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# Improving Condensate Recovery Using Water Injection Model at Dew-Point Pressure

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***Abstract: -*** Mathematical model equation was successfully developed for improving oil recovery in Gas-Condensate Reservoirs. The condensable hydrocarbons recovery modelling using water injection at dew-point pressure was developed based on traditional simulation and can be used in condensable hydrocarbons recovery evaluations. The primary input data of the model are injected water invasion factor and permeability uniformity factor of the reservoir. The techniques for monitoring proper pressure maintenance were also developed using daily reservoir voidage out replacement by the injected water volume. The estimated cumulative liquid (oil) recovery was high and encouraging. The recovery factor (percentage oil recovery value) ranges from 62 to 76% for 80% water invasion factor and uniformity factor.

***Keywords:-*** *Gas-Condensate, Condensate-Liquid (Oil) Water-Injection, Dew-point Pressure, Invasion-Factor, Molar Volume and Voidage-Out Replacement*

## I. INTRODUCTION

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, et al, 1950***]

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 oil to be recovered depends on the quantity of the injected water invasion. The water invasion value depends on the void spaces in a reservoir to be replaced as a displacing agent. Water injection at dew-point pressure gears towards an overall recovery factor of 0.62 to 0.76. The control or dependant parameters are rock permeability uniformity, displacement and injected-water invasion/swept efficiencies. The high recovery value is due to better pressure maintenance by the injected water and vapour condensation at the dew-point pressure. 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]***

## II. SIMULATION & MODELLING IN GAS-CONDENSATE

The objective of this work is to develop models equations for studying and improving oil recovery factor in gas condensate reservoir, at reduced cost. The models would assist us to maximize 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 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 - Invasion factor of the injected fluid
- Permeability uniformity/efficiency of the reservoir - Displacement efficiency of each fluid used

**Standing, (1952)** 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 ($\mathbf{C}^{7+}$) composition changes could affect the calculation.

***Rodger et al, (1957)*** 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. This would improve the overall accuracy of the calculation.

***Jacoby et al (1958)*** 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 Hawkin, (1958)*** 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, et al (1950)*** 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 produce higher condensate at lower pressure than the theoretical calculations based equilibrium ratios techniques only. They suggested 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)*** 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:

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

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

***Eilerts, (1957),*** 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 below shows his (Eilerts) experimental result of the gas-oil ratio in the 3-fields and table 2 shows the phase relation to tank oil gravity.

**Table 1 Phase Relation to Gas-Oil Ratios in 3 Fields**

| LGR GPM.SCF | GOR MScf/bbl | Fields A | Fields B | Fields C | Total | % of 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 2 Phase Relation to Tank Oil Gravities in 3 Fields**

| LGR GPM.SCF | Gravity API | Fields A | Fields B | Fields C | Total | % of Total |
|---|---|---|---|---|---|---|
| | < 40 | 2 | 1 | 0 | 3 | 1.80 |
| | 40 – 45 | 4 | 2 | 0 | 6 | 3.60 |
| | 45 – 50 | 12 | 12 | 0 | 24 | 14.60 |
| | 50 – 55 | 24 | 17 | 7 | 47 | 28.50 |
| | 55 – 60 | 19 | 13 | 12 | 49 | 29.70 |
| | 60 - 68 | 23 | 8 | 3 | 30 | 18.20 |
| | > 68 | 3 | 1 | 2 | 6 | 3.60 |
| Total | | 87 | 54 | 24 | 165 | 100 |

## III. RESEARCH METHODOLOGY

### *a. Models Development Procedure*

**The** principal method of postulating the evaluation model equations was based on Craze and Buckley volumetric Material Balance Equation (MBE) with no appreciable decline in pressure and the injected water invasion factor (F).

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

$$E_R = \left[\frac{(1 - S_{wi})B_{gi} - S_{gr}B_g}{(1 - S_{wi})B_{gi}}\right][F] \qquad 2$$

***Assumptions:***

For good accuracy the gas volume was collected based on the following assumptions.

i. Liquid recovery factor to be 25%$C_4$, 50%$C_5$, 75%$C_6$ and 100%$C_{7+}$
ii. Total area of the pay zone = a 1ac.ft. It can be integrated into any area
iii. Average pressure of all the separators was used
iv. Average gas gravity was used in this calculation
v. The gas deviation factor (Z) was estimated from the combined oil and gas gravity
vi. The reservoir pressure was above the dew-point pressure. This indicates that there was little or no oil-zone under it
vii. Field and laboratory estimated (displacement, permeability uniformity and sweep) efficiency was 80% each.

viii. 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 ($\boldsymbol{B_{gi}}$**scf/cu.ft**) remains substantially constant, because the reservoir pressure does not decline, $\boldsymbol{B_{gi} = B_g}$**.** Substituting this into model equation eqn2 and multiply by the water invasion factor gives eqn3, the evaluation model equation.

$$E_R = \frac{F(1 - S_{wi} - S_{gr})}{1 - S_{wi}} \quad \mathbf{3}$$

Simplifying eqn3 gives eqn4, the evaluation model equation.

$$E_R = F\left[1 - \frac{S_{gr}}{1 - S_{wc}}\right] \quad 4$$

***Laboratory Test Data Validation Models***

$$GLR = 1000(V_{gs} + V_{gt}) \quad 5$$

$$\gamma_{avg} = \frac{V_{gs}\gamma_{gs} + V_{gt}\gamma_{gt}}{V_{gs} + V_{gt}} \quad 6$$

$$\gamma_o = \frac{141.5}{API + 131.5} \quad 7$$

$$\gamma_f = \frac{R_g\gamma_{avg} + V_{gs}\gamma_o}{R_g + \frac{132800\gamma_o}{M_o}} \quad \mathbf{8}$$

$$M_o = \frac{44.21\gamma_0}{1.03 - \gamma_0} = \frac{6084}{API - 5.9} \quad \mathbf{9}$$

$$Z = f(P_{Pr}, T_{Pr}) = f\left(\frac{P}{P_{PC}}, \frac{T}{T_{PC}}\right) \quad 10$$

$$P_{PC} = f(\gamma_f) \; \& \; T_{PC} = f(\gamma_f) \quad 11$$

$$G_b = \frac{43560\, V_m P_i\, \emptyset\, (1 - S_{wc})}{Z\ R\ T} \quad 12$$

- $V_m = molar\ Volume = 379.4\ constant$

$$n_g = \frac{V_{gs} + V_{gt}}{V_{ot}} \quad \& \quad n_0 = \frac{350\,\gamma_g}{M_0} \quad 13$$

$$S_{gr} = 1 - S_o - S_w \quad 14$$

$$f_g = \frac{n_g}{n_g + n_0} = \frac{R_g/V_m}{\frac{R_g}{V_m} + \frac{350\gamma_g}{M_0}} \quad 15$$

$$G_P = G_b\, f_g,\ Mscf/ac.ft \quad 16$$

$$N_P = \frac{G_P}{R_g},\ bbl/ac.ft \quad 17$$

***Voidage out Replacement Modelling***

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

$$V_0 = \frac{ZP_sT_iG_p}{T_sP_i} = \frac{0.02827ZT_iG_p}{P_i},\ cu.ft/d \quad 18$$

*b.* ***Evaluated Model Equations Applications***

This model was applied on 121 samples data from 3 wells with connate waster saturation ($\boldsymbol{S_{wc}}$) reduced from 100% $to$ $\mathbf{11, 13}$ & 15% residual gas saturation ($\boldsymbol{S_{gr}\ of}$ $\mathbf{15, 20, 25, 30, 35}$ & 40%). The results showed that the liquid (oil) recovery increases with the injected water invasion factor and the quantity recovered depends on the residual gas saturation. The lower the residual gas saturation, the higher the recovery factor and the higher the injected water invasion factor the higher recovery factor. Table 4.3 shows this application results.

## IV. RESULTS AND DISCUSSION

***Results***

Table 4.1 shows the confirmed water injection for reservoir pressure maintenance evaluation models. Table 4.2 shows the laboratory test data validation models for business viability and recovery management. Fig 4.1 shows Recovery Factor based on the Injected Water invasion

*Table 3 Liquid Recovery using water injection models*

| Eqns | *Evaluation Model Equations* | Remarks |
|---|---|---|
| 4 | $E_R = F\left[1 - \frac{S_{gr}}{1-S_{wc}}\right]$ | Liquid Recovery Factor is effective at dew-point Pressure |
| 18 | $V_w = \frac{0.02827ZT_iG_p}{P_i}$ | Daily Volume of Water to be Injected, $cu.ft/d$ |

*Table 4 Laboratory test data validation models*

| Eqns | Validation Evaluation Models |
|---|---|
| 5 | $GLR = 1000(V_{gs} + V_{gt})$ |
| 6 | $\gamma_{avg} = \frac{V_{gs}\gamma_{gs}+V_{gt}\gamma_{gt}}{V_{gs}+V_{gt}}$ & $\gamma_o = \frac{141.5}{API+131.5}$ |
| 8 | $\gamma_f = \frac{R_g\gamma_{avg}+V_{gs}\gamma_o}{R_g+\frac{132800\gamma_o}{M_o}}$ |
| 9 | $M_o = \frac{44.21\gamma_0}{1.03-\gamma_0} = \frac{6084}{API-5.9}$ |
| 10 | $Z = f(P_{Pr}, T_{Pr}) = f\left(\frac{P}{P_{PC}}, \frac{T}{T_{PC}}\right)$ |
| 11 | $P_{PC} = f(\gamma_f)$ & $T_{PC} = f(\gamma_f)$ |
| 12 | $G_b = \frac{43560\,V_mP_i\,\emptyset\,(1-S_{wc})}{Z\ R\ T}$ |
| 13 | $n_g = \frac{V_{gs}+V_{gt}}{V_{ot}}$ & $n_0 = \frac{350\,\gamma_g}{M_0}$ |
| 14 | $S_{gr} = 1 - S_o - S_w$ |
| 15 | $f_g = \frac{n_g}{n_g+n_0} = \frac{R_g/V_m}{\frac{R_g}{V_m}+\frac{350\gamma_g}{M_0}}$ |
| 16 | $G_P = G_b\,f_g,\ Mscf/ac.ft$ |
| 17 | $N_P = \frac{G_P}{R_g},\ bbl/ac.ft$ |
| * | $V_m = molar\ Volume = 379.4$ |

*Table 5 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 Eq4 and the Prosy Model]**

Source: [Generated Using Table 5]

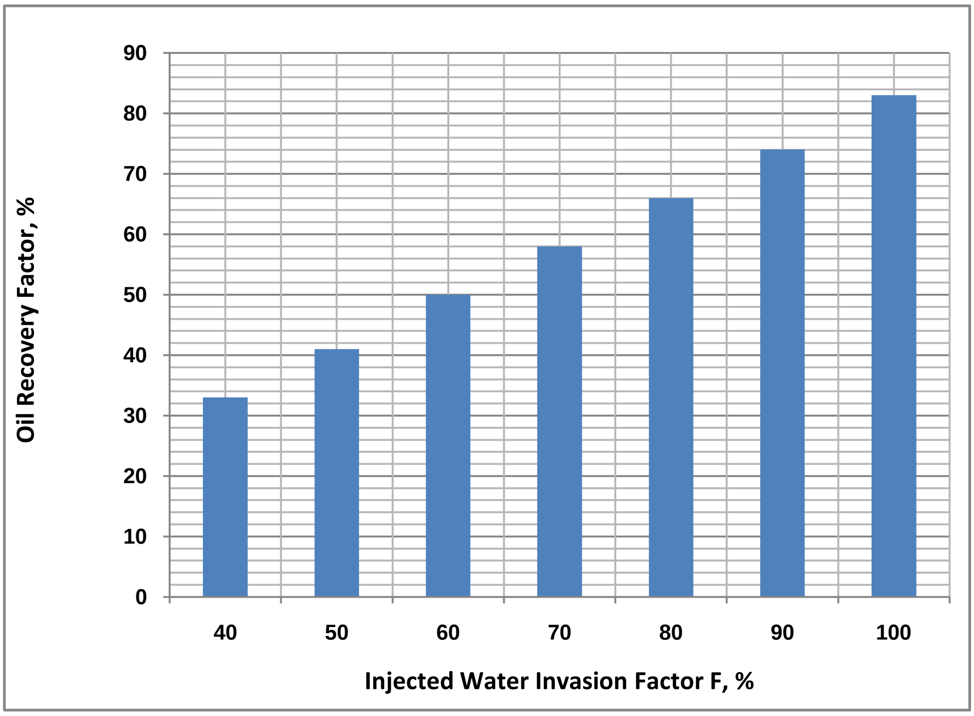


**Fig 1: recovery Factor Based on the Injcted Water Invasion**

***Source (Result using Depletion Models)***

Gas

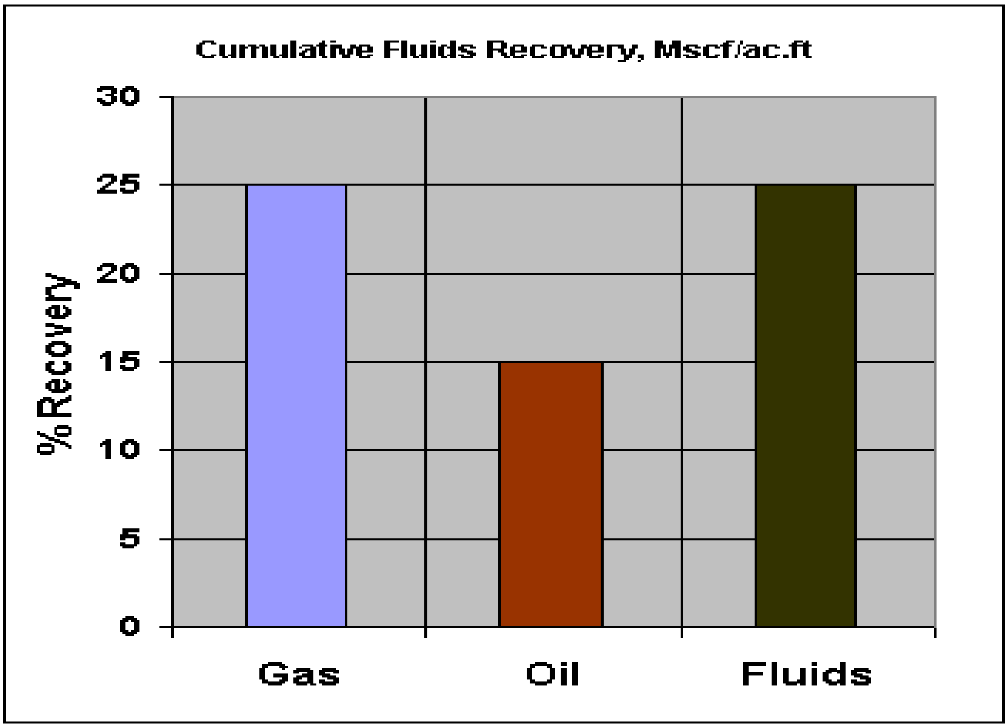


**Figure 2 Cumulative Fluids Estimation by Depletion Technique**

*Source (Result from Depletion Models)*

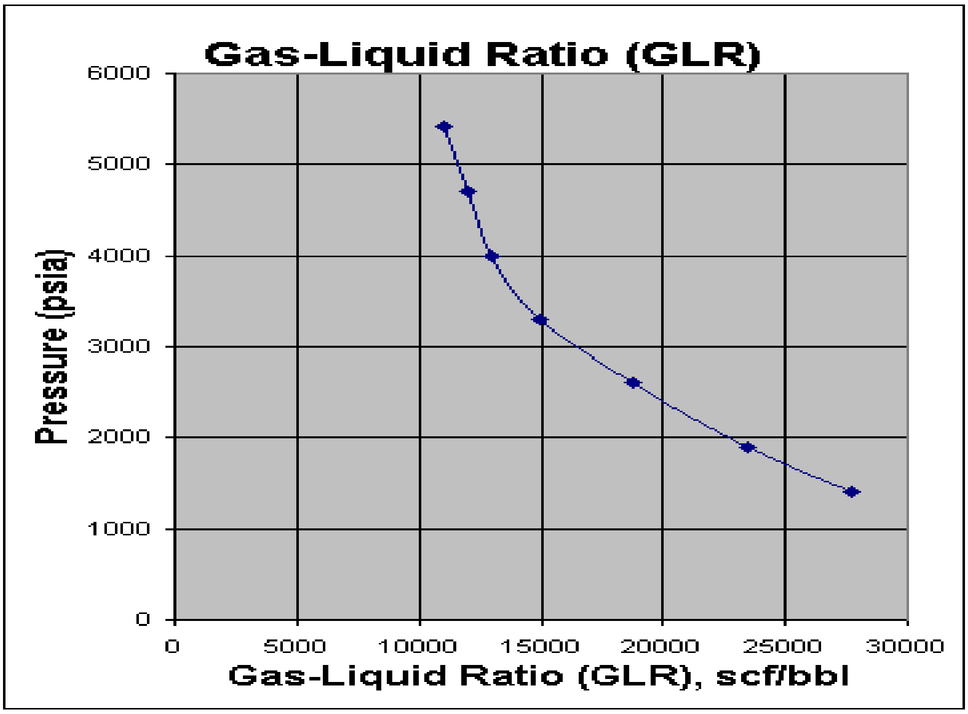


**Figure 3 Estimated Gas-Liquid (GLR) by Depletion Technique**

*Source (Comparing Results with the Other Techniques)*

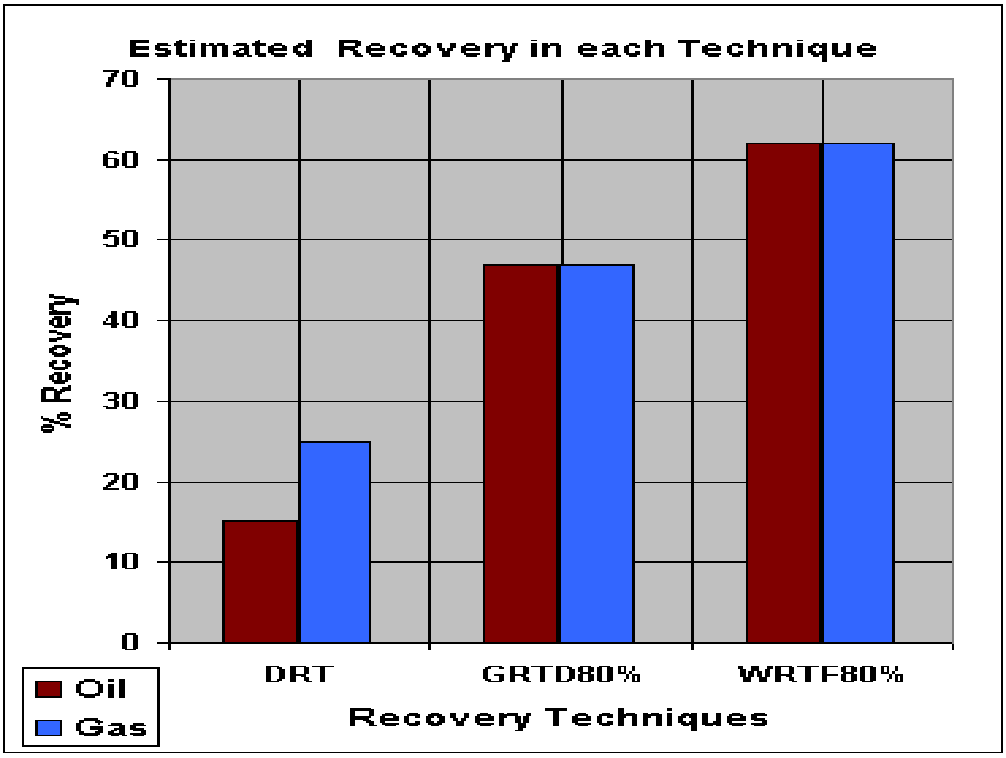


**Figure 4: Comparison of Results from the 3 Techniques**

**Key**

| |
|---|
| **DRT** = Volumetric Depletion Recovery Technique |
| **GRTD80%** = Gas Recycling Technique with 80% Displacement or Sweep Efficiency |
| **WRTF80% =** Water Injection Technique, with 80% Invasion Factor |

## V. DISCUSSION

The input data are residual gas saturation ($S_{gr}$), connate water saturation ($S_{wc}$) and injected water invasion factor. The sample data were grouped into residual saturation of 40%, 35%, 30%, 25%, 20% and 15% based on yearly production records. The total of 18 samples of residual gas saturations in 3 wells with connate water saturation 11%, 13% and 15% were used based on 121 samples of injected water invasion factor. Table 5 shows that when the residual gas saturation was reduced from 100% recoverable value to 15% in a well with 11% connate water saturation and invasion factor of 80%, 67% of the recoverably fluid was recovered. This model tool is so flexible and was designed with an incorporated provision for studying the field and laboratory test data, for good material balance and history matching. This insures accurate pressure management, fluid saturation, production and injected water replacement values estimations. The user requires just the basic knowledge of reservoir rock and fluids properties only to implement the model simulator.

## VI. CONCLUSION AND RECOMMENDATIONS

***Conclusion***

Mathematical models were successfully derived for studying reservoirs fluids, estimating the recovery factor using water injection at dew-point pressure. The application of the model is good in most gas-condensate reservoirs to study the reservoir characterization, predict its performance, and estimate the overall fluid recovery factor. More so, the tool finds valuable applications results in analysis of reservoirs data, and monitoring plants for integrity. Validation of the model depends on successful forecast, using the field, and laboratory data available. Proper history matching is an added advantage.

***Recommendations***

This work assists us to maximize recovery in gas-condensate reservoirs, using various options, which maintain pressure, possibly at dew-point pressure to avoid retrograde condensations.

**i.** Water injection is recommended here, because it is cheap, good pressure maintenance and has high displacement efficiency with high recovery factor.

**ii.** The only force, which binds components in the subsurface, is an equilibrium system, so correct adjustment on the equilibrium ratio is a sure success in the results. So prediction of gas-condensate reservoir performance should be backed up with the available laboratory data. This insures accurate equilibrium ratio adjustment to give a close copy of the reservoir performance using this technique.

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