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Surman **J**ournal for **S**cience and **T**echnology
ISSN: Online (2790-5721) - Print (2790-5713)

مجلة صرمان للعلوم والتقنية
Vol **6**, No.**2**, Jun - Dec. 2024
Pages: 261 ~ 280

PVT DATA ESTIMATION FOR RESERVOIR FLUIDS OF FASHA AND GIR FORMATIONS IN GHANI OILFIED, LIBYA

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Abstract:

PVT properties are very important in reservoir and production engineering analyses such as material balance calculations, well testing, reserve estimation, inflow performance, production operations and design of surface facilities. It is used to distinguish the properties of reservoir fluids, which is significant in various reservoir studies. The current paper is about a case study of the Ghani oilfield. This study was conducted to highlight PVT data analysis for Ghani oil field that carried out on two wells namely and Well XX 11-11 including two rock formations are Facha and Gir Formations respectively. The primary objective of this study is to present the most commonly used PVT correlations and properties for saturation pressure (p_{sat}), solution gas/oil ratio (R_s), oil density (ρ_o), deviation factor (z) and the gas formation volume factor (B_g) at saturation pressure. A subsurface sample was collected from the subjected wells for use in a reservoir fluid study. The results that obtained from different tests revealed that the hydrocarbon composition analysis of the studied fluid for the investigated Well XX-1-11 of Facha Formation shows heptanes plus 59.91 mole percent, with specific density 0.8463 and API 35.5; while in Well XX 11-11 of Gir Formation is 54.76 mole percent with specific density, 0.8476 and API 35.3. The saturated pressures are 283 and 351 psig with viscosity 1.02 and 1.37 centipoise at 130 and 122ºF respectively. The results of reservoir fluid data of separation tests showing a variation in values for the investigated parameters e. g., gas/oil ratio, stock tank gravity (ºAPI), formation volume factor, separator volume factor and specific gravity of flashed gas at different ranges of pressure and separator temperature 75ºF for both the two wells. The hydrocarbon analysis of separator gas samples were examined at different conditions e. g. 80 @ 75ºF, 40 @ 75ºF and 0 psig @ 75ºF. The components of studied hydrocarbons are varied with changing separator conditions.

Keywords: *PVT data, reservoir fluids, fluid properties, hydrocarbons, pressure, temperature.*

الملخص

تُعد خواص الضغط-الحجم-الحرارة (PVT) غاية في الأهمية لكلٍ من التحليلات الهندسية للمكامن والإنتاج على حدٍ سواء كتلك التي تتعلق بحسابات موازنة المادة، اختبار الآبار، التقديرات الاحتياطية، أداء التدفق، العمليات الإنتاجية وتصميم المرافق السطحية. كما أنها تُستخدم أيضاً لمعرفة خواص موائع المكمن والتي تحظى باعتبارات مختلفة في الدراسات المكمنية. ويتناول هذا البحث حالة دراسية بحقل الغاني النفطي والتي تمت لتسلط الضوء على تحليل بيانات PVT للحقل من خلال دراسة بئرين نفطيين يُشار إليهما بـ Well XX 1-11 و Well XX 11-11 ليشملا تكوينين صخريين هما تكوين الفاشا وتكوين الجير على التوالي. إن الهدف الرئيسي لهذه الدراسة يتمثل في تقديم مضاهاة PVT والخواص الأكثر استخداماً في تعيين ضغط التشبع p_{sat}، ونسبة النفط للغاز R_s، وكثافة النفط ρ_o، ومعامل الانضغاط (الحيود) z ومعامل الحجم الطبقي للغاز B_g عند ضغط التشبع. لقد تم جمع العينات من الآبار قيد الدراسة لدراسة موائع المكمن، حيث أظهرت النتائج المتحصل عليها من الاختبارات المختلفة بأن تحليل مكونات الهيدروكربونات لموائع البئر Well XX-1-11 في تكوين الفاشا هو

هيبتان زائد 59.91% بكثافة نوعية 0.8463 وكثافة قياسية (°API) 35.5، بينما أظهرت بيانات البئر 11-11 XX في تكوين الجير 54.76% وكثافة نوعية 0.8476 وكثافة قياسية 35.3. كما كانت ضغوط التشبع هي 283 و 351 psig وكانت قيم اللزوجة 1.02 و 1.37 سنتبويز عند درجان حرارة 130 و 122 فهرنهيت على التوالي. من جهةٍ أخرى أسفرت بيانات اختبارات الفاصل تبايناً في القيم في معاملات الدراسة مثل نسبة النفط للغاز، الكثافة القياسية لنفط المستودع، معامل الحجم الطبقي، عامل حجم الفاصل والكثافة النوعية لغاز الوميض عند مديات مختلفة للضغط ودرجة حرارة 75 فهرنهيت للفاصل لكلا البئرين. لقد تم اختبار عينات غاز الفصل عند ظروف ضغط مختلفة مثل 80 psig عند 75 فهرنهيت، 40 psig عند 75 فهرنهيت و 0 psig عند 75 فهرنهيت، وقد كانت المكونات لهيدروكربونات الدراسة متباينة مع تغير ظروف الفاصل.

الكلمات الدالة: بيانات PVT، موائع المكمن، خواص الموائع، الهيدروكربونات، الضغط، الحرارة.

1. INTRODUCTION

Naturally occurring hydrocarbon systems found in petroleum reservoirs are mixtures of organic compounds that exhibit multiphase behavior over wide ranges of pressures and temperatures. These hydrocarbon accumulations may occur in the gaseous state, the liquid state, the solid state, or in various combinations of gas, liquid, and solid.

Reservoir fluids are generally classified into five different fluid types: black oil, volatile oil, gas condensate, wet gas, and dry gas (American Petroleum Institute, 2003). Only the black and volatile oils are relevant to this thesis, so the analysis will be based on them.

Black oils are sometimes referred to as ordinary oils and are the most common type of oil reservoirs (Danesh, 1998). They are generally composed of more than 20% C_{7+}, indicating a large quantity of heavy hydrocarbon components.

These differences in phase behavior, coupled with the physical properties of reservoir rock that determine the relative ease with which gas and liquid are transmitted or retained, result in many diverse types of hydrocarbon reservoirs with complex behaviors. Frequently, petroleum engineers have the task to study the behavior and characteristics of a petroleum reservoir and to determine the course of future development and production that would maximize the profit. However, Figure 1. graphical representation of standard PVT properties (Walsh and Lake, 2003).

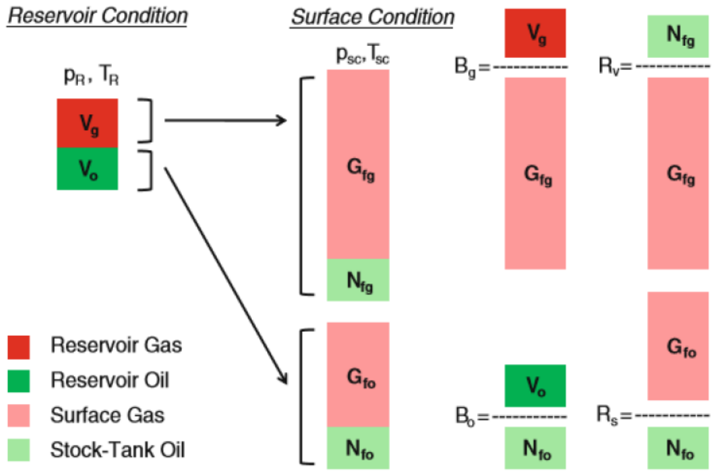

Fig. 1 Graphical representation of standard PVT properties (Walsh and Lake, 2003)

2. RESERVOIRS CLASSIFICATION AND RESERVOIR FLUIDS

Petroleum reservoirs are broadly classified as oil or gas reservoirs. These broad classifications are further subdivided depending on:

1. The composition of the reservoir hydrocarbon mixture
2. Initial reservoir pressure and temperature
3. Pressure and temperature of the surface production

The conditions under which these phases exist are a matter of considerable practical importance. The experimental or the mathematical determinations of these conditions are conveniently expressed in different types of diagrams commonly called *phase diagrams*. One such diagram is called *the pressure-temperature diagram.*

3. PRESSURE-TEMPERATURE DIAGRAM

Figure 2 shows a typical pressure-temperature diagram of a multicomponent system with a specific overall composition. Although a different hydrocarbon system would have a different phase diagram, the general configuration is similar.

These multicomponent pressure-temperature diagrams are essentially used to:

1. Classify reservoirs
2. Classify the naturally occurring hydrocarbon systems
3. Describe the phase behavior of the reservoir fluid

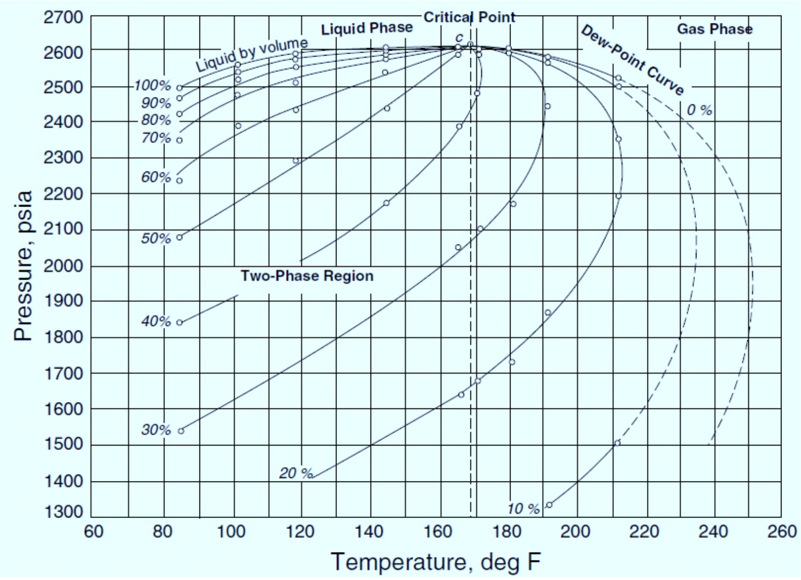

Fig. 2 Typical P-T diagram for a multicomponent system

Pressure-Volume-Temperature Correlations

Pressure-Volume-Temperature (or PVT) correlations are sets of equations used to predict oil properties with typically 5 inputs. These inputs include:

1. Saturation pressure (p_{sat}) (for the oil formation volume factor correlations),
2. Reservoir temperature (T),
3. Stock tank oil gravity ($°API$),
4. Specific gas gravity (γ_g or SG), and
5. Solution gas-oil ratio (R_s).

4. LOCATION OF STUDY

Libya involved five major basins e. g. Sirte basin, Kufra basin, Murzuk basin, Ghadamis basin and Cyrenaica. Various oil fields that represented the major ones were selected for this study that belonging to Arabian Gulf Oil Company (AGOCO), and the others of Sirte Oil Company. Figure 3 a map shows the different locations of oilfields.

This study was conducted on Ghani oil field throughout an investigated producing oil well to evaluate its performance and predicted its future behavior.

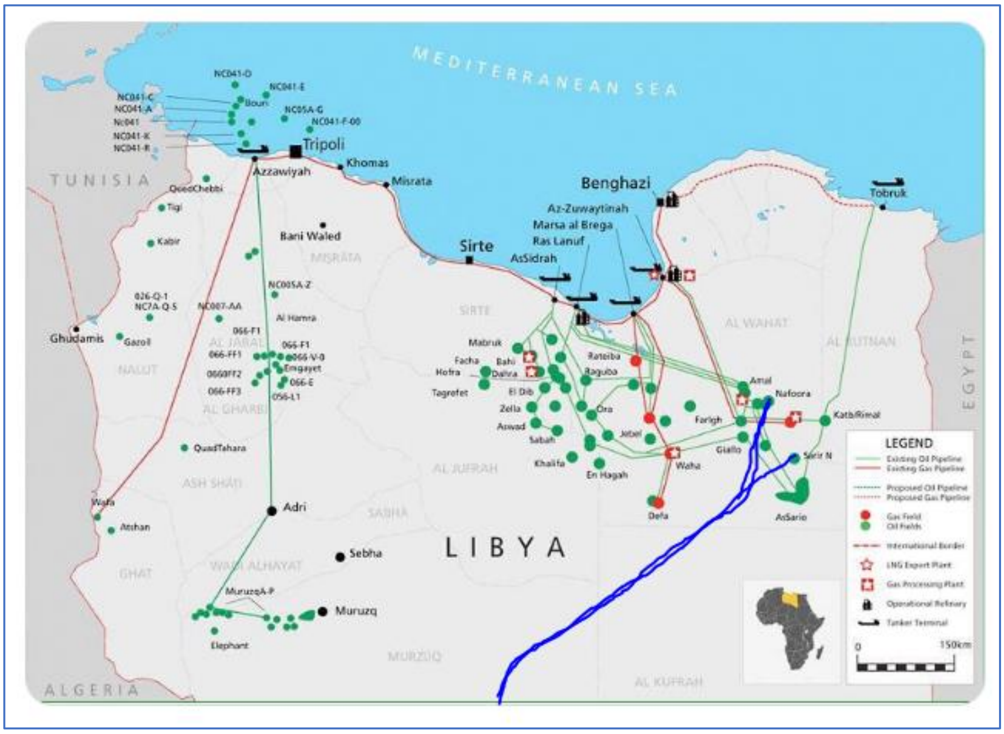

Fig. 3 Map showing the location of oil and gas fields and investigated oil field

5. METHODOLOGY

The methodology of this study was based on the applying of PVT analysis techniques to determine the hydrocarbon composition and main characterization of reservoir fluids in Ghani oilfield. It is mainly depending on the variation of some parameters against pressure to estimate fluid properties.

The main objective of a successful sampling campaign is to obtain representative samples with adequate volume and determine PVT properties. Then, if it is required, it may be executed geochemical analysis for fluid source identification and reservoir continuity, as well as crude assay for refinery process (Speight, 2001, 2002, 2009. 2014; American Petroleum Institute, 2003).

The most important considerations in designing a sampling procedure are presented by Lang and Donohue, 1985; American Petroleum Institute, 2003 and American Petroleum Institute, 1966.

6. OBJECTIVES OF STUDY

This study spotlights on the PVT data of Ghani oilfield to:

1. Highlighting the methods can be applied to estimate the PVT of producing oil wells.
2. Due to the importance of PVT for evaluating production processes.
3. Estimate reservoir characterizations.
4. Determine fluid properties.

7. LITERATURE REVIEW

The development of correlations typically involves the development of a statistically relevant database from laboratory reports or public literature, and then creating (empirical) equations using graphical or non-linear regression methods. The inventory of existing PVT correlations includes:

Author	Definition
Standing (1947)	Original correlations for p_{sat} and *Bob*, generally most simple forms (105 data points).
Lasater (1958)	p_{sat} only, used a completely different correlation form than Standing (158 data points).
Vasquez and Beggs (1980)	Correlations for p_{sat} and *Bob*, independently correlated for < or > 30 API (600 data points).
Al-Marhoun (1988)	Power-law relation for p_{sat}, *Bob* correlation uses a polynomial expansion of a power-law variable (160 Middle East data sets).
Glaso (1980)	Polynomial expansion of Standing's type of correlating variables (26 North Sea data sets).
Kartoatmodjo and Schmidt (1994)	Power-law relation for p_{sat} (uses separate results for < or > 30 API) and Standing-type relation for *Bob* (training set = 5,396 data points, validation set = 998 data points).
Velarde, Blasingame, and McCain (1997)	*psat* and *Bob* correlation equations are a variation of Petrosky and Farshad's formulations (728 data points).
Petrosky and Farshad (1998)	*psat* and *Bob* correlation equations are a variation of Standing forms (81 data sets).
Dindoruk and Christman (2004)	*psat* relation is a complex variation of Standing's correlation, and *Bob* relation is a complex variation of Al-Marhoun's correlation (100 Gulf of Mexico data sets).

8. RESULTS AND DISCUSSION

8.1. Reservoir Fluid Study for Ghani Oilfield

This section discusses the obtained results of PVT data analysis for Ghani oil field that conducted on two wells denoted by Well: XX-1-11 and Well XX-11-11 including two rock formations are Facha and Gir Formations respectively.

A subsurface sample was collected from the subjected wells for use in a reservoir fluid study. The results of the PTV data analysis were discussed.

A portion of the reservoir fluid was charged to a high-pressure visual cell and thermally expanded to the reported reservoir temperature of 130ºF and 122ºF for the two wells respectively. During a constant composition expansion at this temperature, bubble point pressure of 283 and 392 psig was observed in the two wells. The results of pressure-volume relations are discussed and the associated compressibility data for the undersaturated fluid.
A large quantity of the reservoir fluid was subjected to differential vaporization at the reservoir temperature of 130ºF and 122ºF. As a result, a total of 153 and 216 standard cubic feet of gas per barrel of residual oil at 60ºF was liberated with an associated relative oil volume of 1.132 and 1.158 barrels of saturated oil per barrel of residual oil for the two wells respectively. At each depletion pressure levels below the observed saturation pressure, oil densities, gas deviation factors and gas gravities were monitored.

Maintaining reservoir temperature, the viscosity of the liquid phase was measured through a series of pressures beginning well above saturation pressure to atmospheric pressure. These values showed a variation from a minimum at saturation pressure of 1.02 and 1.18 centipoise to a maximum at atmospheric pressure of 1.76 and 2.28 centipoise respectively.
At conditions specified, a series of separation tests were performed in the laboratory, and the viscosity of the stock tank oil measured at 75ºF.

8.2. Hydrocarbon Analysis of Reservoir Fluids

8.2.1. Facha Formation

The hydrocarbon composition analysis of the studied fluid for the investigated Well: XX 1-11 was presented in Table 1.

Table 1 Hydrocarbon composition analysis

Component	Chemical formula	Mole percent	Weight percent	Density	ºAPI	Mole weight
Hydrogen sulphide	H_2S	3.12	0.75			
Carbon dioxide	CO_2	1.43	0.44			
Nitrogen	N_2	0.25	0.05			
Methane	CH_4	4.84	0.55			
Ethane	C_2H_6	1.87	0.40			
Propane	C_3H_8	4.24	1.32			
iso-Butane	C_4H_{10}	3.09	1.26			
n-Butane	C_4H_{10}	6.09	2.50			
iso-Pentane	C_5H_{12}	5.27	2.68			
n-Pentane	C_5H_{12}	4.23	2.15			
Hexanes	C_6H_{14}	5.66	3.42			
Heptanes plus	$C_6H_{14}^{+}$	59.91	84.48	0.8463	35.5	200
$\sum$		100.00	100.00			

8.2.1.1. Pressure-Volume Relations at 130ºF

Table 2 presents the data of pressure-volume relations at the temperature test of 130ºF. The calculations were carried out according to the following equations:

$Relative\ volume = V/V_{sat}$; is the barrel at indicated pressure per barrel at saturated pressure.

$Y\ Function = \frac{(p_{sat}-p)}{(p_{abs})(V/V_{sat})}$

Table 2 Pressure-volume relations at the temperature test of 130ºF

Pressure (psig)	Relative volume	Y Function
2000	0.9869	
1500	0.9904	
1000	0.9942	
800	0.9958	
700	0.9966	
600	0.9974	
500	0.9983	
400	0.9990	
300	0.9999	
283 Saturated pressures	**1.0000**	
240	1.1066	1.566
225	1.1599	1.504
206	1.2451	1.431
187	1.3516	1.359
172	1.4582	1.296
158	1.5860	1.233
144	1.7566	1.160
130	1.9698	0.092
113	2.3948	0.952
93	3.0345	0.869
75	4.1005	0.745

8.2.1.2. Differential-Vaporization at 130ºF

Table 3 gives the results of differential-vaporization at 130ºF of the investigated Well XX 1-11 for Facha Formation.

On the other hand, the results of this fluid were represented graphically for some PVT parameters as shown in Figures 4 & 5, which depicts the relationship between the pressure (psig) and both relative oil volume and solution gas/oil ratio. Obviously, both of them are increasing with increasing pressure.

Table 3 Differential-vaporization at 130ºF of the studied fluid

Pressure (psig)	**Solution gas/oil ratio (1)**	**Relative oil volume (2)**	**Relative total volume (3)**	**Oil density (gm/cc)**	**Deviation factor (Z)**	**Gas formation volume factor (4)**	**Incremental gas gravity**
283	153	1.132	1.132	0.7710			
250	143	1.128	1.234	0.7718	0.942	0.05941	1.001
200	133	1.124	1.389	0.7730	0.958	0.07447	0.941
150	120	1.118	1.694	0.7745	0.968	0.09805	0.997
100	102	1.109	2.396	0.7767	0.975	0.14170	1.131
70	82	1.098	3.535	0.7794	0.980	0.19269	1.257
0	0	1.034		0.7975			1.737
	At 60ºF = 1.000						
Gravity of residual oil = 39.90 API at 60ºF							
(1) Cubic feet of gas at 14.73 psia and 60ºF, per barrel of residual oil at 60ºF.							
(2) Barrels of oil at indicated pressure and temperature per barrel of residual oil at 60ºF.							
(3) Barrels of oil plus liberated gas oil at indicated pressure and temperature per barrel of residual oil at 60ºF.							
(4) Cubic feet of gas at indicated pressure and temperature per cubic foot at 14.73 psia and 60ºF.							

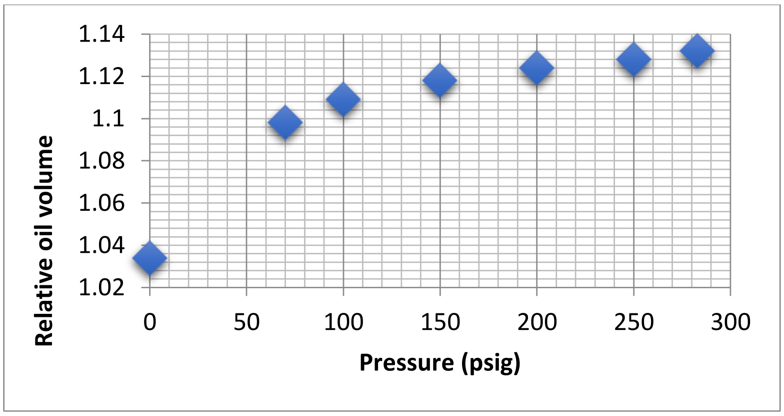

Fig. 4 Pressure against relative oil volume

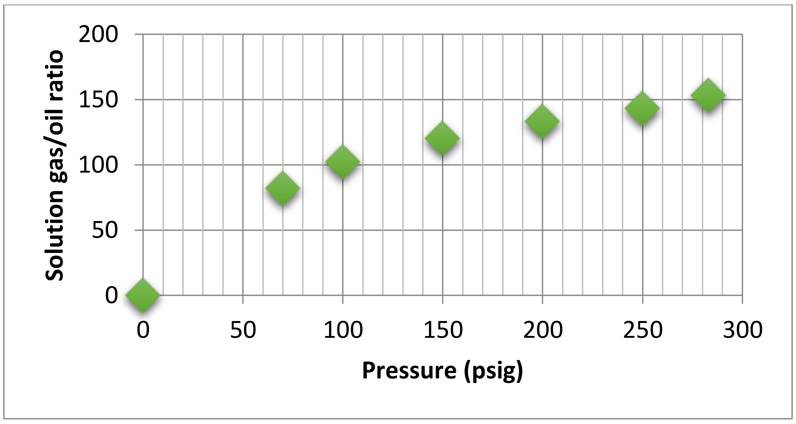

Fig. 5 Pressure against solution gas/oil ratio

Figures 6 through 9 display the relationships between pressure versus relative total volume, oil density, deviation factor and gas formation volume factor, whereas all these parameters are decrease with increasing pressure.

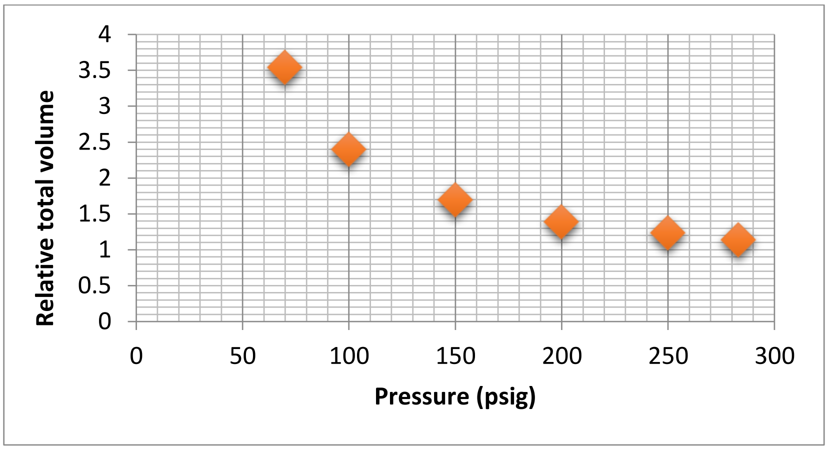

Fig. 6 Relative total volume versus pressure

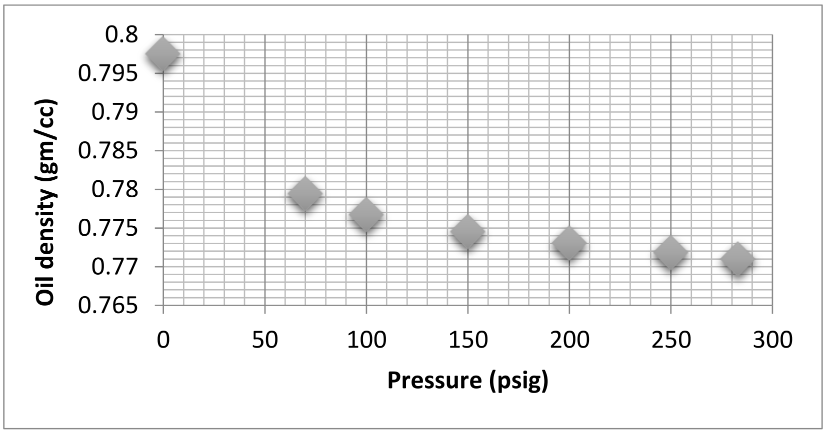

Fig. 7 Pressure against oil density

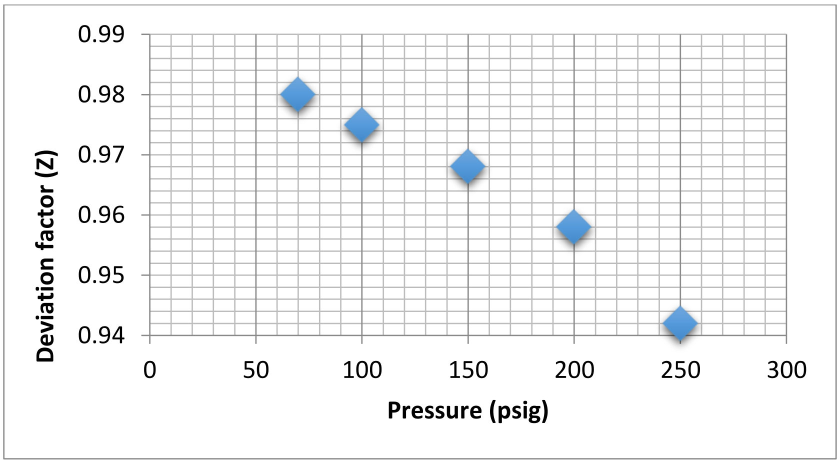

Fig. 8 Deviation factor versus pressure

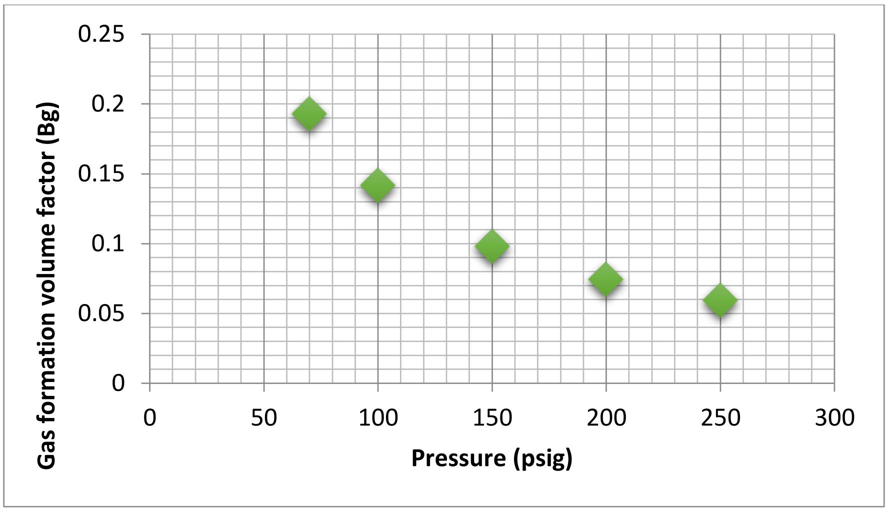

Fig. 9 Gas formation volume factor versus pressure

8.2.1.3. Viscosity Data at 130ºF

The viscosity property of the investigated fluid was determined at 130ºF, and the obtained results were presented in Table 4.

Table 4 Viscosity of the studied fluid

Pressure (psig)	**Oil viscosity centipoise**	**Calculated gas viscosity centipoise**	**Oil/gas viscosity ratio**
2000	1.19		
1500	1.14		
1000	1.09		
800	1.07		
600	1.05		
283 Saturated pressures	1.02		
250	1.03	0.0109	94.5
200	1.05	0.0109	96.1
150	1.08	0.0106	101.5
100	1.11	0.0101	109.9
70	1.16	0.0097	120.2
0	1.76		

The bubble point pressure (saturated pressure) was determined as 283 psi as shown in Figure 10 which depicts the relation between oil viscosity and pressure.

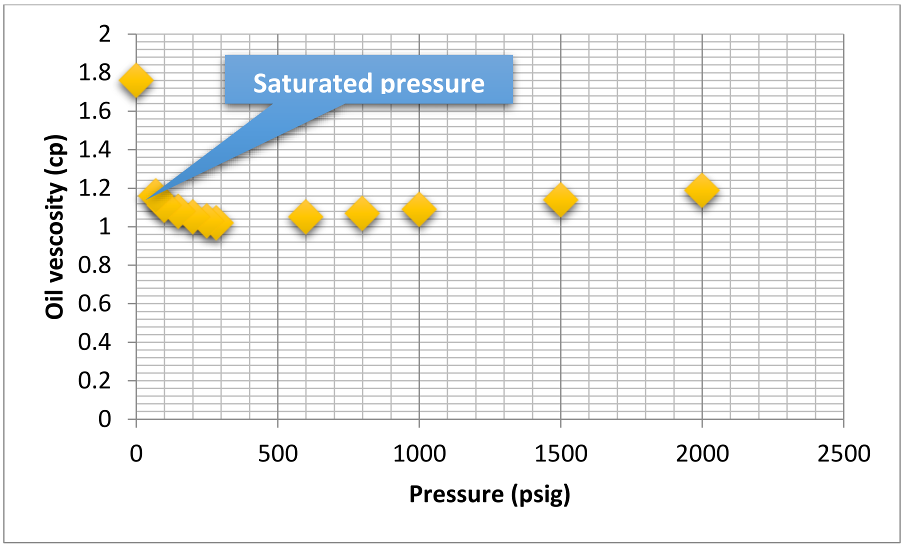

Fig. 10 Oil saturated pressure

8.2.1.4. Separation Tests of Reservoir Fluid

The results of reservoir fluid data of separation tests were given in Table 5. Separation conditions are provided below the table.

Table 5 Separation Tests data of reservoir fluid

Separator pressure (psig)	Separator temperature (°F)	Gas/oil ratio (1)	Gas/oil ratio (2)	Stock tank gravity (°API) @ 60°F	Formation volume factor (3)	Separator volume factor (4)	Specific gravity of flashed gas
80 to 0	75	35	37			1.061	0.899*
	75	84	85	41.6	1.112	1.007	1.117
Viscosity of stock tank oil at 75°F = 2.61							
40 to 0	75	51	53			1.052	0.970*
	75	65	65	41.6	1.109	1.007	1.171
Viscosity of stock tank oil at 75°F = 2.67							
0	75	135	136	40.9	1.115	1.007	1.296*
Viscosity of stock tank oil at 75°F = 2.74							
* Gas collected and analyzed for hydrocarbon composition							
(1) Gas/oil ratio in cubic feet of gas at 14.73 psia and 60°F per barrel of oil at indicated pressure and temperature.							
(2) Gas/oil ratio in cubic feet of gas at 14.73 psia and 60°F per barrel of stock tank oil at 60°F.							
(3) Formation volume factor is barrels of saturated oil at 283 psig and 130°F per barrel of stock tank oil at 60°F.							
(4) Separator volume factor is barrel of oil at indicated pressure and temperature per barrel of stock tank oil at 60°F..							

8.2.1.5. Hydrocarbon Analysis of Separator Gas Samples

The hydrocarbon analysis of separator gas samples were examined at different conditions e. g. 80 psig @ 75ºF, 40 psig @ 75ºF and 0 psig @ 75ºF. The components of studied hydrocarbons are varied with changing separator conditions as shown in Table 6.

Table 6 Hydrocarbon analysis of separator gas samples

Separator conditions	**Chemical formula**	**80 psig @ 75ºF**		**40 psig @ 75ºF**		**0 psig @ 75ºF**	
Component		**Mole percent**	**GPM**	**Mole percent**	**GPM**	**Mole percent**	**GPM**
Hydrogen sulphide	H_2S	6.69		10.48		14.21	
Carbon dioxide	CO_2	11.36		12.24		7.85	
Nitrogen	N_2	8.36		4.90		2.84	
Methane	CH_4	57.34		50.79		28.72	
Ethane	C_2H_6	6.75		8.56		9.35	
Propane	C_3H_8	4.83	1.329	6.59	1.813	14.56	4.005
iso-Butane	C_4H_{10}	1.45	0.474	2.06	0.674	6.42	2.099
n-Butane	C_4H_{10}	1.73	0.545	2.52	0.794	9.16	2.887
iso-Pentane	C_5H_{12}	0.57	0.209	0.85	0.311	3.11	1.138
n-Pentane	C_5H_{12}	0.25	0.091	0.40	0.145	1.39	0.504
Hexanes	C_6H_{14}	0.32	0.131	0.28	0.114	0.39	0.379
Heptanes plus	$C_6H_{14}^+$	0.35	0.159	0.33	0.150	1.46	0.663
∑		100.00	2.938	100.00	4.001	100.00	11.675
Calculated gas gravity		0.89		0.970		1.296	
Calculating gross heating value (BTU/ft^3 dry gas @ 14.73 psia & 60ºF		1036		1131		1731	

8.2.2. GIR FORMATION

The hydrocarbon composition analysis of the studied fluid for the investigated Well: XX 11-11 at Gir Formation was presented in Table 7.

Table 7 Hydrocarbon composition analysis

Component	**Chemical formula**	**Mole percent**	**Weight percent**	**Density**	**ºAPI**	**Mole weight**
Hydrogen sulphide	H_2S	1.08	0.26			
Carbon dioxide	CO_2	4.15	1.31			
Nitrogen	N_2	0.27	0.06			
Methane	CH_4	5.58	0.64			
Ethane	C_2H_6	3.77	0.81			
Propane	C_3H_8	7.24	2.28			
iso-Butane	C_4H_{10}	2.65	1.10			
n-Butane	C_4H_{10}	6.82	2.84			
iso-Pentane	C_5H_{12}	4.20	2.18			
n-Pentane	C_5H_{12}	4.30	2.23			
Hexanes	C_6H_{14}	5.18	3.18			
Heptanes plus	$C_6H_{14}^+$	54.76	83.11	0.8476	35.3	212
∑		100.00	100.00			

8.2.2.1. Pressure-Volume Relations at 122ºF

Table 8 presents the data of pressure-volume relations at the temperature test of 122ºF. The calculations were carried out according to the following equations:

$Relative\ volume = V/V_{sat}$; is the barrel at indicated pressure per barrel at saturated pressure.

$$Y\ Function = \frac{(p_{sat}-p)}{(p_{abs})(V/V_{sat})}$$

Table 8 Pressure-volume relations at the temperature test of 122ºF

Pressure (psig)	Relative volume	Y Function
2000	0.9870	
1000	0.9945	
700	0.9971	
600	0.9978	
500	0.9987	
400	0.9996	
351 Saturated pressure	1.0000	
336	1.0193	2.194
322	1.0400	2.133
303	1.0731	2.044
284	1.1150	1.956
260	1.1790	1.848
236	1.2645	1.732
213	1.3712	1.625
192	1.4993	1.538
171	1.6702	1.444
157	1.8838	1.282
130	2.3142	1.160
106	2.9552	1.036

8.2.2.2. Differential-Vaporization at 122ºF

Table 9 gives the results of differential-vaporization at 130ºF of the investigated Well XX 11-11 for Facha Formation.

However, the results of this fluid were represented graphically for some PVT parameters as shown in Figures 11 & 12, which depicts the relationship between the pressure (psig) and both relative oil volume and solution gas/oil ratio. Obviously, both of them are increasing with increasing pressure.

Table 9 Differential-vaporization at 122°F of the studied fluid

Pressure (psig)	**Solution gas/oil ratio (1)**	**Relative oil volume (2)**	**Relative total volume (3)**	**Oil density (gm/cc)**	**Deviation factor (Z)**	**Gas formation volume factor (4)**	**Incremental gas gravity**
351	216	1.158	1.58	0.7757			
300	205	1.154	1.252	0.7769	0.957	0.05009	0.891
200	179	1.142	1.635	0.7801	0.976	0.07484	0.956
122	148	1.127	2.557	0.7832	0.981	0.11805	1.123
80	124	1.112	3.910	0.7882	0.984	0.17076	1.267
0	0	1.030		0.8030			1.806
	At 60°F = 1.000						
Gravity of residual oil = 39.30 API at 60°F							
(1) Cubic feet of gas at 14.73 psia and 60°F, per barrel of residual oil at 60°F.							
(2) Barrels of oil at indicated pressure and temperature per barrel of residual oil at 60°F.							
(3) Barrels of oil plus liberated gas oil at indicated pressure and temperature per barrel of residual oil at 60°F.							
(4) Cubic feet of gas at indicated pressure and temperature per cubic foot at 14.73 psia and 60°F.							

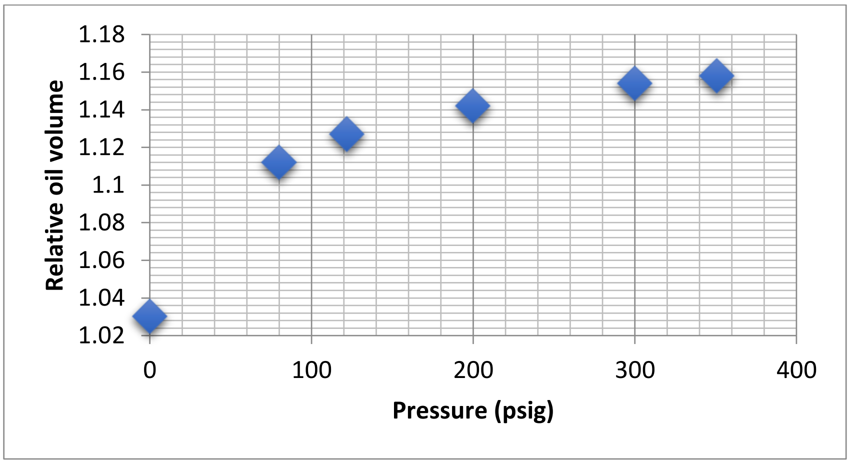

Fig. 11 Pressure against relative oil volume

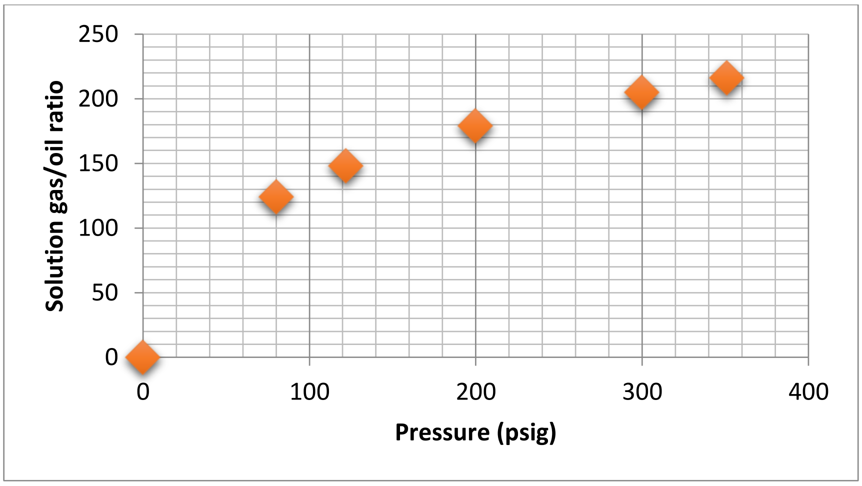

Fig. 12 Pressure against solution gas/oil ratio

Figures 13 through 16 display the relationships between pressure versus relative total volume, oil density, deviation factor and gas formation volume factor, whereas all these parameters are decrease with increasing pressure.

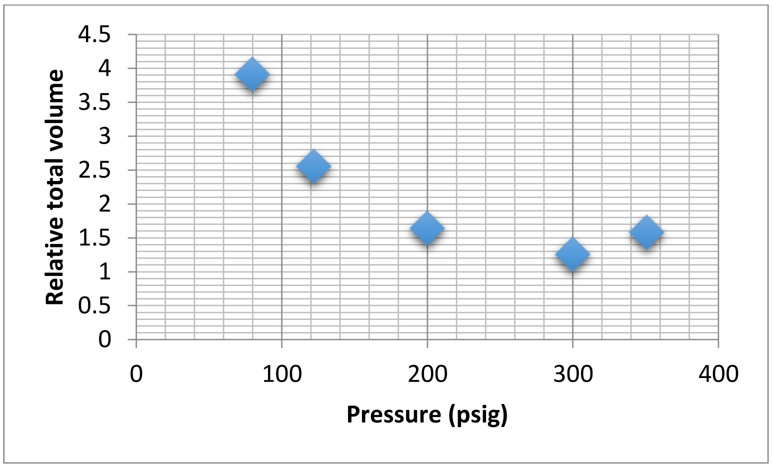

Fig. 13 Relative total volume versus pressure

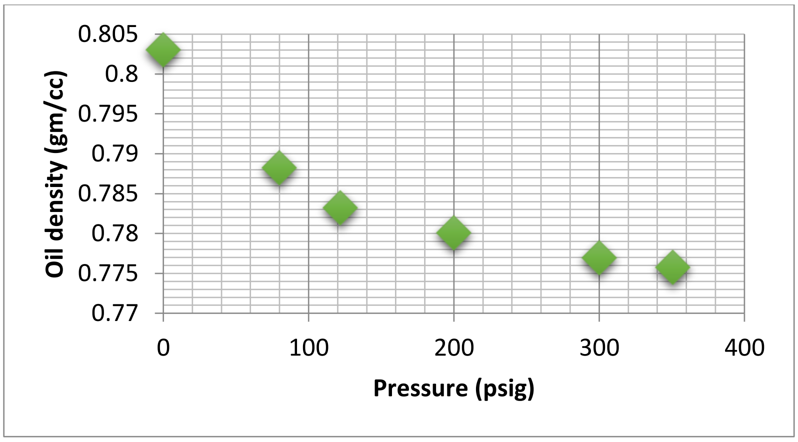

Fig. 14 Pressure against oil density

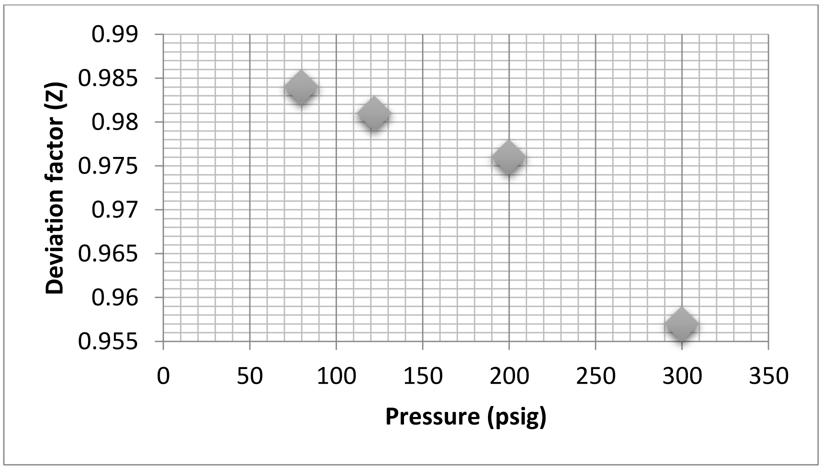

Fig. 15 Deviation factor versus pressure

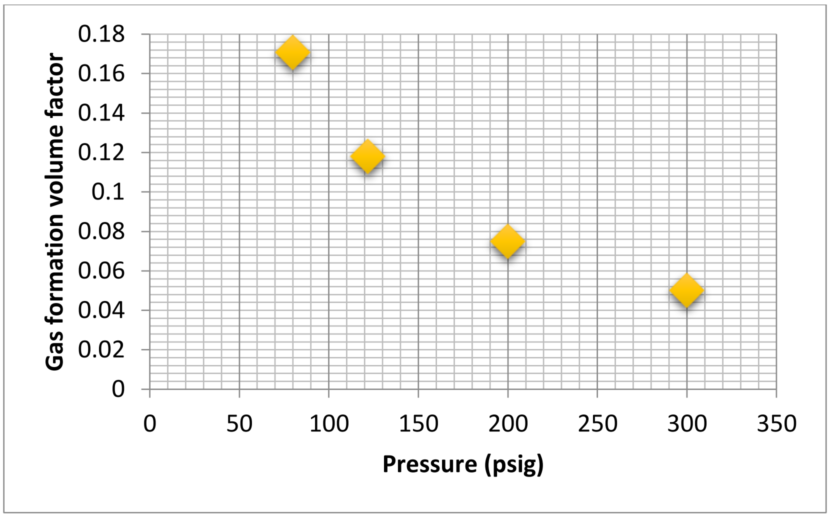

Fig. 16 Gas formation volume factor versus pressure

8.2.2.3. Viscosity Data at 122ºF

The viscosity property of the investigated fluid was determined at 130ºF, and the obtained results were presented in Table 10.

Table 10 Viscosity of the studied fluid

Pressure (psig)	Oil viscosity centipoise	Calculated gas viscosity centipoise	Oil/gas viscosity ratio
2000	1.37		
1000	1.25		
700	1.22		
600	1.20		
500	1.19		
400	1.18		
351 Saturated pressure			
300	1.20	0.0112	107
200	1.26	0.0107	117
122	1.34	0.0100	134
80	1.40	0.0095	147
0	2.28		

The bubble point pressure (saturated pressure) was determined as 351 psi as shown in Figure 17 which depicts the relation between oil viscosity and pressure.

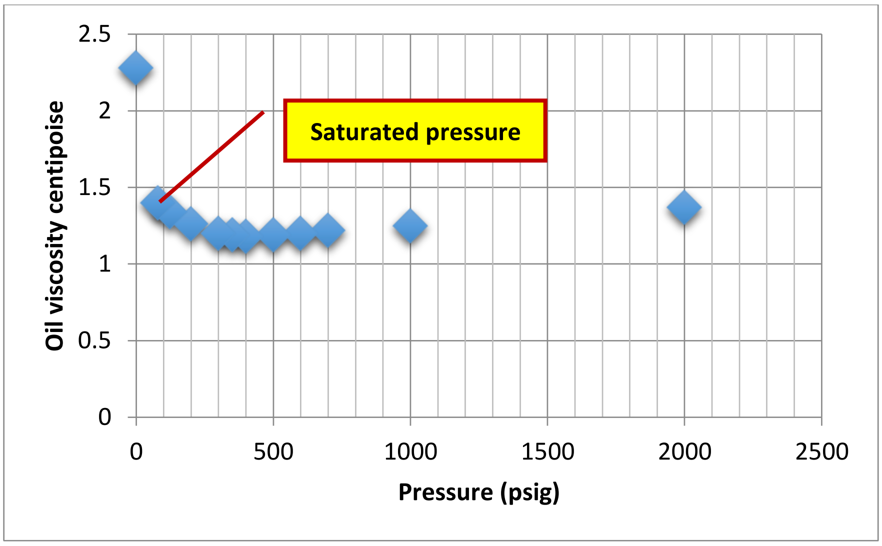

Fig. 17 Oil saturated pressure

8.2.2.4. Separation Tests of Reservoir Fluid

The results of reservoir fluid data of separation tests were given in Table 11. Separation conditions are provided below the table.

Table 11 Separation Tests data of reservoir fluid

Separator pressure (psig)	Separator temperature (ºF)	Gas/oil ratio (1)	Gas/oil ratio (2)	Stock tank gravity (°API) @ 60ºF	Formation volume factor (3)	Separator volume factor (4)	Specific gravity of flashed gas
80 to 0	75	60	65			1.077	1.083*
	75	105	106	40.5	1.131	1.007	1.307
Viscosity of stock tank oil at 75ºF = 2.61							
40 to 0	75	84	89			1.061	1.159*
	75	76	77	40.7	1.129	1.007	1.382
Viscosity of stock tank oil at 75ºF = 2.67							
0	75	202	203	39.9	1.146	1.007	1.415*
Viscosity of stock tank oil at 75ºF = 2.74							
* Gas collected and analyzed for hydrocarbon composition							
(1) Gas/oil ratio in cubic feet of gas at 14.73 psia and 60ºF per barrel of oil at indicated pressure and temperature.							
(2) Gas/oil ratio in cubic feet of gas at 14.73 psia and 60ºF per barrel of stock tank oil at 60ºF.							
(3) Formation volume factor is barrels of saturated oil at 283 psig and 130ºF per barrel of stock tank oil at 60ºF.							
(4) Separator volume factor is barrel of oil at indicated pressure and temperature per barrel of stock tank oil at 60ºF.							

8.2.2.5. Hydrocarbon Analysis of Separator Gas Samples

The hydrocarbon analysis of separator gas samples were examined at different conditions e. g. 80 psig @ 75ºF, 40 psig @ 75ºF and 0 psig @ 75ºF. The components of studied hydrocarbons are varied with changing separator conditions as shown in Table 12.

Table 12 Hydrocarbon analysis of separator gas samples

Separator conditions	**Chemical formula**	**80 psig @ 75ºF**		**40 psig @ 75ºF**		**0 psig @ 75ºF**	
Component		**Mole percent**	**GPM**	**Mole percent**	**GPM**	**Mole percent**	**GPM**
Hydrogen sulphide	H_2S	8.01		6.65		4.52	
Carbon dioxide	CO_2	21.51		20.53		15.24	
Nitrogen	N_2	3.07		2.37		1.44	
Methane	CH_4	37.51		32.40		19.89	
Ethane	C_2H_6	12.95		14.83		13.96	
Propane	C_3H_8	12.10	3.329	14.26	3.923	20.76	5.711
iso-Butane	C_4H_{10}	1.33	0.435	2.50	0.818	5.68	1.857
n-Butane	C_4H_{10}	2.27	0.715	4.27	1.346	10.71	3.375
iso-Pentane	C_5H_{12}	0.53	0.194	0.91	0.333	3.17	1.160
n-Pentane	C_5H_{12}	0.36	0.130	0.62	0.225	2.15	0.779
Hexanes	C_6H_{14}	0.15	0.061	0.26	0.106	1.06	0.432
Heptanes plus	$C_6H_{14}^+$	0.21	0.095	0.40	0.182	1.52	0.690
$\sum$		100.00	4.959	100.00	6.933	100.00	14.004
Calculated gas gravity		1.083		1.159		1.415	
Calculating gross heating value (BTU/ft^3 dry gas @ 14.73 psia & 60ºF		1138		1311		1886	

9. CONCLUSION

PVT studies are important reservoir engineering experiments that have a wide range of applications, including reserve estimation, surface installations, and storage operations.

From the previous results that obtained from the studied fluids throughout two wells for PVT in Ghani oilfield for two formations namely Facha and Gir Formations, the following conclusion can be drawn:

1. The hydrocarbon composition analysis of the studied fluid for the investigated Well RRR-1-11 of Facha Formation shows heptanes plus 59.91, with specific density 0.8463 and API 35.5; while in Well XX 11-11 of Gir Formation is 54.76 mole percent with specific density, 0.8476 and API 35.3 respectively.
2. The pressure-volume relations at the temperature test of 130ºF revealed that the bubble point pressure or saturation pressure is 283 psig of Well XX -1-11 but for Well-RRR 11-11 is 351 psig at temperature 122ºF.
3. The differential-vaporization at 130ºF of the studied fluid of Well 1-11 has GOR, relative oil volume, and oil density 153, 1.132 and 0.7710 at bubble point pressure 283; while for Well 11-11 are 216, 1.158 and 0.7757 respectively at 122ºF.

4. The viscosity property of the investigated fluid was determined at 130ºF for Well XX 1-11 is 1.02 centipoise at saturation pressure, but for Well XX 11-11 is 1.37 centipoise at 122ºF 351 centipoise.
5. The results of reservoir fluid data of separation tests exhibited a variation in values for the investigated parameters e. g., gas/oil ratio, stock tank gravity (ºAPI), formation volume factor, separator volume factor and specific gravity of flashed gas at different ranges of pressure and separator temperature 75ºF for both the two wells.
6. The hydrocarbon analysis of separator gas samples were examined at different conditions e. g. 80 psig @ 75ºF, 40 psig @ 75ºF and 0 psig @ 75ºF. The components of studied hydrocarbons are varied with changing separator conditions.

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