

COMPARATIVE STUDY OF GAS AND WATER INJECTIONS AT DEW-POINT PRESSURE METHODS TO IMPROVE CONDENSATE' RECOVERY

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Abstract— Water and gas injection techniques were compared, gearing towards improving oil recovery factor in Gas-Condensate Reservoirs. The primary input data of the model 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 uniformity factor (E_R), displacement (E_D) and sweep (E_{sweep}) efficiencies, injected fluid invasion factor (F) and laboratory test data of the field of study. The condensable hydrocarbons recovery modeling using water-injection and gas-injection 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 in gas-injection method under similar conditions. This advantage was attributed better pressure maintenance by water than gas injection. More so, some of the injected gas was produced, some zone into shrink gas-cap and some initial zones been displaced by gas.

Index Terms— Condensate Recovery (Liquid and Gas), Water and Gas Injections, 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/distillate) is condensed at the surface separator. [Allen, 1950]^[1]

Water or gas injection at dew-point pressure is a reservoir pressure maintenance agent used to control fluid recovery efficiency in a gas condensate reservoir. The other functions 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 condensate fluids recovery in water injection to gas injection technique. The specific objective is to develop mathematical models for studying and improving oil recovery factor in gas condensate reservoir, at reduced cost. The models gear towards maximizing pressure maintenance in any gas condensate reservoir and avoid retrograde condensation, 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

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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 a condensate reservoir, invasion factor of the injected fluid, permeability uniformity/efficiency of the reservoir and displacement efficiency of the fluid 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] worke compared the predicted and the actual production histories of volumetric gas-condensate reservoir and found out that retrograde condensate reservoirs with high initial gas-oil ratios produce higher condensate at lower pressure than the theoretical calculations based 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 study.

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:
$$E_R = \frac{(1 - S_{wi})E_{gi} - S_{gr}E_g}{(1 - S_{wi})E_{gi}} \quad [2.1]$$

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 1.1 below shows his (Eilerts) experimental result of the gas-oil ratio in the 3-fields and table 1.2 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 1.1 Phase Relation to Gas-Oil Ratios in 3 Fields

LGR	GOR	Fields		% of
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GPM,SCF	MScf/bbl	A	B	C	Total	Total
< 0.4	≥ 105	38	12	7	57	31.10
0.4 - 0.8	52.5 – 1.05	33	18	4	55	32.00
0.8 – 1.2	35.0 – 52.5	12	15	5	32	18.60
1.2 – 1.6	26.2 – 35.0	1	8	1	10	5.80
1.6 - 2.0	21.0 – 26.2	1	3	1	5	3.90
> 2.0	< 21.0	2	5	6	13	7.60
Total		87	61	24	172	100

Table 1.2 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	1.80
0.4 - 0.8	40 – 45	4	2	0	6	3.60
0.8 – 1.2	45 – 50	12	12	0	24	14.60
1.2 – 1.6	50 – 55	24	17	7	47	28.50
1.6 - 2.0	55 – 60	19	13	12	49	29.70
> 2.0	60 - 68	23	8	3	30	18.20
	> 68	3	1	2	6	3.60
Total		87	54	24	165	100

3. Materials and Methods

a. Materials

The materials used in this research were collected from the 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 history of the field and laboratory test data. Table 3.2 shows the gas condensate fluid recovery data. Table 3.3 shows the field and laboratory fluids test composition of the gas-condensate reservoir and Table 3.4 shows field and laboratory test data (oil and gas) volume increments and the corresponding gas deviation factors.

Table 3.1 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_r , °F	240
Connate Water Saturation	S_{wi} , %	11
Average Porosity	ϕ , %	23
Daily Tank Oil	V_{ot} , bbl/d	220
Stock Tank Oil	V_{st} , stb/d	24.06
Oil Gravity	Y_o , °API	46.8
Daily Separator Gas	V_{gs} , Mscf	2640
Separator Gas Gravity	Y_{gt} , Mscf	0.716
Daily Tank Gas	Y_g	144
Tank Gas Gravity	T_{sep} , °F	1.30
Separator Temperature	P_{sep} , psia	83
Separator Pressure	T_{sep} , °F	25
Standard Temperature	V_{cell} , cu. cm	60
Standard Pressure	GLR , scf/bbl	15
Initial Cell Volume	V_m , cu. ft/mole	1000
Gas-Liquid Ratio	B_{so} , bbl/stb	7890
	M_{C7+} , lb/lb. wt	379.4
	Y_{C7+}	1.275
	S_{gr} , %	
	Tables 3.2, 3.3 & 3.4	

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Molar Volume (constant)		
Separator Liquid Volume Factor		160
Molar of C_{7+} in initial Fluid		
Sp.Gr of C_{7+} in Separator Liquid		0.718
Residual Gas Saturation		20
Gas Composition/Liquid Volume		-

Table 3.2 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	-

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 Estimated based on the following procedures:

- i. Liquid recovery factors of condensable components were assumed, 25% C_4 , 50% C_5 , 75% C_6 and 100% $C_7 +$
- ii. Total pay-zone area, A: assumed = a = 1 acre.foot. This can be integrated into the entire reservoir area.
- iii. Average pressure of the operating separators was estimated and used
- iv. The stock tank vapour at main high pressure separators was estimated and used
- v. The average gas gravity was estimated and used in this calculation
- vi. The gas deviation factor, Z was estimated from the combined gravity of oil and gas
- vii. The reservoir pressure ($P_i = 6290psia$) was above the dew-point pressure ($P_d = 5412psia$).
- viii. The field and laboratory test estimated displacement efficiency, permeability uniformity factor and sweep efficiency was 80% in each case.
- ix. In a pressure maintenance recovery, there is no retrograde condensation, so the gas-oil ratio remains fairly constant. The recovery depends on connate water (S_{wi}) expansion, residual gas saturation (S_{gr}) and injected water invasion fraction (F). Since the gas formation volume factor (B_{gi} scf/cu.ft) remains substantially constant, because the reservoir pressure would not decline, $B_{gi} = B_g$.

x.

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:

$$GLR = \frac{1000 (V_{gs} + V_{gt})}{V_{or}} = \frac{1000(2640+144)}{220} =$$

12,655scf/bbl

[3.1]

Average Fluids Gravity:

$$Y_{avg} = \frac{V_{gs} Y_{gs} + V_{gt} Y_{gt}}{V_{gs} + V_{gt}} = \frac{2640 \times 0.716 + 144 \times 1.30}{2640 + 144} = 0.7462$$

[3.2]

Oil Gravity: $Y_o = \frac{141.5}{API + 131.5} = \frac{141.5}{48.6 - 131.5} = 0.7857$ [3.3]

Tank Oil Molecular Weight: $M_o = \frac{6084}{API - Y_o} = \frac{6084}{48.6 - 5.9} = 142.5 \text{ lb.wt}$ [3.4]

Well Fluid Gravity:

$$Y_f = \frac{V_{gs} Y_{gs} + V_{gt} Y_{gt}}{R_g + \frac{132800 Y_o}{M_o}} = \frac{132800 \times 0.7462 + 2640 \times 0.7857}{7890 + \frac{132800 \times 0.7857}{142.5}} = 0.9234$$

[3.5]

Gas Deviation Factor:

$$Z_i = f(P_{pr}, T_{pr}) = f\left(\frac{P_i}{P_{pc}}, \frac{T_i}{T_{pc}}\right) \text{ Using AGA Table}$$

[3.6]

Where:

$$P_{pc} = f(Y_f) = f(0.9234) = 665 \text{ psia} \quad \& \quad P_i = 6290 \text{ psia}$$

implying that condensate

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

Bulk Reservoir Rock:

$$G_b = \frac{43560 V_m P_i \phi (1 - S_{wi})}{Z_i R T_i} = \frac{43560 \times 379.4 \times 6290 \times 0.23 \times (1 - 0.11)}{1.078 \times 10.73 \times 700} = 2620 \text{ Mscf/ac.ft}$$

[3.7]

Liquid (Oil): $V_L = \frac{G}{CLR} = \frac{2620000}{12655} = 207.03 \text{ bbl/ac.ft}$ [3.8]

Condensate (Oil and Gas) Volume Fraction in moles:

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

Liquid Phase moles: $n_o = \frac{350 Y_o}{M_o} = \frac{350 \times 0.7857}{142.5} = 1.93$ moles [3.10]

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

Recoverable Gas:

$$C_{p1} - C_o f_g - \left[\frac{43560 V_m P_i \phi (1 - S_{wi})}{Z_i R T_i} \right] \left[\frac{n_g}{n_g + n_o} \right] - 2620 = 0.8676 = 2400 \text{ Mscf/ac.}$$

[3.12]

Total Reservoir Voidage:

$$V_g = \frac{C Z_i T_i P_g}{P_i T_g} = \frac{2400 \times 10^3 \times 1.078 \times 700 \times 15}{6290 \times 520} = 8306 \text{ cu.ft/day}$$

[3.13]

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

Table 3.3 Gas Condensate Fluid Using Laboratory Sample Test Result

1	2	3	4	5	6	7	8
Condensate	Gas componen	Liquid Compone	AGA Molar Weight	(3) * (4) Separato r	Liquid Volume	(3) * (6) Separato r	(2) * GLR Separator Gas-Oil

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componen t	t Mole	nt Mole	lb/mole	Molar-wt lb/mole	bbl/mole	Liquid- Wt bbl/mole	Ratio Scf/bbl
CO₂	0.0017	0.0012	-	-	-	-	0.3914
C₁	0.8265	0.0992	16.04	1.5912	0.0540	0.0054	193.5663
C₂	0.0630	0.0340	30.07	1.0200	0.1030	0.0035	14.7546
C₃	0.0602	0.0893	44.49	3.9370	0.1524	0.0136	14.0988
iC₄	0.0134	0.0419	58.12	2.4350	0.1991	0.0083	3.1383
nC₄	0.0157	0.0679	58.12	3.9460	0.1990	0.0135	3.6769
iC₅	0.0040	0.0441	72.15	3.1820	0.2471	0.0109	0.9368
nC₅	0.0027	0.0420	72.15	3.0300	0.2470	0.0104	0.6323
C₆	0.0015	0.0656	86.17	5.6530	0.2951	0.0194	0.3513
C₇₊	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	(8) + (9)	(10) : n_D 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]: $M_{C_{7+}} = 160 \text{ lb/lb.wt}$ & $Sp.Gr_{C_{7+}} = 0.718$

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: $\sum[(3) * (4)] = 118.5734 \text{ lb/mole}$ [3.14]

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

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

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

[3.18]

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

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

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

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

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

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

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

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

$n_i = \frac{P_i V_i}{Z_i R T_i} = \frac{43560 P_i \emptyset}{Z_i R T_i} = \frac{43560 * 6290 * 0.23}{1.078 * 10.73 * 700} =$
 7783 mole/ac.ft [3.28]

Gas Mole Fraction:

$\%n_g = \frac{R_g}{R_g + n_L} = \frac{n_g}{n_g + n_L} = \frac{n_f - n_L}{n_f} =$
 $\frac{236.6045 - 2.31}{236.6045} = 99.02 \%$ [3.29]

Bulk

Reservoir

Rock:

$G_b = \frac{\%n_g n_i V_m}{1000} = \frac{0.9902 * 7783 * 379.4}{1000} =$
 2900 Mscf/ac.ft [3.30]

Daily

gas

condensate:

$G_{p2} = \frac{\text{Daily Separator Gas}}{\text{Gas Mole Fraction}} = \frac{2640}{0.9902} = 2700 \text{ Mscf/}$
 day [3.31]

Total Oil in condensate: $N_2 = \frac{n_i(1 - n_g)}{n_L B_{oi}} = \frac{7783 * (1 - 0.9902) * 42}{2.31 * 1.275 * 5.615} = 248 \text{ bbl/ac.ft}$ [3.32]

Daily voidage at reservoir condition:

$V_g = \frac{G_p Z_i T_i P_s}{P_i T_s} = \frac{2700 * 10^3 * 1.078 * 700 * 15}{6290 * 520} = 9344 \text{ cu.ft/}$
 day [3.33]

Conventionally:

$G_p = \frac{G_{p1} + G_{p2} + G_{p3}}{3} = 2454 \frac{\text{Mscf}}{\text{ac}} \cdot \text{ft}$ and $V_L =$
 $\frac{V_{L1} + V_{L2} + V_{L3}}{3} = 220.74 \text{ bbl/ac.ft}$ [3.34]

Gas-Liquid Ratio: $GLR = \frac{11532 + 10887 + 11117}{3} = 11,195 \text{ Mscf/bbl}$ [3.35]

Gas Injection Techniques Procedure

The principal factors considered in this gas injection or recycling methods are displacement efficiency stratification permeability and sweep efficiency of 80% each

$[\text{Recovery}] = [\text{Displacement}] [\text{Permeability}] [\text{Sweep}]$
 $[\text{Efficiency}] = [\text{Efficiency}] [\text{Efficiency}] [\text{Efficiency}]$

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$$E_R = E_D * E_K * E_{swp} = 0.8 * 0.8 * 0.8 = 0.51$$

2 [3.36]

Using the general material balance equation, MBE by *Eilert, (1957)*

$$[Bulk\ Condensate\ in\ the\ Reservoir] = [Total\ Condensate\ Recovery] - [Total\ Water\ Enchroachment] + [Total\ Water\ Production]$$

$$G_p B_{gi} = G (B_g - B_{gi}) + W_e + W_p \Rightarrow G = \frac{G_p B_g - 5.615 (W_e - W_p)}{B_g - B_{gi}}$$

[3.37]

In gas-recycling or injection operations, there is no water influx and water was not produced here, meaning that: $W_e = W_p = 0$, substituting these (W_e and W_p) into eqn3.37 and rearranging, it generated eqn3.38

$$G_b = \frac{G_p B_g}{B_g - B_{gi}} = \frac{V_m}{3} \left[\frac{35456 P_i \phi (1 - S_{wi})}{Z_i R T_i} + \frac{n_g n_f}{1000} \right] = 2629 Mscf/ac. ft$$

[3.38]

$$G = \frac{(G_{p1} + G_{p2} + G_{p3})}{n} = \frac{1}{3} \left[\frac{354560 V_m n_g P_i \phi (1 - S_{wi})}{Z_i R T_i (n_g + n_0)} + \frac{V_g}{n_g} + \frac{35.56 V_m P_i \phi (1 - S_{wi})}{Z_i R T_i} \right] = 2454 Mscf/ac. ft$$

[3.39]

$$\%G_p = \%N_p = \frac{G E_R}{G_b} = \frac{G E_D E_K E_{swp}}{G_b} = \frac{51.2 * 2454}{2629} = 47.79 \%$$

[3.40]

Daily Voidage out Replacement:

$$V_g = \frac{G_p Z_i P_i T_i}{P_i T_s} = \frac{2454 * 1078 * 15 * 700}{6290 * 520} = 84.924 cu. ft/ac. ft$$

[3.41]

Water Injection Techniques Procedure

The principal method of postulating the evaluation model equations was based on *Craze and Buckley (1945)*, "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 (S_{wi}) and gas (S_{gr}) saturations. Since the gas formation volume factor (B_{gi}) remains substantially constant, because the reservoir pressure does not decline, $B_{gi} = B_g$.

$$[Gas\ Condensate\ Recovery] = \left[\left(\frac{Initial\ Gas\ Condensate}{Gas\ Condensate\ Left} \right) - \left(\frac{Gas\ Condensate\ Left}{Gas\ Condensate\ Left} \right) \right] [Invasion\ Factor]$$

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

[3.42]

Since, $B_{gi} = B_g$, rearranging eqn3.45 and simplifying gives eqn3.47.

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

$$0.8 * \left(1 - \frac{0.20}{1 - 0.11} \right) = 62.02$$

[3.43]

Voidage out Replacement Modelling

[Voidage Out is the Total Oil Produced] = [Voidage In, the Required Water Replacement]

$$V_L = \frac{Z P_s T_i G_p}{T_s P_i} = \frac{0.02827 Z T_i G_p}{P_i}, \text{ cu. ft/ d}$$

[3.44]

Table 3.4 Water at Dew-Point Pressure Application Results

S_{gr}	S_{we}	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 Eqn4 and the Prosy Model]

4. Results and Discussion

i. Results: Table 4.1 shows the **confirmed** evaluation models for initial fluids estimations and conventionally, average values were considered to reduce percentage error. Table 4.2 shows the **confirmed** evaluation models for recovery factors estimations. Table 4.3 Estimated results

Table 4.1 Gas Condensate Confirmed evaluation models for Initial fluids Estimations

S/No	Parameter	Gas-Condensate Evaluation Models
1.	Bulk Gas - Condensate	$G_b = \frac{V_m}{3} \left[\frac{354.56 P_i \phi (1 - S_{wi})}{Z_i R T_i} + \frac{n_g n_f}{1000} \right]$ and $Wt_{C7+} = \frac{1000 M_{C7+}}{V_m Z R Y_{C7+}}$
2.		
3.	Initial Gas	$G = \frac{1}{3} \left[\frac{354560 V_m n_g P_i \phi (1 - S_{wi})}{Z_i R T_i (n_g + n_0)} + \frac{V_g}{n_g} + \frac{35.56 V_m P_d \phi (1 - S_{wi})}{Z_i R T_i} \right]$
4.		
	Initial Liquid	

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(Oil)	$V_L = \frac{1}{3} \left[\frac{43.56 V_m V_{or} P_i \phi (1 - S_{wi})}{Z_i R T_i (V_{gs} + V_{gt})} + \frac{V_g}{n_g} + \left(8C_4 + 18.16C_2 + 30.03C_6 - \frac{1000M_{C7+}}{V_m Z R Y_{C7+}} \right) \right]$
GLR and Voidage Out	Gas-Liquid Ratio: $GLR = \frac{G}{V_r}$ and $V_{out} = \frac{2.885 \cdot 10^{-2} G_p Z_i T_i}{P_i}$

Table 4.2 Confirmed Fluids Recovery Factors Models in Gas and water injection

Eqns	Evaluation Modes	Remarks	
3.40	$\%G_p = \%N_p = \frac{G E_D E_R E_{swp}}{G_b}$	Gas Injection Model Water Injection Model Voidage Out Replacement	Liquid Recovery Factors for both gas and water injection methods are effective at dew-point Pressure Daily Volume of Gas or Water to be Injected (cu.ft/d)
3.43	$E_R = F \left[1 - \frac{S_{gr}}{1 - S_{wc}} \right]$		
3.44	$V_{out} = \frac{2.827 * 10^{-2} Z_i T_i G_p}{P_i}$		

Table 4.3 Comparing Depletion and Gas-Injection Methods in Fluids Recovery and Factors

Condition: $P_d = 5412 \text{ psia}$ $F = 80\%$	Gas-Condensate $M \text{ scf/ac. ft}$			Condensate Liquid $bbl/ac. ft$			Residue Gas $M \text{ scf/ac. ft}$		
	G	G_p	$\% G_p$	N	N_p	$\% N_p$	G	G_r	$\% G_r$
Gas-Injection	2454	1173.0	47.80	220.14	105.2	47.80	2415.33	1154.5	47.80
Water Injection	2454	1522	62.02	220.14	136.4	62.02	2415.33	1497.99	62.02

Source [Generated using values on Table 4.3]

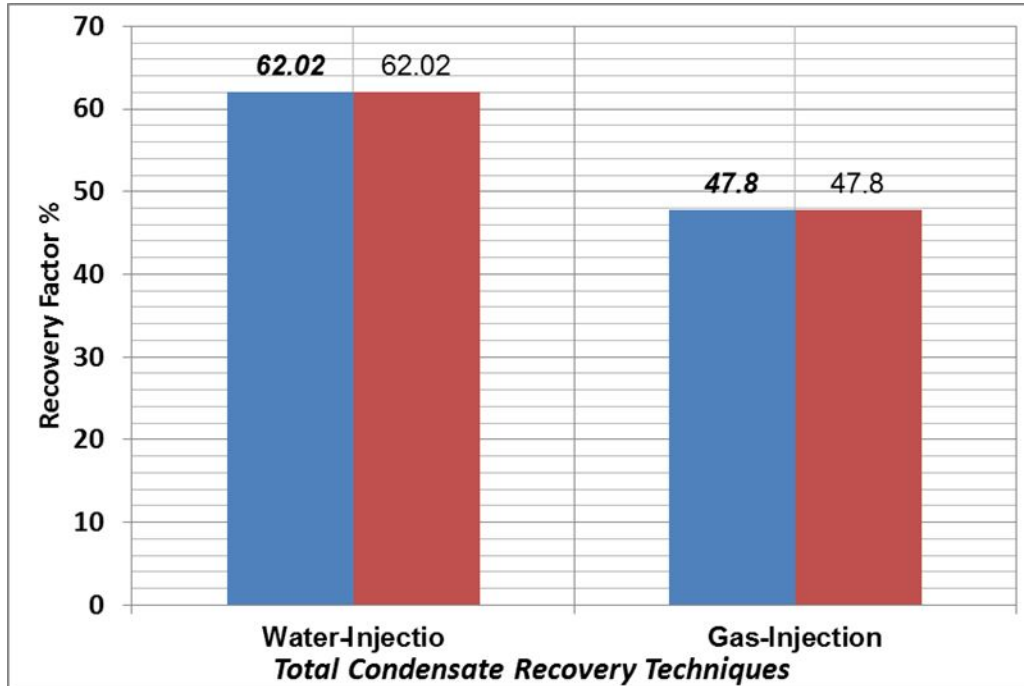


Fig 4.1 Estimated Gas-Liquid Ratio in Volumetric depletion Method

DISCUSSION

Table 4.1 shows models for estimation of initial condensate in place. 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 Compared recovery

values and factors in water and gas injection techniques. It was found that fluids recovery factor in water injection was higher than in gas injection. The higher recovery factor in water injection was due to better pressure maintenance (62.02% against 47.8%). Figure 4.1 is the graphical representation of the fluids recovery factor of water and gas at dew-point pressure (P_d).

CONCLUSION AND RECOMMENDATIONS

a. Conclusion

The recovery factor in water-injection technique was found to be 62.02% and was higher than 47.80% in gas-injection technique. This was possible because the reservoir pressure was fully maintained through voidage out replacement in water-injection, but fairly maintained in gas-injection technique. It means that Water-injection can favour condensate recovery in a good injected water invasion factor, displacement and sweep efficiencies than gas-injection at similar conditions, so has little or no retrograde condensation. Normally when pressure is not maintained, retrograde condensation of heavier hydrocarbons would be established as the flowing fluid-stream approaches the wellbore. More so, retrograde liquid is less mobile due to high viscosity and gravity effects. Generally pressure maintenance in gas condensate reservoir requires additional cost, since more wells, compressors and distribution systems would be needed in the injection and liquid recovery plants. In addition, gas injection technique has: high cost of re-cycling and deferred income from the sale of gas. Improving recovery factor in a gas-condensate reservoir depends on the techniques used by the operator.

b.Recommendations

- i. Water- injection method is recommended here since it has higher recovery factor than gas-injection 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. Higher values of the separator are attributed to that.

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

Water injection is recommended here, because it is cheap, a good pressure maintenance agent and has high displacement efficiency with high recovery factor than gas-injection.

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