Modelling the Effects of Condensate Banking on High CGR Reservoirs

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ABSTRACT

This paper presents the results of a study undertaken to evaluate the effect(s) of condensate banking on retrograde gas reservoirs particularly, high condensate gas ratio (CGR) reservoirs. The effects of composition, fluid properties, liquid dropout rate, and the gas-oil relative permeability on gas productivity, were investigated using a scaling number, the Capillary Number, N_c. Results from the case study show that the impact of condensate banking would be severe for these reservoirs if the physical processes expected in these reservoirs are not correctly modelled. Also, the impact is not likely to be serious if the reservoir conditions are favourable as are prevalent in the Niger Delta basin of Nigeria.

Keywords: Condensate banking, Retrograde Gas Reservoirs, Liquid dropout rate, Gas Productivity, Niger Delta basin

INTRODUCTION

Retrograde natural gas reservoirs, are populated with single phase fluid(s) – natural gas, with temperatures between the critical temperature and the cricodentherm (1, 2). The significance of these reservoirs have grown significantly over the years as drilling targets hit deeper depths, subsequently encountering very high temperatures and pressures which are necessary for their presence. The cost and risk to develop these reservoirs under severe conditions of pressure and temperature highlight the need to be able to confidently predict the recovery of gas and liquid drop-outs from these reservoirs (2, 4). Retrograde gases exhibit dew points and initially release increasing volumes of liquid hydrocarbons – condensates, into the pore space as the reservoir pressure is reduced below the dew point value, on production. This is the retrograde condensation of hydro-carbon liquids from the natural gas. The amount of condensates deposited as pressure declines depends essentially on the composition of the hydrocarbon fluids, particularly on the amount of heavy ends in the condensate, giving rise to two phase reservoir systems (5).

The retrograde gas fluids, single phase, are usually very rich in liquid contents such that with pressures at/and below the dew point, large volumes of liquid are deposited. In general, rich gas condensate reservoirs, with two phase fluids, occur close to the critical point on the phase diagram and are sometimes referred to as near-critical Gas Condensate Reservoirs and these confers on them certain properties which include(6.

1. High liquid saturation in the pore spaces and around the wellbore: The condensate is considered mobile in the pore spaces, when its saturation is greater than the critical value.
2. Near-Miscible conditions: due to this closeness to critical point, the physical properties of the gas and condensate phases are very similar and they are therefore almost miscible with each other.
3. Low interfacial tension between the gas and condensate phases occurs for systems particularly close to the critical point. In the development of these fluid systems,

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these properties must be clearly modelled and understood to optimise production. Figure 1.0 shows the liquid dropout from a rich gas condensate reservoir. The figure clearly shows the rapid build-up of liquid as pressure declines.

Due to the large volumes of condensates deposited for small drops in pressure, and most often with saturation values lower than the critical, condensate banking phenomenon will occur in the reservoir resulting in gas productivity decline.

CONDENSATE BANKING

Condensate banking is a phenomenon associated with retrograde natural gas fluids. During the production of these fluids with the reservoir pressure declining below dew point values, hydrocarbon liquids – condensates, drop out. The saturation may rapidly build up for high CGR reservoirs quickly exceeding critical saturation for mobility and the condensates flow towards the producing wells where a "bank of condensates– hydrocarbon liquids", is generated around the wells. The condensate bank can grow as both reservoir and well flowing bottom hole pressures decline further. This can potentially lead to impairment on well deliverability of gas and condensate. This can be more severe for reservoirs with high initial CGR and low permeability.

Field examples show that the effect of condensate banking could be severe leading to productivity loss factor of between 2 to 6. An example is the Arun Field in North Sumatra, Indonesia, which experienced a decline in productivity by a factor of 2 when the well bottom hole flowing pressure fell below the dew point(3). The generation of a condensate bank around producing wells and the potential impact on productivity is however dependent on a number of reservoir, fluid and flow parameters and these parameters determine if there will be productivity impairment or not. Therefore in the treatment of condensate banking, there is a need to look at the type of condensate systems been described as it would be wrong to appropriate the same behaviour of condensate banking on all types of retrograde gas condensate systems, due to the dependence on fluid and flow properties.

Properties of the gas condensate fluids play a key role in the process of condensate banking and mobility. For near-critical fluids, the expected trend will be a similarity between the gas and liquid phases. For rich gas, the large amount of condensates deposited exceeds the critical condensate saturation necessary for mobility and therefore the condensate is mobile. Also the interfacial tension (IFT) between the condensate and gas phases will initially be very small (6). Under these conditions, the displacement process becomes more "miscible-like" and straight-line relative permeability curves could be used to describe the recovery process. Further depletion below the dew point causes the phases to become more distinct and the IFT becomes larger and immiscible-like and capillary-dominated flow begins to dominate again. Therefore the IFT is a key parameter controlling the flow of gas and condensate for conditions close to the critical point (6).

In general, for natural gas reservoirs; near the wellbore, viscous forces and flow velocities can become very high. At these high velocities, two competing phenomena occur which control the productivity of the wells

1. Increase in relative permeability due to increase in velocity. This effect is sometimes called VISCOUS STRIPPING or POSITIVE COUPLING.
2. Inertial (non-Darcy) flow effects, which reduce the effective permeability at high velocity. This is generally referred to in modelling as NON-DARCY EFFECT.

These effects tend to act in opposite directions and both need to be accounted for in flow calculations to accurately represent well productivity.

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The first effect of viscous stripping needs to be built into the relative permeability model. The magnitude of the effect depends on the balance between viscous (stripping) forces and capillary (trapping) forces. This is described below in terms of the capillary number, a scaling number.

Productivity above the dew point pressure is controlled principally by the reservoir permeability and thickness, and the viscosity of the retrograde gas. Below the dew point, the degree of productivity reduction will be controlled by the critical condensate saturation and the shapes of the gas and condensate relative permeability curves.

Capillary Number – The Scaling Parameter

The capillary number is a dimensionless parameter defined as the ratio of the viscous force to the capillary force, and is an indication of the relative strength of viscous stripping to capillary trapping. Capillary number, N_c, is a function of fluid viscosity (μ), velocity (V), and the interfacial tension (σ), and is expressed mathematically as:

$$N_c = \frac{V * \mu}{\sigma} = -\frac{K}{\sigma}\frac{dP}{dx} \quad \text{...1}$$

The reservoir and fluid properties, particularly the interfacial tension, determine whether miscible or immiscible conditions will prevail. Further, the flow rate determines the magnitude of the viscous force and the ability to overcome capillary trapping forces. The combined effect needs to be captured in the relative permeability and flow model. It has been proposed by several authors that the Capillary Number, N_c, be used as a scaling number to assign the correct relative permeability values throughout a model [7, 8, 9, 10].

It is generally accepted that for capillary numbers less than 10^{-5} (commonly referred to as the threshold value), the residual oil saturation is almost constant and the displacement process can be adequately represented by traditional immiscible Corey type relative permeability curves where capillary forces tend to dominate. For capillary numbers greater than 10^{-5}, viscous forces or miscible effect (low IFT) begin to play a more dominate role. The residual oil saturation decreases with increasing capillary number and ultimately, miscible relative permeability curves should apply. It is not well established at what upper limit value of capillary number, fully miscible (straight line) relative permeability curves should be used. Sensitivity studies were made to test the impact of the upper limit. This is described in the results section below.

STUDY METHODOLOGY

The focus of this case study is to investigate the near wellbore effects controlling well productivity in rich gas condensate systems. The reservoir is a sandstone reservoir in the Niger Delta region of Nigeria, with layers of shale in between its various sand beds. For the study, a single well radial dynamic model was chosen to investigate the condensate banking and dropout effects. The model is described as follows:

- A 2-dimensional (r-z coordinate) system, with
- A 30 block radial grid with increasing grid spacing to capture near well pressure sink,
- A single layer to nullify gravitational effects,
- No aquifer, and
- A fully completed well.

The model was populated with uniform reservoir properties. These properties are given in Table 1. Monitors or trackers were created in the model to track the behaviour of gas and condensate saturation, interfacial tension and the capillary number in different grid blocks; the distance of these grid blocks from the wellbore being 1ft, 5ft, 20ft and 100ft.

The reservoir is at a depth of about 9800 Ftss. The original pressure of the reservoir is 6101 psia. As stated earlier, it is a stratified reservoir with a very rich retrograde gas having a high level of condensate fluids, and it is compositionally graded with the top of the reservoir known to have a leaner gas condensate fluid.

Retrograde gas, the fluid used in this investigation, has an initial average CGR of 240bbl/mmscf, determined from PVT analysis. The dew point pressure of the fluid is 5377 psi from PVT analysis. The PVT data used in this model were based on a bottom-hole sample collected above the dew point pressure of the fluid. The Peng-Robinson 78 equation-of-state was used to achieve an acceptable simulation of the fluid behaviour. The simulation of the PVT data resulted in a 10-component model shown in Table 2. Compositional grading was also introduced into the PVT model. The CCE experiment shows a maximum liquid dropout of 44.0%. The phase envelope of the fluid is shown in Figure 2.

Two relative permeability curves were used for this study. One is the Corey function relative permeability and the other is the parameter dependent relative permeability; the parameter being the capillary number, N_c. The data/parameters for the two models are shown in Table 3.

RESULTS OF STUDY

The monitors in the radial model were used to determine the impact of condensate banking in the reservoir. The model was constrained to produce at a constant initial rate of 70 mmscf of gas per day until the rate could no longer be sustained. The model was run initially with an absolute permeability of 1000 md and it made use of lift tables in predicting the performance of the well.

The gas and condensate saturation for the different grid blocks were plotted against time and this is shown in Figure 3. The plot shows that the condensate saturation quickly builds up to almost 50% as pressures deplete and gas saturation declines thereby exceeding the critical condensate saturation at the first dropout.

The relative permeability behaviour of the model for the first grid block plotted as a function of gas saturation shows both the miscible and the immiscible relative permeability curves. In Figure 4, it could be seen that during production just below the dew point, the model made use of the miscible relative permeability to define the relative permeability behaviour of the fluid. However as production continues, there is a transition from the miscible relative permeability curve to the Corey function relative permeability plot due to production termination as a result of lift die out. Also, shown, is the relative permeability behaviour of the fluids in the first grid block in Figure 5.

This effect came as a result of the behaviour of the capillary number which can be attributed to the interplay of the interfacial tension behaviour and the effect of viscous stripping. The capillary number for the same four monitored grid blocks is shown in Figure 6. The grid block closest to the well is predicted to have the highest capillary number due to a combination of high flow rate and low Interfacial Tension. Capillary number is plotted on a logarithmic scale, emphasising the huge variation in the value as the simulation proceeds.

The capillary number for all monitored grid blocks was initially predicted to be several orders of magnitude larger than the value at which capillary forces dominate. (Capillary forces are expected to dominate for N_c values up to 10^{-5}). For the grid block closest to the well, N_c is above 10^{-5} throughout the simulation run, indicating that the Corey function relative permeability never applies to this grid block. Grid blocks further out in the reservoir fall to below 10^{-5} towards the end of the simulation period, at which point Corey relative permeability functions are applicable.

Very low interfacial tension values are predicted immediately below the dew point pressure. Interfacial tensions gradually increase with time as the pressure continues to decline and the phases become less miscible as can be seen in Figure 7. It is noted that the plot is on a logarithmic scale emphasising the large change in values.

In other to be able to verify the effects of this behaviour on productivity, the production rate of both the gas and the condensate fluids at the surface equipments, were plotted as a function of time. Figure 8 shows that just below the dew point, there was no decline in production due to condensate dropout or banking.

It is generally accepted that the threshold capillary number below which capillary forces and immiscible behaviour dominates, is 10^{-5}. The flow characteristics at these low capillary numbers are well described by the standard Corey type relative permeability functions. However, as the capillary number increases above 10^{-5}, the displacement and recovery process becomes increasingly miscible-like. At a threshold value of the capillary number, the displacement is fully miscible. There is no industry accepted threshold value for miscibility, although, it is generally quoted to be in the range10^{-3} to 10^{-2}. The reference case model described above assumes 10^{-2}.

Sensitivities to threshold values of 10^{-2}, 10^{-1} and 10^{-0} are shown in Figures 9 and 10. Productivity reduces as the threshold capillary number increases. For threshold value of 1.0, the impact of low IFT and high flow rates is suppressed and the recovery process is dominated by standard Corey function.

Finally, in other to investigate the effect of absolute permeability of the reservoir on condensate banking and productivity decline, sensitivity simulations to lower permeability values were performed and are shown in Figure 11. The case for 500 md is very similar to the reference case of 1000 md. However productivity drops dramatically for the case with 150 md. Condensate banking and gas productivity impairment effects are more evident at lower permeability values. For fixed gas production rate at 70 mmscf/d, the drawdown increases as the permeability reduces. At some point, the minimum bottom-hole pressure is reached and the production falls off plateau. For low permeability reservoirs, the effects of banking can be more severe as in the case of the Arun field [(3)], which has permeability on the range 0.1 md to 1 md.

CONCLUSIONS

From this study, we infer the following conclusions:

1. Near-critical retrograde gas systems are characterised by high CGR and high initial liquid dropout saturation.
2. There is a high rapid liquid saturation build-up around the wellbore, with low interfacial tension and potentially high capillary numbers, N_c, exhibiting near-miscible properties displacement.
3. The capillary number, N_c, is highest closer to the wellbore, indicative of viscous stripping.
4. Condensate banking effects are controlled to a large extent by relative permeability of gas and condensate, and for near-critical gas condensate systems, the relative permeability is a function of interfacial tension and flow rate of gas.

5. Failure to correctly model the physical processes expected in a reservoirs could lead to wrong prediction on the impact of condensate banking.
6. Simulation of the case reservoir from the Niger Delta region of Nigeria shows that reservoirs with higher values of permeability are unlikely to be affected by condensate banking.

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Appendix

Nomenclature

bbls: barrels

CGR: Condensate Gas Ratio

Ftss: Feet sub-surface

Mmscf: million standard cubic feet

PVT: Pressure, Volume, Temperature

Table 1. Properties of the Single Well Radial Model

Parameter	*Value*
Grid size (NX x NY x NZ)	30 x 1 x 1
External radius, r_e	6350 ft
Well-bore radius, r_w	0.75 ft
Dip	0 degrees
Reservoir Angle	PI radians (180°)
Thickness, h	100 ft
NTG	1.0
Phi (Porosity)	0.22
Perm	1000 md
GIIP	3.0 Bscf
CIIP	80.0 MMstb

Table 2. 10-component PVT data showing composition at a depth of 9630 Ftss

Composition	*Mole %*
N_2 - C_1	0.69384
$CO_2 – C_2$	0.07397
$C_3 – C_4$	0.08448
$C_5 – C_6$	0.03236
$C_7 – C_{11}$	0.06974
$C_{12} – C_{16}$	0.02553
$C_{17} – C_{19}$	0.00755
$C_{20} – C_{21}$	0.00494
$C_{22} – C_{26}$	0.00443
$C_{27} – C_{45}$	0.00316

Table 3. Relative Permeability Data/Parameters

Parameters	*Corey model Immiscible*	*Straight line Miscible*
S_{cw}	0.0431	0.0431
K_{rw}	0.33	0.33
N_w	4.11	4.11
S_{orw}	0.21	0.00
S_{org}	0.10	0.00
K_{row}	0.75	1.00
N_{og}	3.47	1.00
N_{ow}	2.11	2.11
S_{gc}	0.10	0.00
K_{rg}	0.90	1.00
N_g	2.11	1.00

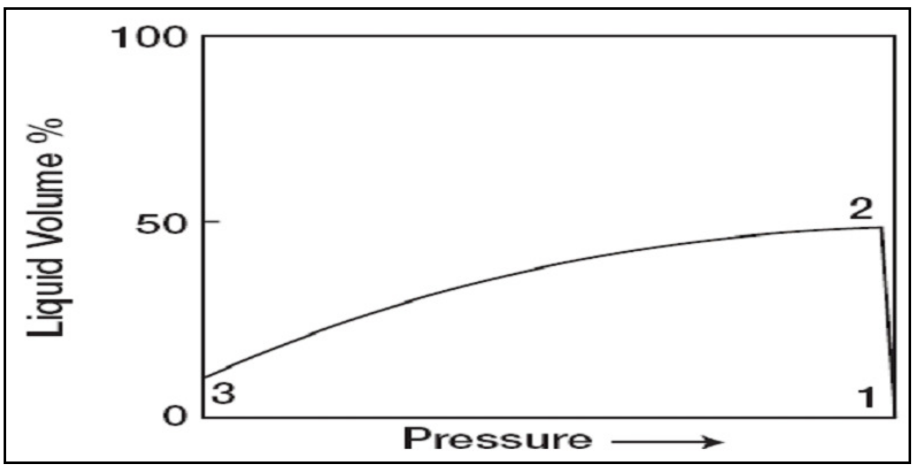

Figure 1. Liquid Dropout Curve for a near-Critical Gas Condensate System

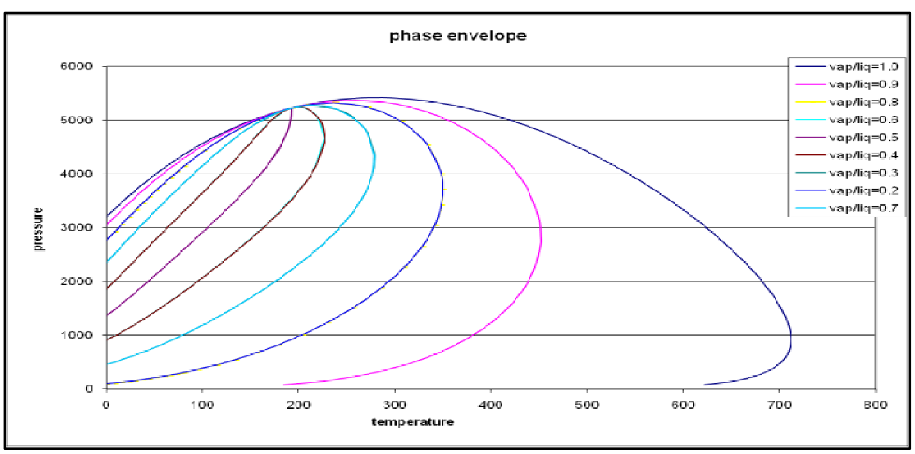

Figure 2. Phase Diagram of the Fluid used in the Model (Reservoir Temp.: 224.2^{o}F)

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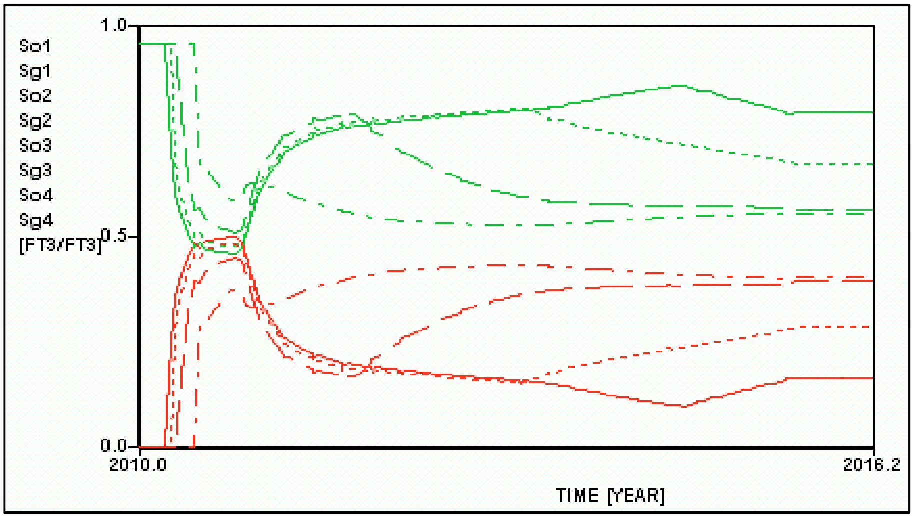

Figure 3. Condensate Saturation for the Radial Model from Selected Grid Blocks

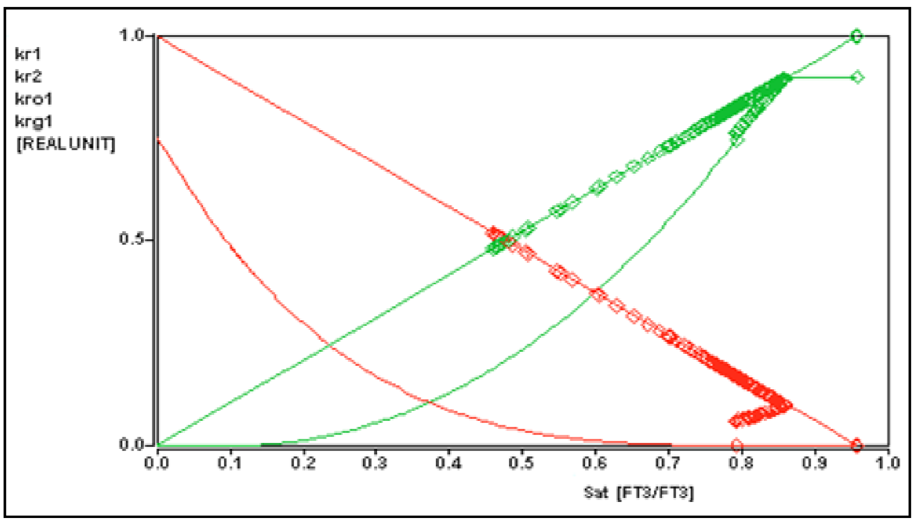

Figure 4. Relative Permeability Plots showing the Performance of the Reservoir in terms of Miscibility

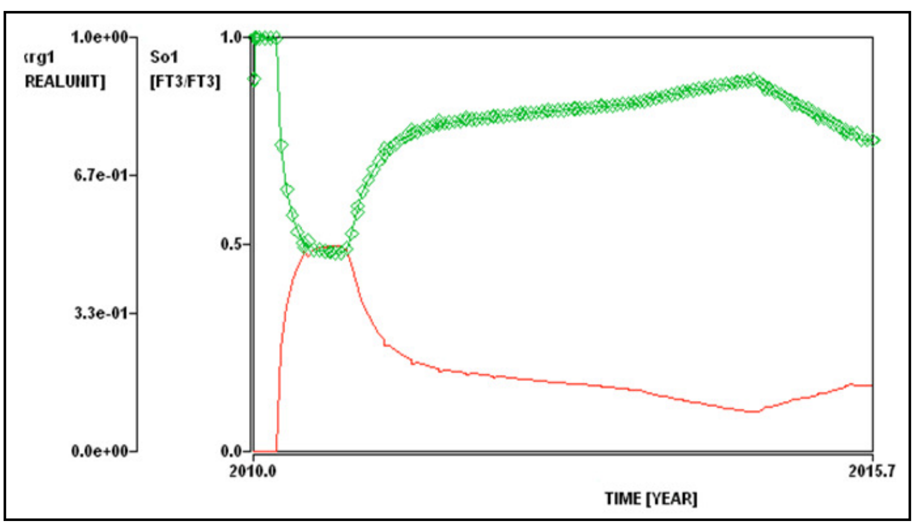

Figure 5. Relative Permeability to Gas and Condensate Saturation Plot against Time

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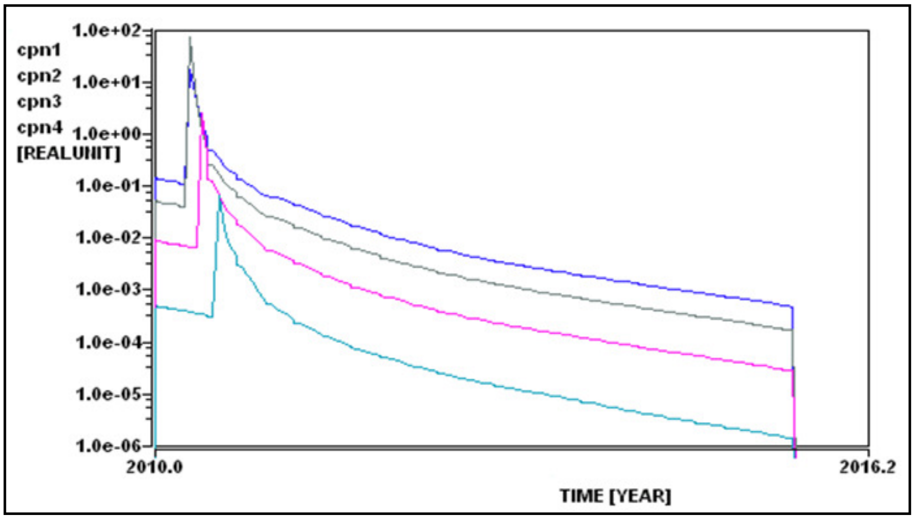

Figure 6. Capillary Number Plots for Selected Grid Blocks (Simulator generated)

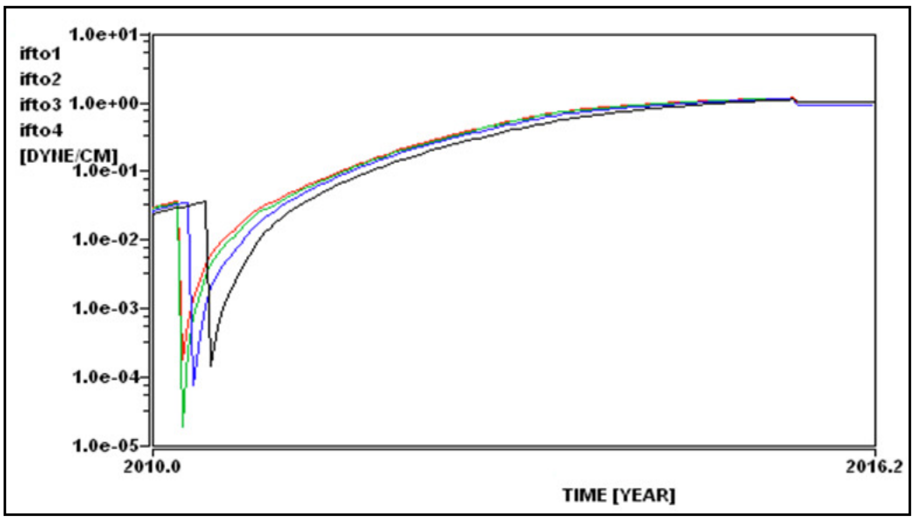

Figure 7. Prediction of Interfacial Tension Behaviour for Model Fluid

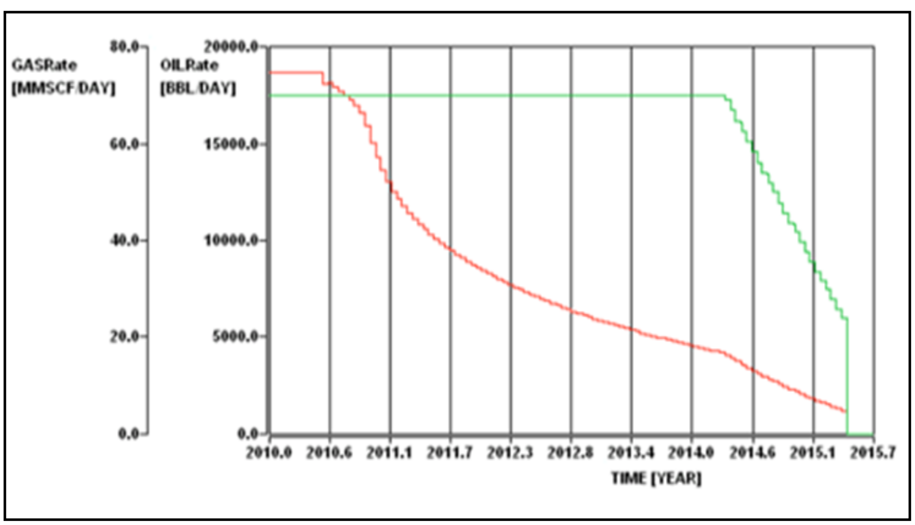

Figure 8. Gas and Condensate Production Plot of the Model

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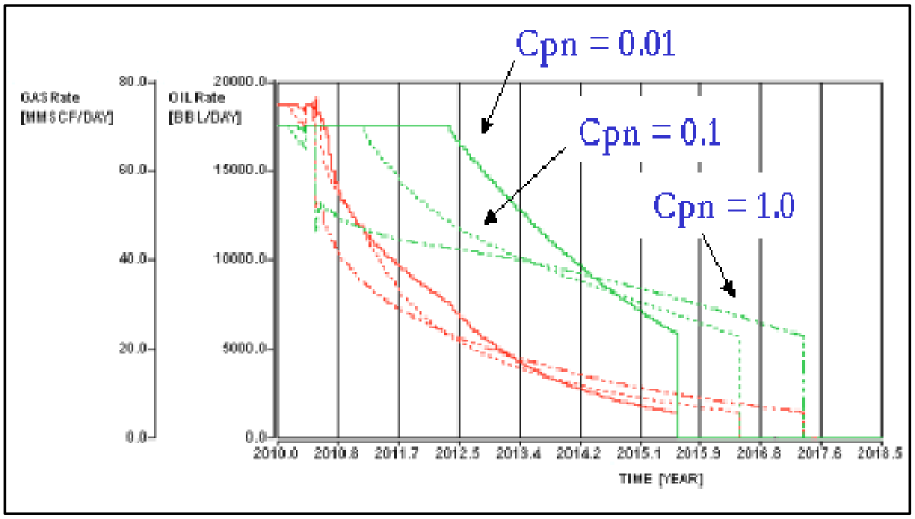

Figure 9. Dependency of Gas and Condensate Production Rates on the threshold Capillary Number necessary for Miscibility

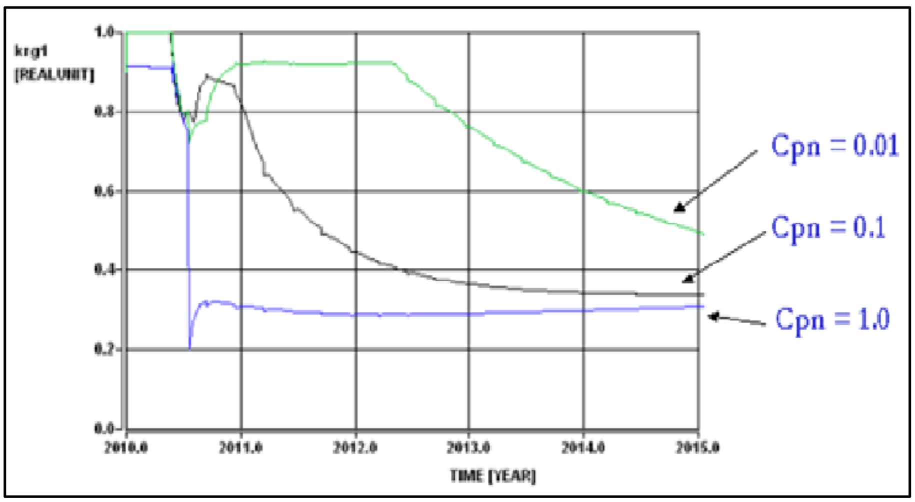

Figure 10. Relative Permeability to Gas Behaviour due to Capillary Number for Miscibility Changes

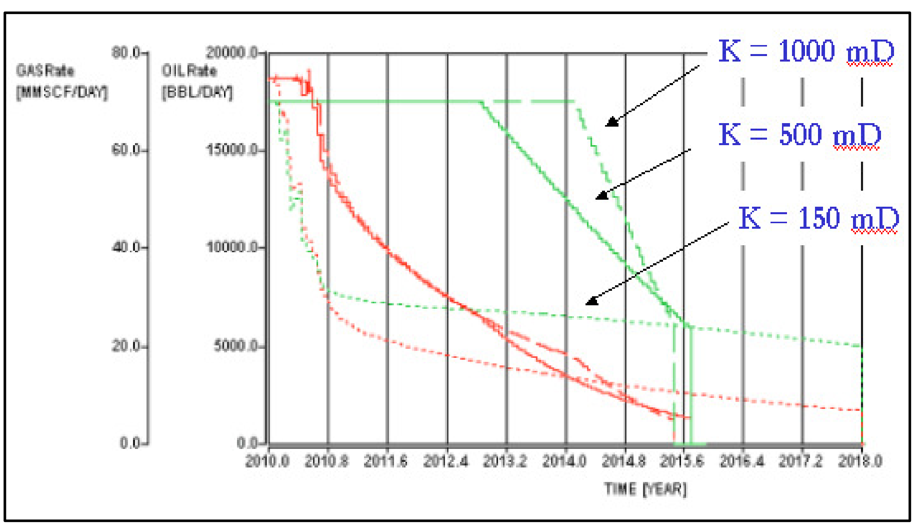

Figure 11. Gas and Condensate Production Plots for different Values of Permeability

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