخدام برنامج (pipe simulator) وتم حساب نقطة الحقن المثلى وكانت قيمتها (3600قدم) باستخدام الطريقه الحجميه , وقيمتها (4183 قدم) بإستخدام ال (pipe simulator) .

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1-1 Introduction:

In petroleum engineering there are two main types of production :

- Natural production :

In this type of production the energy of the reservoir is enough to push the oil from the reservoir to the surface without using any artificially method.

- Artificial production :

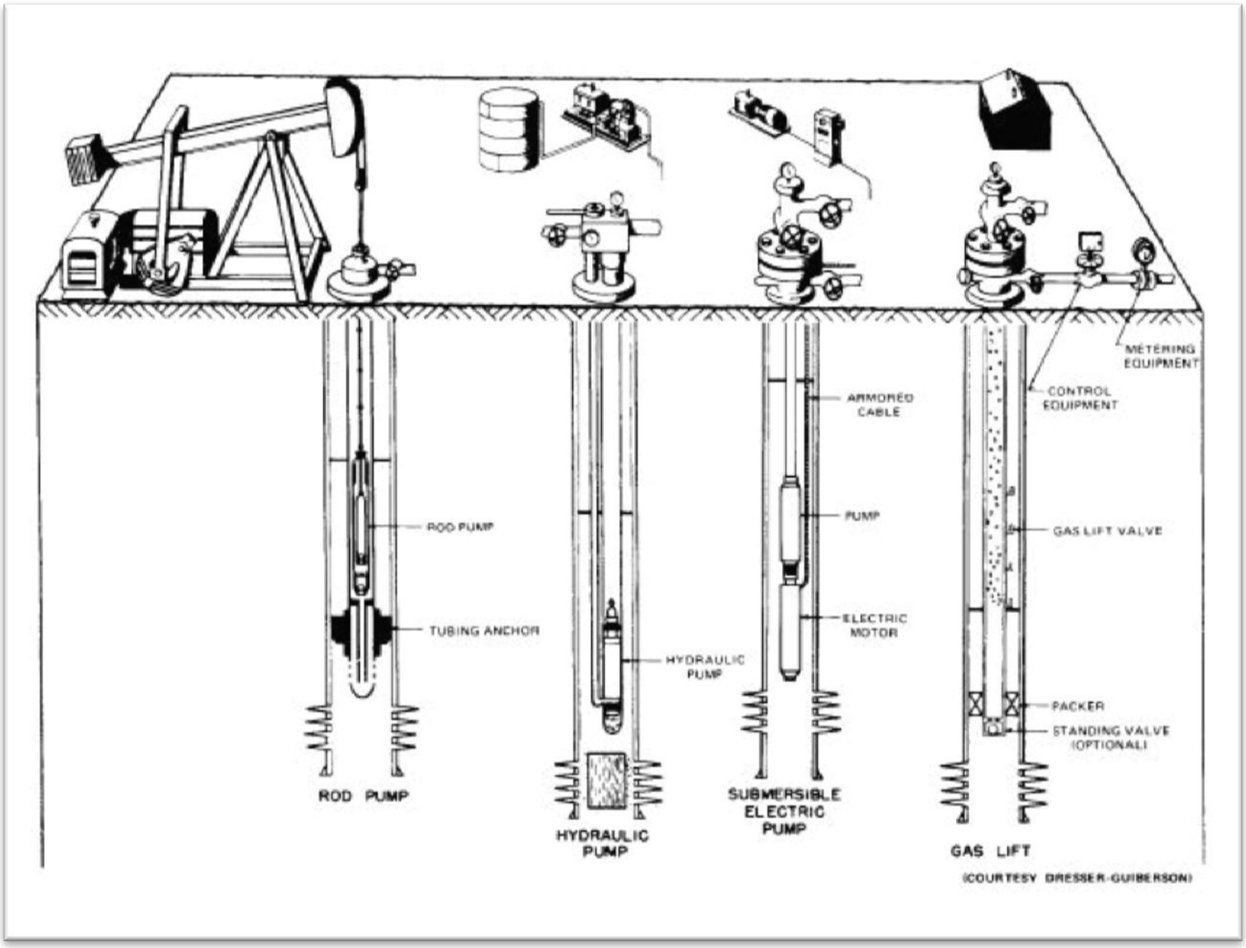
Artificial lift is used when the pressure in the oil reservoir have failed to the point where a well will not produce at its most economical rate by natural driving mechanism (eg .aquifer/or gas cap).

The only way to obtain a high production rate of a well is to increase production pressure drawdown by reducing the bottom-hole pressure with artificial methods, more and more wells in the world are being placed on artificial lift and the number will continue to increase.

1-1-1 Artificial lift methods:

BoyunGuo William C.lyous, Ali Ghalambor, 2007 stated that , the common artificial lift methods including the following :

- Sucker rod pumping (beam pumping).
- Electrical submersible pumping.
- Hydraulic pump.
- Plunger (free piston) lift.
- Progressing cavity pumping.
- Gas lift.



figure(1-1): artifitial lift typs[2]

<u>1-1-2</u> Selecting an artificial lift method:

Difficult or easy, depend upon the conditions-generally more than one method of lift, The selecting of the most suitable type of artificial lift for a well or group of wells can be can be used .

The methods historically used to select the lift method for a particular field vary broadly across the industry:

- operator experience
- What methods are available for installation in certain areas of the world.
- Determining what methods will lift at the desired rate and required depth.
- Evaluation of initial costs, operating costs, production capabilities , etc.

With the use of economics as a tool of selecting, usually on present value basis These methods consider:

- Geographic location
- Capital cost.
- Operating cost.
- Production flexibility.
- Reliability.
- Mean time between.

1-2 The objectives:

1- The main objective of this project is to determine the optimum injection point for gas lift system (using volumetric balance method and pipe simulator software).

2- Study the effect of the tubing diameter in the depth of optimum injection point and gas injection rate (using pipe simulator).

1-3 Problem statements:

In well X block 6, the bottom hole pressure is not sufficient to lift the oil to the surface.

1-4 The Methodology:

The volumetric balanced method has been applied in this project to determine the optimum injection point and then we used pipe simulator software to determine the optimum injection point and to study the effect of the tubing size on the injection point.

<u>2-1</u> Gas lift:

More and more wells in the world are being placed on artificial lift , and the number will continue to increase . Often a well does not have sufficient natural energy to move liquids to the surface at desired rates. Changing well conditions, such as reduced reservoir pressure, increasing water cuts and decreasing gas liquid ratios can make consistent and predictable production a challenge. You need a means of artificial lift that is flexible enough to optimize production throughout the life of the well from initial kick-off to depletion. Capable of producing wells with a range of flow rates, Opti-Flow Gas Lift is an extremely flexible artificial lift solution that can be used throughout the lifespan of the well .There are many instances where gas lift is both effective and economical, including:

- Producing wells that can't flow on their own.
- Initial unloading of well that will flow on their own later.
- Accommodating deviated and horizontal well bores
- Overcoming sand and scale problems.
- Unloading a well affected by adjacent drilling and fracturing.
- Back flowing in injection or disposal well.

“The success of gas lift is largely dependent upon the initial design of the system. Installation of Opti-Flow Gas Lift begins with a carefully engineered design . Using a number of well characteristics, helps determine the optimal amount of gas needed to deliver fluids to the surface and the best locations in the production string, based on pressure, for the gas to be injected. These determinations are critical, as <u>identifying the proper points of injection is the key to optimal production.</u>

While the software is a central component of system design, the experience and expertise of our personnel is the real key to the success of Opti-Flow Gas Lift systems, With more than 30 years of experience designing, installing and troubleshooting gas lift, our production experts have the experience and know-how to design systems for a variety of well conditions and deliver the best possible production outcomes” ,PCS Ferguson, 2013.

“Gas lift technology increase oil production rate by injection of compressed gas into the lower section of tubing through the casing-tubing annulus and orifice installed in the tubing string, 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
b) The gas accretes the oil so that effective density of the fluid is less and ,thus , easier to get to the surface .

There are four categories of wells in which a gas lift can be considered:

1. High productivity index (PI) , high bottom hole pressure.
2. High PI , low bottom-hole pressure wells.
3. Low PI , high bottom-hole pressure wells.
4. Low PI , low bottom-hole pressure wells.

Wells having a PI of 0.50 or less are classified as law productivity wells . Wells having a PI greater than 0.50 are classified as a high productivity wells. High bottom-hole pressure will support fluid column equal to 70% of the well depth . Low bottom-hole pressure will support a fluid column less than 40% of the well depth” BoyunGuo, William C.lyous,Ali Ghalambor, 2007.

2-1-1 The benefits of using gas lift system:

- Well depth is not a limitation.
- A crouched\deviated holes present no problem.
- It is also applicable to off-shore operations.
- Lifting cost for a large number of wells are generally very low.
- Surface control of production.
- Unaffected by produced sand.
- Durable with few moving parts.

2-1-2 The limitations of using gas lift system:

- It requires lift gas within or near the oil fields.

- It is usually not efficient in lifting small fields with a small number of wells , if gas compression equipment is required.
- Corrosive gas lift gas can increase the cost of gas lift operations if it is necessary to treat the dry gas before use.

2-1-3 The history of developing of the gas lift system:

The following chronological development of gas lift was given by Brown, Canalizo and Robertson in a paper published in 1961:

1. Prior to 1864: Some laboratory experiments performed with possibly one or two practical applications.
2. 1864-1900: This era consisted of lifting by compressed air injected through the annulus or tubing. Several flooded mine shafts were unloaded. Numerous patents were issued for foot-pieces, etc.
3. 1900-1920: Gulf Coast Area “air for hire” boom. Such famous fields as Spindle Top were produced by air lift.
4. 1920-1929: Application of straight gas lift with wide publicity from the Seminole Field in Oklahoma.
5. 1929-1945: This era included the patenting of about 25,000 different flow valves. More efficient rates of production as well as proration caused the development of the flow valve.
6. 1945 to present: Since the end of World War II, the pressure-operated valve has practically replaced all other types of gas lift valves. Also in this era, many additional companies have been formed with most of them marketing some version of a pressure-operated valve.
7. 1957: Introduction of wireline retrievable gas lift valves.

There are some researches related to this project established as a result of students projects and one of them have been presented at 2012 as a graduation project with name (Gas lift system design using pipe-simulator) of B.Sc. in petroleum engineering , Sudan University of Science and Technology , Khartoum , Sudan.

The comparison between the researches (Gas lift system design using pipe simulator) which mentioned above and our research can obtain a main difference between them which is : the first one have gain results by the pipe simulator to design the gas lift system, but this project have been designed using two methods are pipe-simulator software, Graphical method and compared the result between them.

The second project have been presented at 2013with name (continuous gas lift design (case study)) of B.Sc. in petroleum engineering , Sudan University of Science and Technology , Khartoum , Sudan.

The comparison between this project and our project is: they using the graphical method with the pipe simulator , but this project is used the volumetric balanced method with pipe simulator .

2-1-4 Gas lift system:

A complete gas lift system consist of a gas compression ,station , a gas injection manifold with injection shocks and time cycle surface controller , a tubing string with installations of unloading valves and operating valves , and adown hole chamber. Figure(2-1)

2-1-5 Types of gas lift:

There are two type of gas lift:

2-1-5-1Continuous flow gas lift :

The most majority of gas lift wells are produced by continuous flow . which very similar to natural flow , in continuous flow gas lift the formation gas is supplemented with additional high-pressure gas from an outside source . gas is injected continuously into the product conduit at a maximum depth that depends upon the injection-gas pressure and well depth , the injection gas mixes with the produce well fluid and decrease the density , and subsequently the flowing pressure gradient of the mixture from the point of gas injection to the surface. The decreased flowing pressure gradient reduces the flowing bottom-hole pressure below the static bottom-hole pressure thereby creating a pressure differential that allows the fluid to flow into the well bore.

2-1-5-2 Intermittent-flow gas lift:

As the name implies, intermittent flow is the periodic displacement of liquid from the tubing by the injection of high-pressure gas . The action is similar to that observed when a bullet is fired from a gun. The liquid slug that gas accumulated in the tubing represent the bullet when the trigger is pulled (gas lift valve opens) high-pressure injection gas inters the chamber (tubing) an rabidly expands , this action forces that liquid slug from the tubing in the same way expanding gas forces the bullet from the gun .

There are two types of intermittent gas lift:

-Single point injection:

In single point injection intermittent lift all of the gas necessary to expend the slug to the surface is injected through the operation valves.

-Multi point intermittent flow:

The operating valve must pass enough gas to expend the slug to the next valve up the hole, [Kermit C, brown,1980].

When we use continuous-flow and when we use intermittent-flow?

Continuous gas lift method is used in wells with a high PI (≥0.5 stb/day/psi), And a reasonably high reservoir pressure relative to well depth. Intermittent gas lift method is suitable to wells with

- High PI and low reservoir pressure
- Low PI and low reservoir pressure

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 an pressure and the well reservoir conditions such as the case when the high instantaneous bottom-hole pressure.

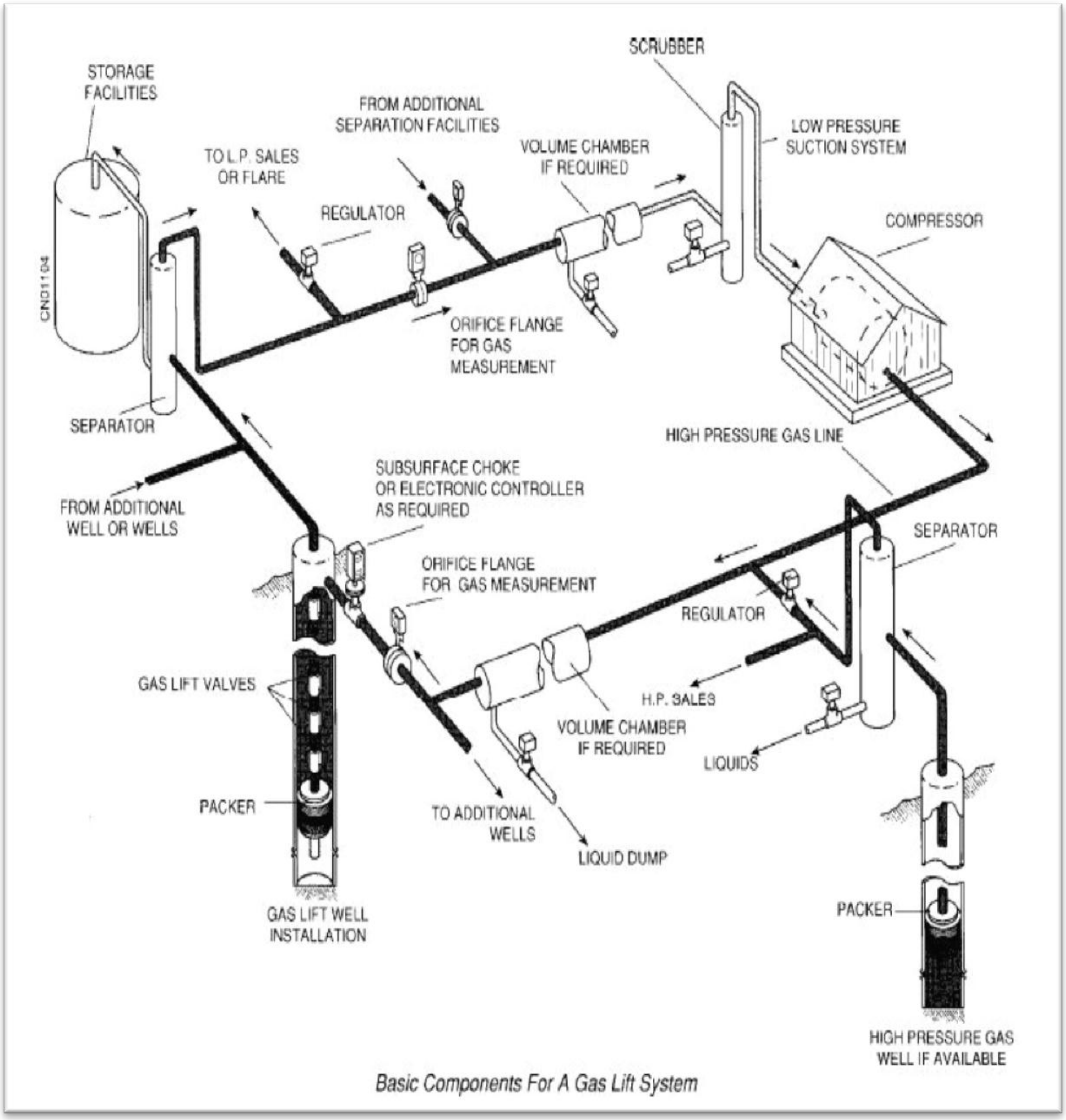


figure (2-1) Gas lift system[3]

<u>3-1</u> GAS LIFT VALVES:

A gas lift valve is designed to stay closed until certain conditions of pressure in the annulus and tubing are met. When the valve opens, it permits gas or fluid to pass from the casing annulus into the tubing. Gas lift valves can also be arranged to permit flow from the tubing to the annulus. (Figure(3.1), shown on the following page, illustrates the basic operating principles involved. Mechanisms used to apply force to keep the valve closed are: (1) a metal bellows charged with gas under pressure, usually nitrogen; and/or (2) an evacuated metal bellows and a spring in compression. In both cases above, the operating pressure of the valve is adjusted at the surface before the valve is run into the well. The bellows dome may be charged to any desired pressure up to the pressure rating of a particular valve. The compression of the spring can be adjusted. All gas lift valves when installed are intended for one way flow, i.e. check valves should always be included in series with the valve.

The forces that cause gas lift valves to open are (1) gas pressure in the annulus and (2) pressure of the gas and fluid in the tubing. As the discharge of gas and liquid from the tubing continues and well conditions change, the valve will close and shutoff gas flow from the annulus. In the case of a continuous flow system, the one valve at the point of gas injection will remain open, thus, the injection of gas will be continuous.

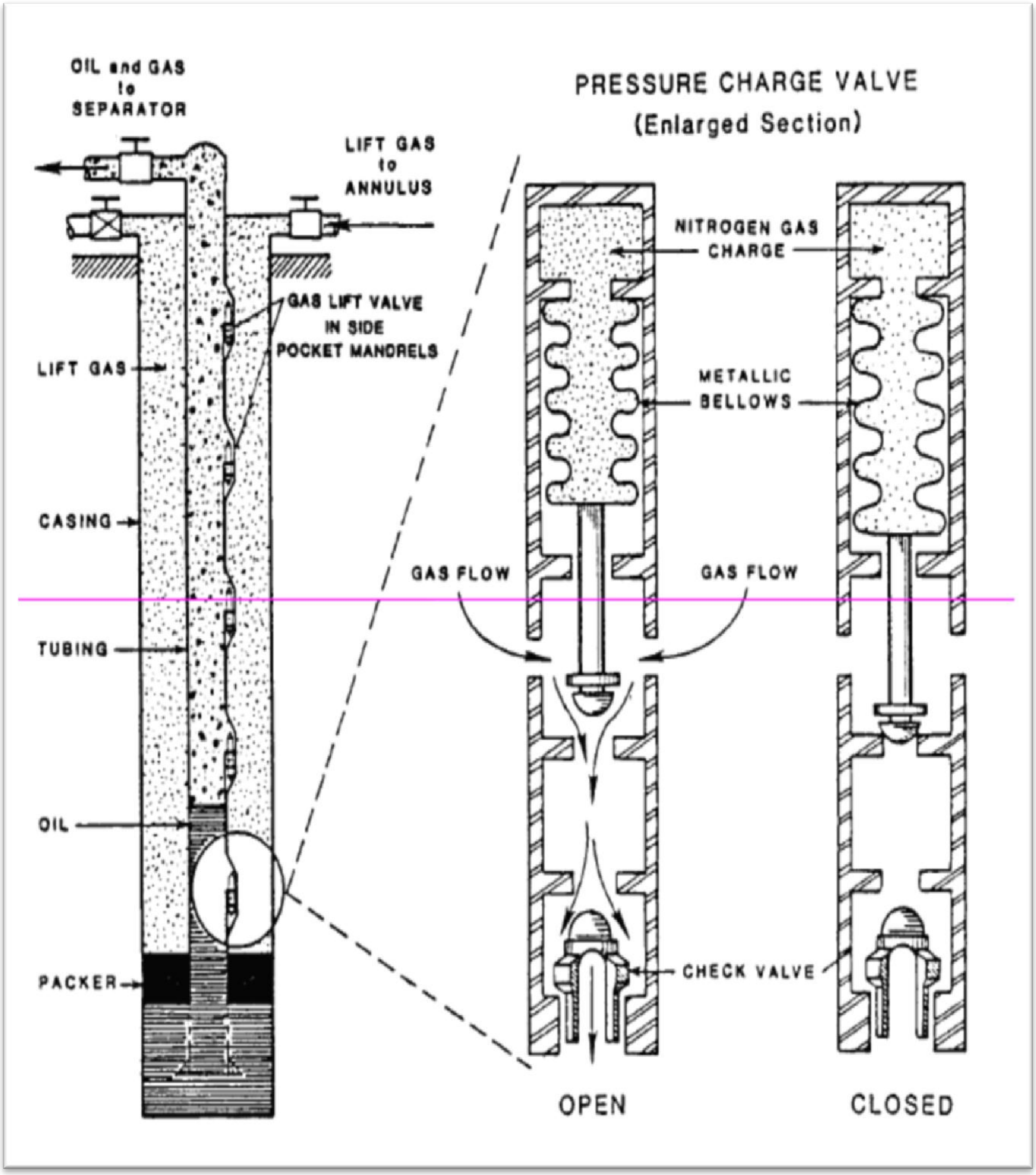


figure (3-1):gas lift valve[3]

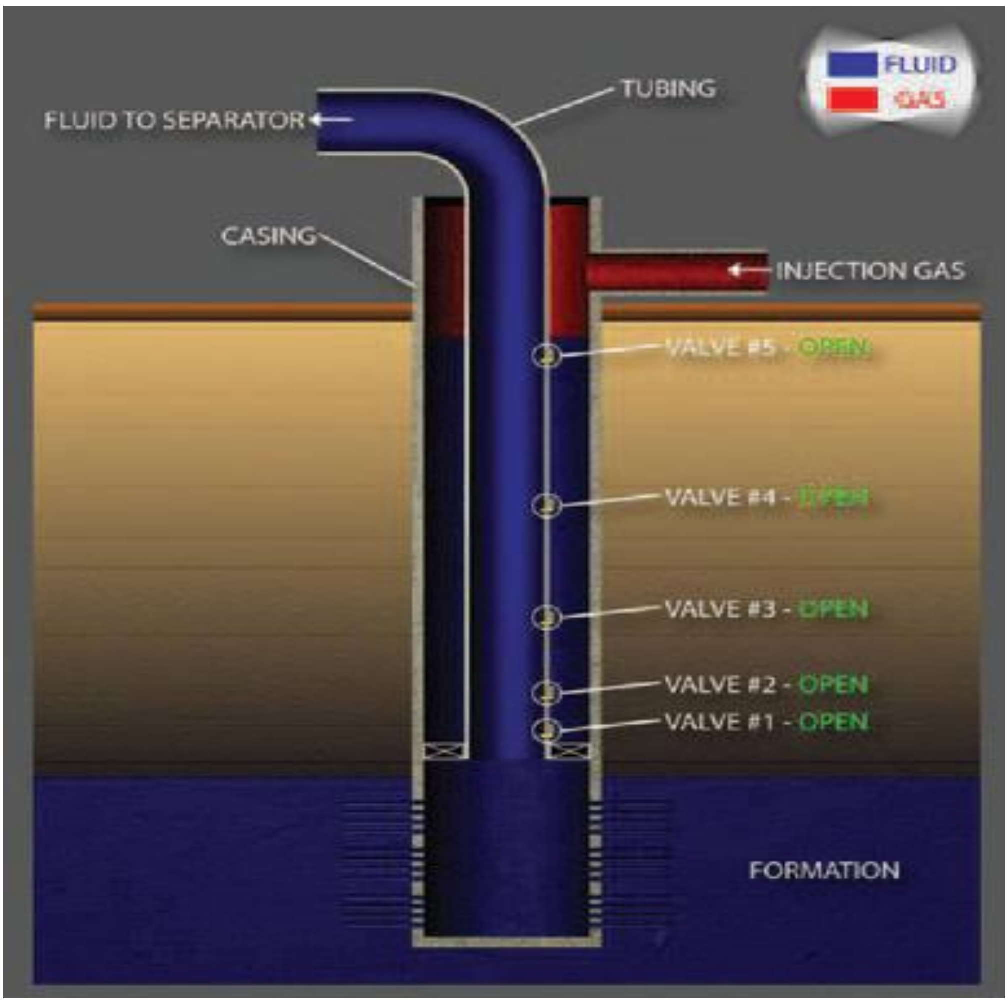
<u>3-2</u> Considerations for Gas Lift Design and Operations:

“If a well can be gas lifted by continuous flow, this form of gas lift should be used to ensure a constant injection gas circulation rate within the closed loop of a rotative gas lift system. Continuous flow reduces the probability of pressure surges in the flowing bottom hole pressure, flow line and the low and high pressure surface facilities that occur with intermittent gas lift operations. Over-design rather than under-design of the gas lift valve spacing is always recommended when the well data are questionable. The subsurface gas lift equipment in the well is the least expensive portion of a closed rotative gas lift system. The larger OD gas lift valves are recommended for lifting high rate wells.
Most gas lift installation designs include several safety factors to compensate for errors in well information and to allow for an increase in the injection gas pressure to open (adequately stroke) the unloading and operating gas lift valves. It is difficult to properly design or analyze a gas lift installation without understanding the operating characteristics of the gas lift valves in a well. The operators should be familiar with the construction and operating principles of the gas lift valves in their wells. When an installation is properly designed, all gas lift valves above an operating valve will be closed and all valves below will be open in a continuous flow installation.
A large bore seating nipple which is designed to receive a lock is recommended near the lower end of the tubing for many gas lift installations. There are numerous applications for a seating] nipple which include installation of a standing valve for testing the tubing and the gas lift valve checks”,Bunhanan mik,1990 .

<u>3-3</u> Gas lift mechanism:

Gas lift uses a high-pressure source to inject gas down the annulus and into the tubing string. The gas is injected through gas lift valves, which are housed in gas lift mandrels. The mandrels are installed at specific intervals in the tubing as determined by the design of the system, downward to the lowest point possible.

The gas lift valves open and close based on preset pressure settings. When open, they allow gas to be injected into the production string. They also allow liquids to escape the casing when using gas lift to initially unload a well. As the gas flows to the surface, it expands, reducing the density and column weight of the fluid. By reducing the flowing tubing pressure, differential pressure between the reservoir and the well bore is created, allowing the well to flow.



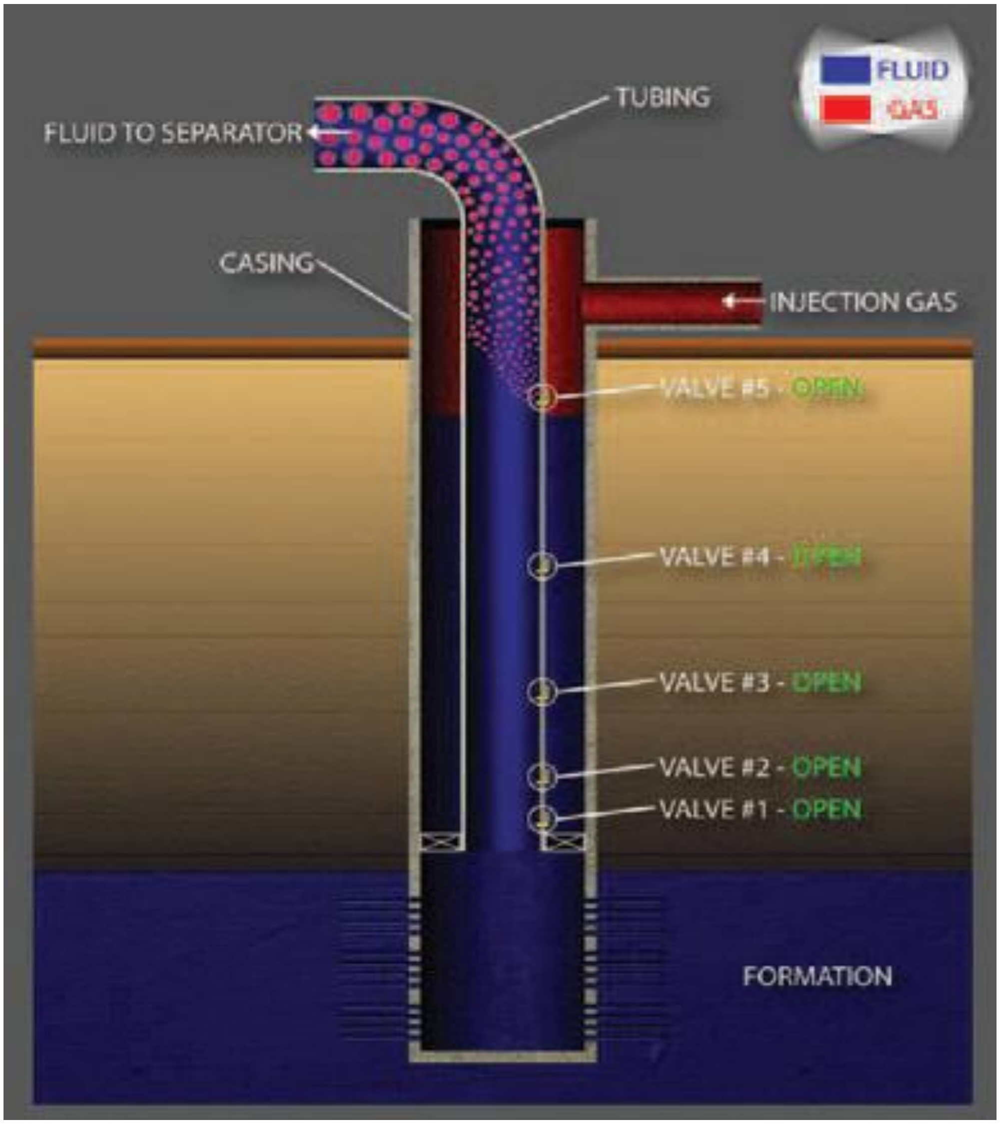
Figure(3-2):gas lift mechanism A [6]

<u>In this figure:</u>

•Gas injection into the casing has begun

•Fluid is u-tubed through all open valves

•No formation fluids being produced; all fluids are from the tubing and casing



Figure(3-3) gas lift mechanism B [6]

<u>In this figure:</u>

•The fluid has been unloaded to top (#5) valve

•The fluid is aerated above this point in the tubing and fluid density decreases

•Pressure is reduced at top valve, as well as all lower valves

•Unloading continues through lower valves

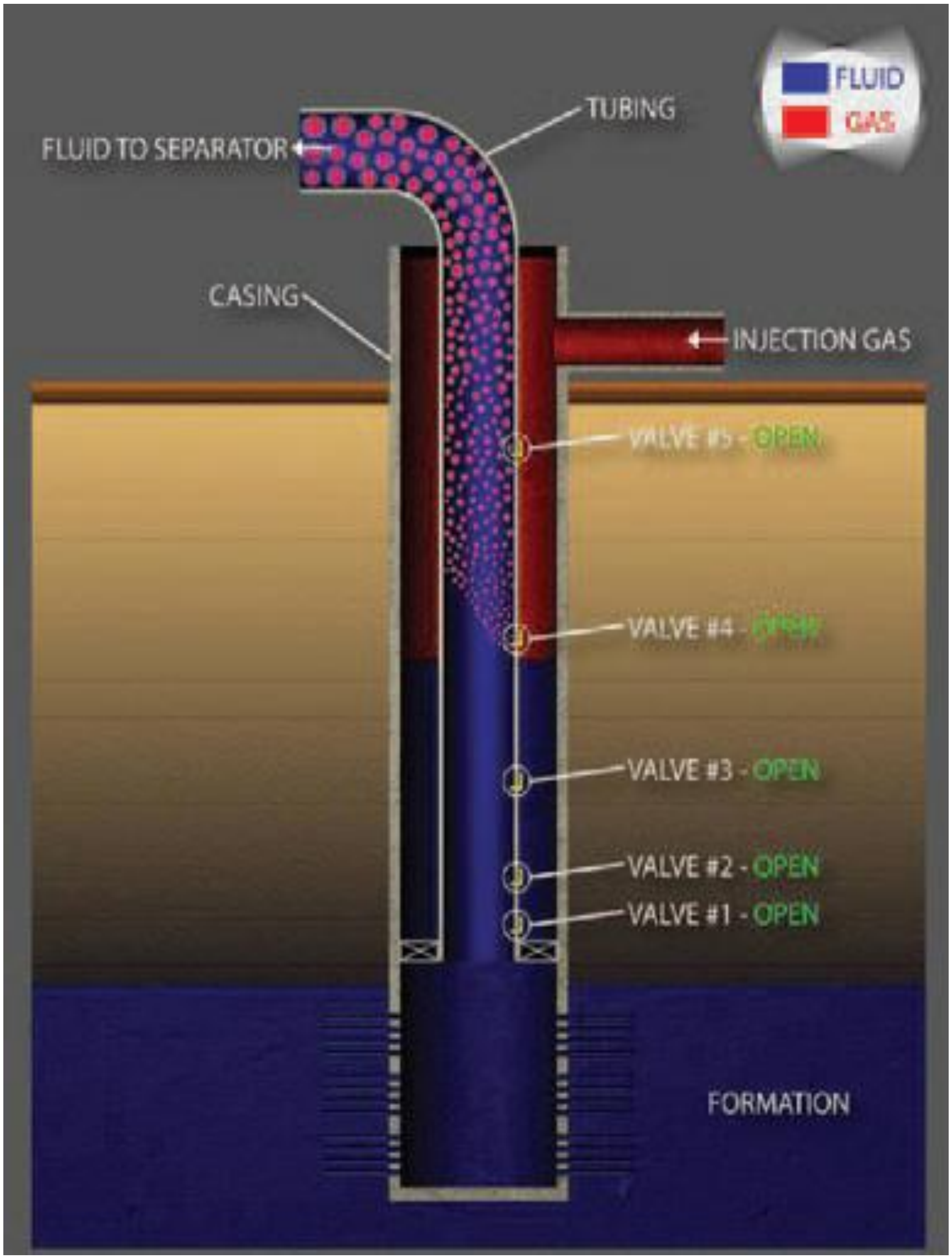


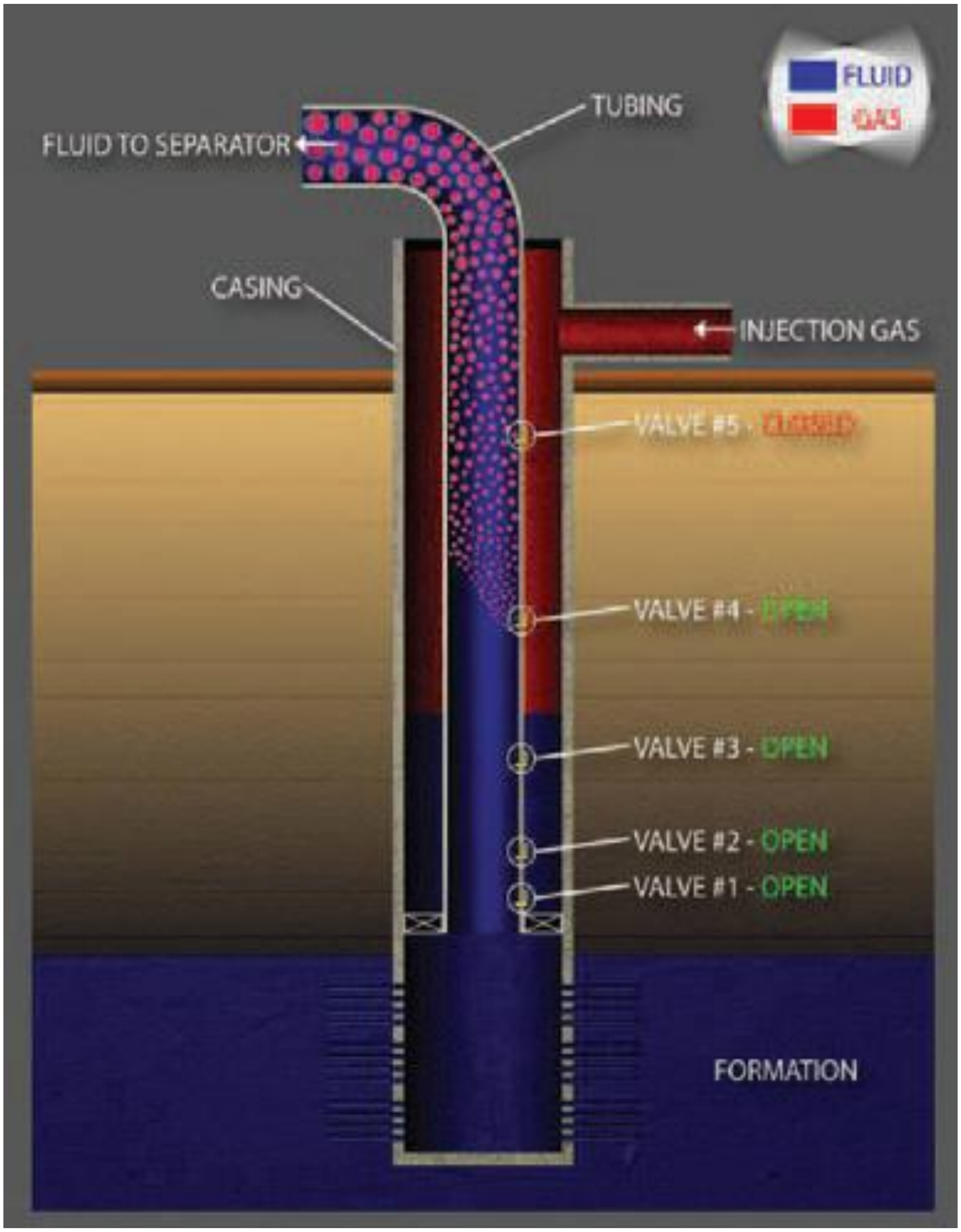
Figure (3-4) gas mechanism C [6]

<u>In this figure:</u>

•Fluid level is now below valve #4

•Injection transfers to valve #4 and pressure is lowered

•Unloading continues through lower valves



Figure(3-5) gas lift mechanism D [6]

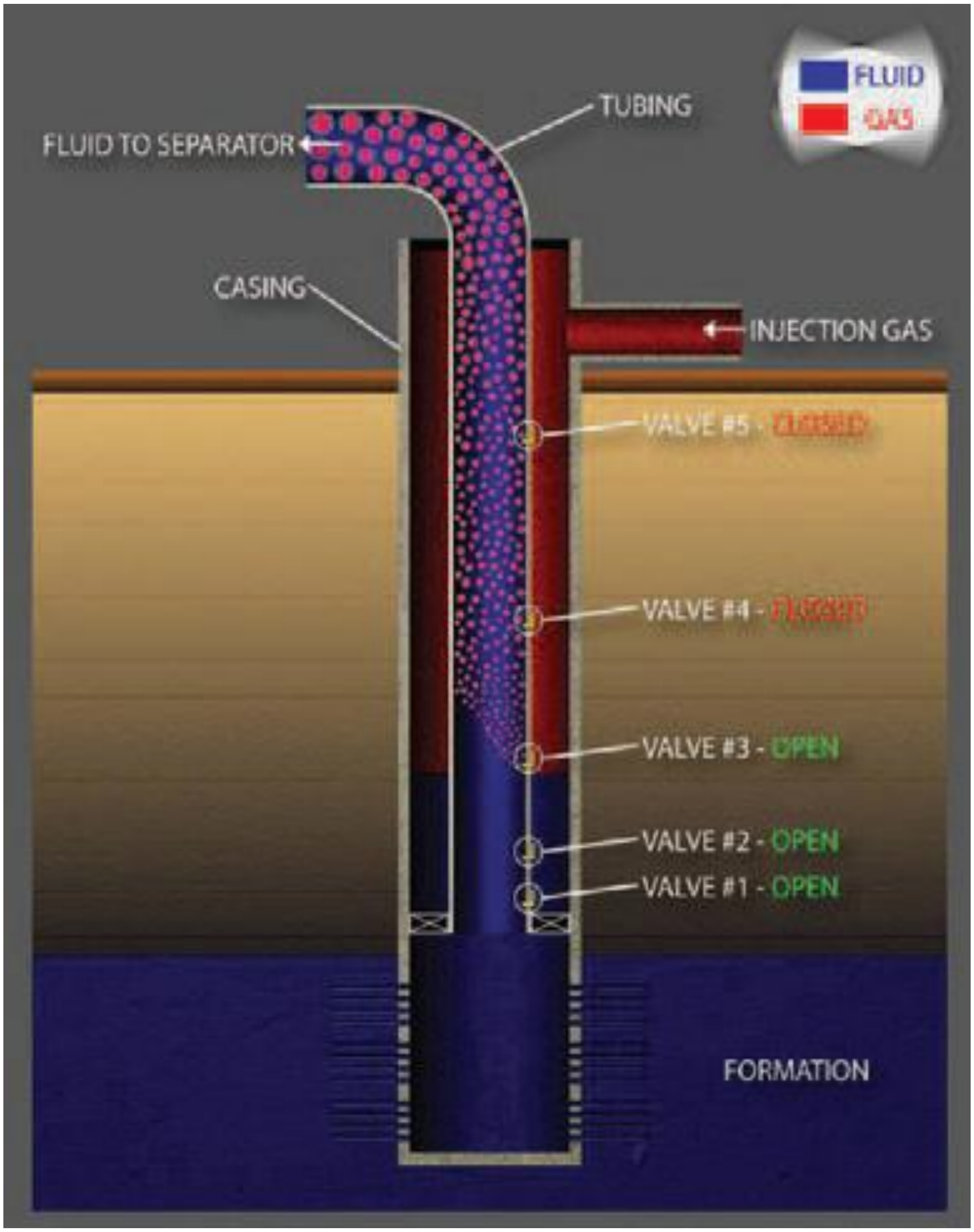
<u>In this figure:</u>

•Casing pressure drops and valve #5 closes

•All gas is being injected through valve #4

•Lower valves remain open

•A reduction in casing pressure causes upper valve to close



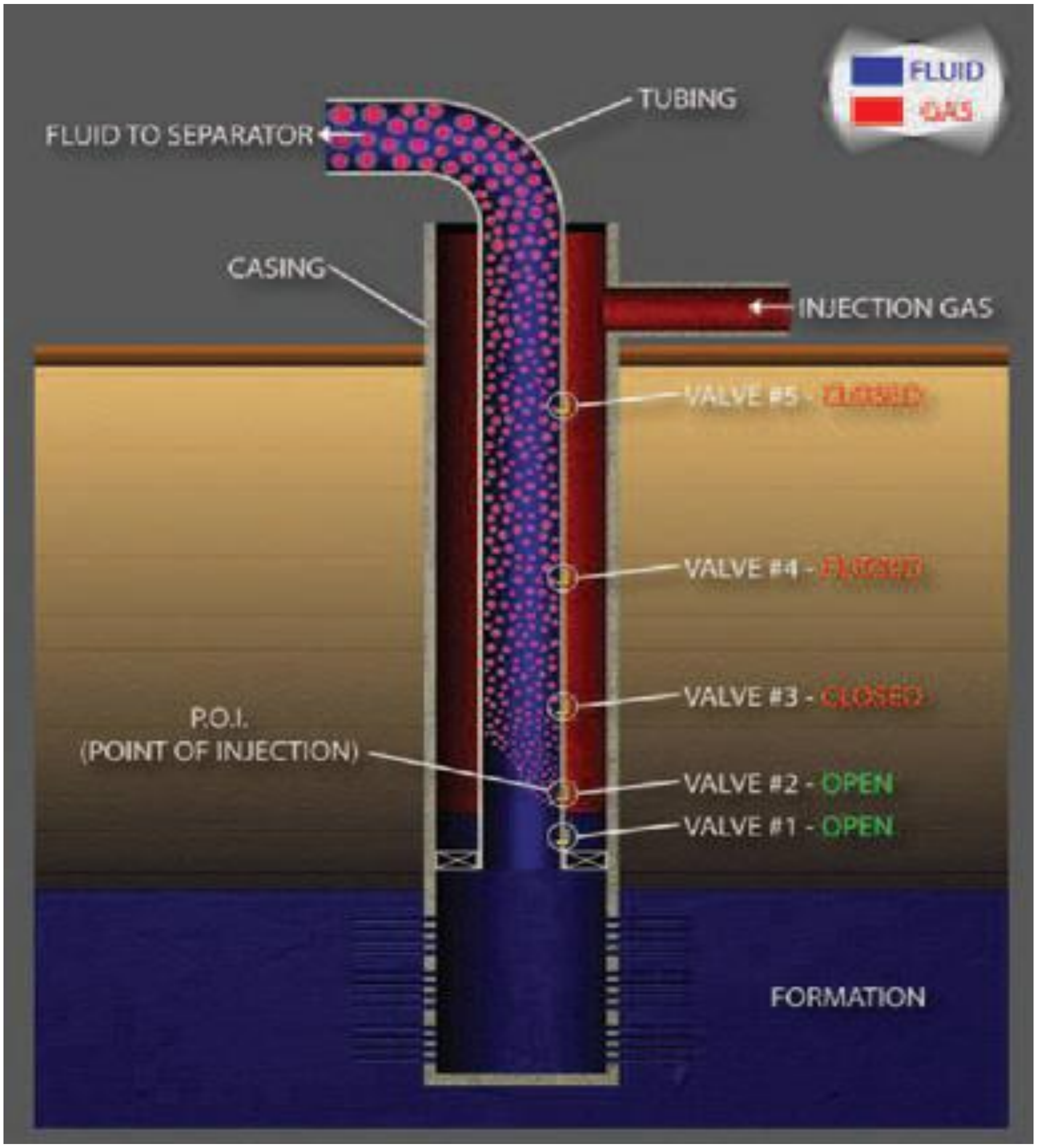
Figure(3-6) gas lift mechanism E [6]

<u>In this figure:</u>

•All gas is being injected through valve #3

•Lower valves remain open

•A reduction in casing pressure causes upper valves to close in sequence.



Figure(3-7) gas lift mechanism F [6]

<u>In this figure:</u>

•Valve #2 open; this is the Point of Injection (ability of reservoir to produce fluids matches the ability of the tubing to remove fluids)

•Casing pressure is dictated by operating valve set pressure

•Upper valves are closed

•Valve #1 remains submerged unless operating conditions change in the reservoir (i.e. formation drawdown)

3-4 Method of determining optimum injection point:

The determination of optimum injection point can be obtained by several methods such as:

1- Graphical method.

2- Volumetric balanced method.

3-4-1 Graphical method:

Data required for graphical method:

1. static bottom hole pressure.
2. Well productivity index.
3. Flowing tubing pressure.
4. Surface kick off pressure.
5. Well depth.
6. Gravity of oil and surface water.

` Graphical method steps:

1. Plot pressure versus depth.
2. Calculate static gradient.

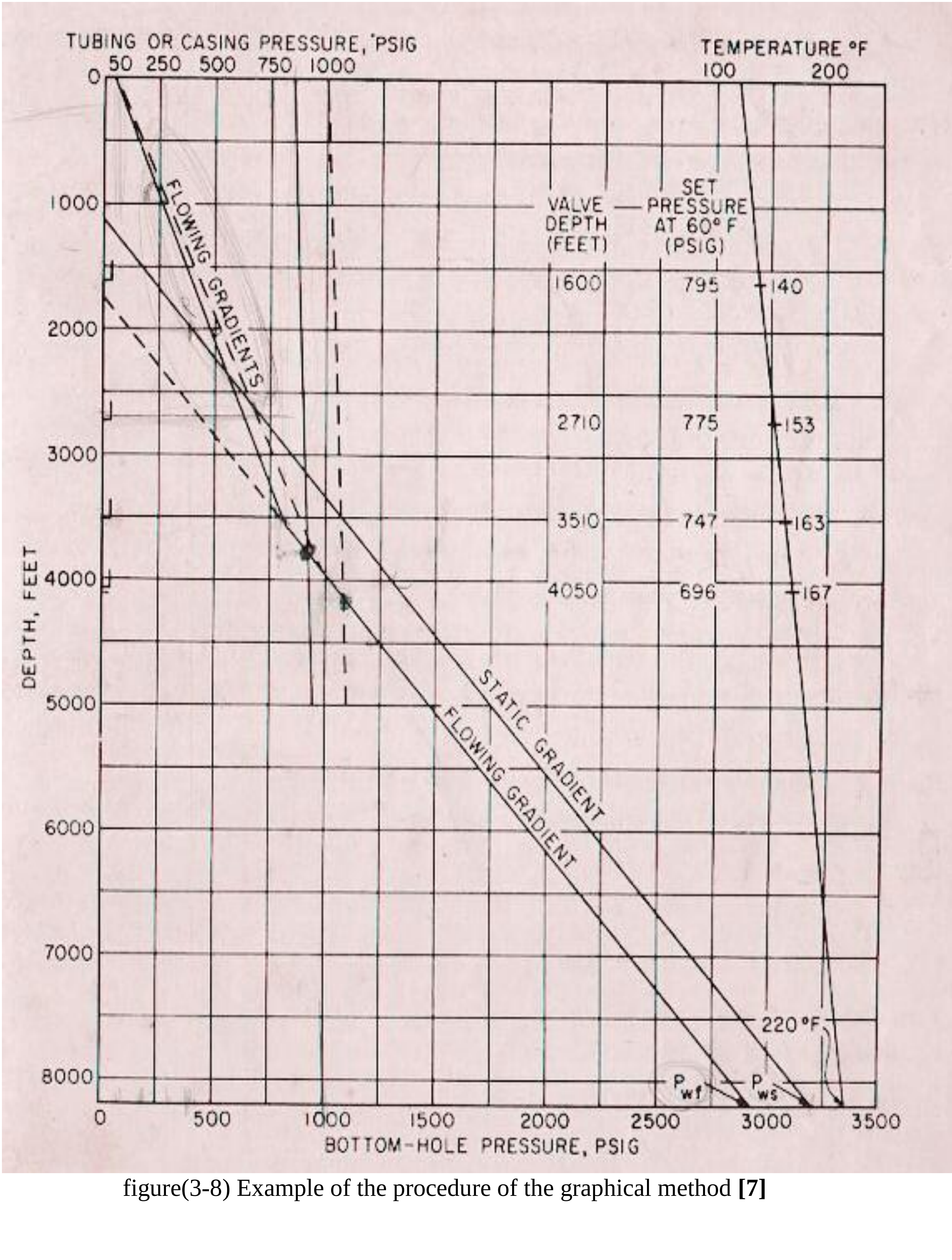
$$G_o = 0.433 \times SG_O \qquad (3.1)$$

$$G_w = 0.433 \times SG_w \qquad (3.2)$$

3. Plot the static gradient between static bottom hole pressure and any point and extrapolate it to intersect the coordinates.

4. Plot the casing gradient from the surface casing pressure to the pressure at half of the well depth.

5. The point of intersection between casing and flow gradient is a point at which tubing and casing pressure are equal, 100psi differential pressure is taking.



figure(3-8) Example of the procedure of the graphical method **[7]**

3-4-2 Volumetric balanced method:

In the preceding graphical method of determining the pressure traverse, it was assumed that all fluid in the well was some average density , and therefore straight lines were obtained for the flowing traverse . The mass flow rate m in pounds of production gas, oil and water per barrel of stock-tank oil, is same at any point in the tubing, but the respective volumes of gas and liquid, expressed as composite volume factorβ_t , are variable. Therefore, the density of production $\boldsymbol{m}/\beta_t$is different for each pressure point in the tubing and the pressure traverse a curve rather than a straight line.

Kirkpatrick has calculated similar pressure traverse for small tubing. The application of the gradient curves (figure (3-10)) in determining pressure traverse for gas-lift wells can now be considered. The following well data are needed for the volumetric balance calculation:

1. Metered producing liquid and gas rate.
2. Operating tubing wellhead pressure.
3. Specific gravity of oil, water, and gas.
4. Static bottom-hole pressure.
5. Productivity index.
6. Wellhead and bottom-hole temperature.
7. Size of tubing and depth set.
8. Depth of midpoint of perforated interval.

The procedure for optimum design of continuous-flow gas-lift systems include:

Firstly : calculating the mass flow rate ***m***

$$\boldsymbol{m} = 350.17\left(\gamma_o + \frac{q_w}{q_o}\gamma_w\right) + R\,\rho_a\gamma_g \qquad (3.3)$$

Where :

$q_o = \text{oil}\ production, barrels\ per\ day$

$q_w = water\ production, barrels\ per\ day$

$\gamma_o = specific\ gravity\ of\ oil\ at\ 60\ F$

$\gamma_w = specific\ gravity\ of\ water\ at\ 60\ F$

$\gamma_g = specific\ gravity\ of\ gas\ at\ 60\ F$

$R = gas\ oil\ ratio, standerd\ cubic\ feet\ per\ stock - tanck\ barrels$

$\rho_a = density\ of\ air\ at\ 60\ F = 0.07640\ lb\ per\ cu\ ft$

$350.17 = weight\ of\ water\ in\ lb\ per\ bbl\ at\ 60\ F$

Secondly: calculate the average tubing temperature

Static temperature gradient: $G_i = \frac{T_r - T_s}{well\ depth}$

Flowing gradient from figure(3.11)

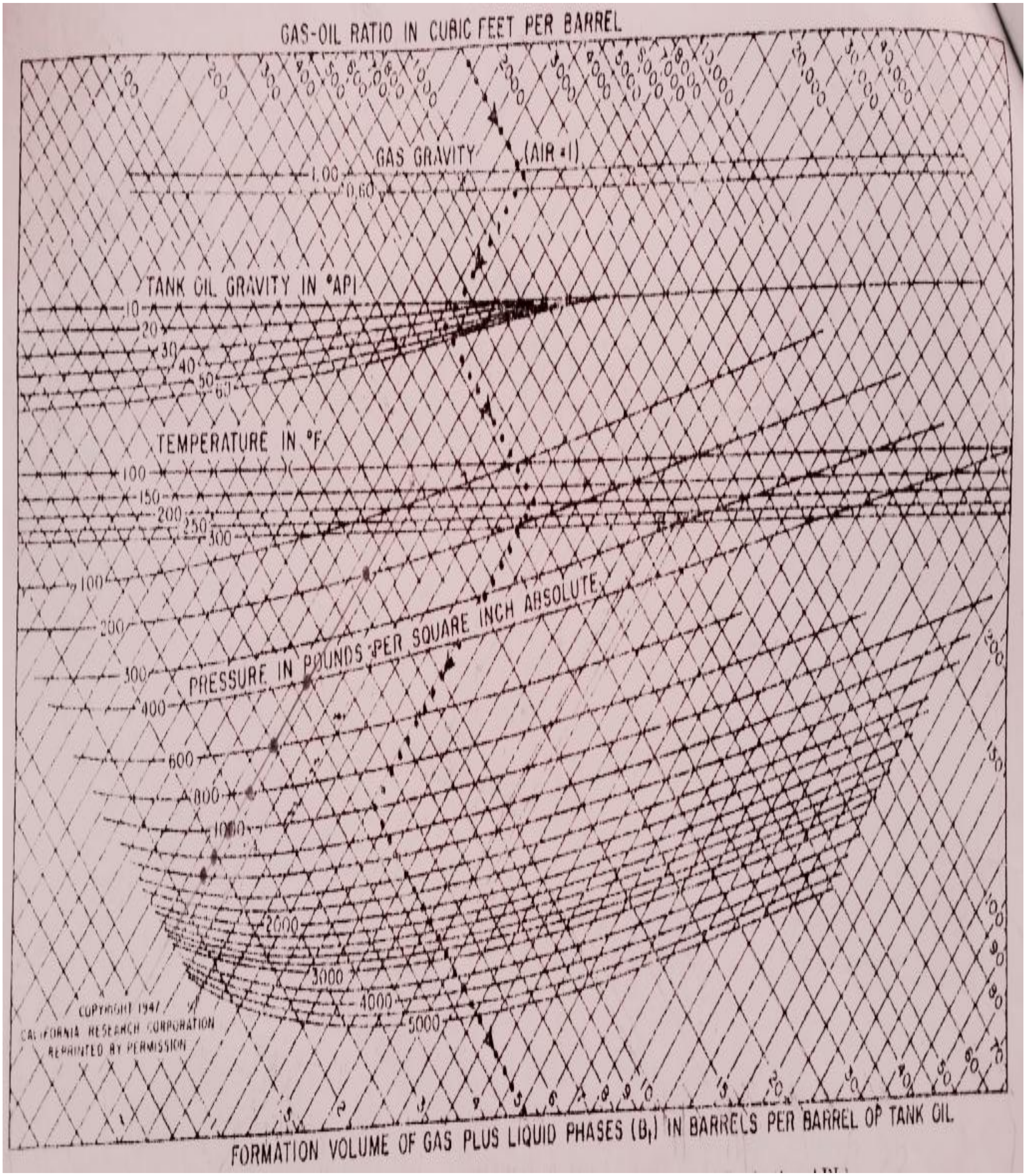
$$T_{avg} = \frac{surface\ temp + bottom-hole\ temp}{2} \quad (3.4)$$

Thirdly: the other procedure is shown in the table below:

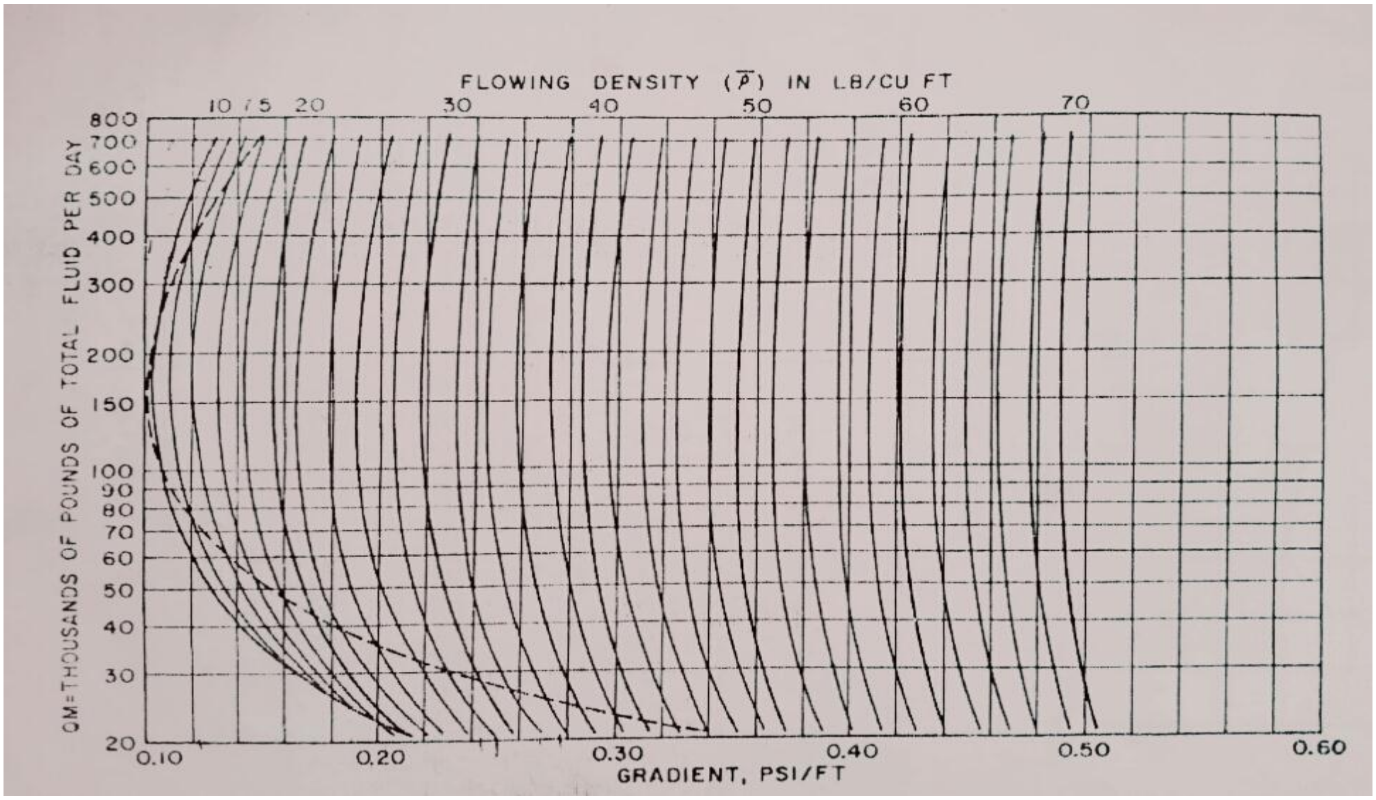
Table 3-1 example of the volumetric method solution procedure.

(1) Tubing pressure *psi*	(2) Two-phase volube factor ***B***t	(3) Total composite vol. factor ***B***t $+ q_w/q_o$	(4) Density of productionρ,(m/5.615) *Lb/cu ft*	(5) Gradient *G*, *Psi/ ft*	(6) Average gradient, *Psi/ft*	(7) Distance between pressure points,*ft*	(8) Depth to pressure point,*ft*
-	-	-	-	-	-	-	-

At the pressure given in Col (1) of the table and the average temperature, and using the other well data, the tow-phase volume factor Col (2) are read from (figure (3-9)) for each pressure increment. The water-oil ratio is added to the tow-phase volume factor of Col (2) and place in Col (3). The density production in pound per cubic feet, Col (4), is obtained by dividing the weight rate of production $\boldsymbol{m}$ by the total composite volume factor at each pressure point and it converted to pound per cubic feet by dividing by 5.615 cu ft per barrel. The gradient in Col.(5) corresponding to the value of $q_o m$ and $q_o$is read from the pressure gradient curve for the specific tubing size (figure (3-10)) .the average gradient is the arithmetical of the gradient in Col.(6),and the distance between the pressure point Col.(7), is obtained by dividing the pressure increment by the average gradient between the pressure points. The depth to the assumed pressure point, Col (8), is obtained by cumulative subtraction of the distance between the pressure points from the total depth.



Figure(3-9) standing's composite volume factor chart [7]



Figure(3-10)pressure traverse for 2.441 in nominal tubing ID [7]

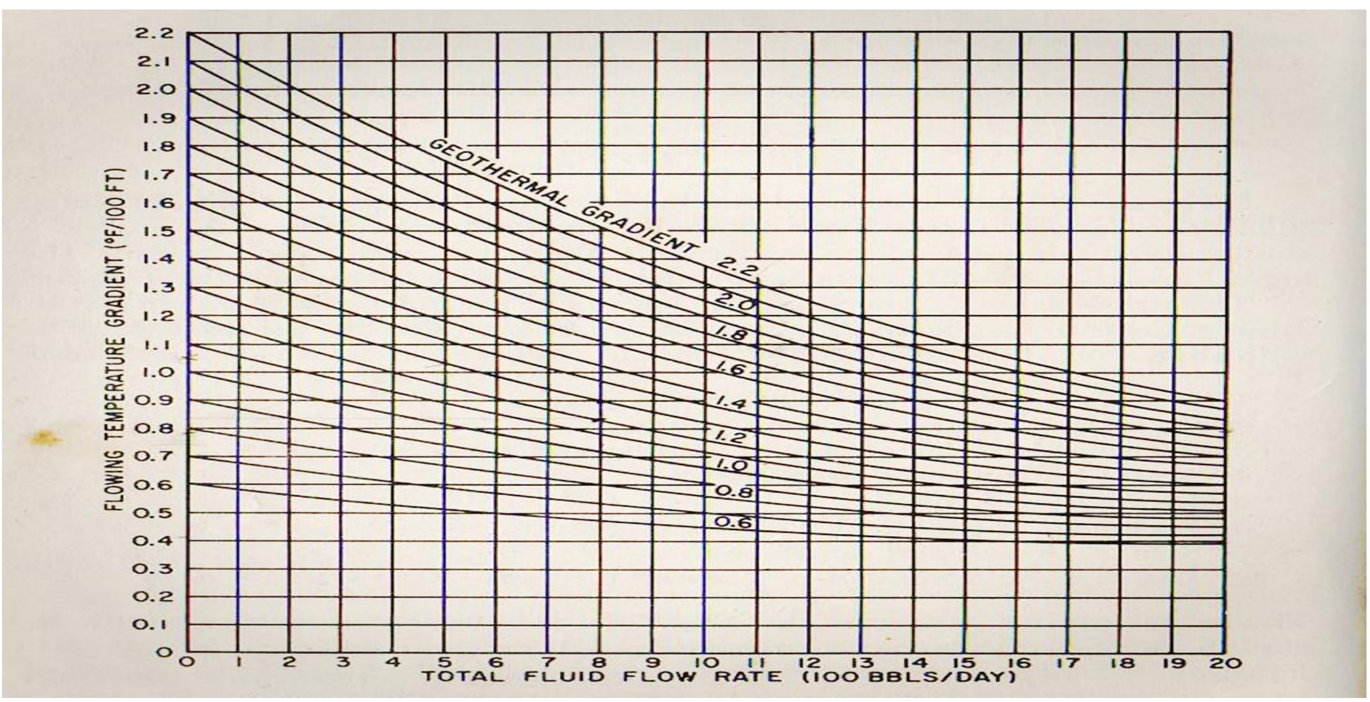


Figure (3-11)flowing temperature gradients for different flow rates , geothermal gradient , and tubing sizes.

4-1 The Data:

The well X in block 6 has data as below:

Table 4-1 General information and well data :

Well name	X, block 6
Well depth	1500 m
Pay zone	AG
Casing size	4.8819 inches
Production zone	1300-1500 m
The current flow rate	598 bbl/day

Table 4-2 The reservoir data:

The parameters	**SI unit**	**Field unit**
Reservoir depth	1500 m	4921.3 ft
Reservoir pressure	16 Mpa	2320.6 psi
Reservoir temperature	65℃	149 °F
Productivity index	39.2 $sm^3/d/Mpa$	1.7 bbl/ d/psi

Table 4-3 Physical properties of field:

The parameters	Si unit	Field unit
Water cut	60%	60%
Gas oil ratio	44.53 sm^3/sm^3	250 Scf/STB
Specific gravity of gas	0.64	0.64
Specific gravity of water	1.05	1.05
API	31.5	31.5
Specific gravity of kill fluid	1.07	1.07

Table 4-4 Tubing parameter:

The parameter	Si unit	Field unit
The tubing size	0.075999 m	2.

Table 4-5 Surface parameters:

The parameter	Si unit	Field unit
Injected gas relative density	0.64	0.64
Injection pressure	8 Mpa	1160.3 psi
Surface temperature	35℃	95 °F
Well head pressure	1.6 Mpa	232.06 psi

<u>4-2</u> Case study Solution:

<u>4-2-1</u> Volumetric balance method:

Step1 :

$$\gamma_o = \frac{141.5}{131.5 + 31.5} = 0.868$$

$$q_w = \frac{60}{100} \times 598 = 358.8 \frac{bbl}{d}$$

$$m = 350.17 \times \left(0.868 + \frac{358.8}{239.2} \times 1.05 \right) + 250 \times 0.0764 \times 0.64$$

= 867.7lb/stb

Step2:

Static temperature gradient:

$$G_i = \frac{149 - 95}{4921.26} = 1.09°\text{F}/100ft$$

Flowing temperature gradient:

From figure(3.11) =0.86°F$/100ft$

$$T = 149 - 0.86 \times 49.21 = 106.68°\text{F}$$

Average Flowing Temperature

$$T_{avg} = \frac{149 + 106.68}{2} = 127.84°\text{F}$$

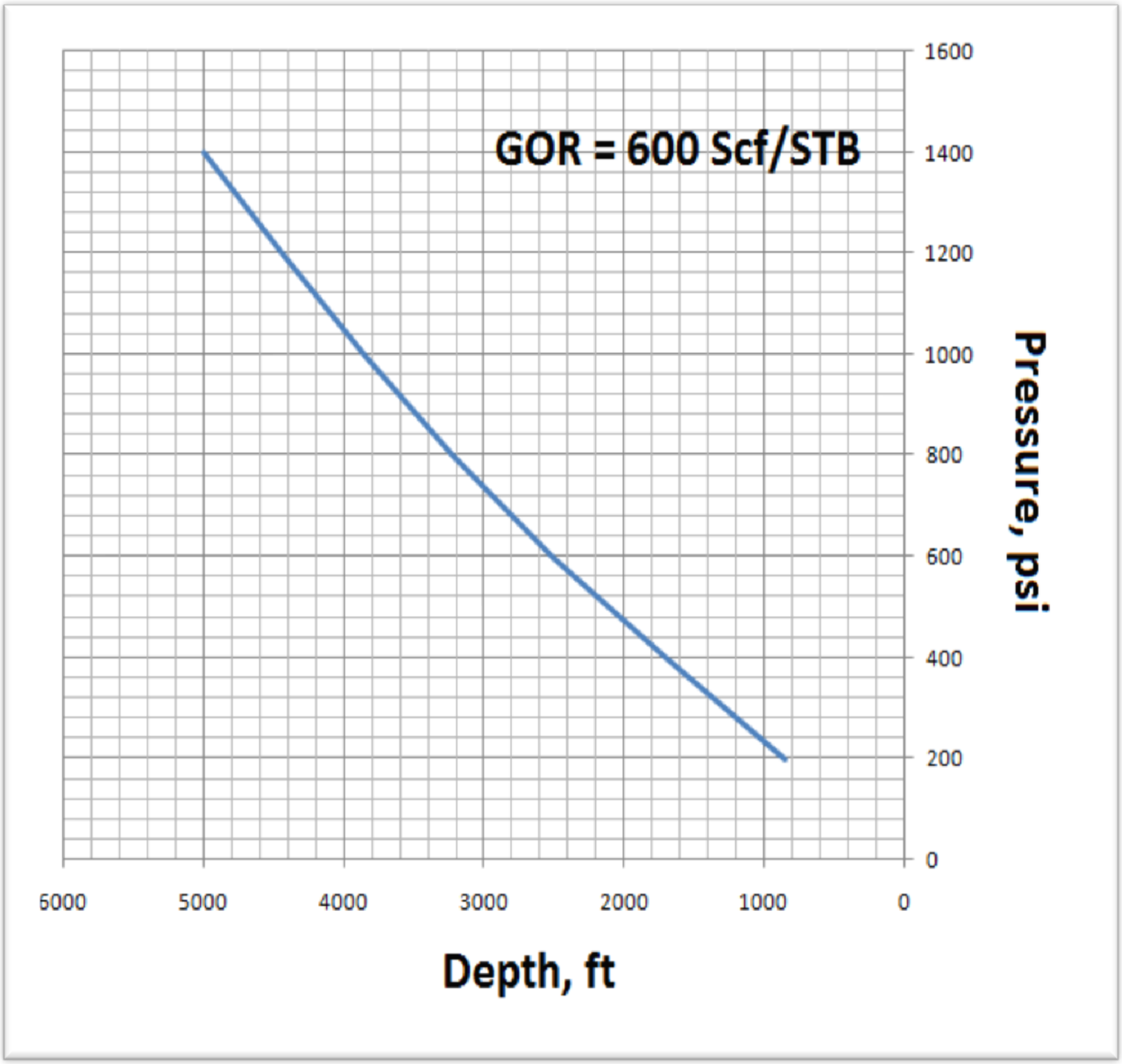
Step3:

Table 4-6 volumetric balanced method solution of the case study.

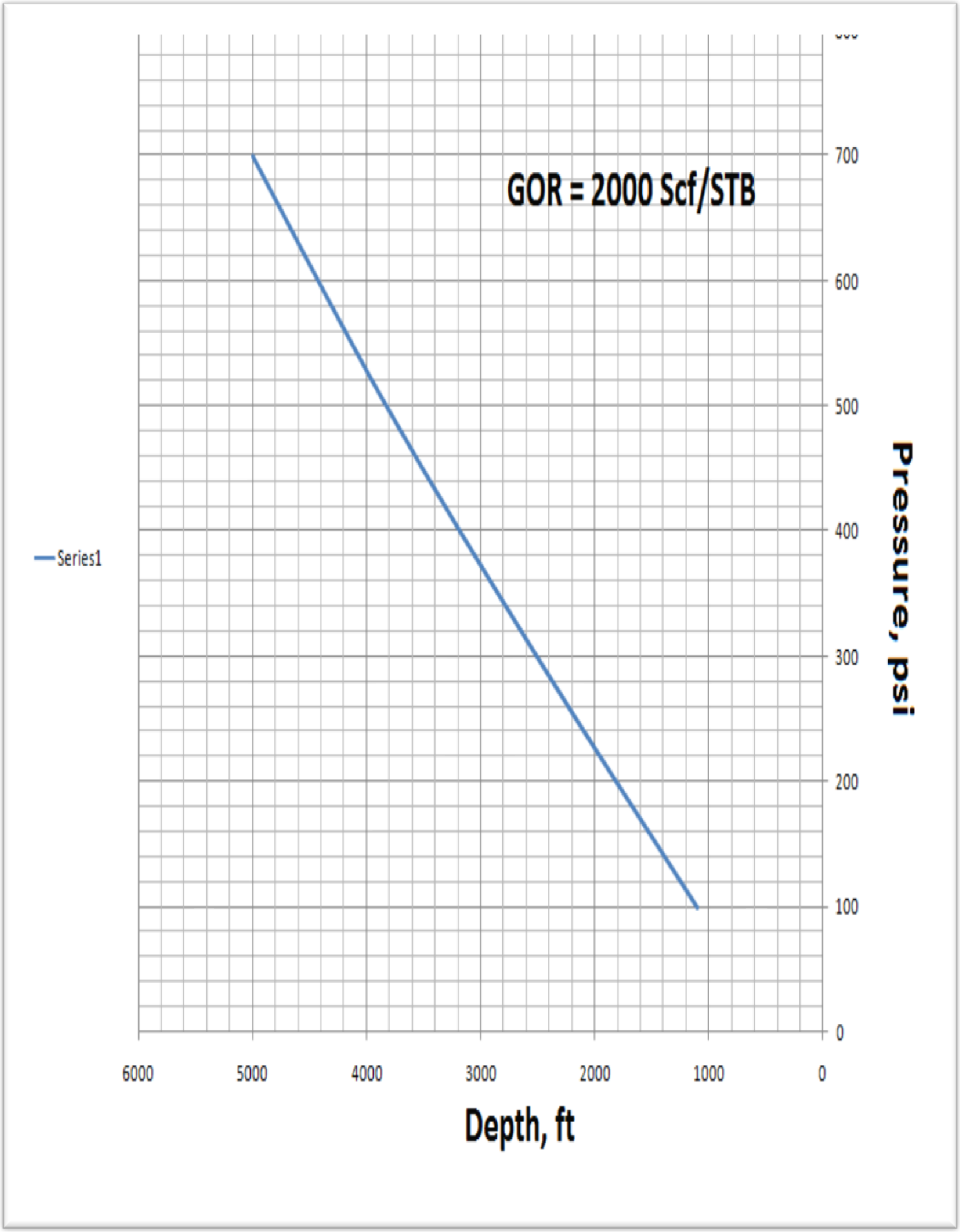
Tubing pressure	Two phase volume factor,β_t	$\beta_t + \frac{q_w}{q_o}$	$\bar{\rho}$ Lb/cuft	G_f Psi/ft	Average gradient Psi/ft	Distance between pressure point, ft	Depth to pressure point, ft
$m = 867.7\ lb/STB$, $q_o m = 207554\ lb/D$, $R = 250\ Scf/STB$							
1970	0.85	2.35	65.76	0.48	-	-	4920
1770	0.89	2.39	64.66	0.472	0.476	420	4500
1570	0.94	2.44	63.33	0.465	0.4865	427	4073
1370	0.98	2.48	62.31	0.458	0.4615	433	3640
$m = 884.8\ lb/STB$, $R = 600\ Scf/STB$, $R_i = 350\ Scf/STB$ E$q_o m = 211644\ lb/D$							
200	9.00	10.50	15.0	--	--	--	--
400	4.90	6.40	24.2	0.230	--	850 (from figure)	850
600	3.50	5.00	31.5	0.265	0.2475	808	1658
800	2.75	4.25	37.0	0.300	0.2825	708	2366
1000	2.25	3.75	41.9	0.330	0.3150	635	3001
1200	1.95	3.45	45.7	0.350	0.3400	588	3589
1400	1.80	3.30	47.8	0.365	0.3575	559	4148

$m = 953\ lb/STB$, $R = 2000\ Scf/STB$, $R_i = 1750\ Scf/STB$ $q_o m = 227957.6\ lb/D$							
100	36	37.5	4.53	--	--	--	--
300	20	21.5	7.90	0.143	--	1404 (from figure)	1404
500	12	13.5	12.60	0.160	0.1515	1320	2724
700	9	10.5	16.2	0.180	0.1700	1176	3900
$m = 894.6\ lb/STB$, $R = 800\ Scf/STB$, $R_i = 550\ Scf/STB$ $q_o m = 213988\ lb/D$							
200	12.0	13.5	11.8	--	--	--	--
400	6.2	7.7	20.7	0.21	--	919 (from figure)	919
600	4.2	5.7	28.0	0.25	0.230	870	1789
800	3.4	4.9	32.5	0.27	0.260	769	2558
1000	2.8	4.3	37.0	0.30	0.285	702	3260
1200	2.4	3.9	40.8	0.32	0.310	645	3905
1400	2.2	3.7	43.0	0.33	0.325	615	4520
1600	1.9	3.4	46.8	0.36	0.345	580	5100
$m = 880\ lb/STB$, $R = 500\ Scf/STB$, $R_i = 250\ Scf/STB$ $q_o m = 210496\ lb/D$							
200	7.00	8.50	17.0	--	--	--	--
400	3.90	5.40	27.4	0.25	--	802 (from figure)	802
600	2.75	4.25	34.8	0.285	0.2675	748	1550
800	2.25	3.75	39.5	0.315	0.3000	667	2217

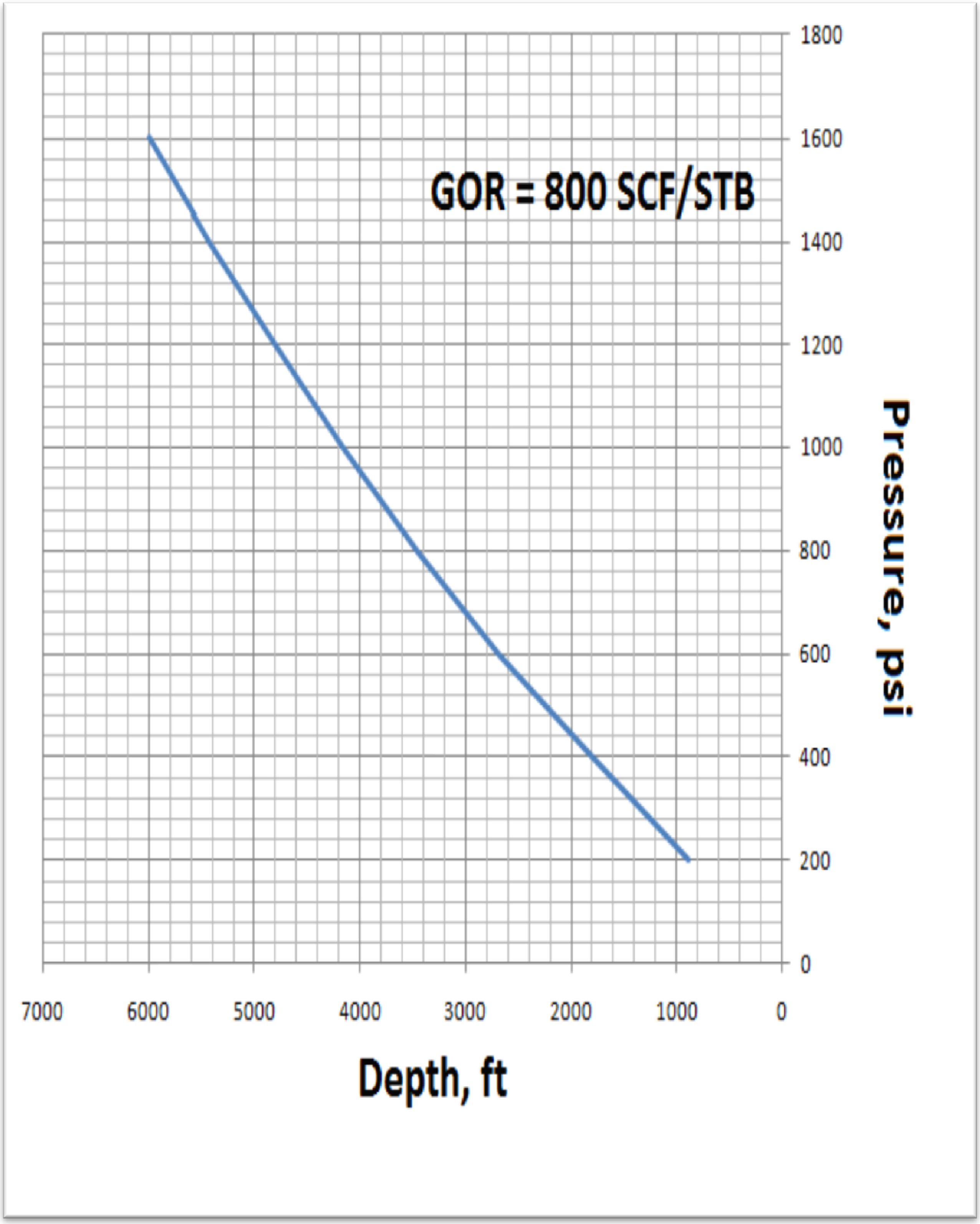
1000	1.80	3.30	44.8	0.347	0.3310	604	2821
1200	1.60	3.10	47.7	0.365	0.3560	562	3383
1400	1.45	2.95	50.2	0.375	0.3700	540	3923
1600	1.40	2.90	51.0	0.380	0.3775	530	4453



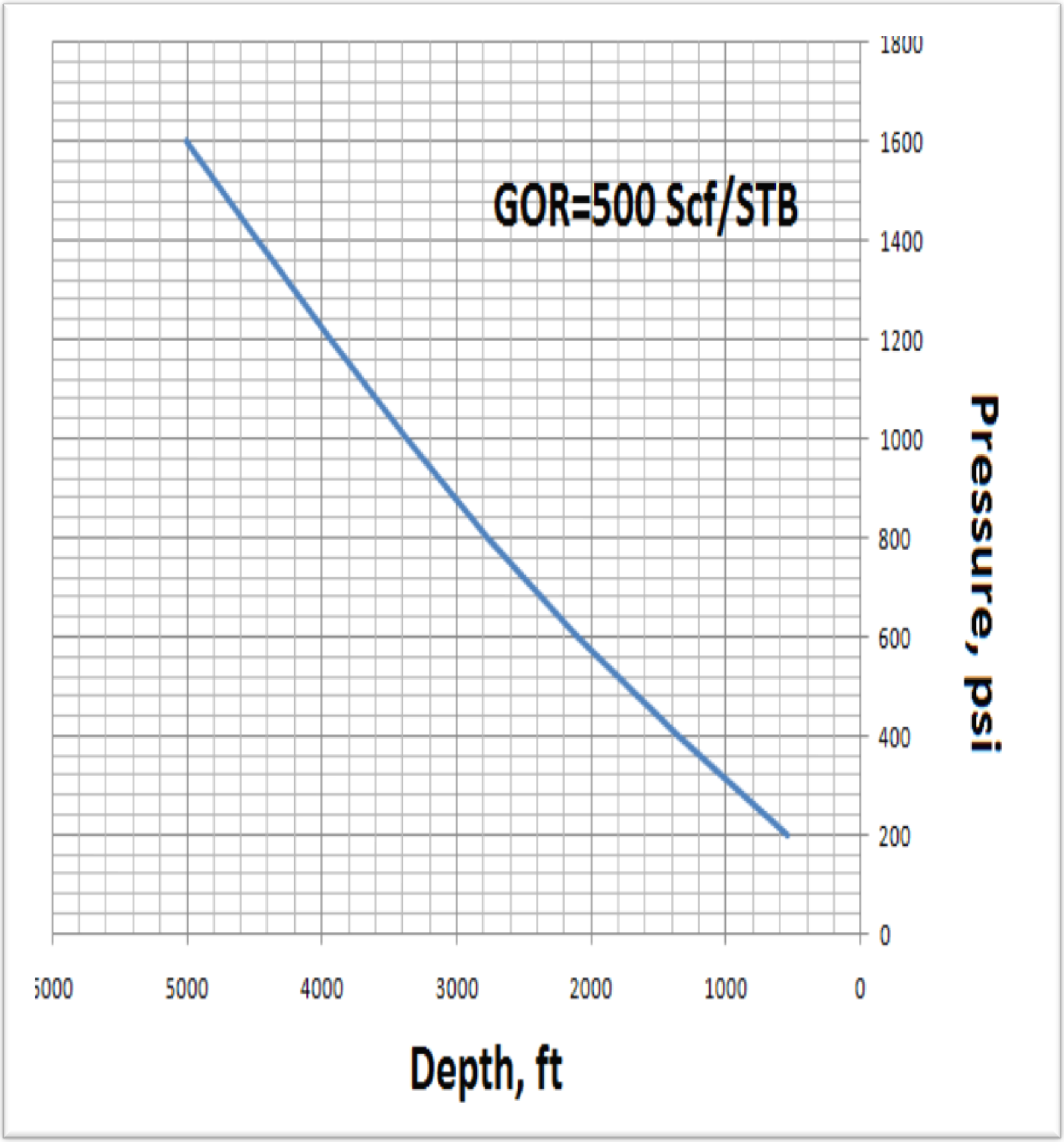
Figure(4-1) pressure Vs. depth for GOR = 600 Scf/STB



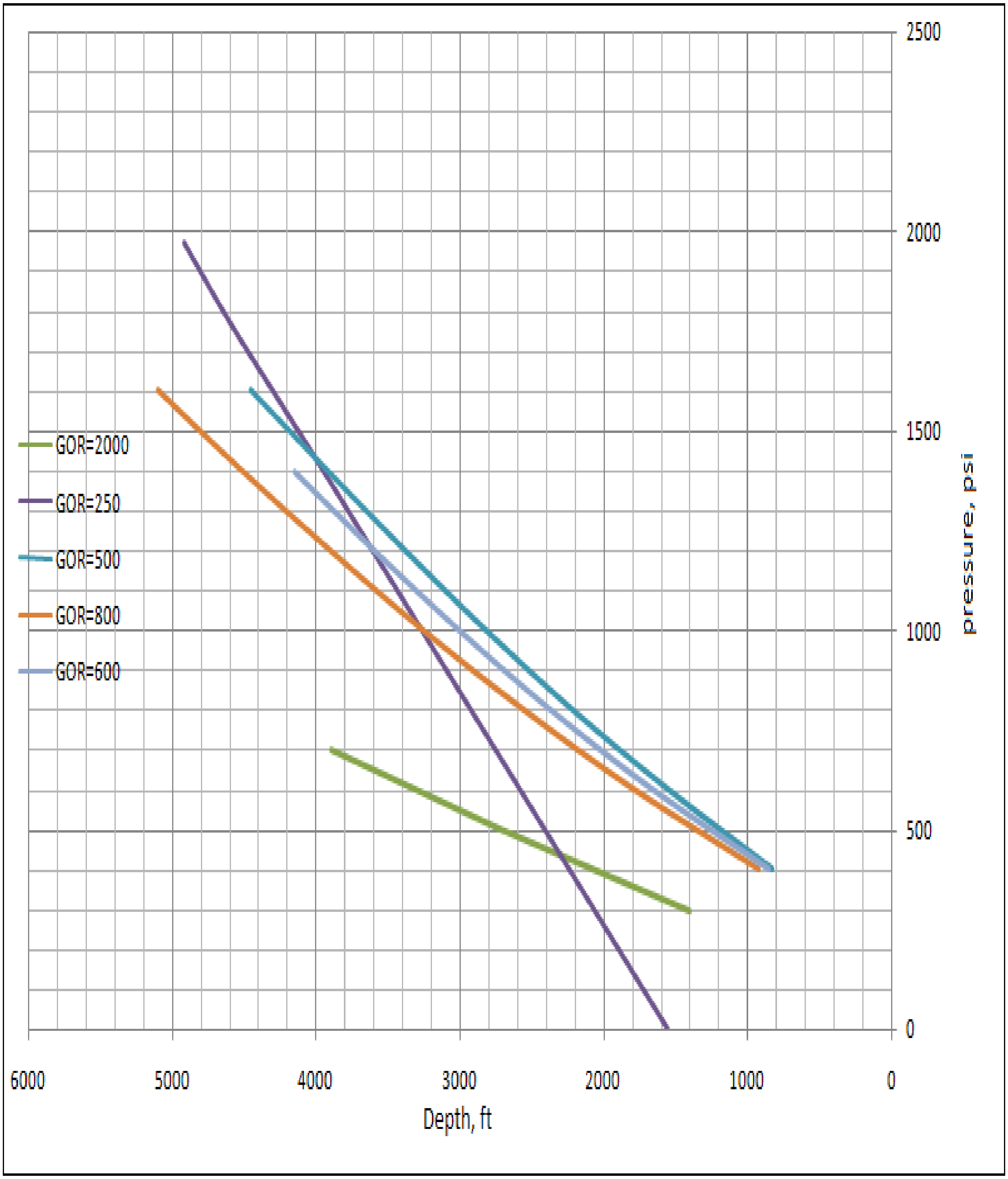
Figure(4-2) pressure Vs. depth for GOR 2000 Scf/STB



Figure(4-3) pressure Vs. depth for GOR = 800 Scf/STB



Figure(4-4) pressure Vs. depth for GOR = 500 Scf/STB



Figure(4-5) pressure Vs. depth for All values of GOR

In Sudan (our case study) they use 8 Mpa as standard value of injection pressure Depending on volumetric method that used to calculate the optimum pressure and depth ,calculation result of pressure and depth according to different gas oil ratios are detailed in the below table:

Table (4-7) volumetric method calculation result

Injection gas oil ratio(scf/stb)	Tubing pressure at intersection (psi)	Depth to intersection (ft)
2000	450	2300
800	1000	3300
600	1200	3600
500	1420	4000

Then according to standard value of injection pressure in Sudan (which is 8 Mpa) we choose the 1200 psi as optimum pressure and the corresponding optimum depth is 3600 ft

4-2-2 Pipe simulator:

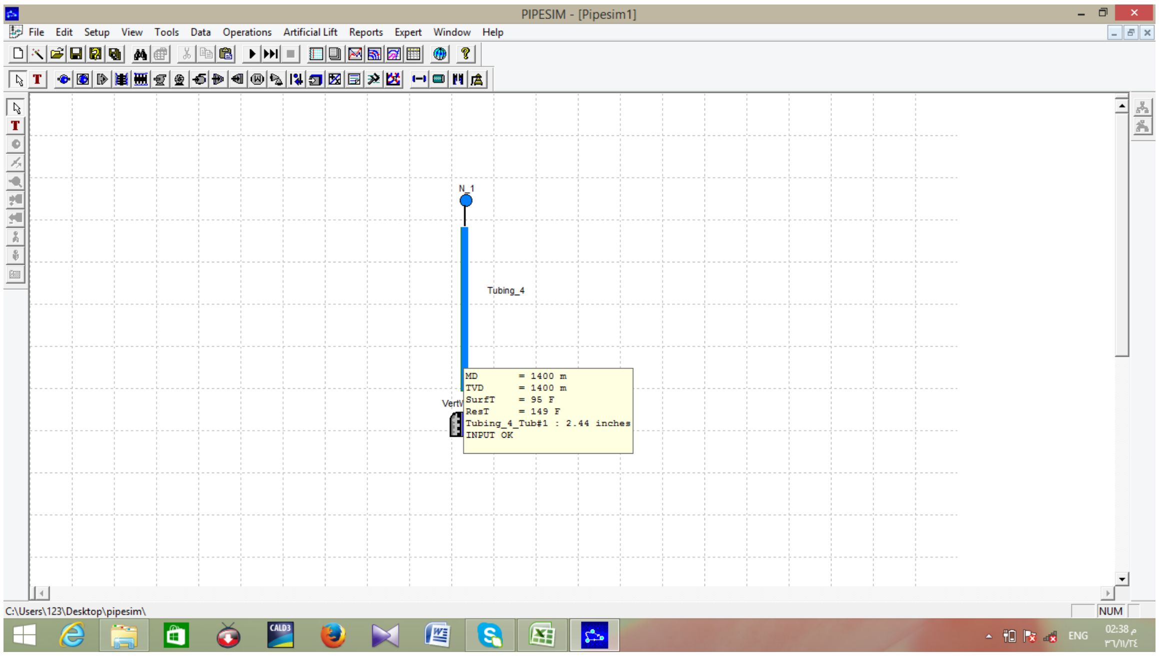
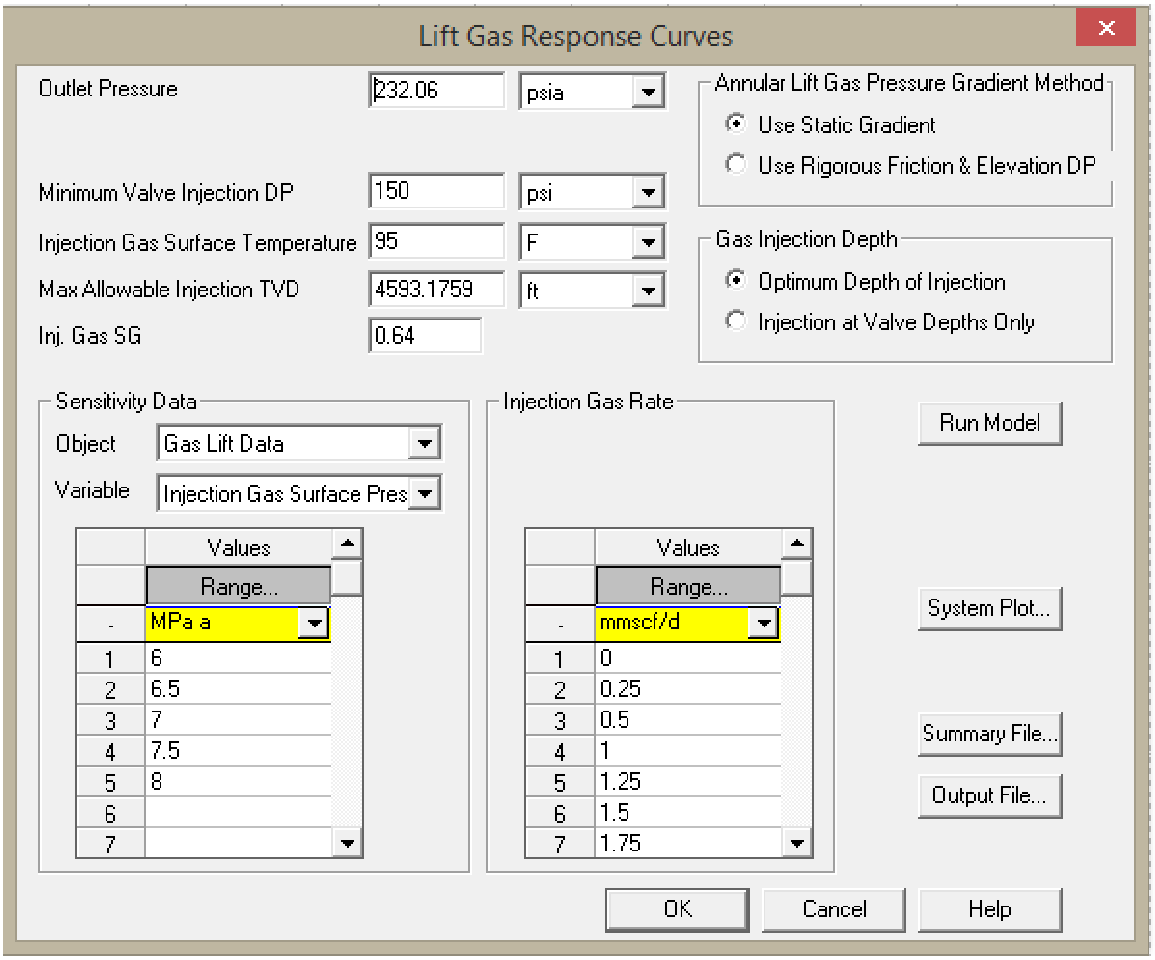
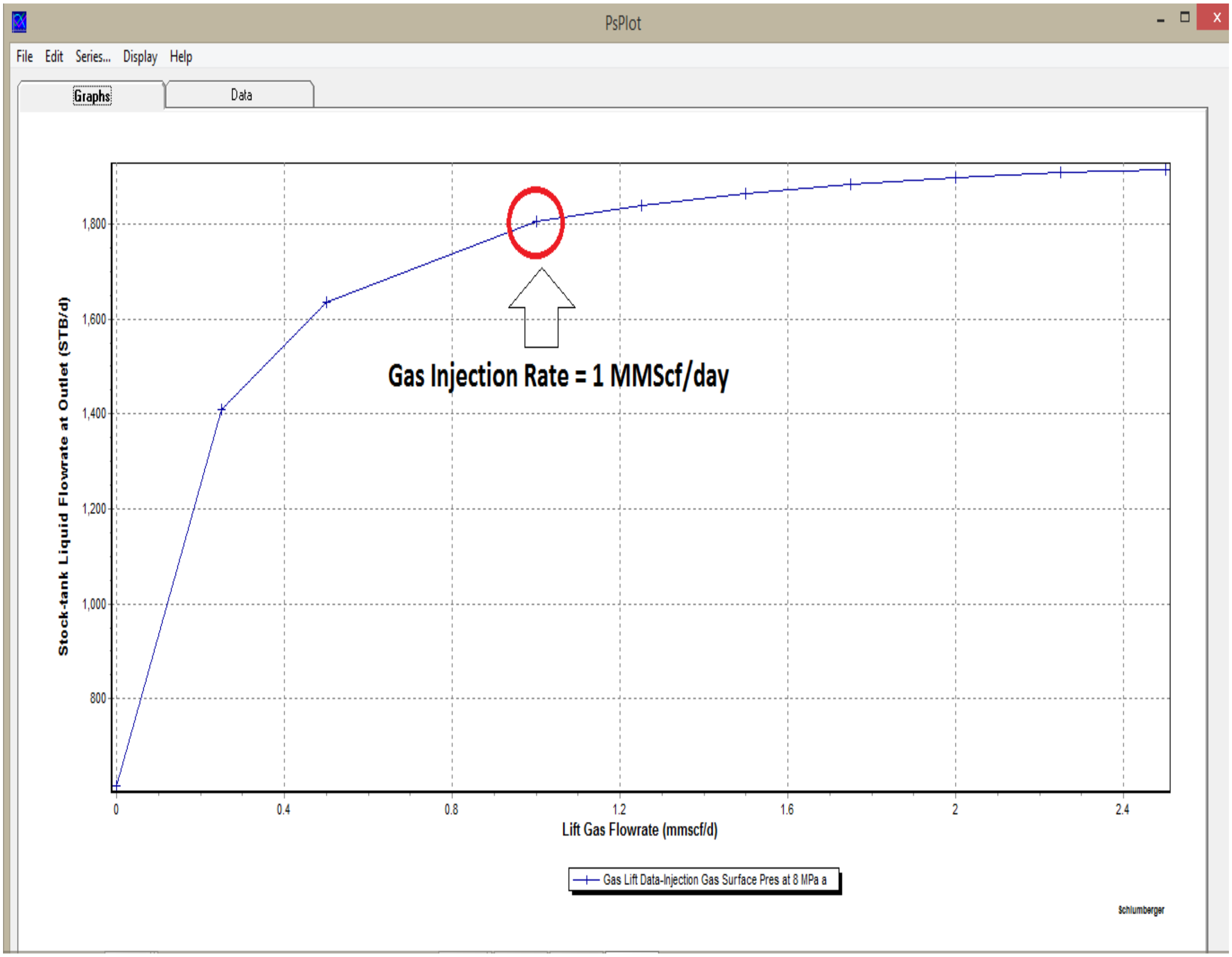


Figure (4-6) well information in pipe simulator



Figure(4-7) lift gas response curves



Figure(4-8) Gas Injection rate vs liquid flow rate at outlet-pipe simulator

From above figure the optimum injection gas rate is 1MMscf/day which gives the production rate1800bbl/day this production rate is selected as optimum because the production difference between 1MMscf/day and 2.4 MMscf/day is less than 100bbl/day .

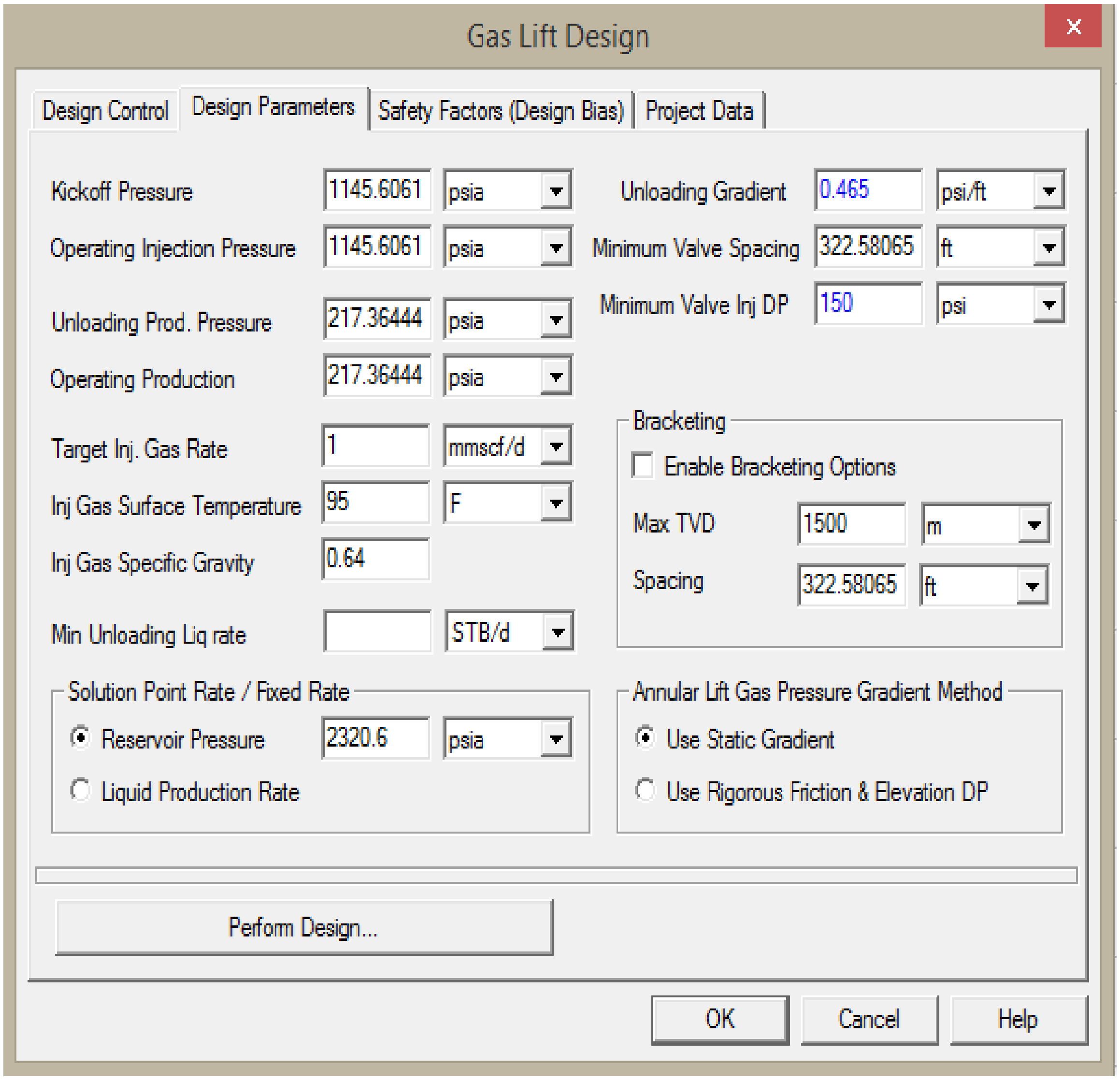
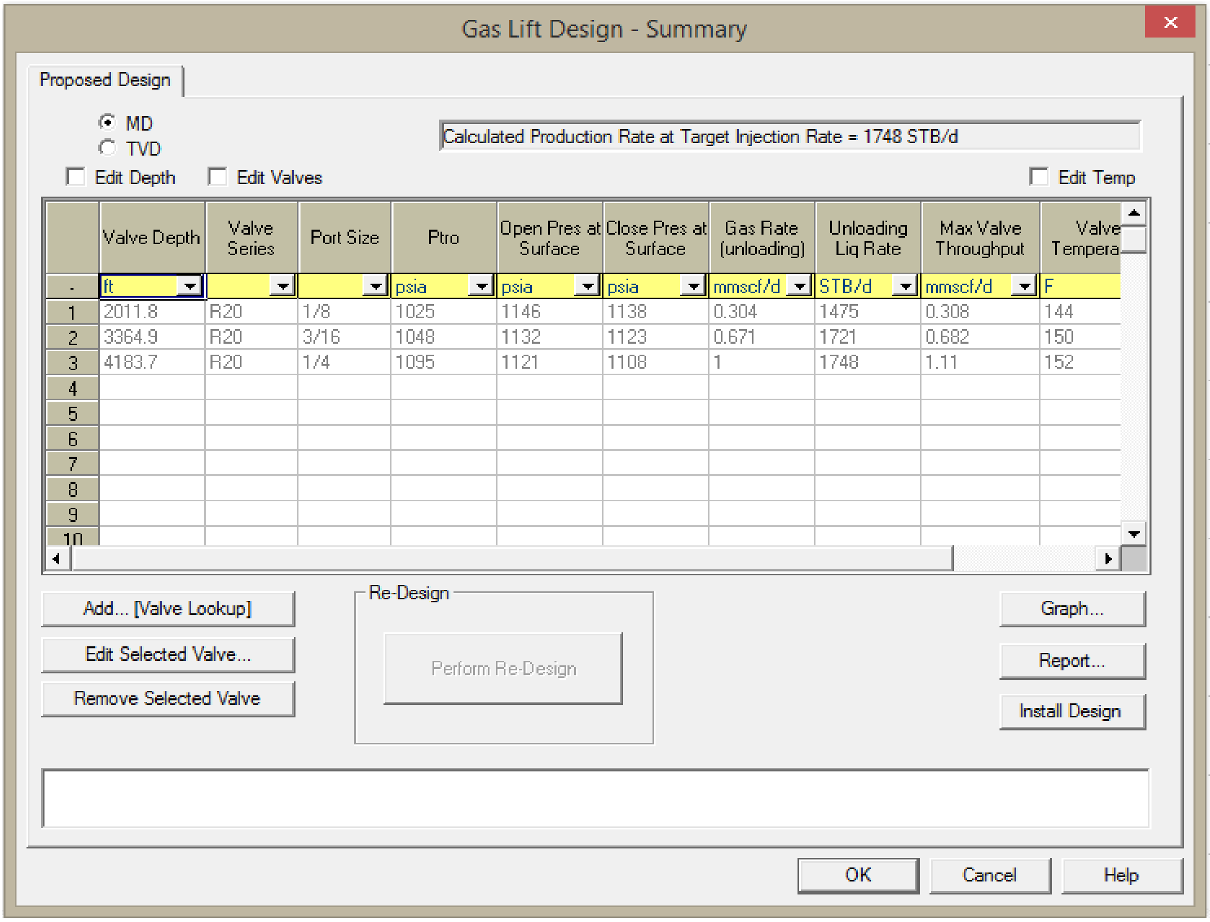


Figure (4-9) gas lift design-pipe simulator



Figure(4-10) gas lift design summary-pipe simulator

Table (4-8) Pipe simulator design results

St. Num	Valve MD (ft)	Valve TVD (ft)	Valve Model	Port Size (inches)	Ptro (@60F)	Valve Choke
1	2011	2011	R20	1/8	1025	
2	3364	3364	R20	3/16	1048	
3	4183	4183	R20	¼	1095	

St. Nm	Valve Temp (F)	Closing Press at Surface (psia)	Open Press at Surface (psia)	P dome (psia)	P prod (psia)	Inj Press Drop b/w Valves (psi)
1	144	1136	1144	1194	564	
2	150	1122	1132	1218	828	25
3	152	1108	1121	1226	1012	15

<u>4-3</u> Effect of the diameter on the production rate:

For the pipe diameters : 1.991 , 2.441 , 2.991 (by using pipe simulator) for the same well data the production rates are 1400 , 1800 , 2060 respectively and the optimum injection points are 3840, 4183 , 4450 respectively.

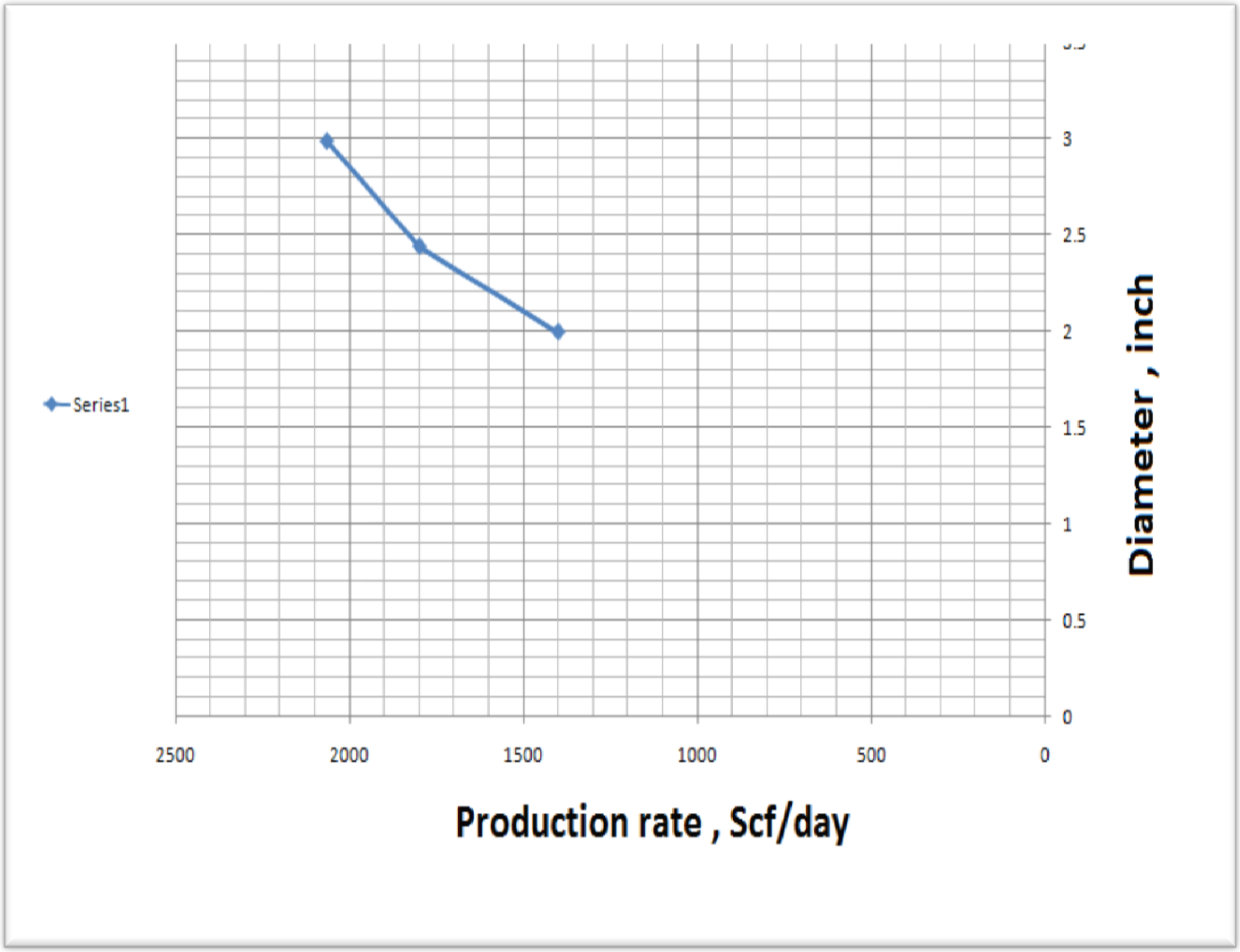


Figure (4-11) Diameter Vs. production rate

From the figure above we observe that the production rate proportionally increase with diameter .

4-4 Effect of the diameter on optimum injection depth:-

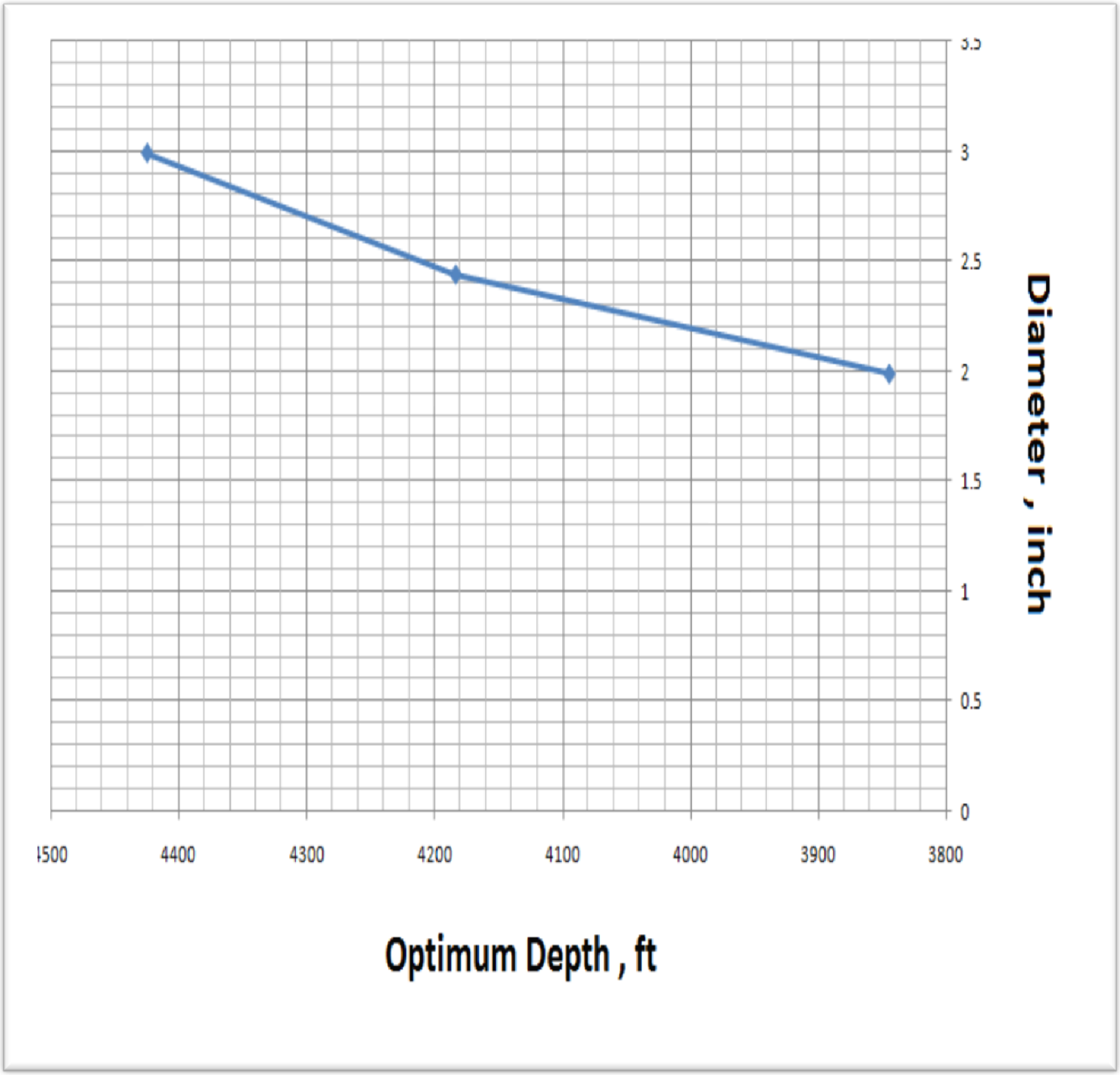


Figure (4-12) diameter Vs. optimum injection depth

From the figure above we observe that optimum depth proportionally increase with diameter.

4-5 Result Discussion:

Table (4-9) Result discussion

Pipesim software result	Volumetric method result
• The optimum depth (4183 ft) • gas injection rate (1 mmscf/day) • production rate (1800 bbl/day)	• Optimum depth (3600 ft)

- The difference between two values calculated by using volumetric method and pipe simulator is appear for some reasons , such as :
  1. Assumed values in volumetric method used to calculate the optimum injection point like (Injection Gas Oil Ratio GOR).
  2. Errors that result from estimating some values visually from curves.

5-1 Conclusions:

- Based on well data , the optimum injection point was (3600 ft) by volumetric balanced method , and (4183 ft) by pipe simulator .
- The optimum injection rate for this well is 1 mmScf/day determined by pipe simulator .
- From the result of sensitivity analysis increasing pipe diameter will increase the depth of optimum injection point.

5-2 Recommendation:

- We strongly recommend using the result of the pipe simulator rather than the result of the volume method.
- We recommend extending the utilization of the non-associated gas that produced from Sudanese oil fields as a lifting gas to increase the wells production rate.
- Data must be available from the college or department for any designing projects.

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