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Modelling and Simulation of a Gas Condensate Reservoir

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ABSTRACT: *The efficient development of Gas condensate reservoirs has been a subject for any decades in the petroleum industry. The main purpose of this study is to perform a compositional modeling of a gas condensate reservoir system and establish the behavior during different conditions of reservoir depletion, development and pressure variations. In this study a three-dimensional (3-D) model was developed and simulated using a reservoir simulator ECLIPSE 300. First, a model validation phase was carried to prove the reliability of the model in handling gas condensate behaviors. A phase diagram for a gas condensate reservoir was plotted based on the model description and assumptions for a gas condensate reservoir. The results of this simulation are consistent with the typical phase diagram lots seen in existing literatures.From the findings of this study, it was observed that for a gas condensate reservoir, the field Gas Oil Ratio tends to increase with production time; significantly when there is enough pressure maintenance by fluid (gas or water) injection. Additionally, it was observed that composition and condensate saturation change significantly as a function of producing sequence. The higher the BHP, the less the condensate banking and a smaller amount of heavy component is trapped in the reservoir. Comparing the basic development strategies employed in the development of gas condensate reservoirs, it was also observed that In the case of a HW length of 350 ft, the relative increase in cumulative gas production amounts to maxima of 33%, 18%, and 11% for the reservoir with 50, 100, and 200 ft thickness while the corresponding values for the HW length of 1550 ft are 95%, 52%, and 27%, respectively. It is concluded that increasing the thickness of the reservoir decreases the relative gain in the total gas production compared to that of a VW. Increasing the length of the horizontal section from 350 to 1550 ft in the reservoir 50 ft thick increased the relative gain in the total gas production compared to that of a VW from 33% to 95%, while the corresponding value in the reservoir 200 ft thick increased only from 11% to 27%. It is concluded that the effect of the length of the horizontal section on the total gas productivity is more pronounced in the case of the reservoirs with smaller thicknesses.*

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I. INTRODUCTION

In recent years, Gas Condensate reservoirs are becoming more popular as development and operational technologies are being extended to greater depths and higher-pressure formations. A reservoir with a temperature falling in between critical and cricondentherm points is characterized as a gas condensate reservoir. In these types of reservoirs, the fluids are initially gaseous, however, during depletion and reduction in system pressure, liquids start to drop out of the gas. These fluids are called condensates. Figure 1.1 shows a classic phase envelope diagram of a gas condensate system mixture.

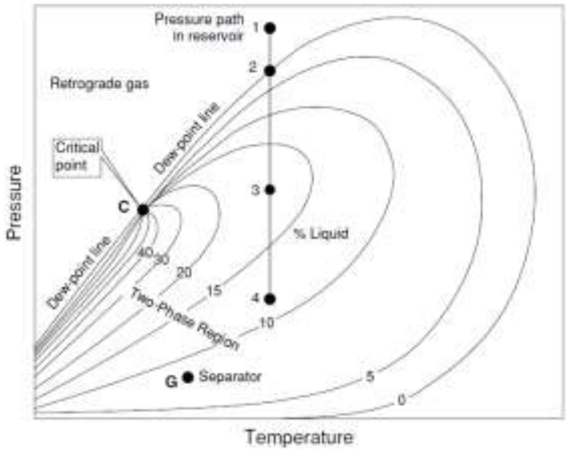


Figure 1.1: Phase envelop for a gas condensate reservoir system (Tarek, 2004).

In gas condensate reservoirs unlike gas reservoirs, two hydrocarbon phases (gas and condensate) can exit under reservoir conditions. This makes the phase and flow behavior totally different from those for dry gas reservoirs. Also, it is well documented that fluid flow behavior of near critical gas condensate systems is different from that of conventional oil gas systems, especially around the wellbore, a region, which significantly affects the well productivity. That is, gas condensate systems are characterized by very low interfacial tension. Thus, the relative permeability of gas condensate systems has a unique dependency on interfacial tension (Bloom et. al 1997).

The condensate phase can cause severe loss in gas production and recovery. For gas condensate reservoirs the composition of the well stream during the depletion process changes with time and differs from the reservoir fluid. Therefore, an accurate and highly sophisticated prediction of the performance and recovery of such systems depends on a comprehensive understanding of their phase and flow behaviors.

Hydrocarbons in a gas condensate reservoir are single-phase during the time of discovery. Under the isothermal depletion process, once the pressure falls below the fluid dew-point pressure, retrograde condensation will commence in the reservoir and condensate saturation will increase as depletion continues. However, it will reach a maximum value, referred to as maximum liquid dropout (MLDO), after which condensate saturation will decrease and may it be vaporized if depletion continues to a certain pressure in the fluid phase envelope.

The main challenge in gas condensate reservoir development, therefore, is how to maximize fluid recovery with the minimum retrograde condensation at reservoir conditions. It is well documented that flow behavior of gas condensate reservoir differs from the conventional oil gas system in several phases, especially in phase distribution and behavior (Jamiolahmady et al 2000). Understanding of phase and fluid flow behavior relationships is essential if we want to make accurate engineering computations for gas-condensate systems (e.g., well testing, estimating reserves and predicting production trends).

The production and development of gas condensate reservoirs is quite difficult. Wells that have been drilled into such reservoirs perform badly because of the condensing oil or liquid banking inside the pore spaces. The pressure near well bore decreases when the gas has been started to deplete. Whenever it reaches a certain point, condensation starts, and liquid phase builds up which results to have the gas flow impeded by the condensate phase. Well impairment by condensate drop out is more complicated multi-phase flow problem in which we may expect an effect of near miscibility on the relative permeability curves. A realistic estimate of well impairment is highly important to enable decisions on the number of wells that will be drilled in the reservoir.

The main purpose of this study is to perform a compositional modeling of gas condensate reservoir system and establish behavior during different conditions of reservoir depletion, development and pressure variations.

In other to achieve the stated aim above, the specific objectives of this study are to:

Use compositional models, principles and assumptions to model the behavior of condensate reservoir systems during reservoir simulations.

- Determine the impact of geometric and harmonic average permeability distribution on condensate recovery from
- Simulate the developed model using ECLIPSE 300 software.
- Validate the developed model using data from a gas condensate reservoir from ALEXOC Nigeria Limited.

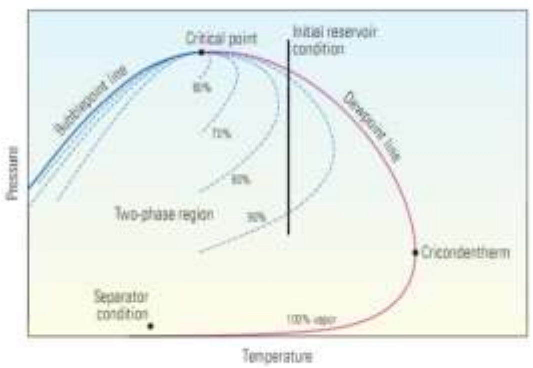
II. THEORETICAL BASIS OF MODEL DEVELOPMENT

Compositional Modeling of Gas Condensate Reservoirs

A good understanding of fluid flow through a porous medium requires a good prediction of physical properties and the fluid phase behavior. A typical representative gas condensate fluid consists of many components which are distributed between the vapor and liquid phase under equilibrium phase changes. The phase behaviour and fluid properties of such systems depend on the pressure and also on fluid composition at the reservoir temperature. For that reason, the study of flow behaviour in these systems requires a compositional model to adequately describe the fluid phase behaviour and properties. A compositional model uses equations of state (EOS) to estimate the phase behaviour and physical properties of the fluid. An equation of state presents a theoretical relationship between pressure, volume and temperature. The Peng-Robinson and Soave-Redlich-Knowng equations of state are commonly used in the petroleum industry. The phase composition is determined by flashing the fluid over a wide range of pressures. The equations which need to be solved by compositional simulation are the mass balance equation for each component, the sum of all phases saturations to 1.0, and the phase behaviour which has to be consistent with temperature, pressure and composition in each cell. The number of these equations that the simulation should solve increases as the number of components increases. Nowadays, with the rapid advancements in computing techniques, a fully compositional simulation is becoming more feasible; however for multi-millions of cells it is still impractical.

2.1 Condensate Build Up in Condensate Reservoirs

The main characteristic of a gas condensate system is the appearance of retrograde condensate, which considerably affects the well productivity. First, the condensate liquid accumulates around the wellbore where bottom hole pressure is below dew point, Figure 2.1. The condensate bank will propagate away from the wellbore as the pressure drops below dew point across the reservoir, Figure 2.1 and 2.2. This process creates two regions across the reservoir. The first region is a two-phase region where both gas and condensate exist and flow to the wellbore. While away from the wellbore, a second region contains a single-phase gas only.



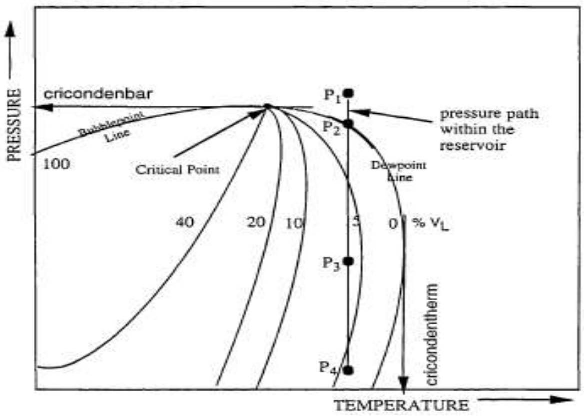


Figure 2.1: Phase diagram of gas condensate reservoir system
Figure 2.2: Detailed phase diagram for condensate reservoirs

Model Summary and Assumptions

Gas condensate reservoirs are simulated frequently with fully compositional models. This study presents a pseudoization (pseudo steady state assumption) procedure that reduces the multicomponent condensate fluid to a pseudo two-component mixture of surface gas and oil. This allows the use of a simpler, less expensive, modified black-oil model that accounts for both gas dissolved in oil and oil vapor in the gas.The phase behaviour and fluid properties of such systems depend on the pressure and also on fluid composition at the reservoir temperature. For that reason, the study of flow behaviour in these systems requires a compositional model to adequately describe the fluid phase behaviour and properties. A compositional model uses equations of state (EOS) to estimate the phase behaviour and physical properties of the fluid. An equation of state presents a theoretical relationship between pressure, volume and temperature. The Peng-Robinson and Soave-Redlich-Knowng equations of state are commonly used in the petroleum industry.

Gas condensate system presents a complex system for modeling however, with relevant and accurate assumptions; they could be modeled with a high degree of accuracy. This model is developed based on Pseudo-steady state flow conditions.

The following assumptions were made during the development of this generalized model. They include:

1. The reservoir regime is Pseudo steady

2. Two phase flow of gas and condensate liquids
3. Fixed total composition over the whole reservoir system at anytime
4. Three dimensional (3-D) reservoir model
5. Darcy's fluid flow model is applicable
6. the multiphase flow is assumed to be laminar because of the presence of heavy gas components in the gas condensate mixture
7. The reservoir is completely saturated with the petroleum fluids
8. The reservoir pressure is maintained by a strong aquifer drive during production operations.
9. Isothermal reservoir
10. Horizontal fluid flow, therefore gravitational effects are negligible.

III. MATHEMATICAL BASIS OF MODEL DEVELOPMENT

Reservoir simulation is an important method in the Petroleum Industry, particularly for the field development and asset-management evaluation. Development strategy, forecasting, history matching, and asset evaluation are an important application in reservoir simulation techniques. The objective of reservoir modeling is to evaluate the optimal production strategy for the gas-condensate reservoir. Define and apply the mechanisms to enhance the condensate production is primary target in field development strategy.

As mentioned earlier, modeling gas condensate systems requires the use of the equation of state for component characterization. To develop this model, several relevant equations will be considered. The equation describing the two phase horizontal flow of gas and condensate liquids in a system are as follows:

$$\nabla \cdot \left((\rho v)_{avg}\right) + q = \frac{d\left(\rho_{avg}\,\emptyset\right)}{dt} \qquad [3.1]$$

Equation 3.1 can further be expressed as:

$$\frac{\partial}{\partial x}\left((\rho v)_{avg}\right)_x + \frac{\partial}{\partial y}\left((\rho v)_{avg}\right)_y + \frac{\partial}{\partial z}\left((\rho v)_{avg}\right)_z + q = \frac{d\left(\rho_{avg}\,\emptyset\right)}{dt} \qquad [3.2]$$

Where

ρ_{avg} is the average weighted density of the phases

$v$is the velocity flux

$\emptyset$is the reservoir porosity

x, y and z are flow directions or coordinate axes

The average density is a weighted density that could be obtained by considering the fraction of each flowing phase in the total gas fraction f_{tg}. Mathematically,

$\rho_{avg} = \rho_g f_{tg} + \rho_c\left(1 - f_{tg}\right)$[3.3]

From the knowledge of multiphase flow system, the gas fraction which is also referred to as the no-slip liquid hold up can be written as:

$$f_{tg} = \frac{\text{Velocity of Gas}}{\text{Velocity of Gas} + \text{Velocity of Liquid}} [3.4]$$

$$f_{tg} = \frac{v_g}{v_g + v_c} [3.5]$$

Substituting equation 3.5 in to equation 3.3, we have:

$$\rho_{avg} = \rho_g \frac{v_g}{v_g + v_c} + \rho_c\left(1 - \frac{v_g}{v_g + v_c}\right) [3.6]$$

Expanding and simplifying, we have that:

$$\rho_{avg} = \frac{\rho_g v_g}{v_g + v_c} + \frac{\rho_c v_g}{v_g + v_c} [3.7]$$

$$\rho_{avg}\left(v_g + v_c\right) = (\rho v)_g + (\rho v)_c = (\rho v)_{avg} [3.8]$$

Substituting equation 3.8 into equation 3.1 we have that:

$$\nabla \cdot \left((\rho v)_g + (\rho v)_c\right) + q = \frac{d\left(\rho_{avg}\,\emptyset\right)}{dt} \qquad [3.9]$$

Darcy Equation

The velocity flux as described by Darcy's fluid flow principle is directly proportional to the pressure gradient. Mathematically, this can be written as:

$$v_i = \frac{k k_{ri}}{\mu_i} \nabla \cdot P; \qquad [3.10]$$

For gas we have:

$$v_g = \frac{kk_{rg}}{\mu_g}\nabla \cdot P; \qquad [3.11]$$

For condensates we have:

$$v_c = \frac{kk_{rc}}{\mu_c}\nabla \cdot P; \qquad [3.12]$$

Substituting equation 3.11 and 3.12 into equation 3.9, we have that:

$$\nabla \cdot \left[\left(\rho\frac{kk_r}{\mu}\nabla \cdot P\right)_g + \left(\rho\frac{kk_r}{\mu}\nabla \cdot P\right)_c\right] + q = \frac{d(\rho_{avg}\,\emptyset)}{dt} \quad [3.13]$$

Simplifying further by factorization

$$\nabla \cdot \left\{\left[\left(\rho\frac{k_r}{\mu}\right)_g + \left(\rho\frac{k_r}{\mu}\right)_c\right] k\nabla \cdot P\right\} + = \frac{d(\rho_{avg}\,\emptyset)}{dt} \qquad [3.14]$$

For constant composition system, and for a system with approximately maintained performance pressure by water drives, the density will be constant with time.

$$\nabla \cdot \left\{\left[\left(\rho\frac{k_r}{\mu}\right)_g + \left(\rho\frac{k_r}{\mu}\right)_c\right] k\nabla \cdot P\right\} = \rho_{avg}\frac{d(\emptyset)}{dt} \qquad [3.14]$$

$$\text{Porosity}, \emptyset = \frac{\text{Pore Volume}}{\text{Bulk Volume}} = \frac{pv}{V} \qquad [3.15]$$

Substituting equation 3.15 into equation 3.14 we have that:

$$\nabla \cdot \left\{\left[\left(\rho\frac{k_r}{\mu}\right)_g + \left(\rho\frac{k_r}{\mu}\right)_c\right] k\nabla \cdot P\right\} = \frac{\rho_{avg}}{V}\frac{d(pv)}{dt} \qquad [3.15]$$

$\frac{d(pv)}{dt}$ is the total well flow rate or production for a particular time period, dt which can be written as q_m

That is:

$$-\nabla \cdot \left\{\left[\left(\rho\frac{k_r}{\mu}\right)_g + \left(\rho\frac{k_r}{\mu}\right)_c\right] k\nabla \cdot P\right\} = \frac{\rho_{avg}\,q_w}{V} \qquad [3.16]$$

Where $q_w = (q_g + q_c)_w$

For compositional modeling and simulation, the concept of fluid composition has to be introduced into equation 3.16. Furthermore, as mentioned above, at any time the total fluid composition (zj) is constant as fluid flows through the porous media. However, there is mass transfer between the two phases for each component; therefore the total fluid composition can be written as:

$$z_i = \frac{\rho_g y_i f_{tg} + \rho_c x_i (1 - f_{tg})}{\rho_g f_{tg} + \rho_c (1 - f_{tg})} \qquad [3.17]$$

For a multi-component and multi-phase system, incorporating equation 3.17 into 3.16 will result to a complex equation that cannot be solved by known methodology.

For simplicity let us use x_{iph} to represent the mole fraction of a component in a phase, equation 3.16 can be re-arranged and summed up for all the phases present to have:

$$-V \times \nabla \cdot \left\{\sum_{ph=g,c}\left[x_{iph}\,\rho_{ph}\frac{kk_{rph}}{\mu_{ph}}\nabla \cdot (P)\right]\right\} = q_w \;\; ; \; i = 1,2,3,4,5 \ldots, N \qquad [3.18]$$

Where: N is the total number of components in the fluid mixture

x_{iph} is the total mole fraction of component i, in a phase (g or c) and represents the simplification of the reciprocal of ρ_{avg} using equation 3.17 in consistent units.

The flow rate term however, represents the rate of flow of a component in the combined phase and can be obtained as:

$$q_w = \sum_{ph=g,c}\left[x_{iph}\,\rho_{ph}\frac{kk_{rph}}{\mu_{ph}}(P_{re} - P_{wf})\right]; \; i = 1,2,3,4,5 \ldots, N \qquad [3.19]$$

Where P_{re} is the initial reservoir pressure and P_{wf} is the wellbore flowing pressure.

Substituting into equation 3.18 we have:

$$V \times \nabla \cdot \left\{\sum_{ph=g,c}\left[x_{iph}\rho_{ph}\frac{kk_{rph}}{\mu_{ph}}\nabla \cdot (P)\right]\right\} = \sum_{ph=g,c}\left[x_{iph}\rho_{ph}\frac{kk_{rph}}{\mu_{ph}}(P_{wf} - P_{re})\right] \quad ; \; i = 1,2,3,4,5 \ldots, N \;\; [3.20]$$

Applying the finite difference technique to the differential parameter, ∇, we have:

$$\sum_{ph=g,c}\left[Vx_{iph}\rho_{ph}\frac{kk_{rph}}{\mu_{ph}}\frac{(P_{j+1}+2P_{j-1}-P_j)}{\Delta l}\right]=q_w \quad ; i=1,2,3,4,5\dots,N \quad [3.20]$$

Introducing the transmissibility term which in this case is defined as:

$$T_n=\frac{\rho_{ph}Vkk_{rph}}{\mu_{ph}\Delta l} \qquad [3.21]$$

Equation 3.20 becomes:

$$\sum_{ph=g,c}\left[x_{iph}T_j\frac{(P_{j+1}+2P_{j-1}-P_j)}{\Delta l}\right]=q_w \quad ; i=1,2,3,4,5\dots,N \quad [3.22]$$

Summing up equation 3.22for all the components we have that:

$$\sum_{i=1;ph=g,c}^{N}x_{iph}=\sum_{ph=g,c}x_{ph} \quad [3.23]$$

$$\sum_{ph=g,c}\left[x_{ph}T_j\frac{(P_{j+1}+2P_{j-1}-P_j)}{\Delta l}\right]=\sum_{i=1}^{N}q_w \qquad [3.24]$$

Introducing the simulation time levels, equation 3.24 becomes:

$$\sum_{ph=g,c}\left[x^n{}_{ph}T^n{}_j\frac{(P^n{}_{j+1}+2P^n{}_{j-1}-P^{n+1}{}_j)}{\Delta l}\right]=\sum_{i=1}^{N}q_w \qquad [3.25]$$

Equation 3.25 is the general equation governing gas condensate flow in a reservoir system and will be modeled using Eclipse 300 compositional simulator.

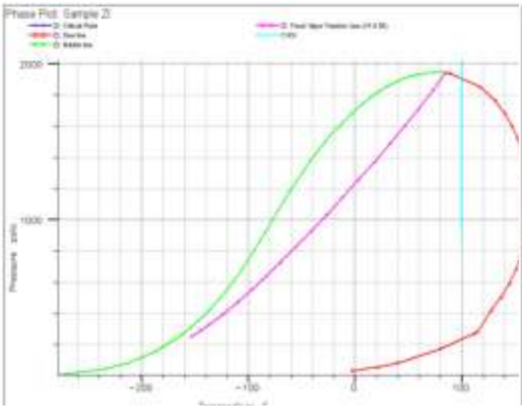
IV. RESULTS AND DISCUSSIONS

Table 4.1: Detailed composition data for a gas condensate fluid (Danesh 1998)

Components	Mol%	Components	Mol%
Nitrogen	0.298	n-Octane	0.168
Carbon dioxide	1.72	i-Nonanes	0.158
Methane	79.139	Aromatics C8	0.143
Ethane	7.483	Cyclanes C9	0.061
Propane	3.293	n-Nonane	0.113
i-Butane	0.515	i-Decanes	0.176
n-Butane	1.255	Aromatics C9	0.054
i-Pentanes	0.359	n-Decane	0.084
n-Pentane	0.551	Undecanes	0.318
i-Hexanes	0.282	Dodecanes	0.273
n-Hexane	0.334	Tridecanes	0.253
i-Heptane	0.111	Tetradecanes	0.225
Benzene	0.271	Pentadecanes	0.178
Cyclanes C7	0.389	Hexadecanes	0.144
n-Heptane	0.235	Heptadecanes	0.126
i-Octanes	0.145	Octadecanes	0.127
Toluene	0.150	Nonadecanes	0.063
Cyclanes C8	0.253	Eicosanes-plus	0.553

Simulation Results

The first simulation performed is the validation of the model developed in chapter three. A phase diagram for a gas condensate reservoir was plotted based on the model description and assumptions for a gas condensate reservoir. The results of this simulation are presented in figure 4.1 and 4.2.



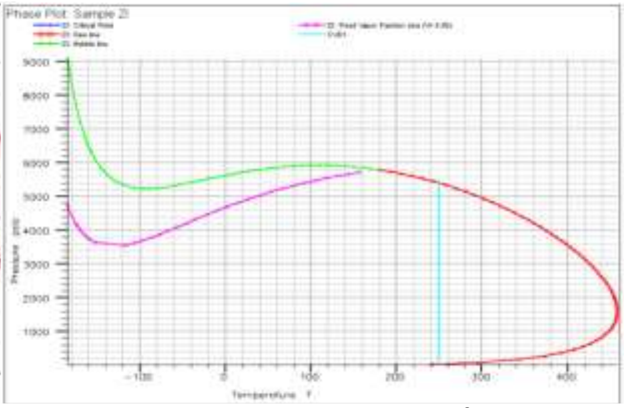
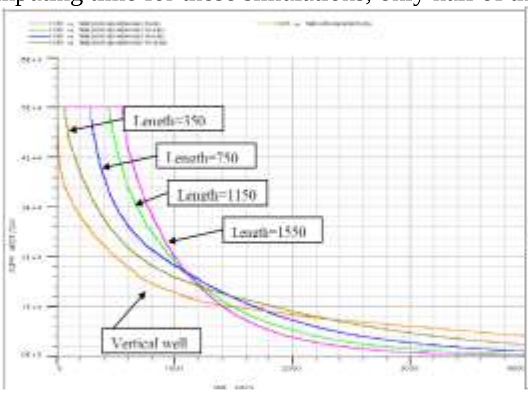


Figure 4.1: Phase Diagram for a gas condensate mixture at P=1950psia and T = 150^{o}F
Figure 4.2: Phase Diagram for a gas condensate mixture at P=1950psia and T = 150^{o}F

It can be observed that the shape of the phase is similarly to that described by Tarek (2001) in his Reservoir Engineering text. This result is an indication that the model developed is a representative of a gas condensate reservoir system. Observe that the shape of the phase diagram changed with varying pressure. This is obtainable for any reservoir fluid system since the phase diagram is basically a function of pressure and temperature.Gas condensate reservoir are developed using all kinds of well geometries, ranging from vertical, horizontal and deviated wells. In this study, a simulation analysis to determine how well geometry affects condensate recovery procedure was considered using well description option in ECLIPSE – 300 schedule section.
Many simulation runs were performed for different well lengths varying from 700 to 3100 ft in a reservoir with the thickness of 50, 100, and 200 ft. As the model is symmetrical in a Cartesian system, in order to reduce computing time for these simulations, only half of the model has been selected.



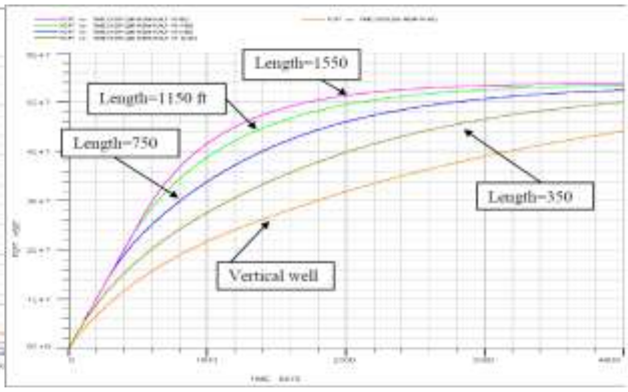
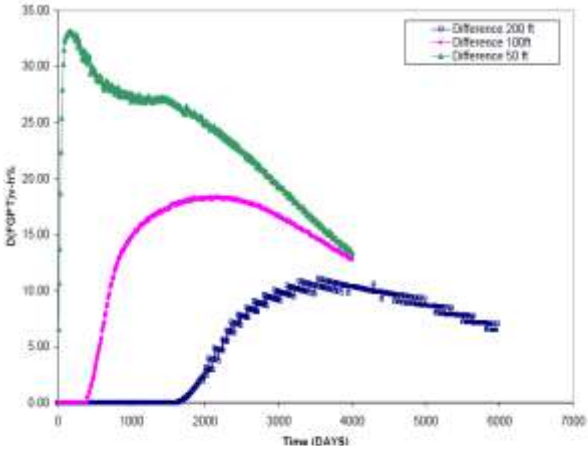


Figure 4.3: Gas production rate and (versus time for the horizontal wells with length of 1550, 1150, 750, and 350 ft, and a vertical well, all in the reservoir with 50 ft thickness
Figure 4.4: Total gas production versus time for the horizontal wells with length of 1550, 1150, 750, and 350 ft, and a vertical well, all in the reservoir with 50 ft thickness

As expected, increasing the length of the Horizontal Wells improved well productivity, although as the length increased, the extra benefit diminished. For example, a 35% increase in the length (from 1150 to 1550 ft) would increase the total production by only 0.48 %, while increasing the HW length from 350 to 472 ft (35% increase in the length) increases the total production by 1.5%, Figure 4.3 and 4.4. It is also noted that the gas recovery is always achieved faster using the HW compared to that of the VW in the reservoir.

Figure 4.5 and 4.6 shows the relative increase in cumulative gas production for the HW compared to that of the VW versus time for three reservoir models with a thickness of 50, 100 and 200 ft. In the case of a HW length of 350 ft, the relative increase in cumulative gas production amounts to maxima of 33%, 18%, and 11% for the reservoir with 50, 100, and 200 ft thickness while the corresponding values for the HW length of 1550 ft are 95%, 52%, and 27%, respectively. It is concluded that increasing the thickness of the reservoir decreases the relative gain in the total gas production compared to that of a VW. Increasing the length of the horizontal section from 350 to 1550 ft in the reservoir 50 ft thick increased the relative gain in the total gas production compared to that of a VW from 33% to 95%, while the corresponding value in the reservoir 200 ft thick increased only from 11% to 27%. It is concluded that the effect of the length of the horizontal section on the total gas productivity is more pronounced in the case of the reservoirs with smaller thicknesses.



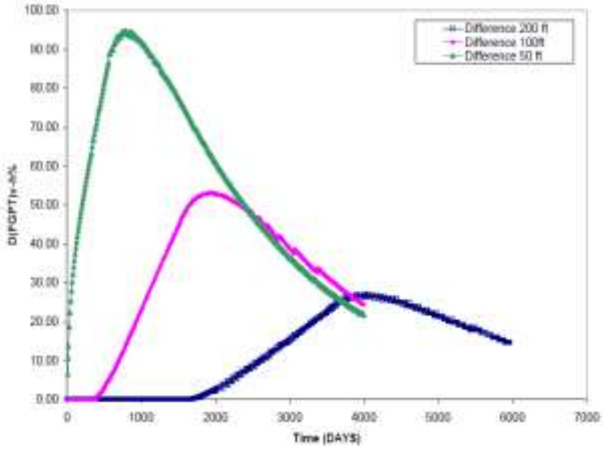


Figure 4.5 Relative increase in cumulative gas production in horizontal wells compared to that of the vertical well Pw<Pdew for horizontal well length= 350; ft

Figure 4.6: Relative increase in cumulative gas production in horizontal wells compared to that of the vertical well Pw<Pdew for a horizontal well length= 1550 ft

Gas condensate flow behavior in the reservoir system is a function of temperature and pressure. A gas condensate reservoir model is presented in figure 4.7.

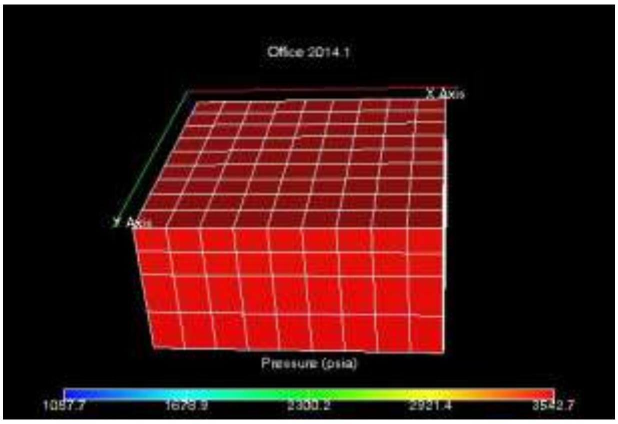


Figure 4.7: Gas Condensate Rectangular Reservoir Geometry

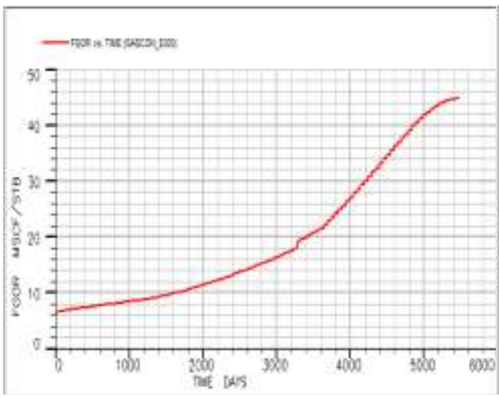


Figure 4.8: Gas Condensate Field Gas Oil Ratio

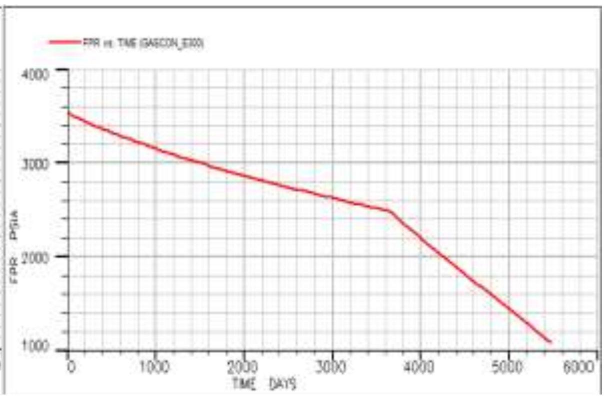
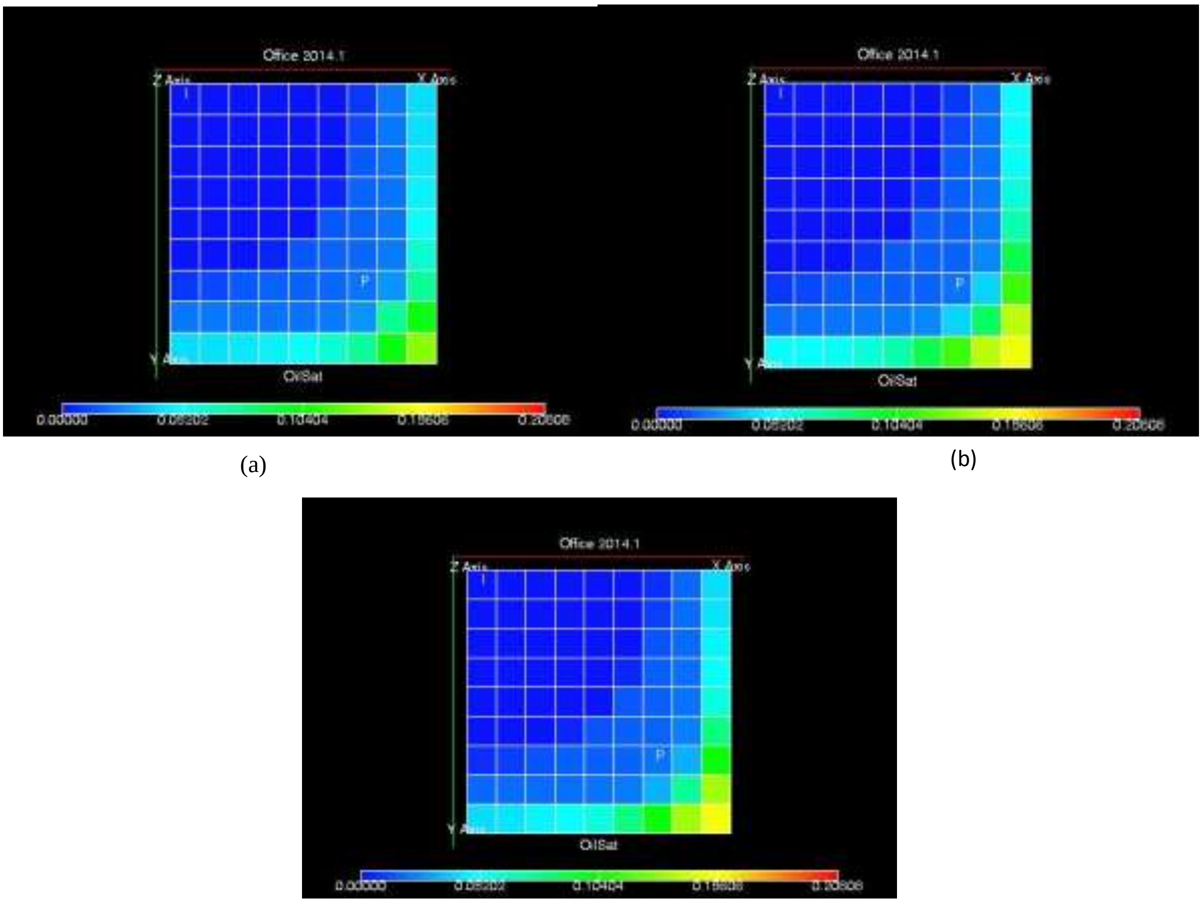


Figure 4.9: Pressure profile for the gas condensate reservoir system

For a gas condensate reservoir, the field Gas-Oil-Ratio tends to increase with production time; significantly when there is sufficient pressure maintenance by fluid (gas or water) injection. This behavior according to (Basckhan, 2002) is not specific of gas condensate reservoir systems. He stated that the behavior of gas condensate systems is dependent on operating reservoir conditions. The pressure profile for this system is shown in figure 4.9.

Fluid flow behavior of the gas condensate system with a production and injection well is represented in figure 4.10a, 4.10b and 4.10c. From these figures it can be observed that the condensate saturation increases around the production well where there is reservoir pressure decline. Around the injection well, condensate saturation is approximately equal to zero, indicating gas saturation. After a period, the condensate saturation around the well bore decreased further due increase in reservoir pressure in this area due to gas injection. It is concluded therefore that, condensate saturation in the condensate gas reservoir fluctuates with varying pressures. Increased reservoir pressure by fluid injection mitigates condensate drop out and ensure optimal fluid recovery.



(a) (b) (c)

Figure 4.10: Gas condensate flow distribution after (a) 365 (b) 1095 (c) 1565days of production and injection

V. CONCLUSIONS

In this study, the flow behavior of gas condensate reservoirs has been considered, also giving consideration to different development strategies and how they impact fluid flow behavior. A model was created using ECLIPSE300, which reproduced the results of the published paper by Holditch (1979), thereby demonstrating the integrity of the proposed approach. It was observed that for a gas condensate reservoir, the field Gas Oil Ratio tends to increase with production time; significantly when there is enough pressure maintenance by fluid (gas or water) injection. In summary, the findings of this study suggest that for a gas condensate reservoir:

- Condensate saturation in the condensate gas reservoir fluctuates with varying pressures. Increased reservoir pressure by fluid injection mitigates condensate drop out and ensure optimal fluid recovery.
- Composition and condensate saturation change significantly as a function of producing sequence. The higher the BHP, the less the condensate banking and a smaller amount of heavy-component is trapped in the reservoir. The lower the producing rate, the lower the amount of heavy-component left in the reservoir.
- Gas productivity can be maximized with a proper producing strategy. The total gas production can be increased by lowering the BHP or optimizing the producing rate.
- Productivity loss can be reduced by optimizing the producing sequence.

- The effect of the length of the horizontal section on the total gas productivity is more pronounced in the case of the reservoirs with smaller thicknesses.
- Increasing the thickness of the reservoir decreases the relative gain in the total gas production of a horizontal well compared to that of a Vertical Well.
- that the combined effect of absolute permeability and effective gas relative permeability reduction in the matrix invaded zone is more pronounced for most of considered cases studied here.

As several assumptions and simplifications have been made to make the attempt to solve problems in the experimental setup presented earlier in this study. Other than the intrinsic restrictions of operating conditions, improvements can still be made to the following aspects to better characterize the gas-condensate flow behavior in the reservoir. Also, a study can be conducted to investigate its impact on the effective wellbore radius approach. If the impact is significant it can be incorporated in the effective wellbore radius calculation of 1-D open-hole system (EOH). The impact of the formation damage because of drilling fluid was not considered here. The distribution of damage around wells influences their performance. It is recommended to extend the study to evaluate the impact of this damage on the well performance. It is suggested to define this effect as another skin, which can be simply employed in the effective wellbore radius calculation.

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