Pressure Changes in Pipe Transporting Mixture of Iraqi Crude Oils (Gathering System)

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Abstract:

A study has been done to represent the pressure changes along gathering system in pipelines transporting Iraqi's crude oils; the study is divided into four parts. The first part represents the calculations of pressure drop in pipelines transporting petroleum fluid from the well head to a gathering point. In this part, there is a two-phase flow (gas and liquid). The calculations of pressure change in this part depends upon determination of some properties such as liquid and gas density, liquid and gas viscosity, liquid hold up and friction factor.

Determining the liquid hold up and then pressure drop are achieved using two methods, the first method is modified Beggs and Brill correlation, depending on three assumed flow patterns. The second is Aziz et al. correlation, depending on three flow patterns also but are different to that of modified Beggs and Brill. While a method of Colebrook used in determination of two-phase friction factor. The results of two-phase flow calculations show that modified Beggs and Brill correlation (having error of 0.26%) better than Aziz et al. correlation (having error of 0.55%).

In the second part there are calculations of pressure change in liquid flow in a pipeline from the gathering point to the first stage of separators. In this part Colebrook correlation is used to determine the friction factor, Brill and Mukherjee method is used for calculation of pressure change.

Mukherjee and Brill method gave good results with respect to the pressure drop of flow in the axial pipeline after the gathering point of the actual field data. The third part deals with the networking in pipelines, types of gathering

systems presented and discussed, the calculations of pressure change in a simple gathering system is studied. The fourth part discusses optimization techniques; Constrained Rosenbrock is used to find optimum pressure which gives favorable oil properties. They have been achieved with some assumptions; they are:

1. Minimum Produced gas oil ratio.
2. Minimum formation volume factor.
3. Maximum API gravity.

Introduction:

A. Pipeline Flow Correlations

The prediction of pressure drop during two-phase, gas-liquid flow in horizontal or semi-horizontal pipes is of great significance to petroleum industry. Extensive theoretical and experimental research has been conducted on horizontal, and inclined multi-phase flow. Most published pressure loss prediction correlations require prediction of three parameters:

1. The liquid hold up.
2. Two-phase friction factor.
3. Flow pattern.

However, many investigators of multiphase flow chose to separate their experimental data into groups that fit the various flow patterns or regimes.

B. Network Pipelines and Gathering Systems

Multiphase flow in gathering systems is of considerable interest to petroleum engineering as well as many working in other branches of Engineering. Petroleum Engineers are particularly interested in the prediction of flow pattern, hold up and pressure drop in well tubing and gathering flow lines or networks.

These calculations are usually rather involved and the problem is further complicated because:

1. No single design method is "the best" under all conditions,
2. Several design methods must be tried to get some appreciation for the possible range of answers, and
3. Where reliable fluid property or other data are not available, sensitivity of results to variations of these data must be investigated.

This made hand calculations impractical. The calculations are, however, particularly amenable to computer programs.

C. Statement of the Problem

The calculations related to gathering system (from the well head to a gathering point and then to the first stage of separators) are very complex and very difficult to solve with hand calculations.

Many studies appeared to describe the calculation of gathering systems, but there is no any study represents the total calculations of gathering systems from the wells to the separator.

In this study a computer program is developed to perform all the complete calculations of the gathering system. The program gave the results in a short time with a high accuracy.

Modeling of flow:

A. Single-phase flow

The pressure gradient is made of three components. Thus[1]:

$$\left(\frac{dp}{dL}\right)_t = \left(\frac{dp}{dL}\right)_f + \left(\frac{dp}{dL}\right)_{el} + \left(\frac{dp}{dL}\right)_{acc} \qquad (1)$$

Finally, two computer programs are developed. Each program performs all the calculations of the four parts. The first program is developed using FORTRAN language, while the second is developed using Visual Basic language.

Where:

$\left(\frac{dp}{dL}\right)_t$: Total pressure gradient

$\left(\frac{dp}{dL}\right)_f$: Pressure gradient results from friction.

$\left(\frac{dp}{dL}\right)_{el}$: Pressure gradient caused by elevation change.

$\left(\frac{dp}{dL}\right)_{acc}$: Pressure gradient results from change in velocity.

The three parameters (pressure gradient) is defined as[2]:

$$\left(\frac{dp}{dL}\right)_f = \frac{f\rho v^2}{2g_c d} \qquad \text{..............................(2)}$$

$$\left(\frac{dp}{dL}\right)_{el} = \rho \frac{g}{g_c}\sin\theta \qquad \text{..............................(3)}$$

$$\left(\frac{dp}{dL}\right)_{acc} = \frac{\rho v dv}{g_c dZ} \qquad \text{..............................(4)}$$

B. Hydraulics of Pipelines

In this section, there is some of the major flow equations used for Hydraulic calculations in pipeline transportation of liquids. Determination of friction factor is studied using formulas of last studies.

Liquids flow in pipelines:

In order to study the liquid flow in pipelines, the types of liquid flow in pipelines must be studied and presented. Determination the type of flow is depending on Reynold's number [3].

$$Re = \frac{1488 \rho u d}{\mu} \qquad \text{.....................................(5)}$$

$$u = \frac{Q}{A_p} \qquad \text{......................................(6)}$$

$$A_p = \frac{\pi}{4}\left(\frac{d^2}{144}\right) \qquad \text{.......................................(7)}$$

There are two basic types of liquid flow; laminar and turbulent. Where:

$Re \leq 2000$; Laminar flow,

$2000 < Re \leq 4000$; Transition flow,

$Re > 4000$; Turbulent flow.

Friction Factor for Single-Phase Flow:

Calculation of frictional losses requires the determination of values for friction factors, the procedure first requires an evaluation of whether the flow is laminar or turbulent.

Moody Friction Factor:

Moody[4] studied the friction factor for Newtonian fluid flow. He presented some correlations to calculate the friction factor as follows:

A- For Laminar Flow

For laminar flow, the friction factor may be calculated from Moody equation[4]:

$$f = \frac{64}{\mathrm{Re}} \qquad \text{.......................................(8)}$$

B- For Turbulent Flow

Colebrook[5] proposed an empirical equation to describe the variation of friction factor in the turbulent flow region. It has become the basis for modern friction factor charts:

$$\frac{1}{\sqrt{f}} = 1.74 - 2\log\left(\frac{2\varepsilon}{d} + \frac{18.7}{\mathrm{Re}\sqrt{f}}\right) \qquad \text{...(9)}$$

Moody [4] prepare a monograph figure (1) that shows the variations of friction factors with Reynold's number and relative roughness.

Two-Phase Flow in Pipelines:

When two or more phases flow simultaneously in pipes, the flow behavior is much more complex than for single-phase flow. The phases tend to separate because of difference in density. Shear stresses at the pipe wall are different for each phase as a result of their different densities and viscosities. Expansion of the highly compressible gas phase with decreasing pressure increases the in-situ volumetric flow rate of the gas. As a result, the gas and liquid phases normally do not travel at the same velocity than the liquid phase, causing a phenomenon known as slippage[1]. Perhaps the most distinguishing aspect of multi-phase flow is the variation in the physical distribution of the phases in the flow conduit, a characteristic known as flow pattern or flow regime. During multi-phase flow through pipes, the flow pattern that exists depends on the relative magnitudes of the forces that act on the fluids[1].

Flow patterns:

Predicting the flow patterns that occurs at a given location in a pipeline is extremely important. The empirical correlation or mechanistic model used to predict flow behavior varies with flow pattern. Beggs and Brill [6] summarized numerous investigations that have described flow patterns in pipes and that made attempts to predict when they occur. Essentially all flow pattern predictions are based on data from low-pressure systems, with negligible mass transfer between the phases and with a single liquid phase[1].

As shown in figure (2), in bubble flow, free gas is present as a bubble in a continuous liquid phase. At the other extreme is mist flow in which the gas phase is continuous and liquid droplets are entrained in the gas. Between these two extremes are other types of flow, including stratified, wavy and slug flow. In slug flow at low flow rates liquid can occupy the entire cross section of the pipeline at points in the line. This is likely to occur at uphill portions of the pipeline. This type of flow can produce liquid slugs that exit the pipeline intermittently. Because of this, it is often necessary to include equipment to catch these slugs of liquid at the end of the pipeline to prevent damage to processing or other facilities.

Flow regime:

Almost invariably, the gas and liquid phases travel through a pipe at different velocities[7]. This gives a rise to a liquid hold up effect, because the fraction of the pipe volume occupied by the liquid phase under flowing conditions will be significantly different from the volume fraction of the liquid in the two-phase mixture entering the pipe. The total pressure losses for a two-phase mixture generally include a hydrostatic head contribution, which is calculated using a mixture density. The correlation used to calculate liquid hold up is the modified Beggs and Brill method[8][6].

In this method the flow regime in horizontal pipes is divided into four patterns, and for each pattern of flow an empirical equation is proposed. The flow pattern prevail in the pipe line section is determined by computing Froud number (N_{FR}) and four dimensionless parameters (L1, L2, L3, L4) which are function of the no-slip liquid hold up (ψ_N).

$$\psi_N = \frac{V_{sl}}{V_m} \qquad \text{.................................. (10)}$$

$$N_{FR} = \frac{V_m^2}{gd} \qquad \text{.................................... (11)}$$

$$L1 = 316\psi_N^{0.302} \quad \text{.................................} (12)$$

$$L2 = .000925\psi_N^{-2.468} \quad \text{.................................} (13)$$

$$L3 = 0.1\psi_N^{-1.452} \quad \text{.................................} (14)$$

$$L4 = 0.5\psi_N^{-6.738} \quad \text{.................................} (15)$$

$$N_{LV} = 1.938 V_{sl} \left(\frac{\rho_l}{\sigma}\right)^{0.25} \quad \text{.................................} (16)$$

The limit of the horizontal flow regimes as defined by the modified Beggs and Brill are as follows:

1- Segregated flow:

$\psi_N < 0.01$ and $N_{FR} < L1$ or $\psi_N \geq 0.01$ and $N_{FR} < L2$

The slip liquid hold up is calculated as follows:

$$\psi_s = \frac{0.98\psi_N^{0.4846}}{N_{FR}^{0.0868}} \quad \text{.................................} (17)$$

2- Intermittent flow:

$0.01 \leq \psi_N < 0.4$ and $L3 < N_{FR} \leq L1$ or $\psi_N \geq 0.4$ and $L3 < N_{FR} \leq L4$

The slip liquid hold up is calculated as follows:

$$\psi_S = \frac{0.845\psi_N^{0.5351}}{N_{FR}^{0.0173}} \quad \text{.................................} (18)$$

3- Disturbed flow:

$\psi_N < 0.4$ and $N_{FR} \geq L1$ or $\psi_N \geq 0.4$ and $N_{FR} > L4$

The slip liquid hold up is calculated as follows:

$$\psi_S = \frac{1.065\psi_N^{0.5824}}{N_{FR}^{0.0609}} \qquad \text{.................................(19)}$$

4- Transition flow:

$\psi_N \geq 0.01$ and $L2 \leq NFR \leq L3$

When the flow fall in the transition region, the slip liquid hold up must be calculated using both segregated and intermittent equations and interpolating using the following weighting factors:

$$\psi_{S(Transition)} = A\psi_{S(Segregated)} + (1-A)\psi_{S(Intermittent)} \qquad \text{................................. (20)}$$

$$A = \frac{L3 - N_{FR}}{L3 - L2} \qquad \text{................................. (21)}$$

Total Pressure Losses in Multi-Phase Flow:

Modified Beggs and Brill Method

The pressure gradient equation for single phase can be modified for multi-phase flow by considering the fluids to be homogeneous mixture. Thus:

$$\frac{dp}{dL} = \frac{f\rho v^2}{2d} + \rho g \sin\theta + \rho v \frac{dv}{dL} \qquad \text{.................................. (22)}$$

Where the definition for ρ and *v* can vary with different investigators [1].

Equation (22) shows that the total pressure drop for a two phase flow pipeline is the sum of the pressure losses due to:

1- Fluid friction effects,

2- Hydrostatic head effects, and

3- Kinetic energy or acceleration effects.

Thus:

$$\Delta P_t = \Delta P_f + \Delta P_E + \Delta P_{KE} \qquad \text{.................................. (23)}$$

where: ΔP_t : total pressure drop.

ΔP_f : pressure drop due to friction.

ΔP_E : pressure drop due to elevation.

ΔP_{KE} : pressure drop due to kinetic energy effects.

The pressure loss due to fluid friction is calculated according to Beggs and Brill method, by the following expression[9]:

$$\Delta P_f = \frac{f_{tp} \rho_n L u_m^{\ 2}}{2dg_c} \qquad \text{.................................. (24)}$$

The two phase friction factor, f_{tp}, had been defined by Beggs and Brill as an empirical ratio multiplied by a no slip friction factor as follows[8]:

$$f_{tp} = R_f \times f_{ns} \qquad \text{.................................. (25)}$$

$$f_{ns} = \frac{1.325}{\left[\ln\left(\frac{\varepsilon}{3.7d} + \frac{5.74}{R_{en}^{\ 0.9}}\right)\right]^2} \qquad \text{.................................. (26)}$$

$$R_{en} = \frac{1488\rho_n u_m d}{\mu_n} \qquad \text{.................................. (27)}$$

where: R_{en}: no slip Reynold's number, dimensionless.

Beggs and Brill gave the following relation to determine (R_f)(10):

$$R_f = e^s \qquad \text{.................................. (28)}$$

where: s: is an empirical function of (y), and:

$$y = \frac{\Psi_N}{\Psi_S^2} \qquad \text{.................................. (29)}$$

$$s = \frac{xs}{-0.0523 + 3.182xs + 0.8725xs^2 + 0.01853xs^4} \qquad \text{.................................. (30)}$$

$$xs = \ln(y) \qquad \text{.................................. (31)}$$

Pressure drop due to elevation (ΔP_E) is calculating from the following expression[11]:

$$\Delta P_E = 0.2234[\rho_L E_f \Sigma H_U - \rho_g \Sigma H_D] \quad \text{.................................} \quad (32)$$

where: E_f : elevation factor, dimensionless.

ΣH_U: sum of rises in pipeline profile, ft.

ΣH_D: sum of falls in pipeline profile, ft.

Flanigan equation[12] is used to calculate the elevation factor:

$$E_f = \frac{1}{1+5.5807 \times V_{sg}^{1.006}} \quad \text{.................................} \quad (33)$$

where: V_{sg}: superficial gas velocity, ft/sec.

Surface Gathering Systems:

In most oil and gas production installations, the flow from several wells will be gathered at a central processing station or combined into a common pipeline. Two common types of gathering systems were illustrated by Szilas [13] figure (3).

When individual flow lines all join at a common point, the pressure at the common point is equal for all flow lines. The common point is typically a separator in an oil production system. The following tubing pressure of an individual well (i) is related to the separator pressure by:

$$P_{tfi} = \Delta P_{fi} + \Delta P_{Li} + \Delta P_{Ci} + P_{sep} \quad \text{.................................} \ (34)$$

where: P_{tfi}: flowing tuping pressure of well (i), psia.

P_{sep}: separator pressure, psia.

ΔP_{Li} : pressure drop through flow line, psia.

ΔP_{Ci}: pressure drop through the choke (if presents), psia.

ΔP_{fi}: pressure drop through fitting, psia.

In gathering system where individual well are tied into a common pipeline, so that the pipeline flow rate is the sum of the upstream well flow rates as in figure (3), left, each well has a more direct effect on its neighbors. In this type of system, individual well head pressure can be calculated by starting at the separator and working upstream[14].

Pressure Drop through Pipe Fittings:

When fluids pass through pipe fittings (elbows, tees, etc.) or valves, secondary flows and additional turbulence create pressure drops that must be included to determine the overall pressure drop in a piping network. The effects of valves and fittings are including by adding the equivalent length of the valves and fittings to the actual length of straight pipe when calculating the pressure drop. The equivalent lengths of many standard valves and fittings have been determined experimentally by Crane(14).

Conduit Laterals Losses:

If lateral are supplied from a main pipeline figure (4), the discharge of the main line decreases at the lateral by the amount of flow supplied to the lateral [15]. If the main pipe has a constant cross section, the streamline expand at the lateral, as the discharge and velocity are reduced and non-uniform flow results. Hence, the energy equation shows that an increase in pressure head will occur. On the other hand, there are losses along the lateral (due to form resistance and boundary resistance) which will cause a decrease in pressure head. These two conditions which cause a change in head tend to counteract each other so that under some conditions the net change in head will be an increase, and under other conditions the head will decrease in the direction of flow.

If the boundary resistance is negligible, the head loss can be written as follows:

$$h_L = C_L \frac{(V_1 - V_2)^2}{2g} \qquad (35)$$

where: h_L: head loss.

C_L: loss coefficient.

Field Data:

A simple gathering system data from Jamboor Field (north of Iraq) is used in this work, the first part of the data are presented in Table (2). These data deal with the flow parameters in pipelines from twelve producing wells to a gathering point. Figure (5) represents a simplest (ideal) scheme of pipelines and gathering point for simple gathering system.

The second part of data deals with flow of resulting fluid in the axial pipeline showed in figure (5) from the gathering point to the separator.

Computer Program:

In order to analyze a gathering system, two computer programs are developed to analyze the total calculation of gathering system from the wells to the separator. The first is developed using FORTRAN language, while the second is developed using Visual Basic language. Every one of them gives complete results of gathering system, so the user can use anyone of the two programs to get the results.

a. Computer Program Using FORTRAN Language

Every component of the gathering system is programmed individually and then linked together in order to determine the pressure losses in every component. The computer program consists of a main program which linked with some subprograms. In the beginning the program reads the input data from a data file then is linked with a subprogram analyzes the calculation of the flow of multi-phase in pipelines from the wells to the gathering point. After that the main program is linked with another subprogram to calculate the pressure drop in the axial pipeline from the gathering point to the separator.

To calculate the optimum pressure which gave minimum GOR, minimum Bo and maximum API; the main program is finally connected with a subprogram to analyze the optimization technique calculations.

After running the program, the results can be seen in some files with the program.

b. Computer Program Using Visual Basic Language

This program is similar to FORTRAN program in most steps and properties, the main difference between the FORTRAN program and this program is that the first program contains some subprograms, while this program doesn't contain any subprogram. This program is simple to use, when the user run the program a form is appeared. The user can press Run button, Then some changes are happened to the form, Exit button is appeared instead of Run button and the value of average absolute percentage error is appeared too. When the user press exit button he can see the results, the results are saved in some files with the program.

Results and Discussion:

Two-Phase Results

Two methods have been used to calculate the pressure in two-phase flow in pipelines presented: Modified Beggs and Brill method [6] and Aziz et al. Method[1]. Calculated pressures for the twelve pipelines using the two methods are presented in Table (5). In this table there is also values of absolute percentage error (AAPE) calculated from:

$$AAPE = \frac{1}{n}\left|\frac{P_c - P_m}{P_m}\right| \times 100\% \qquad (36)$$

where: Pc : calculated pressure (psia).

Pm : measured pressure (psia).

n : no. of the wells.

Figure (6) shows the comparison between the results of the two methods.

Effect of Some Parameters on the Pressure Drops:

A. Effect of Liquid Flow Rate

The effect of flow rate is studied and presented in Table (4) and figures (7& 8). These (table and figures) showed that the liquid flow rate has a significant effect on the pressure results, when the flow rate increase the pressure drop is also increased and then the resulting pressure is decreased.

B. Effect of Oil Specific Gravity

The effect of oil specific gravity studied and presented in Table (5) and figures (9 & 10) . There are results of original specific gravity and specific gravity plus\minus (0.1). It is found that the specific gravity of oil varies directly with the pressure drop, i.e. the pressure drop increases when the specific gravity increases, and decreases when the specific gravity decreases.

C. Effect of oil formation volume factor

Table (6) and figures (11& 12) showed that the change of oil formation volume factor has greatly effect on the pressure results. The increasing in the oil formation volume factors of (0.1 bbl/STB) causes an increase in pressure drop of about (3 psi), i.e. oil formation volume factor varies directly with the pressure drop.

D. Effect of Gas Formation Volume Factor

Table (7) and figures (13 & 14) showed that the change of gas formation volume factor has a significant effect on the pressure results. The increasing in the gas formation volume factors of (0.001 ft^3/SCF) causes an increase in pressure drop of about (1.2-2 psi), i.e. gas formation volume factor varies directly with the pressure drop.

E. Effect of oil Viscosity

Table (8) and figures (15) and (16) showed that the change of oil viscosity has a significant effect on the pressure results. The increasing in oil viscosity of (0.1 cp) causes an increase in pressure drop of about (2 psi), i.e. oil viscosity varies directly with the pressure drop.

F. Effect of Gas Viscosity

Table (9) and figures (17 & 18) showed that the change of gas viscosity has no significant effect on the pressure results. The increasing in oil viscosity of (0.001 cp) causes an increase in pressure drop of about (.01 psi), i.e. change of gas viscosity has a very little effect on pressure drop.

G. Effect of Produced Gas-Oil Ratio

Table (10) and figures (19 & 20) showed that the change of gas-oil ratio has a significant effect on the pressure results. The increasing in gas-oil ratio of (100 SCF/STB) causes an increase in pressure drop of about (2 psi), i.e. change of gas viscosity has a very little effect on pressure drop.

Results of Flow in the Axial Pipeline:

The flow in the axial pipeline is two-phase (gas and liquid), but the two methods (modified Beggs and Brill method and Aziz et al. method) failed to give an accurate results in this section, so a method of single phase flow (Brill and Mukherjee) is used to calculate the pressure changes in this section and it gave good results with respect to field data.

Table (13) shows the output data of computer program for assuming different inlet pressures with the program results of oil formation volume factor, solution gas-oil ratio and separator pressure. From the optimization technique, calculation of optimum pressure depends upon two objective functions, the first is to minimize the oil formation volume factor, and the second is to minimize the solution gas-oil ratio.

A. Effect of Pressure Changes on the Oil Formation Volume Factor

Figure (21) shows the effect of pressure changes on the oil formation volume factor in single-phase flow, it is clearly that the pressure is varies directly with the oil formation volume factor.

B. Effect of Pressure Changes on the Solution Gas-Oil Ratio

Figure (22) shows the effect of the pressure change on the solution gas-oil ratio in single-phase flow, the figure shows that when the pressure is increased then the solution gas-oil ratio is increased (i.e. the pressure change varies directly with the solution gas-oil ratio).

C. Effect of Pressure Changes on the Oil Viscosity

Figure (23) shows the effect of the pressure change on the oil viscosity in single-phase flow. In this figure, it is clearly that the pressure varies inversely with the oil viscosity.

D. Effect of Pressure Changes on the API

Figure (24) shows the effect of the pressure change on the API in single-phase flow. The figure shows that the pressure varies inversely with the API gravity.

Conclusions:

1. The sensitivity of the pressure results in two-phase flow is widely dependent upon some parameters such as; oil density, oil and gas formation volume factor, pipeline size and length, oil viscosity and gas-oil ratio. While other parameters have minor effect on the pressure results such as; gas density, gas viscosity and liquid surface tension.
2. Two methods are used to calculate the pressure drop of the two-phase flow in pipelines; they are modified Beggs and Brill method and Aziz et al. method. Both of the two methods gave good results. Modified Beggs and Brill method gave an AAPE of (0.26%), while Aziz et al. method gave an AAPE equal to (0.55%).
3. For the flow in the axial pipeline, it is found that the pressure of gathering point varies directly with the oil formation volume factor and solution gas oil ratio, and inversely with the oil viscosity and API.
4. Mukherjee and Brill method gave good results with respect to the pressure drop of flow in the axial pipeline after the gathering point of the actual field data.

Nomenclature:

English Symbols

Symbol	Definition	Unit
A_P	Cross sectional area of pipeline.	ft^2
API	American Petroleum Institute gravity.	API
B_o	Oil formation volume factor.	bbl/STB
B_g	Gas formation volume factor.	ft^3/SCF
C_o	Oil compressibility.	$psia^{-1}$
d	Inside diameter of pipeline.	in
du/dy	Shear rate.	sec^{-1}
f_{tp}	Two phase friction factor.	dimensionless
g	Gravitational constant.	Ft/sec^2
g_c	Conversion factor, (=32.174).	$lb_f.ft/lb_m.sec^2$
L	Pipeline section length.	ft
N_{FR}	Froud Number.	dimensionless
N_{LV}	Liquid Velocity number.	dimensionless
P	Pressure.	Psia
Q	Liquid flow rate.	ft^3/sec
R_e	Reynold's number.	dimensionless
R_s	Solution gas oil ratio.	SCF/STB
T	Temperature.	^oF
u	Velocity.	ft/sec

Greek Symbols:

Symbol	Definition	Unit
γ	Oil specific gravity.	dimensionless
γ_{g100}	Gas specific gravity at (100 psia).	dimensionless
ρ	Density.	lb_m/ft^3
μ	Viscosity.	cp
ψ_s	Liquid hold up.	dimensionless
ΔP	Pressure drop.	psia
ε	Roughness of pipe.	in.
ν	kinematic viscosity	ft^2/sec

Subscript:

Symbol	Definition
tp	two-phase.
o	oil.
l	liquid.
g	gas.
ns	no slip.

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Table (1) Coefficients for Vazqeuz and Beggs Correlations

Coefficient	API ≤ 30	API > 30
C_1	0.0362	0.0178
C_2	1.0937	1.1870
C_3	25.7245	23.931

Table (2) Jamboor Field Measurements Data of a Gathering System

Well Head Pressure (psia)	Flow Rate, STB/Day	Well Head temp., °F	Chock Size, 1/64 in.	Gas Specific Gravity	Liquid Specific Gravity	Gas Viscosity, cp	Liquid Viscosity, cp	Oil Formation Volume Factor, bbl/STB	Gas Formation Volume Factor, SCF/ft^3	Diameter of the pipe, in.	Pipe Length, ft	Produced GOR, SCF/STB	Solution GOR, SCF/STB	Upstream Pressure of gathering point, psia
1425	3600	210	42	0.795	0.8360	0.0190	0.83363	1.137	3600	6.5	22989	1245	610	1395
1600	7300	210	52	0.761	0.8303	0.0171	0.78580	1.058	7300	6.5	6555	1626	875	1580
1530	3900	210	52	0.794	0.8950	0.0189	0.89878	1.159	3900	6.0	9826	1340	405	1500
1700	4800	210	48	0.771	0.8334	0.0170	0.77627	1.178	4800	6.0	24606	1378	850	1635
1525	3600	210	52	0.763	0.8517	0.0167	0.82900	1.189	3600	6.0	23622	1258	465	1475
1650	5100	210	52	0.787	0.8486	0.0173	0.79858	1.206	5100	6.5	24278	1367	550	1590
1658	8500	149	52	0.774	0.8279	0.0183	0.70998	1.297	8500	6.5	16411	1083	810	1590
1558	7400	210	52	0.780	0.8483	0.0169	0.82700	1.190	7400	6.5	9842	1230	490	1515
1400	5000	210	52	0.781	0.8786	0.0180	0.83312	1.188	5000	6.5	16404	1320	620	1365
1600	6100	210	52	0.808	0.8372	0.0131	0.72878	1.081	6100	6.0	8202	1554	480	1550
1700	7000	210	52	0.758	0.8538	0.0146	0.85936	1.242	7000	6.5	14764	1625	645	1630
1250	6400	149	48	0.766	0.8344	0.0147	0.75743	1.196	6400	6.0	9829	1200	550	1200

Table (3) Comparison between measured and calculated pressure data

Measured Pressure (psia)	Modified Beggs and Brill Method		Aziz et al. Method	
	Calculated Pressure (psia)	Absolute Percentage Error	Calculated Pressure (psia)	Absolute Percentage Error
1390	1392.06	0.14832	1395.75	0.41337
1580	1577.10	0.18308	1579.06	0.05937
1500	1502.28	0.15196	1504.47	0.29825
1635	1638.24	0.19816	1646.83	0.72370
1475	1482.63	0.51744	1485.05	0.68159
1590	1594.66	0.29312	1598.56	0.53834
1590	1586.99	0.18933	1603.86	0.87170
1515	1517.74	0.18075	1523.17	0.53895
1365	1366.20	0.08807	1369.44	0.32501
1550	1558.84	0.57022	1559.32	0.60132
1625	1628.80	0.23369	1634.15	0.56333
1200	1204.45	0.37131	1211.14	0.92859
		AAPE=0.26%		AAPE=0.55%

Table (4) Comparison the Results of Calculated Pressure for Original Flow Rates and Flow Rates ±1000 STB/day for All Gathering Pipelines.

Modified Beggs and Brill Method			Aziz et al. Method		
P at Original Q (psia)	P at (Q+500) STB/day (psia)	P at (Q-500) STB/day (psia)	P at Original Q (psia)	P at (Q+500) STB/day (psia)	P at (Q-500) STB/day (psia)
1206.07	1199.55	1212.16	1395.75	1380.55	1408.13
1367.39	1361.22	1373.07	1579.06	1573.92	1583.71
1401.36	1395.11	1406.94	1504.47	1492.34	1514.51
1483.61	1472.59	1493.41	1646.83	1626.35	1664.34
1507.65	1502.16	1512.58	1485.05	1464.54	1501.82
1517.74	1512.61	1522.58	1598.56	1580.26	1614.40
1553.91	1546.63	1560.66	1603.86	1592.07	1614.60
1574.09	1570.74	1577.25	1523.17	1514.63	1530.86
1597.15	1590.48	1603.51	1369.44	1358.29	1379.05
1597.77	1588.07	1606.71	1559.32	1547.30	1569.95
1636.29	1627.65	1644.41	1634.15	1617.20	1649.37
1638.24	1626.06	1649.41	1211.14	1200.02	1221.01

Table (5) Comparison the Results of Calculated Pressure for Original specific Gravity and Specific Gravity ±0.1 for All Gathering Pipelines.

Modified Beggs and Brill Method			Aziz et al. Method		
P at Original γ_o (psia)	P at (γ_o+.1) (psia)	P at (γ_o-.1) (psia)	P at Original γ_o (psia)	P at (γ_o+.1) (psia)	P at (γ_o-.1) (psia)
1392.06	1388.97	1395.21	1395.75	1392.98	1398.57
1577.10	1574.91	1579.35	1579.06	1577.04	1581.13
1502.28	1499.83	1504.77	1504.47	1502.20	1506.79
1638.24	1632.39	1644.21	1646.83	1641.76	1652.01
1482.63	1478.73	1486.61	1485.05	1481.34	1488.85
1594.66	1589.51	1599.91	1598.56	1593.72	1603.50
1586.99	1580.12	1594.00	1603.86	1598.62	1609.21
1517.74	1513.94	1521.60	1523.17	1519.87	1526.52
1366.20	1363.16	1369.30	1369.44	1366.67	1372.26
1558.84	1554.89	1562.84	1559.32	1555.40	1563.32
1628.80	1622.10	1635.61	1634.15	1627.95	1640.48
1204.45	1200.07	1208.92	1211.14	1207.41	1214.95

Table (6) Comparison the Results of Calculated Pressure for Original oil formation volume factor and oil formation volume factor ±0.1 for All Gathering Pipelines.

Modified Beggs and Brill Method			Aziz et al. Method		
P at Original B_o (psia)	P at (B_o +.1) bbl/STB (psia)	P at (B_o -.1) bbl/STB (psia)	P at Original B_o (psia)	P at (B_o +.1) bbl/STB (psia)	P at (B_o -.1) bbl/STB (psia)
1392.06	1388.69	1395.30	1395.75	1393.33	1398.07
1577.10	1574.09	1579.98	1579.06	1576.92	1581.11
1502.28	1499.43	1505.02	1504.47	1502.44	1506.44
1638.24	1630.46	1645.64	1646.83	1641.30	1652.11
1482.63	1477.63	1487.41	1485.05	1481.46	1488.50
1594.66	1588.24	1600.81	1598.56	1593.96	1602.98
1586.99	1577.99	1595.51	1603.86	1597.57	1609.83
1517.74	1512.84	1522.41	1523.17	1519.70	1526.47
1366.20	1362.10	1370.11	1369.44	1366.51	1372.24
1558.84	1553.91	1563.57	1559.32	1555.83	1562.68
1628.80	1620.99	1636.29	1634.15	1628.63	1639.48
1204.45	1198.90	1209.74	1211.14	1207.24	1214.87

Table (7) Comparison the Results of Calculated Pressure for Original gas formation volume factor and gas formation volume factor ±0.001 for all Gathering Pipelines.

Modified Beggs and Brill Method			Aziz et al. Method		
P at Original B_g (psia)	P at (B_g+.001) ft^3/SCF (psia)	P at (B_g-.001) ft^3/SCF (psia)	P at Original B_g (psia)	P at (B_g+.001) ft^3/SCF (psia)	P at (B_g-.001) ft^3/SCF (psia)
1392.06	1390.82	1393.30	1395.75	1394.12	1397.35
1577.10	1575.94	1578.27	1579.06	1577.59	1580.51
1502.28	1500.88	1503.68	1504.47	1502.66	1506.27
1638.24	1635.86	1640.63	1646.83	1643.92	1649.72
1482.63	1480.57	1484.70	1485.05	1482.22	1487.85
1594.66	1591.92	1597.40	1598.56	1594.94	1602.13
1586.99	1585.29	1588.69	1603.86	1602.11	1605.60
1517.74	1515.71	1519.77	1523.17	1520.77	1525.53
1366.20	1364.63	1367.78	1369.44	1367.39	1371.46
1558.84	1556.52	1561.15	1559.32	1556.21	1562.38
1628.80	1625.02	1632.57	1634.15	1629.40	1638.83
1204.45	1202.41	1206.51	1211.14	1208.79	1213.47

Table (8) Comparison the Results of Calculated Pressure for Original oil viscosity and oil viscosity ±0.1 cp for all Gathering Pipelines.

Modified Beggs and Brill Method			Aziz et al. Method		
P at Original Viscosity (psia)	P at (μ_o+.1) STB/day (psia)	P at (μ_o-.1) STB/day (psia)	P at Original Viscosity (psia)	P at (μ_o+.1) STB/day (psia)	P at (μ_o-.1) STB/day (psia)
1392.06	1390.60	1393.79	1395.75	1394.43	1397.31
1577.10	1576.11	1578.31	1579.06	1578.13	1580.19
1502.28	1501.17	1503.58	1504.47	1503.43	1505.70
1638.24	1635.38	1641.67	1646.83	1644.34	1649.84
1482.63	1480.77	1484.84	1485.05	1483.26	1487.18
1594.66	1592.22	1597.58	1598.56	1596.24	1601.34
1586.99	1583.53	1591.24	1603.86	1601.20	1607.14
1517.74	1516.05	1519.75	1523.17	1521.68	1524.94
1366.20	1364.75	1367.93	1369.44	1368.10	1371.03
1558.84	1556.97	1561.11	1559.32	1557.42	1561.65
1628.80	1625.96	1632.15	1634.15	1631.48	1637.33
1204.45	1202.38	1206.97	1211.14	1209.34	1213.33

Table (9) Comparison the Results of Calculated Pressure for Original Gas Viscosity and Gas Viscosity ±0.1 cp for all Gathering Pipelines.

Modified Beggs and Brill Method			Aziz et al. Method		
P at Original Viscosity (psia)	P at (μ_g+.001cp) (psia)	P at (μ_g-.001 cp) (psia)	P at Original Viscosity (psia)	P at (μ_g+.001cp) (psia)	P at (μ_g-.001cp) (psia)
1392.06	1392.05	1392.07	1395.75	1395.76	1395.74
1577.10	1577.09	1577.12	1579.06	1579.07	1579.05
1502.28	1502.27	1502.29	1504.47	1504.48	1504.46
1638.24	1638.22	1638.26	1646.83	1646.84	1646.82
1482.63	1482.61	1482.65	1485.05	1485.06	1485.04
1594.66	1594.63	1594.69	1598.56	1598.57	1598.55
1586.99	1586.98	1587.00	1603.86	1603.87	1603.85
1517.74	1517.72	1517.76	1523.17	1523.18	1523.16
1366.20	1366.19	1366.22	1369.44	1369.45	1369.43
1558.84	1558.80	1558.88	1559.32	1559.33	1559.31
1628.80	1628.76	1628.84	1634.15	1634.16	1634.14
1204.45	1204.44	1204.48	1211.14	1211.15	1211.13

Table (10) Comparison the Results of Calculated Pressure for Original Gas-Oil Ratio and Gas-Oil Ratio ±100 SCF/STB for All Gathering Pipelines.

Modified Beggs and Brill Method			Aziz et al. Method		
P at Original GOR (psia)	P at (GOR+100) SCF/STB (psia)	P at (GOR+100) SCF/STB (psia)	P at Original GOR (psia)	P at (GOR+100) SCF/STB (psia)	P at (GOR+100) SCF/STB (psia)
1392.06	1390.17	1393.96	1395.75	1393.26	1398.19
1577.10	1575.67	1578.55	1579.06	1577.24	1580.85
1502.28	1500.95	1503.61	1504.47	1502.74	1506.18
1638.24	1633.96	1642.54	1646.83	1641.57	1652.01
1482.63	1480.29	1484.98	1485.05	1481.84	1488.22
1594.66	1591.61	1597.72	1598.56	1594.52	1602.54
1586.99	1581.22	1592.78	1603.86	1597.86	1609.77
1517.74	1515.46	1520.02	1523.17	1520.47	1525.82
1366.20	1364.23	1368.19	1369.44	1366.86	1371.97
1558.84	1556.59	1561.08	1559.32	1556.31	1562.28
1628.80	1625.10	1632.50	1634.15	1629.50	1638.74
1204.45	1201.55	1207.36	1211.14	1207.80	1214.44

Table (11) Results of Pressure, Bo and Rs for the Axial Pipeline.

Pressure (psia)	Bo (bbl/STB)	Rs (SCF/STB)	Separator Pressure (psia)	Viscosity of Oil (cp)	API Gravity
625	1.139	144.930	613.591	0.680	41.277
650	1.142	152.847	638.592	0.668	40.988
675	1.146	160.863	663.593	0.657	40.699
700	1.150	168.975	688.594	0.647	40.413
725	1.154	177.180	713.595	0.636	40.128
750	1.158	185.476	738.596	0.626	39.846
775	1.162	193.860	763.597	0.617	39.565
800	1.166	202.331	788.598	0.607	39.287
825	1.171	210.885	813.599	0.598	39.011
850	1.175	219.523	838.599	0.590	38.738
875	1.179	228.241	863.600	0.581	38.467
900	1.184	237.037	888.601	0.573	38.199

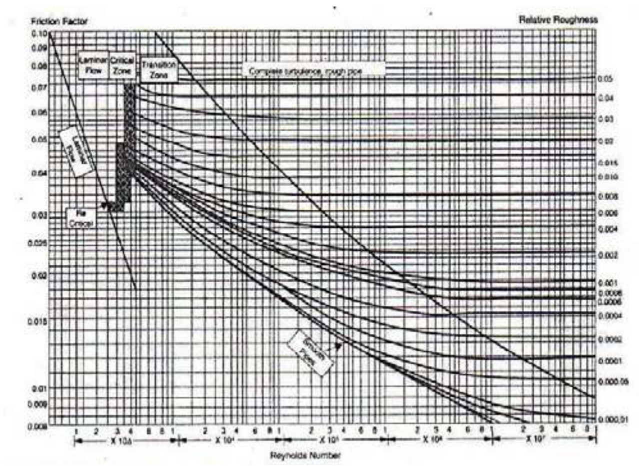

Fig. (1) Moody Diagram Friction Factor for Flow of Fluids in Pipelines

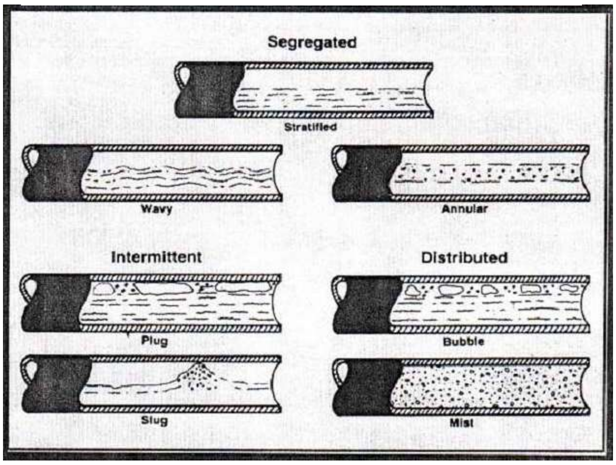

Fig. (2) Flow Regime in Two-Phase Horizontal Pipeline

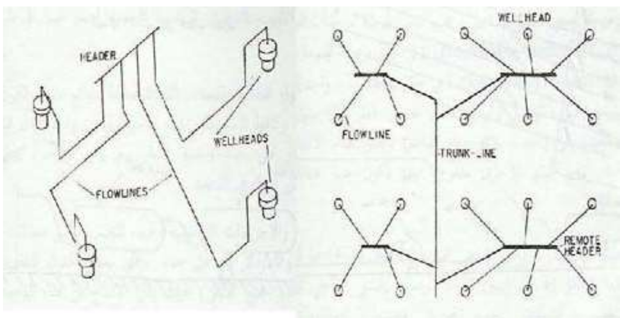

Fig. (3) Oil and Gas Production Gathering System

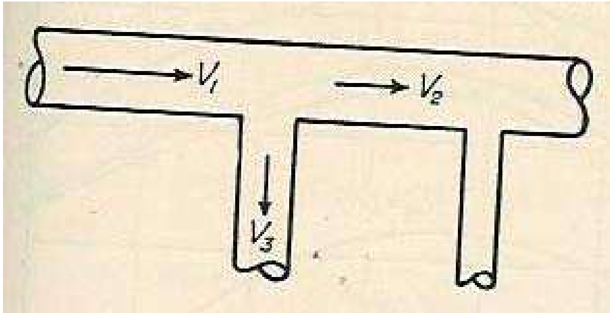

Fig. (4) Conduit Laterals

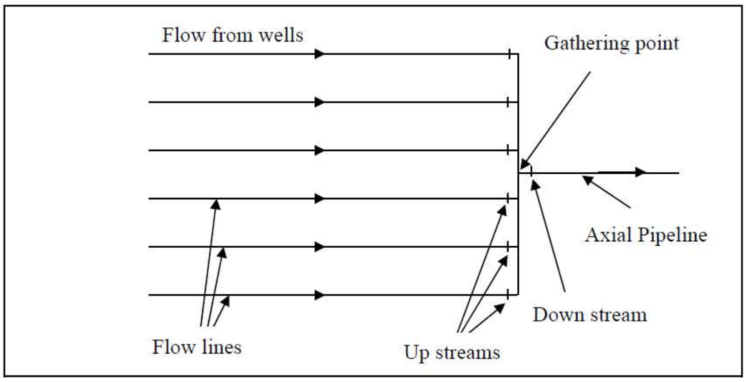

Fig. (5) Simplest Scheme of Simple Gathering

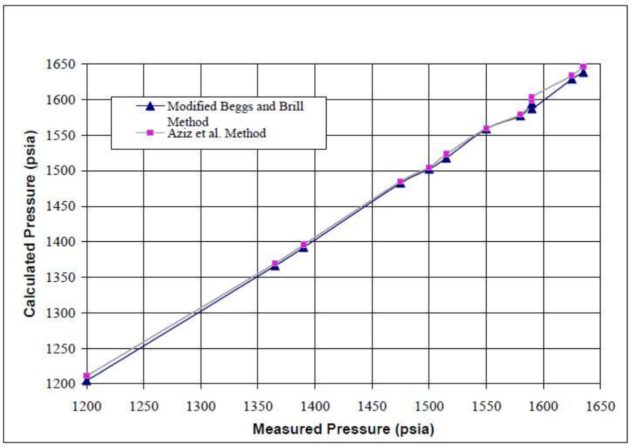

Fig. (6) Comparison between the results of modified Beggs and Brill method and Aziz et al. method

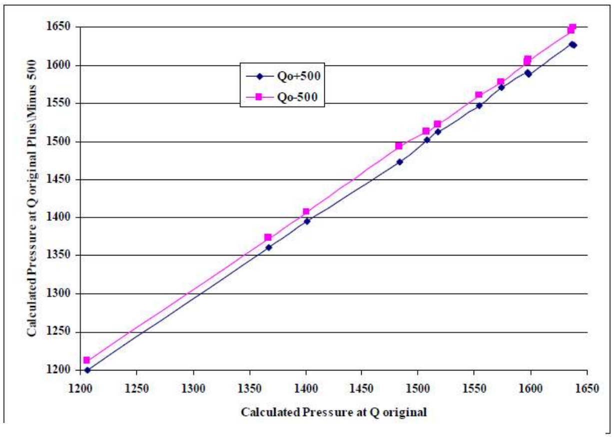

Fig.(7) The Effect of Flow Rate on the Pressure Results Using Modified Beggs

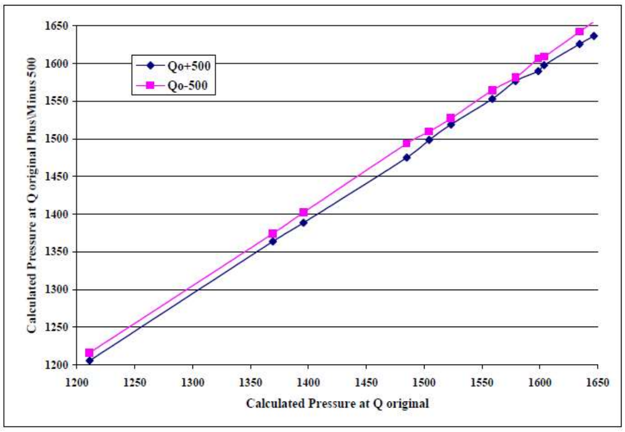

Fig.(8) The Effect of Flow Rate on the Pressure Results Using Aziz et al. Method.

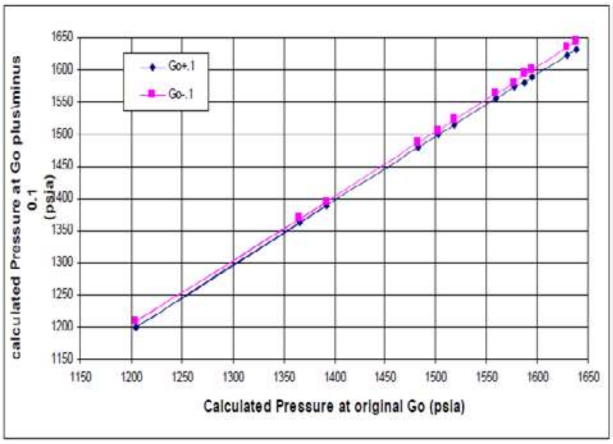

Fig. (9) The effect of specific gravity on the pressure Using Modified Beggs and Brill method.

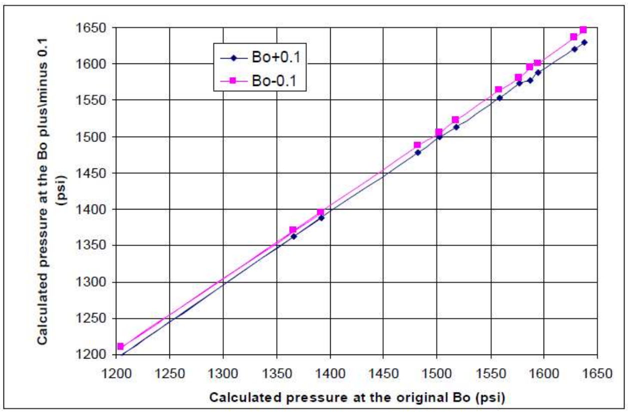

Figure (5-7) Effect of oil formation volume factor on the pressure results using Modified Beggs and Brill Method.

Fig.(11) Effect of oil formation volume factor on the pressure results using Modified Beggs and Brill Method.

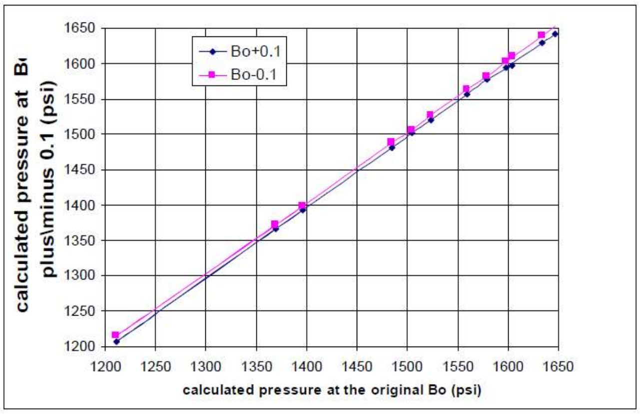

Fig. (12) Effect of oil formation volume factor on the pressure results using Aziz et al. Method.

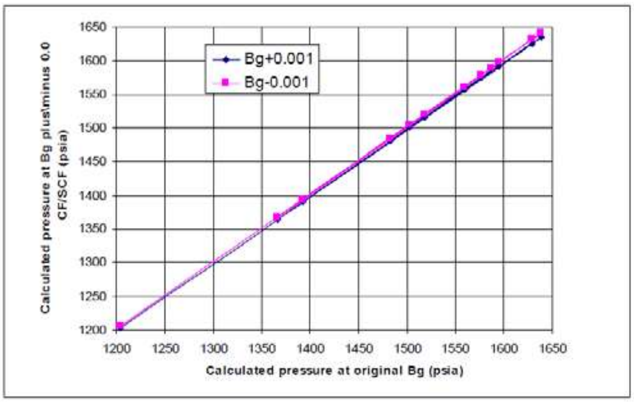

Fig. (13) Effect of gas formation volume factor on the pressure results using Modified Beggs

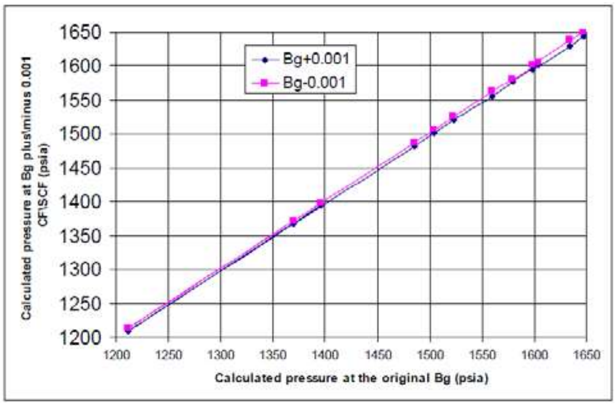

Fig. (14) Effect of gas formation volume factor on the pressure results using Aziz et al. Method.

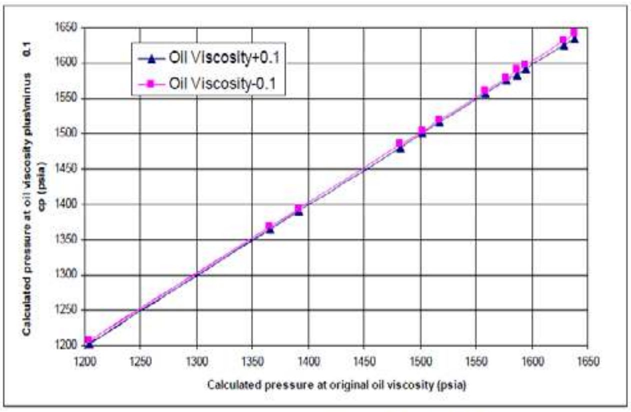

Fig. (15) Effect of oil viscosity on the pressure results using Modified Beggs and Brill Method.

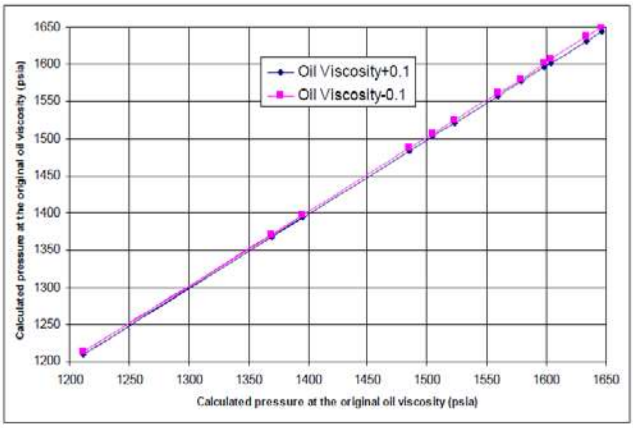

Fig. (16) Effect of oil viscosity on the pressure results using Aziz et al. Method.

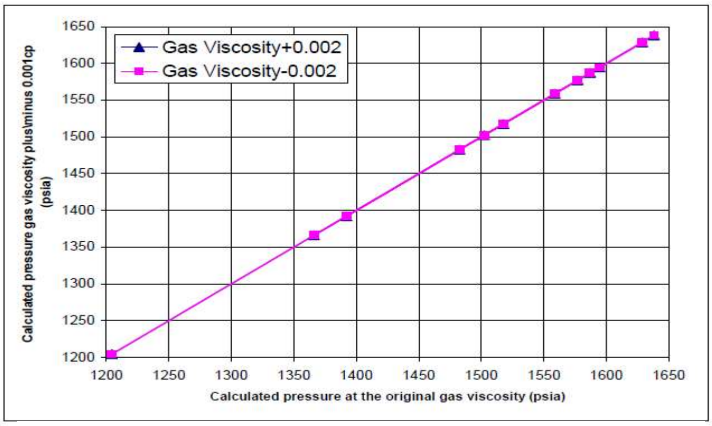

Fig. (17) Effect of gas viscosity on the pressure results using Modified Beggs and Brill Method.

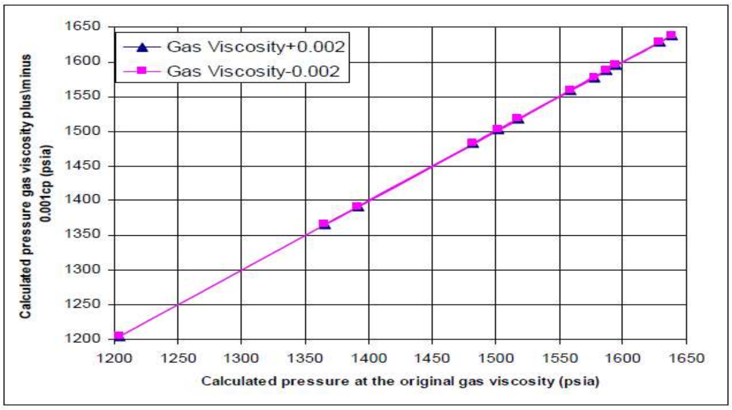

Fig. (18) Effect of gas viscosity on the pressure results using Aziz et al. Method.

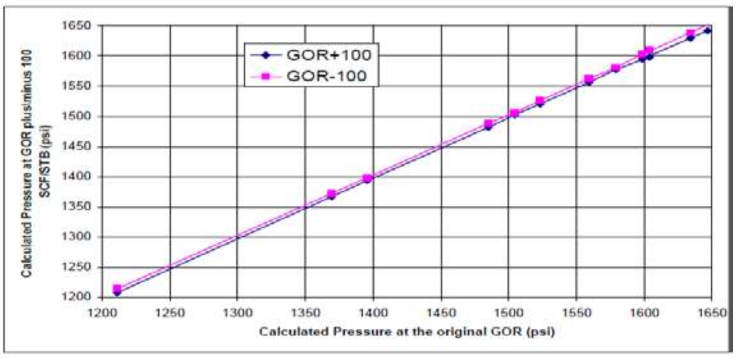

Figure (5-16) Effect of gas-oil ratio on the pressure results using Aziz et al. Method.

Fig. (19) Effect of gas-oil ratio on the pressure results using Modified Beggs and Brill Method.

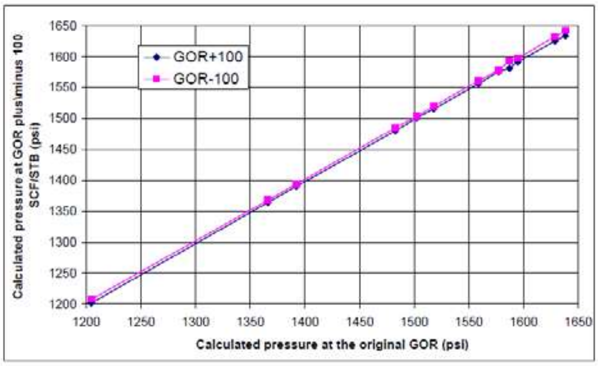

Fig. (20) Effect of gas-oil ratio on the pressure results using Aziz et al. Method.

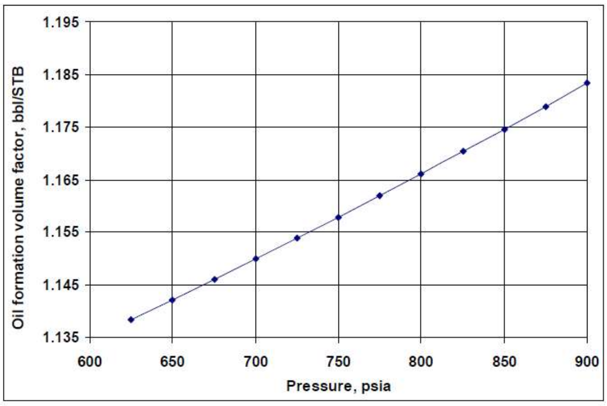

Fig. (21) The Effect of Pressure Change on the Oil Formation Volume Factor.

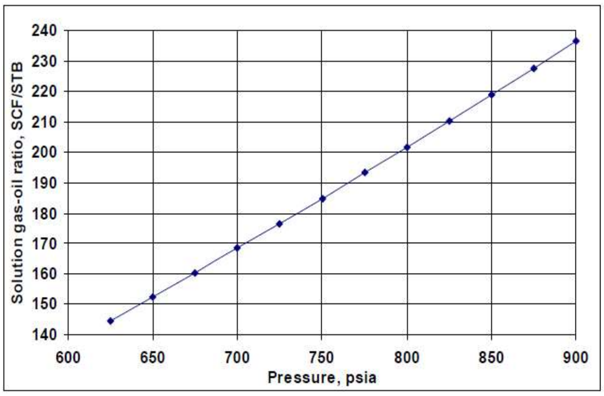

Fig. (22) The Effect of Pressure Change on the Solution Gas-Oil Ratio.

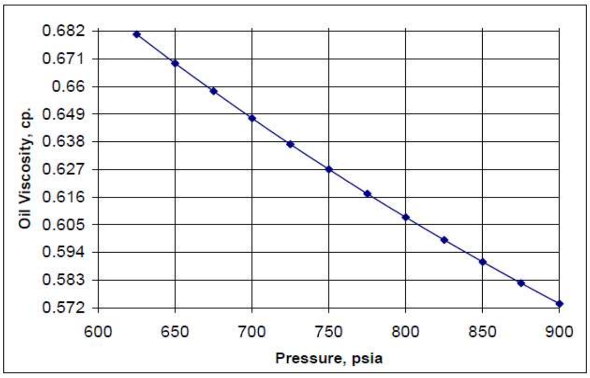

Fig. (23) The Effect of Pressure Change on the Oil Viscosity.

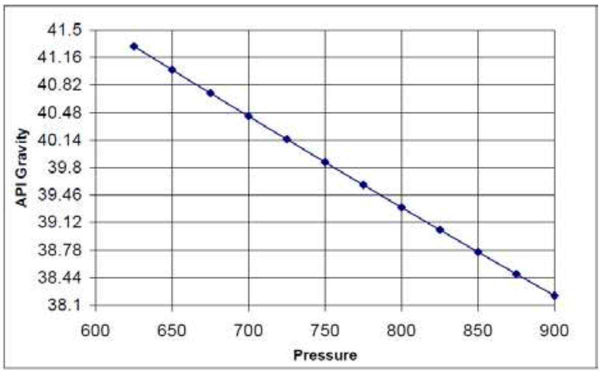

Fig. (24) The Effect of Pressure Change on the API.