COMPARISON OF WATER INJECTION AT DEW-POINT PRESSURE AND VOLUMETRIC-DEPLETION RECOVERY METHODS TO IMPROVE GAS CONDENSATE RESERVOIRS FLUIDS RECOVERY

Udie, A. C., Nwakaudu, M. S.

Abstract— **Water injection at dew-point pressure and volumetric-depletion recovery methods were compared, gearing towards improving oil recovery factor in Gas-Condensate Reservoirs. The primary input data of the evaluation modes were estimated using average values of the field, separator recombined fluids and laboratory test data: total gas-condensate initially in place, recoverable gas and liquid volumes, permeability, volumetric sweep efficiency (E_{swp}) , injected water invasion factor (F) and laboratory test data of the field of study. The condensable hydrocarbons recovery models in water-injection and Volumetric depletion methods were developed. The principles were based on traditional simulation and can be used in condensable hydrocarbons recovery evaluations. The techniques for monitoring proper pressure maintenance were also developed using daily reservoir voidage out replacement by the injected fluids volumes. The estimated cumulative liquid (oil) recovery factor (ranges from 62 to 76%) was higher and more encouraging in water-injection method than Volumetric depletion method under similar conditions.**

Index Terms— **Condensate Recovery (Liquid and Gas), Water injection and Volumetric Depletion, Invasion-Factor, Molar-Volume and Voidage-Out Replacement**

I. INTRODUCTION

Definition

Gas condensate (called Liquid or Distillates Oil) reservoirs are those which produce lighter coloured or colourless stock tank liquids with gravities above 45°API at gas-oil ratios in the range 3,000 to 100,000scf/bbl. The gas condensate production is predominately gas from which liquid (called oil or distillate) is condensed at the surface separator. [Allen, 1952] [1]

Volumetric depletion is a pressure decline method from the dew-point pressure (P_d) to the reservoir abandonment pressure (P_a) while water injection at dew-point pressure (P_d) is a reservoir pressure maintenance agent used to control fluid recovery efficiency in a gas condensate reservoir. The other functions of water injection include: displacement of the condensate from the reservoir rocks, sweeping off the displaced fluids and recovery of the swept fluids at a given time. The importance of the injected fluid is to invade and

gain a replacing factor for improving the recovery. [Udie, et al, 2014] [2]

Liquids recovery in gas-condensate reservoirs is classified under low hydrocarbons fluids reservoirs (marginal oil field), because the techniques, quantity and expenses for liquid (oil) recovery in gas condensate reservoir are off the conventional recovery methods. The quantity of oil to be recovered using gas-injection depends on the quantity of the injected gas invasion and by volumetric depletion depends on the reservoir pressure. The gas invasion value depends on the void spaces in a reservoir to be replaced as a displacing agent. Gas injection gears towards an overall recovery factor of 0.46 to 0.48. The control or dependant parameters are rock permeability uniformity, displacement and injected-gas invasion/swept efficiencies. The recovery value is due to pressure maintenance, sweep efficiency and displacement by the injected gas vapour. If pressure is not enhanced (maintained), low recovery would establish itself through retrograde condensation in the gas-condensate reservoir. Gas re-cycling is only fairly good in a gas condensate with gas-cap, which is overlying by an oil-zone that is also overlain by an active water-drive. In this case the pressure is supported by the aquifer. In the absence of active water-drive, oil-zone can be depleted first, allowing the gas-cap to expand and sweep through the oil-zone, maximizing the recovery. This is because in the absence of active water-drive, the application of gas re-cycling would cause oil to zone into shrink gas-cap and/or the original oil-zone initially displaced by gas, resulting in low recovery. In order to predict the recovery value using this technique in gas-condensate reservoir, validation through field inspection is required. This involves the techniques for studying geological data, reservoir, rocks and fluids characterizations applications to aid history matching. [Williams, 1996] [3]

II. SIMULATION & MODELLING IN GAS-CONDENSATE

The main objective of this work is to compare volumetric-depletion and water-injection techniques for recovery fluids in gas condensate reservoirs. The specific objective is to develop mathematical models for studying and improving oil recovery factor in a gas condensate reservoir, at reduced cost. The models gear towards maximizing pressure maintenance through water injection process in any gas-condensate reservoir and avoid retrograde condensation in volumetric depletion method, which could result in low recovery. The simulator consists of a single well with injection properties and reservoir characterization. The effects of varying permeability uniformity and injected fluids invasion factors calculation are included in the model program. Single-phase flow is considered in single production and injection well system, which could be integrated into

multiple production and injection wells system. The success of this model relies mainly on the following factors: Pressure maintenance in condensate reservoirs, good invasion factor of the injected water, permeability uniformity efficiency of the reservoir and displacement efficiency of the water used.

Standing, (1952) [4] worked on the methods for adjusting equilibrium ratio. He used data from gas-condensate reservoir and applied to different compositions. In his work he gave step by step calculation methods for volumetric performances. His method started with a unit volume of the initial reservoir vapour and a known composition. An increment of vapour phase material was assumed to be removed from the initial volume at constant temperature. The remaining fluid expanded to the initial volume. The final pressure, division in the volume between the vapour and the reservoir liquid phase and the individual composition of vapour and liquid phase are then calculated using the adjusted equilibrium ratio. A second increment of vapour was removed at a lower pressure and the pressure, volume and composition were calculated again. The moles of each component were recorded, so as to determine the total moles of any remaining at each pressure by subtracting from the initial volumes. The calculation was repeated to abandonment pressure and he found out that the prediction of condensate reservoir performance from equilibrium ratio alone is likely to be in considerably error. He recommended that some laboratory test data should be used for comparison. He added that the equilibrium ratios are changing, because the composition of the reservoir or cell system changed or more so the heptanes-plus (C^{7+}) composition changes could affect the calculation.

Rodger et al, (1957) [5] tried to improve standing's work and came out with the conclusion that there must be need to improve procedure in developing the equilibrium ratios for the heavier hydrocarbons. Their reason was that it would improve the overall accuracy of the calculation.

Jacoby et al (1958) [6] worked on the effects of composition, temperature of the fluid phase and depletion performance of gas-condensate systems. They studied the phase behaviours of eight mixtures of separator-oil & gas from lean gas condensate reservoir at recombined ratio in the range of 2,000 to 25,000scf/bbl and temperature range of 100 to 200°F. They found out that the results would be useful in predicting the depletion performance of gas-condensate reservoirs in the absence of laboratory studies. They also found out that there would be a gradual change in the surface production performance from the volatile oil to wet (rich) gas-condensate reservoirs. They recommended that a laboratory examination would be necessary to distinguish between a dew-point and bubble point reservoir, especially in the range of 2,000 to 6,000scf/d gas-oil ratios.

Craft, and Hawkins, (1958) [7] studied the laboratory test data and equilibrium ratio calculated results of a gas-condensate reservoir and compared with the actual field depletion performance history. That was a controlled experiment where 4,000cu.cm cell sample at the reservoir temperature and pressure was used. The cell was pressure depleted, so that only the gas phase passed through the miniature three-phase separator operated at optimum field pressure and temperature. The calculated performance was also obtained from equation involving equilibrium ratio, assuming differential process. They found out that the laboratory model study could adequately predict the gas condensate reservoir behaviour. The performance could as well be calculated from the composition of the initial reservoir fluids, provided representative equilibrium ratios are available. The composition of differential process (constant volume, but changing composition) showed that only the gas would be produced and it could be removed from the liquid contact with the liquid phase in the reservoir while in the flash process (constant composition, but changing volume) showed that all the gas would remain in contact with the retrograde liquid. To this effect they recommended that, for it to be so the volume of the system must increase as the pressure declines.

Allens, and Roe, (1950) [8] worked compared the predicted and the actual production histories of volumetric gas-condensate reservoir and found out that retrograde condensate reservoirs with initial gas-oil ratios, produced higher condensate at lower pressure than the theoretical calculations based on equilibrium ratios techniques only. They concluded that the difference in recovery was due to sampling error or retrograde condensed liquid of the heavier hydrocarbons near the wellbore, which might be immobile. They equally looked at the omission of nitrogen as a constituent of the gas-condensate from the calculations. They stated that a small amount of nitrogen was found in several samples, during the life of the reservoirs studied.

Craze, and Buckley, (1945) [9] developed a material balance equation (MBE) for fluids recovery from water-drive reservoir where he assumed not appreciable decline in pressure. Their volumetric material balance equation was given as:

$$E_R = \frac{(1 - S_{wi})B_{gi} - S_{gr}B_g}{(1 - S_{wi})B_{gi}}$$

[2.1]

Thompson, et al, (1993) [10], worked on gas condensate recovery using well test data

Eilerts, (1957) [11], showed the distribution of gas-oil ratio and gas gravity (API) for 172 gas and gas condensate fields of 3-senerios. He found no correlation between the gas-oil ratio or the API of the tank liquid (oil) in these fields. Table 2.1 below shows his (Eilerts) experimental result of the gas-oil ratio in the 3-fields and Table 2.2 shows the phase relation to tank oil gravity.

Berryman, (1957) [12] pointed out that the classification of wells and reservoirs base entirely on production gas-oil ratio is inadequate. He recommended that proper classification reservoirs should be based on fluids composition, temperature and pressure.

Table 2.1 Phase Relation to Gas-Oil Ratios in 3 Fields

LGR GPM.SCF	GOR MScf/bbl	Fields			Total	% of Total
		A	B	C		

≺ 0.4	≻ 105	38	12	7	57	
0.4 - 0.8	52.5 – 1.05	33	18	4	55	
0.8 – 1.2	35.0 – 52.5	12	15	5	32	
1.2 – 1.6	26.2 – 35.0	1	8	1	10	
1.6 - 2.0	21.0 – 26.2	1	3	1	5	
≻ 2.0	≺ 21.0	2	5	6	1 3	
Total		87	61	24	172	100

Table 2 2 Phase Relation to Tank Oil Gravities in 3 Fields

LGR GPM.SCF	Gravity API	Fields			Total	% of Total
		A	B	C		
≺ 0.4	≺ 40	2	1	0	3	
0.4 - 0.8	40 – 45	4	2	0	6	
0.8 – 1.2	45 – 50	12	12	0	24	
1.2 – 1.6	50 – 55	24	17	7	47	
1.6 - 2.0	55 – 60	19	13	12	49	
≻ 2.0	60 - 68	23	8	3	30	
	≻ 68	3	1	2	6	
Total		87	54	24	165	100

3. Materials and Methods

a. *Materials*

The materials used in this research were collected form Department of Petroleum Resources (DPR), Nigerian National Petroleum Corporation (NNPC): namely Oso Gas-Condensate production data, located in the Niger Delta geological formation. The materials collected covered the Field and Laboratory Test data, specifically from exploration, appraisal and production wells. Table 3.1 shows the gas condensate fluid recovery data, Table 3.2 shows the field and laboratory fluids test composition of the gas-condensate reservoir. Table 3.3 shows history of the field and laboratory test data and Table 3.4 shows field and laboratory test data (oil/gas) volumes increments and the corresponding deviation factors.

Table 3.1 Gas Condensate Fluid from Laboratory Test Result

Condensate component	Gas component % Volume	Liquid Component % Volume	Molar Weight lb/mole
CO_2	0.0017	0.0012	-
C_1	0.8265	0.0992	16.04
C_2	0.0630	0.0340	30.07
C_3	0.0602	0.0893	44.49
iC_4	0.0134	0.0419	58.12
nC_4	0.0157	0.0679	58.12
iC_5	0.0040	0.0441	72.15
nC_5	0.0027	0.0420	72.15
C_6	0.0015	0.0656	86.17
C_{7+}	0.0012	0.5069	165
Others	0.0101	0.0079	-
Total	1.00000	1.0000	-

Table 3.2 Field and Laboratory Fluid Composition of the Condensate at a Pressure

Pressure Psia	CO_2	N_2	C_1	C_2	C_3	iC_4	nC_4	iC_5	nC_5	C_6	C_{7-}
6290, P_i	-	-	-	-	-	-	-	-	-	-	-
5412, P_d	0.0169	0.000	0.728	0.071	0.077	0.017	0.023	0.008	0.006	0.006	0.0417
4700	0.0830	0.000	0.734	0.070	0.075	0.017	0.023	0.008	0.005	0.006	0.0377
4000	0.0179	0.000	0.739	0.070	0.075	0.017	0.022	0.008	0.006	0.006	0.0361
3300	0.0176	0.000	0.744	0.070	0.074	0.017	0.022	0.008	0.005	0.006	0.0328
2600	0.0174	0.000	0.753	0.071	0.074	0.016	0.022	0.007	0.005	0.006	0.0248
1900	0.0172	0.000	0.760	0.071	0.075	0.016	0.022	0.007	0.005	0.006	0.0181
1400, P_a	0.0174	0.000	0.763	0.072	0.076	0.016	0.021	0.007	0.005	0.005	0.0145
Total											

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Table 3.3 Field and Laboratory Test Data

Parameter	Symbol/Unit	Data
Initial Pressure	$P_i, psia$	6290
Dew-Point Pressure	$P_d, psia$	5412
Abandonment Pressure	$P_a, psia$	1400
Reservoir Temperature	$T_i, °F$	240
Connate Water Saturation	$S_{wi}, \%$	11
Average Porosity	$\emptyset, \%$	23
Daily Tank Oil	$V_{ot}, bbl/d$	
Stock Tank Oil	$V_{ot}, stb/d$	220
Oil Gravity`	$Y_o, °API$	24.06
Daily Separator Gas	$V_{gs}, Mscf$	46.8
Separator Gas Gravity	Y_{gt}	
Daily Tank Gas	$V_{gt}, Mscf$	2640
Tank Gas Gravity	Y_g	
Separator Temperature	$T_{sep}, °F$	0.716
		144
Separator Pressure	$P_{sep}, psia$	1.30
Standard Temperature	$T_{sep}, °F$	83
Standard Pressure	$P_{sep}, psia$	25
Initial Cell Volume	$V_{cel}, cu.cm$	60
Gas-Liquid Ratio		15
Molar Volume (constant)	$GLR, scf/bbl$	1000
	$V_m, cu.ft/mole$	7890
Separator Liquid Volume Factor	$B_{so}, bbl/stb$	379.4
Molar of C_{7+} in initial Fluid	$M_{C7+}, lb/lb.wt$	1.275
Sp.Gr of C_{7+} in Separator Liquid	Y_{C7+}	
Residual Gas Saturation	$S_{gr}, \%$	160
Gas Composition/Liquid Volume	Tables 3.2, 3.3& 3.4	0.718
		20
		-

Table 3.4 Field and Lab Test Data (Oil & Gas Volume Increment and Deviation Factor)

Pressure Psia	Gas Volume Recovery at T_i & P_{cel} V_g, Cu.cm	Gas Volume Recovery at Cell T_i & P_{cel} V_{cel}, Cu.cm	Retrograde Liquid in the Cell		Gas Deviation Z - Factor	Mol. Weight of MC_{7+} lb/lb.wt
			Cell Volume V_{cell} = 1000 Cu.cm	Hydrocarbon Volume(HCV) % V_{cell}		
5412, P_d	N/A	0.00	0.000	0.00	1.007	160
4700	,,	143.69	6.955	0.70	0.941	142
4000	,,	324.09	15.710	1.57	o.886	138
3300	,,	542.40	26.625	2.66	0.846	132
2600	,,	806.90	39.625	3.96	0.821	127
1900	,,	1127.11	54.729	5.47	0.816	123
1400, P_a	,,	1359.06	65.836	6.58	0.820	119

b. *Research Methodology*
Procedures

Different techniques were used to estimate the fluids recovery factors. To achieve this, assumptions were made to enable us generate mathematical evaluation models and for good accuracy, the gas volume was collected based on the following procedures: Liquid recovery factors of condensable components were assumed, **25%C_4, 50%C_5, 75%C_6 and 100%C_{7+}.** Total pay-zone area, A: assumed = a = 1acre.foot. This can be integrated into the entire reservoir area. Average pressure of the operating separators was estimated and used. The stock tank vapour and main high pressure separators were used. The average gas gravity was estimated and used in this calculation. The gas deviation factor, "Z" was estimated from the combined gravity of

oil and gas. The reservoir pressure ($P_i = 6290psia$) was above the dew-point pressure ($P_d = 5412psia$). The field and laboratory test estimated displacement efficiency, permeability uniformity factor and sweep efficiency of 80% each.

Input Parameters Estimation Models Using Tank Fluids Records

i. Initial oil and gas in place per acre-foot were estimated using initial field (history) and laboratory test data of the gas-condensate reservoir. *Mathematically:*

Gas: Liquid Ratio: $GLR = \dfrac{1000\,(V_{gs}+V_{gt})}{V_{ot}} = \dfrac{1000(2640+144)}{220} = 12,655 scf/bbl$

[3.1]

Average Fluids Gravity: $Y_{avg} = \dfrac{V_{gs}\,Y_{gs}+V_{gt}\,Y_{gt}}{V_{gs}+V_{gt}} = \dfrac{2640*0.716+144*1.30}{2640+144} = 0.7462$

[3.2]

Oil Gravity: $Y_o = \dfrac{141.5}{API+131.5} = \dfrac{141.5}{48.6-131.5} = 0.7857$

[3.3]

Tank Oil Molecular Weight: $M_o = \dfrac{6084}{API-Y_o} = \dfrac{6084}{48.6-5.9} = 142.5\,lb.wt$

[3.4]

Well Fluid Gravity: $Y_f = \dfrac{V_{gs}\,Y_{gs}+V_{gt}\,Y_{gt}}{R_g + \dfrac{132800\,Y_o}{M_o}} = \dfrac{132800*0.7462+2640*0.7057}{7890+\dfrac{132800*0.785?}{142.5}} = 0.9234$

[3.5]

Gas Deviation Factor: $Z_i = f(P_{pr},T_{pr}) = f\left(P_i/P_{pc},T_i/T_{pc}\right)\ Using\ AGA\ Table$

[3.6]

Where: $P_{pc} = f(Y_f) = f(0.9234) = 665psia$ & $P_i = 6290psia$ $\Big\}$ **implying that condensate**

$T_{pc} = f(Y_f) = f(0.9234) = 465°R$ & $T_i = 700°R$ $\quad Z_i = f(9.5, 1.5) = 1.078$

Bulk Reservoir Rock: $G_b = \dfrac{43560\,V_m P_i\,\emptyset\,(1-S_{wi})}{Z_i\,R\,T_i} = \dfrac{43560*379.4*6290*0.23*(1-0.11)}{1.078*10.73*700} = 2620\,Mscf/ac.ft$

[3.7]

Liquid (Oil): $V_L = \dfrac{G}{GLR} = \dfrac{2620000}{12655} = 207.03\,bbl/ac.ft$

[3.8]

Condensate (Oil and Gas) Volume Fraction in moles:

Gas Phase moles: $n_g = \dfrac{V_{gs}+V_{gt}}{V_{ot}} = \dfrac{2640+144}{220} = 12.65$ moles [3.9]

Liquid Phase moles: $n_o = \dfrac{350\,Y_o}{M_o} = \dfrac{350*0.7857}{142.5} = 1.93$ moles [3.10]

% Gas-Condensate: $f_g = \dfrac{n_g}{n_g+n_o} = \dfrac{12.65}{12.65+1.93} = 86.76\%$ [3.11]

Recoverable Gas: $G_{p1} = G_b f_g = \left[\dfrac{43560\,V_m P_i\,\emptyset\,(1-S_{wi})}{Z_i R T_i}\right]\left[\dfrac{n_g}{n_g+n_o}\right] = 2620*0.8676 = 2400\,Mscf/ac.$

[3.12]

Total Reservoir Voidage: $V_g = \frac{G\,Z_t\,T_t\,F_s}{P_t\,T_s} = \frac{2400*10^3*1.078*700*15}{6290*520} = 8306\,cu.ft/day$

[3.13]

ii. Condensate Fluid Composition in the Separator at the Operating Pressure

Table 3.5 Gas Condensate Fluid Using Laboratory Sample Test Result

1	2	3	4	5	6	7	8
Condensate component	Gas component Mole	Liquid Component Mole	AGA Molar Weight lb/mole	(3) * (4) Separator Molar-wt lb/mole	Liquid Volume bbl/mole	(3) * (6) Separator Liquid-Wt bbl/mole	(2) * GLR Separator Gas-Oil Ratio Scf/bbl
CO_2	0.0017	0.0012	-	-	-	-	0.3914
C_1	0.8265	0.0992	16.04	1.5912	0.0540	0.0054	193.5663
C_2	0.0630	0.0340	30.07	1.0200	0.1030	0.0035	14.7546
C_3	0.0602	0.0893	44.49	3.9370	0.1524	0.0136	14.0988
iC_4	0.0134	0.0419	58.12	2.4350	0.1991	0.0083	3.1383
nC_4	0.0157	0.0679	58.12	3.9460	0.1990	0.0135	3.6769
iC_5	0.0040	0.0441	72.15	3.1820	0.2471	0.0109	0.9368
nC_5	0.0027	0.0420	72.15	3.0300	0.2470	0.0104	0.6323
C_6	0.0015	0.0656	86.17	5.6530	0.2951	0.0194	0.3513
C_{7+}	0.0012	0.5069	185	93.7700	0.6336	0.3212	0.2810
Others	0.0101	0.0079	-	-	-	-	2.3654
Total	1.00000	1.0000	-	118.5744		0.4052	234.1961

Source [Generated using Table 3.2]

9	10	11	12	13	14	15
(3) * n_L Liquid Fraction mole	(8) + (9) Gas Fraction Mole	(10) ÷ n_c Condensate Total Fluid composition Mole	From AGA Table Critical Pressure P_c, Psia	(11) * (12) Pseudo Critical Pressure P_{pc} Psia	From AGA Table Critical Temperature T_c, °R	(11) * (14) Pseudo Critical Temperature T_{pc} °R
0.0062	0.3944	0.0017	1070.2	1.82	547.5	0.93
0.2292	193.5663	0.8197	673.1	552.00	343.2	281.32
0.0785	14.7546	0.0627	708.3	44.41	549.9	34.48
0.2063	14.3051	0.0604	617.4	37.35	666.0	40.29
0.0968	3.1383	0.0136	529.1	7.25	734.6	10.06
0.1568	3.6789	0.0162	550.1	8.91	765.7	12.40
0.1019	0.9368	0.0044	484.0	2.13	829.6	3.65
0.0970	0.6323	0.0031	490.0	1.52	846.2	2.65
0.1515	0.3513	0.0021	440.0	0.92	914.2	1.92
0.1709	0.2810	0.0061	395.9	2.41	972.45	5.93
0.0148	2.3654	0.0100	3209.5	32.10	1165.2	11.77
2.3099	236.5000	1.0000	-	690.82	-	405.44

Source [Generated Using Table 3.2]:   M C_{7+} = 160 lb/lb.wt   &   Sp.Gr C_{7+} = 0.718

Estimation Procedures:

Column - (1): Gas component of the laboratory test results

Column - (2): Mole composition of the gas-phase from the test result

Column - (3): Mole composition of the liquid-phase from the test result

Column - (4): Molar weight from AGA-Table (standard gas table), lb/mole

Column - (5): Molecular weight of the separator liquid: $\sum[(3)*(4)] = 118.5734\,lb/mole$ [3.14]

Column - (6): Liquid component of the fluids: $n_L = \dfrac{(4) * M\,C_{7+}\,lb/bbl}{Sp.Gr\,C_{7+} * 350\,lb/mole} = bbl/mole$ [3.15]

Column - (7): Separator liquid specific weight: $\sum[(3) * (6)] = 0.4062\,lb/mole$ [3.16]

Column - (8): Recombination of Separator fluids for gas-liquid ratio (GLR)

$$GLR = R_g = \sum\left[(2) * \frac{Y_{gs}}{N_T\,B_{sep}\,V_m}\right] = 234.1961\,scf/bbl$$

[3.17]

Column - (9): Mole fraction of liquid component at separator pressure and $60°F$ (n_L)

$$n_L = \frac{350\,Y_0}{wt_{sep}} = \frac{350\,Y_J}{\sum(5)} = 2.31\,mole$$

[3.18]

Column - (10): Fluids (liquid and gas) mole: $n_f = \sum[(8) + (9)] = 236.6045\,mole$ [3.19]

Column - (11): Total mole composition of the well fluids: $n = \sum[(10) \div \sum(10)] = 1.00$ [3.20]

Column – (12): Critical pressure from AGA standard table: P_c [3.21]

Column – (13): Critical partial pressure: $P_{pc} - \sum[(11) * (12)] - 691.25\,psia$ [3.22]

Partial reduced pressure: $P_{pr} = \dfrac{P_i}{P_{pc}} = \dfrac{6290}{691.25} = 9.10$ [3.23]

Column – (14): Critical Temperature: from AGA standard table: T_c [3.24]

Column – (15): Critical partial Temperature: $T_{pc} = \sum[(11) * (14)] = 405.64°R$ [3.25]

Partial reduced Temperature: $T_{pr} = \dfrac{T_i}{T_{pc}} = \dfrac{700}{405.64} = 1.74$ [3.26]

Gas Compressibility factor: $Z_i = f(P_{pr}, T_{pr}) = f(9.10, 1.74)\,Using\,AGA\,Table = 1.078$ [3.27]

Initial total mole of fluids: $n_i = \dfrac{P_i V_i}{Z_i R T_i} = \dfrac{43560\,P_i\,\varnothing}{Z_i R T_i} = \dfrac{43560*6290*0.23}{1.078*10.73*700} = 7783\,mole/ac.ft$ [3.28]

Gas Mole Fraction: $\%n_g = \dfrac{R_g}{R_g + n_L} = \dfrac{n_g}{n_g + n_L} = \dfrac{n_f - n_L}{n_f} = \dfrac{236.6045 - 2.31}{236.5045} = 99.02\,\%$

[3.29]

Bulk Reservoir Rock: $G_b = \dfrac{\%n_g\,n_i\,V_m}{1000} = \dfrac{0.9902 * 7703 * 379.4}{1000} = 2900\,Mscf/ac.ft$

[3.30]

Daily gas condensate: $G_{p2} = \dfrac{Daily\,Separator\,Gas}{Gas\,Mole\,Fraction} = \dfrac{2640}{0.9902} = 2700\,Mscf/day$

[3.31]

Total Oil in condensate: $N_2 = \dfrac{42\,n_i(1 - n_g)}{5.615\,n_L\,B_{ol}} = \dfrac{7783 * 42 * (1 - 0.9902)}{2.31 * 1.275 * 5.615} = 248\,bbl/ac.ft$

[3.32]

Daily voidage at reservoir condition: $V_g = \dfrac{G_p\,Z_i\,T_i\,P_s}{P_i\,T_s} = \dfrac{2700 * 10^3 * 1.078 * 700 * 15}{6290 * 520} = 9344\,cu.ft/day$ [3.33]

iii. Volumetric Depletion Methods Using Gas Condensate Reservoir Laboratory Test Data

Table 3.6 Condensate Recovery per acre foot Using Gas Condensate Laboratory Test Data

1	2	3	4	5	6	7	8	9	10	11
			Residue Gas		Liquid Value		GLR	Recovery Factors		
Pressure Psia	ΔG_p Mscf	$\dfrac{\sum(\Delta G_p)}{2454}$ Mscf	ΔG_r Mscf	$\dfrac{\sum(\Delta G_r)}{2275}$ Mscf	ΔV_L bbl	$\dfrac{\sum(\Delta V_L)}{220.7}$ bbl	$\sum\dfrac{\Delta G_r}{\Delta V_L}$ Scf/bbl	$\dfrac{(3)}{G_p}$ $\%\Delta G_p$	$\dfrac{(5)}{G_r}$ $\%\Delta G_r$	$\dfrac{(7)}{V_L}$ $\%\Delta V_L$
$5412 P_d$	0.0	0.0	0.0	0.0	0.0	0.0	11,119	0.0	0.0	0.0

4700	37.30	37.30	34.13	34.13	3.02	3.02	12,809	1.52	1.50	1.37
400	74.36	111.66	69.38	103.51	5.76	8.78	13,815	4.55	4.55	3.95
3300	109.451	221.11	102.61	206.12	7.24	16.02	15,728	9.01	9.06	7.26
2600	35.95	358.28	124.67	330.79	7.10	23.12	19,633	14.60	14.54	10.47
1900	129.58	487.86	145.60	476.39	7.09	30.21	24,458	19.88	20.94	13.69
1400P_a	118.77	606.63	94.86	571.25	3.13	33.34	2833,34	24.72	25.11	15.06

Source [Generated using Tables 3.3 and 3.4]

At cell temp and pressure: $V_{HC} = V_a = V_i \, @ \, (1 - S_{wi}) = 43560 * 0.23 \, (1 - 0.11) = 8920 \; cu.ft/ac$ [3.34]

Bulk Gas-Condensate: $G_b = \dfrac{V_m P_i V_{HC}}{1000 \, Z_i R T_i} = \dfrac{379.4*6290*8920}{1000*1.078*10.73*700} = 2629 \; Mscf/ac.ft$ [3.35]

Recoverable Condensate: $G_p = \dfrac{V_m P_d V_{HC}}{1000 \, Z_i R T_i} = \dfrac{379.4*5412*8920}{1000*1.078*10.73*700} = 2262 \; Mscf/ac.ft$ [3.36]

Moles Liquid Condensate: $n_L = 25\% C_4 + 50\% C_5 + 75\% C_6 + 100 C_{7+} = 0.0609 \; moles$ [3.37]

Residual Gas: $G_r = G_p (1 - n_L) = 2262 * (1 - 0.0609) = 2275 \; Mscf/ac.ft$ [3.38]

Recoverable Liquid: $V_{L3} = \dfrac{\sum(wt \, n_L)}{42} = \dfrac{[25\% C_4 wt_4 + 50\% C_5 wt_5 + 75\% C_6 wt_6 + 100 C_{7+} wt_{7+}]}{42} = 207.2 bbl$ [3.39]

Gas-Liquid Ratio: $GLR = R_g = \dfrac{G_p}{V_L} = \dfrac{2454 * 10^8}{220.74} = 11,117.2 \; scf/bbl$ [3.40]

Daily Voidageout Replacement: $V_g = \dfrac{G_p Z_i P_s T_i}{P_i T_r} = \dfrac{2262*1.078*15*700}{6290*520} = 84,000 \; cu.ft/ac.ft$ [3.41]

Conventionally: $G_p = \dfrac{G_{p1} + G_{p2} + G_{p3}}{3} = 2454 \; \dfrac{Mscf}{ac}.ft$ and $V_L = \dfrac{V_{L1} + V_{L2} + V_{L3}}{3} = 220.74 bbl/ac.ft$ [3.42]

Gas-Liquid Ratio: $GLR = \dfrac{11582 + 10987 + 11117}{3} = 11,195 \; Mscf/bbl$ [3.43]

Column (2): $\Delta G_p = \dfrac{V_m P V_{gcel}}{1000 \, Z R T_i} = \dfrac{379.4*4700*143.69}{1000*0.941*10.73*700} = 37.30 \; Mscf$ [3.43]

Column (3): $\sum(2) = \sum_{P_a}^{P_d} \Delta G_p = 37.30 + \cdots +$ [3.44]

Column (4): $\Delta G_r = \Delta G_p [1 - n_L] = \Delta G_p [1 - (0.25 C_4 + 0.5 C_5 + 0.75 C_6 + C_{7+})] = 34.13$ [3.45]

Column (5): $\sum(4) = \Delta G_p [1 - n_L] = \dfrac{V_m P V_{gcel}}{1000 \, Z R T_i} [1 - (0.25 C_4 + 0.5 C_5 + 0.75 C_6 + C_{7+})]$ [3.46]

Column (6): $V_L = \dfrac{\Delta G_p}{42} [n_L * wt_i] = \dfrac{\Delta G_p}{42} \left[0.25 * 32 C_4 + 0.5 * 36.32 C_5 + 0.75 * 40.04 C_6 + \dfrac{1000 M C_{7+}}{V_m Z R T_i}\right]$

$\qquad = \dfrac{\Delta G_p}{42} \left[8 C_4 + 18.16 C_5 + 30.03 C_6 + \dfrac{1000 M C_{7+}}{V_m Z R Y_{C7+}}\right] = 2.83 \; bbl/ac.ft$ [3.47]

Column (7): $\sum(6) = \sum_{P_a}^{P_d} \Delta V_L = 2.83 + \cdots +$ [3.48]

Column (8): $GLR = (4) \div (6) = \dfrac{\Delta G_r}{\Delta V_L} = \dfrac{\Delta G_p [1 - (0.25 C_4 + 0.5 C_5 + 0.75 C_6 + C_{7+})]}{\dfrac{\Delta G_p}{42} \left[8 C_4 + 16.16 C_5 + 30.03 C_5 + \dfrac{1000 M C_{7+}}{V_m Z R Y_{C7+}}\right]}$

$\qquad = \dfrac{42 \, [1 - (0.25 C_4 + 0.5 C_5 + 0.75 C_6 + C_{7+})]}{\left[8 C_4 + 16.16 C_5 + 30.03 C_6 + \dfrac{1000 M C_{7+}}{V_m Z R Y_{C7+}}\right]};$ $\quad Note: Wt_{C7+} = \dfrac{M_{C7+}}{\dfrac{V_m}{1000} Z R V_{C7+}}$ [3.49]

Column (9): $E_{Gp} = \dfrac{\Delta G_p}{G_p} = \dfrac{(3)}{G_p} = 1.52$ [3.50]

Column (10): $E_{Gr} = \dfrac{\Delta G_r}{G_r} = \dfrac{(5)}{G_r} = 1.50$ [3.51]

Column (11): $E_{Vl} = \frac{\Delta V_L}{V_2} = \frac{(7)}{V_L} = 1.37$

[3.52]

Table 3.7 Cumulative Gas Condensate Depletion performance in the Reservoir

Pressure Psia	Deferential $\Delta P = P_d - P$ Psia	Fluids Recovery at a ΔP			Gas- Liquid Ratio Scf/bbl
		Gas %	Liquid %	Residual Gas % G_r	
5412 P_d	0.0	0.00	0.0	0.00	11,119
4700	712	1.50	1.37	1.52	12,809
4000	1412	4.55	3.95	4.55	13,815
3300	2112	9.06	7.26	9.01	15,728
2600	2812	14.54	10.47	14.60	19,633
1900	3512	20.94	13.69	19.68	24,458
1400 P_a	4012	25.11	15.06	24.72	28,725

Source [Generated using Tables 3.6]

Water Injection Techniques

Procedure

The principal method of postulating the evaluation models was based on ***Craze and Buckley (1945)*** [9], "Volumetric Material Balance Equation (MBE)" with no appreciable decline in pressure. This means that there is no retrograde condensation and the gas-liquid ratio remains fairly constant. The recovery will depend on injected water invasion factor (F), irreducible water saturation (S_{wi}) and gas residual saturation (S_{gr}). Since the gas formation volume factor $\left(B_{gi}\right)$ remains substantially constant, because the reservoir pressure would not decline, $B_{gi} - B_{g}$.

$$\begin{bmatrix} Gas\ Condensate \\ Recovery\ Factor \end{bmatrix} - \left[\begin{pmatrix} (Initial \\ Gas\ Condensate \end{pmatrix} - \begin{pmatrix} Gas Condensate \\ Left \end{pmatrix} \right] \begin{bmatrix} Invasion \\ Factor \end{bmatrix}$$

$$E_R = \left[\frac{(1 - S_{wi})B_{gi} - S_{gr}B_g}{(1 - S_{wi})B_{gi}} \right][F]$$

[3.53]

Since, $B_{gi} - B_g$: rearranging eqn3.53 and simplifying gives eqn3.54.

$$E_R = \frac{F B_{gi} (1 - S_{wi}) - S_{gr}B_{gi}}{B_{gi}(1 - S_{wi})} = F\left[1 - \frac{S_{gr}}{1 - S_{wi}}\right] = 0.8 * \left(1 - \frac{0.20}{10 - 0.11}\right) = 6$$

[3.54]

Table 3.8 Water at Dew-Point Pressure Application Results

S_{gr}	S_{wc}	Injected Water Invasion Factor F, %						
		0.4	0.5	0.6	0.7	0.8	0.9	1.0
15	11	33.3	41.6	49.9	58.2	66.5	74.8	83.2
	13	33.1	41.4	49.7	57.9	66.2	74.5	82.8
	15	32.9	41.2	49.4	57.7	65.9	74.1	82.4
20	11	31.0	38.8	46.5	54.3	62.0	69.8	77.5
	13	30.8	38.5	46.2	53.9	61.6	69.3	77.0
	15	30.6	38.2	45.9	53.5	61.2	68.8	76.5
25	11	28.8	36.0	43.2	50.3	57.5	64.7	71.9
	13	28.5	35.6	42.8	49.9	57.0	64.1	71.3
	15	28.2	35.3	42.4	49.4	56.5	63.5	70.6
30	11	26.5	33.2	39.8	46.4	53.0	59.7	66.3
	13	26.2	32.8	39.3	45.9	52.4	59.0	65.5
	15	25.9	32.4	38.8	45.3	51.8	58.2	64.7
35	11	24.3	30.3	36.4	42.5	48.5	54.6	60.7

	13	23.9	29.9	35.9	41.8	47.8	53.8	59.8
	15	23.5	29.4	35.3	41.2	47.1	52.9	58.8
40	11	22.0	27.5	33.0	38.5	44.0	49.6	55.1
	13	21.6	27.0	32.4	37.8	43.2	48.6	54.0
	15	21.2	26.5	31.8	37.1	42.4	47.7	52.9

Source: [Calculated using Eqn3.54 at variable residual water and gas]

Voidage out Replacement Modelling

$$\begin{bmatrix} Voidage\ Out \\ is\ the\ Total \\ Oil\ Produced \end{bmatrix} = \begin{bmatrix} Voidage\ In,\ the \\ Required\ Water \\ Replacement \end{bmatrix}$$

$$V_L = \frac{ZP_sT_iG_p}{T_sP_i} = \frac{0.02827ZT_iG_p}{P_i}, cu \qquad [3.55]$$

Results and Discussion

i. **Results**

Table 4.1 shows the evaluation models for initial fluids estimations. Table 4.2 shows the incremental recovery values evaluation models estimations. Table 4.3 Initial fluids estimated Using evaluation models on Table 4.1. Table 4.4 *compares fluids recovery in volumetric depletion and water-injection methods*. Conventional average values were considered to reduce percentage error.

Table 4.1 Gas Condensate evaluation models for Initial fluids Estimations

S/No.	Parameter	Gas-Condensate Evaluation Models
1.	**Bulk Gas - Condensate**	$G_b - \frac{V_m}{3}\left[\frac{354.56\,P_i\,\emptyset\,(1-S_{wi})}{Z_i\,R\,T_i} + \frac{n_g\,n_f}{1000}\right]$ and $Wt_{C7+} - \frac{1000\,M_{C7-}}{V_m\,Z\,R\,Y_{C7+}}$
2.		
3.	**Initial Gas**	$G = \frac{1}{3}\left[\frac{354560\,V_m\,n_g\,P_i\,\emptyset\,(1-S_{wi})}{Z_i\,R\,T_i\,(n_g+n_0)} + \frac{V_g}{n_g} + \frac{35.56\,V_m\,P_i\,\emptyset\,(1-S_{wi})}{Z_i\,R\,T_i}\right]$
4.	**Liquid (Oil)**	$V_l = \frac{1}{3}\left[\frac{43.56\,V_m\,V_{ot}\,P_i\,\emptyset\,(1-S_{wi})}{Z_i\,R\,T_i\,(V_{gs}+V_{gt})} + \frac{V_g}{n_g} + \left(8C_4 + 18.16C_5 + 30.03C_6 + \frac{1000M_{C7+}}{V_m\,Z\,R\,Y_{C7+}}\right)\right]$
	GLR and Voidage Out	Gas –Liquid Ratio: $GLR = \frac{G}{V_l}$ and $V_{out} = \frac{2.885\times10^{-7}\,G_p\,Z_i\,T_i}{P_i}$

Table 4.2 Evaluation Models for Incremental Recovery Values Estimations in Volumetric Depletion

No.	Parameters	Volumetric Depletion Recovery Models

1.	Incremental Gas	$\Delta G_p = \dfrac{V_m\, P\, V_{gcel}}{1000\, Z\, R\, T_i}$ at a given pressure
2.	Total Gas Sum-up	$\sum \Delta G_p = \sum\limits_{P_a}^{P_d}\left(\dfrac{V_m\, P\, V_{gcel}}{1000\, Z\, R\, T_i}\right)$
3.	Residue Gas Value	$\Delta G_r = \Delta G_p\left[1 - (0.25C_4 + 0.5C_5 + 0.75C_6 + C_{7+})\right]$
4.	Residue Gas Sum	$\sum \Delta G_r = \sum\limits_{P_c}^{P_c}\left(\dfrac{V_m\, P\, V_{gcel}}{1000\, Z\, R\, T_i}\left[1 - (0.25C_4 + 0.5C_5 + 0.75C_6 + C_{7+})\right]\right)$
5.	Incremental Liquid	$\Delta V_L = \dfrac{\Delta G_p}{42}\left[8C_4 + 18.16C_5 + 30.03C_6 + \dfrac{1000\, M\, C_{7+}}{V_m\, Z\, R\, Y_{C7+}}\right]$
6.	Liquid Recovered	$\sum \Delta V_L = \sum\limits_{P_a}^{P_d}\left(\dfrac{\Delta G_p}{42}\left[8C_4 + 18.16C_5 + 30.03C_6 + \dfrac{1000\, M\, C_{7+}}{V_m\, Z\, R\, Y_{C7+}}\right]\right)$
7.	Gas-Liquid Ratio	$GLR = \dfrac{42\left[1 - (0.25C_4 + 0.5C_5 + 0.75C_6 + C_{7+})\right]}{\left[8C_4 + 16.16C_5 + 30.03C_6 + \dfrac{1000\, M\, C_{7+}}{V_m\, Z\, R\, Y_{C7+}}\right]}$
8.	Gas Recovery Factor	$\% G_p = \dfrac{\sum\limits_{P_a}^{P_d}\Delta G_p}{G} = \dfrac{\sum\limits_{P_a}^{P_d}\left(\dfrac{V_m\, P\, V_{gcel}}{1000\, Z\, R\, T_i}\right)}{G}$
9.	Liquid Recovery Factor	$\% V_L = \dfrac{\sum\limits_{P_a}^{P_d}\Delta V_L}{V_L} = \dfrac{\sum\limits_{P_a}^{P_d}\left(\dfrac{\Delta G_p}{42}\left[8C_4 + 18.16C_5 + 30.03C_6 + \dfrac{1000\, M\, C_{7+}}{V_m\, Z\, R\, Y_{C7+}}\right]\right)}{V_L}$
10	Percentage residue Gas	$\% G_r = \dfrac{\sum\limits_{P_a}^{P_d}\Delta G_r}{G_r} = \dfrac{\sum\limits_{P_a}^{P_d}\left(\dfrac{V_m\, P\, V_{gcel}}{1000\, Z\, R\, T_i}\left[1 - (0.25C_4 + 0.5C_5 + 0.75C_6 + C_{7+})\right]\right)}{G_r}$

Table 4.3 Condensate Reservoir Initial Fluids Estimation Using Different Methods

Condensate	symbol	Theoretical Field Data	Separator Recombined	Laboratory Test Data	Average Data Considered
Bulk Volume	G_b	2620.00	2900	2629.00	2716.33
Recoverable	G				2454.00
Residue Gas	G_r	2400.00	2700	2262.00	2415.33
Liquid Value	V_L	2300.00	2671	2275.00	220.74
Gas-Liquid	GLR	207.03	248.00	207.20	11,153.33
Voidage Gas	V_g	11,593.00	10,887	10,980.00	8683.33
		8306.00	9344	8400.00	

Source [Generated Using Theoretical, Separator and Laboratory-Test Data]

Table 4.4 Comparing Fluids Recovery in Volumetric Depletion and Water-Injection Methods

Recovery Method 6290 – 1400 psia	Gas-Condensate M scf/ac.ft			Condensate Liquid bbl/ac.ft			Residue Gas M scf/ac.ft		
	G	G_p	$\% G_p$	N	N_p	$\% N_p$	G	G_r	$\% G_r$
Volumetric Depletion	2454	606.6	24.72	220.14	33.34	15.06	2415.33	571.3	25.11
Water-Injection	2454	1522	62.02	220.14	136.5	62.02	2415.33	1498	62.02

Source [generated from Table 4.4]
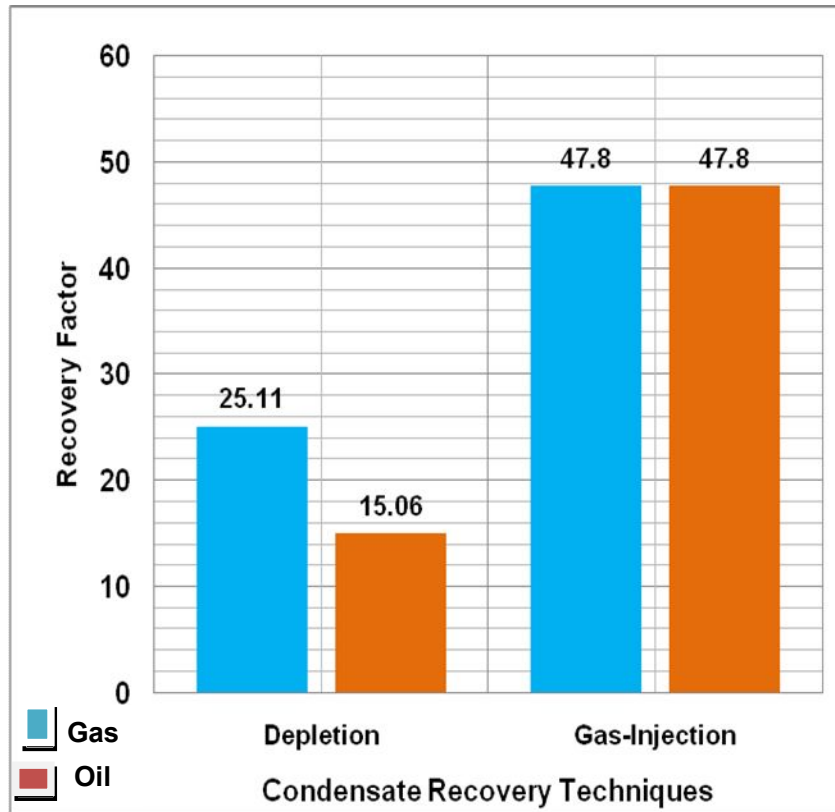
Fig 4.1 Estimated Recovery Factor of each Fluid in the Condensate

Source [**Generated using Tables 3.7**]

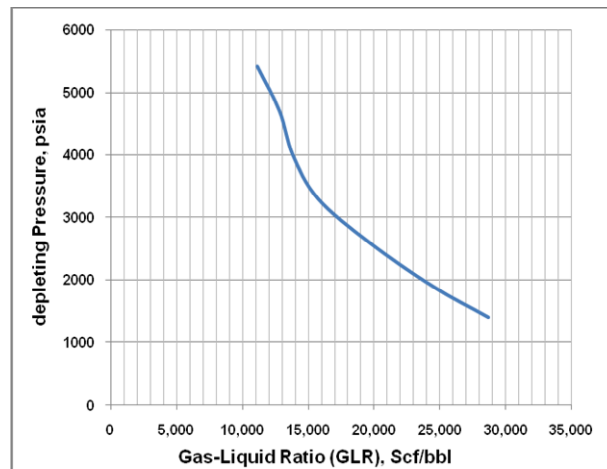|	
11,119	5412
12,809	4700
13,815	4000
15,728	3300
19,633	2600
24,458	1900
28,725	1400

Fig 4.2 Estimated Gas-Liquid Ratio in Volumetric depletion Method

DISCUSSION

Table 4.1 shows models for initial condensate in place estimation. The models were generated using theoretical, separator and laboratory-test data and conventional average equations were considered in order to reduce percentage error. Table 4.2 Shows Evaluation models to estimate gas-condensate recovery values and factors. Table 4.3 Shows results of gas-condensate reservoir initial fluids estimation using theoretical, separator and Laboratory-test data. Here it was observed that the bulk condensate initially in place would be best estimated using theoretical and Laboratory-test data

only, because the separator data showed high percentage error. It could be due to unaccounted for particulate and shrinkage factor of the separator fluids, in the volumetric Material Balance Equation (MBE) used. Table 4.4 Compared recovery values and factors in volumetric depletion and water injection techniques. It was found out that gas-condensate recovery factor using water injection as pressure maintenance was 62.02% for both fluids and much higher than using volumetric depletion method which with recovery factors: 25.11% for gas and 15.06% for oil. Figure 4.1 is the graphical representation of the fluids recovery factor from the dew-point pressure (P_d) to the abandonment pressure (P_a). Figure 4.2 is a graphical representation of the GLR behavior with the deferential pressure.

CONCLUSION AND RECOMMENDATIONS

a. Conclusion

Water injection technique has higher recovery factor (62.02% for both oil and gas) than volumetric depletion technique with recovery factors of 25.11% for gas and 15.06% for oil. This was possible because the reservoir pressure was maintained through voidage out replacement using water injection technique. Water-injection favours condensate recovery with good injected water invasion factor, displacement and sweep efficiencies. The disadvantages in water injection technique include: The cost of water treatment, additional wells, compressors and distribution systems which would be needed in the injection and liquid recovery plants. Volumetric depletion from initial or dew-point pressure to abandonment had lower recovery factor, because the reservoir pressure was not maintained. Normally when pressure is not maintained, retrograde condensation of heavier hydrocarbons establishes itself as the flowing fluid-stream approaches the wellbore. Retrograde liquid is less mobile due to high viscosity and gravity effects. Improving recovery factor in a gas-condensate reservoir depends on the techniques the Operator used.

b. Recommendations

These comparison evaluation models should be put in a computer program (as a simulator) for fast evaluation of gas-condensate reservoirs fluids and accurate recovery estimation.

Water injection is recommended here since it has higher recovery factor than volumetric-depletion method.

ii. Particulates (water and sand particles in the samples) and acid gases should not be omitted from the composition, this insures correct recovery history. It might have been the case in the separator values

iii. Gas condensate reservoir performances prediction should be backed-up with the available laboratory data. This improves initial reserve values estimation.

Volumetric depletion method should be considered only if there are no other options,

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