EFFECTS OF NEAR WELLBORE AND RESERVOIR FLUID COMPOSITIONAL CHANGES ON CONDENSATE BANKING

A thesis presented to the Department of Petroleum Engineering

African University of Science and Technology

In partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE IN PETROLEUM ENGINEERING

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December, 2017

CERTIFICATION

This is to certify that the thesis titled "**EFFECTS OF NEAR WELLBORE AND RESERVOIR FLUID COMPOSITIONAL CHANGES ON CONDENSATE BANKING**" submitted to the school of postgraduate studies, African University of Science and Technology (AUST), Abuja, Nigeria for the award of the Master's degree is a record of original research carried out by Adanenche Daniel Edoh in the Department of Petroleum Engineering.

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By

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ABSTRACT

Gas condensate reservoirs are initially discovered as single-phase gas reservoirs. As the reservoir is produced below the fluid dew-point pressure, an increase in condensate saturation in the near wellbore region occur which reduces the relative permeability to gas and in turn causes productivity impairment. It is pertinent to predict condensate banking behavior accurately during a field's operational phase to avoid problems with a well's ability to attain production targets. This paper seeks to explore the effects of near wellbore and reservoir fluid compositional changes on condensate banking using Velocity Dependent Relative Permeability (VDRP). To achieve this, a PVT data for gas condensate reservoir from a field was used to build an input data file using Eclipse 300. A single-layer, radial, 3D reservoir model was used to investigate the effects of VDRP on productivity index, relative permeability to gas and condensate recovery. A fully perforated vertical well was located at the center of the reservoir model. The reservoir model consisted of 30 grid blocks increasing logarithmically with radius away from the wellbore. The use of fine-resolution gridding near the wellbore was to ensure that change in condensate was accurately simulated. When Velocity Dependent Relative Permeability (VDRP) option was adopted for volume flow rate of 10Mscfpd, there was no change in the gas relative permeability and productivity index. This was due to low flow rate. However, when the flow rate was increased to 1000Mscfpd and 2000Mscfpd, the gas relative permeability reduced only by 36.1% and 23.6% respectively while the Productivity Index reduced by 34.2% and 21.7% respectively. The positive effect of VDRP assisted these low values.

In contrast, for situations where VDRP does not apply, the effects of condensate banking were significant. That is, neglecting the VDRP option under the same flow rates, a reduction in the gas relative permeability and the Productivity Index was observed to be approximately 72%. Adopting VDRP does not improve the condensate recovery as expected probably due to large uncertainty in VDRP parameters due to lack of core experimental data. These results suggest that the most detrimental effect of condensate banking is caused by neglecting VDRP. It is intended that the findings of this study be used to screen for potential condensate banking in later life of wells in gas condensate reservoirs.

Keywords and Phrases: Velocity Dependent Relative Permeability, Condensate Banking, Gas Condensate Reservoirs, Capillary Number Models, Interfacial Tension, Viscous forces, Gas Relative Permeability, Productivity Index.

ACKNOWLEDGMENT

Firstly, I acknowledge and express my sincere gratitude to Saka Matemilola (Ph.D.) for his guidance and impeccably timely response during this study. Your time in reading and correcting this report is appreciated. Through this study, I have gained a better understanding of reservoir engineering, and I believe that my career is truly better for it. I thank Prof. Ogbe for the measures he put in place as the HOD to keep me on my toes, as well as his questions and suggestions during this study.

I appreciate and especially acknowledge Samuel Jemimah-Sandra for her time, support and collaboration during this study, thank you.

I acknowledge the Petroleum Technology Development Fund (PTDF) for giving me the opportunity, through a scholarship, to be part of this petroleum engineering program. I appreciate the staff, my dear friends and colleagues at the African University of Science and Technology, Abuja for your part in making my study a comfortable and meaningful one.

DEDICATION

I dedicate this work to Almighty God for the life He gave to me to be where I am today. To you alone be all thanks.

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CHAPTER ONE

INTRODUCTION

Gas condensate reservoirs are typically discovered as single-phase gas reservoirs. During the production life of wells drilled in gas condensate reservoirs, the pressure declines near-isothermally from the reservoir boundary to the well. If the well flowing bottom-hole pressure drops below the dew-point pressure, the condensate drops out of the gas and forms a bank of liquid around the well (Gringarten *et al.,* 2000; Hashemi *et al.,* 2006) which is mainly composed of intermediate and heavier hydrocarbon components.

When the condensate drops out in the reservoir, at first, the condensate liquid will not flow until the accumulated condensate saturation exceeds the critical condensate saturation. This leads to a loss of valuable hydrocarbons because the condensate contains most of the heavy hydrocarbon components. Besides that, near the wellbore where the condensate bank appears, there will be a multiphase flow, so the gas relative permeability is reduced. The reduction of gas relative permeability due to the condensate bank is called condensate blocking (or condensate banking). The condensate blocking effect leads to a reduction of gas productivity of the well. Ultimately, the buildup of condensate in the reservoir affects the economic value of the project. Characterization of a gas condensate reservoir is often an uphill task because multiphase flow exists in the reservoir and during production, there are changes in overall composition in both time and space. This situation complicates well deliverability analysis, well testing, evaluation of productivity and the sizing of surface facilities (Yami, 2003).

Extensive experimental research into the dependence of gas and condensate relative permeability on flow velocity has been conducted at Heriot-Watt University over the past decade (Danesh *et al.*, 2000), sponsored by a consortium of oil companies. Results of the experiments have demonstrated that relative permeability increases as flow velocity increases.

A mathematical model for relative permeability has been derived from the results (Danesh *et al.*, 2000) and has been implemented in some commercial reservoir simulators. The model includes Velocity Dependent Relative Permeability (VDRP) effects. This model can be used to study the condensate banking phenomenon in detail using grids fine enough to resolve the near-well region.

1.1 PROBLEM STATEMENT

Danesh *et al.* (2000) conducted extensive experimental research into the dependence of gas and condensate relative permeability on flow velocity and a mathematical model for the relative permeability was derived from the result which has been implemented in some commercial reservoir simulators. Bang *et al.* (2006) used this model to study the effect of the capillary number on gas relative permeability for different Krg/Kro ratio. No study has been carried out on the effect of this model on condensate recovery using numerical simulation.

1.2 AIM AND OBJECTIVE

The thesis aims to study in detail the effects of condensate banking on gas relative permeability and productivity index using the Velocity Dependent Relative Permeability (VDRP) model.

The objectives of the study are:

1. To build an Eclipse input data file.
2. To propose VDRP as the solution for increasing well productivity in a gas condensate reservoir.
3. To better understand the negative impact of condensate blockage on total gas production from a gas condensate reservoir.

1.3 JUSTIFICATION

The justifications of the research include the following:

- To develop an optimal production strategy for gas condensate reservoirs.
- To reduce the impact of condensate banking.
- To maximize recovery of both gas and condensate.

1.4 SCOPE

The scope of the work covers the following:

1. Build a compositional simulation model in Eclipse 300 for a gas condensate reservoir.
2. Use the model to study the effects of VDRP on gas relative permeability and productivity index from a gas condensate reservoir.
3. Identify the key parameters that drive production recovery of both gas and condensate.
4. Provide recommendations on the optimal recovery of condensate in a gas condensate reservoir.

CHAPTER TWO

LITERATURE REVIEW

2.1 PHYSICAL BEHAVIORS OF GAS CONDENSATE

2.1.1 Hydrocarbon Reservoir Fluids

Hydrocarbon reservoir fluids contain methane and a wide variety of intermediate and large molecules. The physical state of a hydrocarbon reservoir fluid depends on its composition, reservoir pressure, and temperature. If a hydrocarbon reservoir fluid contains small molecules, its critical temperature may be below the reservoir temperature, and the fluid would be in a gaseous state. However, when the hydrocarbon reservoir fluid contains heavy molecules, its critical temperature may be higher than the reservoir temperature, and the fluid would be in liquid state.

Generally, the deeper the reservoir, the higher proportion of light hydrocarbons due to degradation of complex organic molecules.

The most common classification of hydrocarbon reservoir fluids is based on the degree of volatility. According to this classification, reservoir hydrocarbon fluids are classified as gas, gas condensate, volatile and black oil. Gas is classified further as dry gas or wet gas depending on whether or not there will be liquid condensation at the surface.

2.1.1.1 Dry gas

Dry gas is mainly composed of methane and non-hydrocarbons such as N_2 and CO_2. Figure 2.1 shows a phase diagram of dry gas. Due to the lack of heavy components, the two-phase envelope is located mostly below the surface temperature. The hydrocarbon mixture is solely gas from the reservoir to the surface.

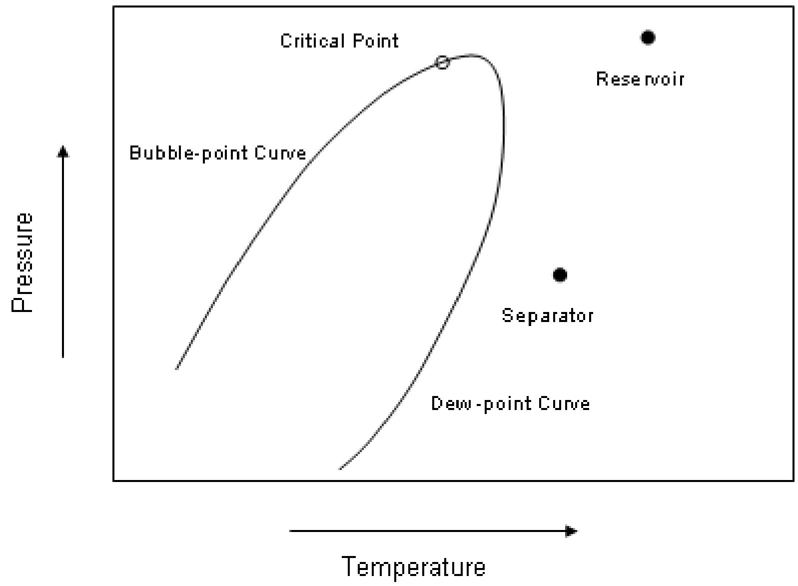

Figure 2. 1: Phase diagram of dry gas.

2.1.1.2 Wet gas

Wet gas is mainly composed of methane and other light hydrocarbons with a phase diagram as in Figure 2.2. A wet-gas reservoir exists solely as a gas through the isothermal reduction of pressure in the reservoir. However, the separator conditions lie within the two-phase envelope causing liquid formation at the surface.

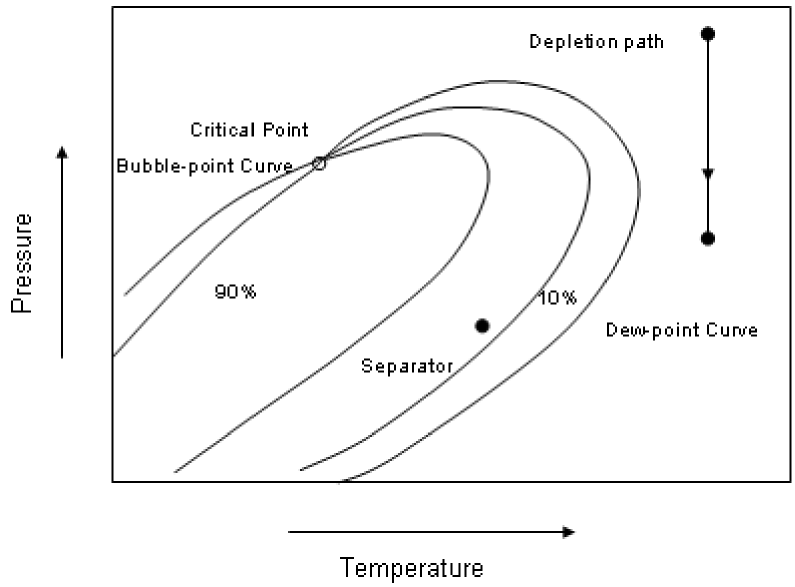

Figure 2. 2: Phase diagram with a line of isothermal reduction of reservoir pressure of wet gas.

2.1.1.3 Gas condensate

Gas condensate contains a small fraction of heavy components. The presence of the heavy components expands the two-phase envelope of the fluid mixture to the right (Figure 2.3) compared to that of wet gas (Figure 2.2). Hence, the reservoir temperature lies between the critical temperature and the cricondentherm. The liquid will dropout of the gas when the pressure falls below the dew-point pressure in the reservoir. Further liquid condensation will occur on the surface.

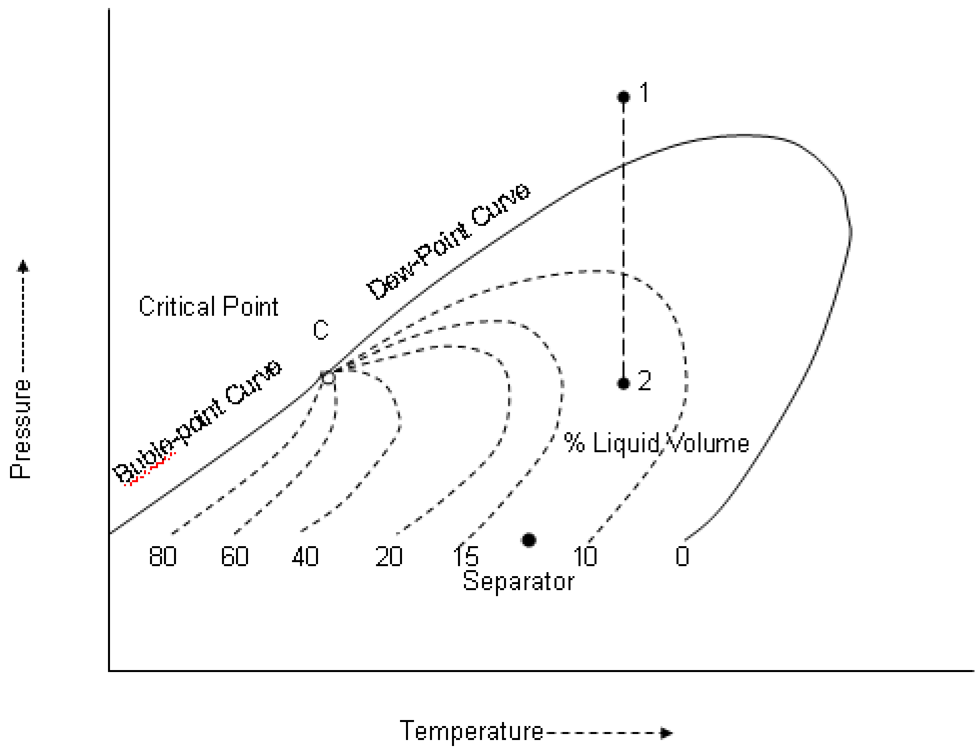

Figure 2. 3: Phase diagram with a line of isothermal reduction of reservoir pressure of gas condensate.

2.1.1.4 Volatile oil

Volatile oil contains more heavy components (heptanes plus) than gas condensate, so it behaves like liquid at reservoir conditions. A two-phase envelope of volatile oil is shown in Figure 2.4. The reservoir temperature is lower but near critical temperature. The isovolume lines are closer and tighter near the critical point, so a small isothermal reduction of the pressure below the bubble-point pressure results in a large portion of liquid volume vaporized. Hence the oil is called “volatile” oil.

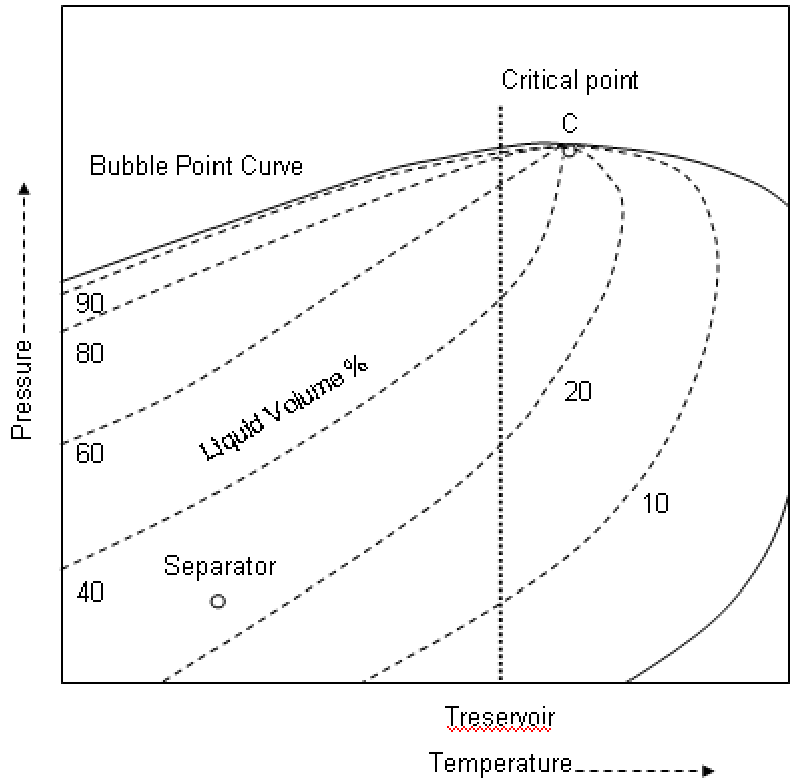

Figure 2. 4: Phase diagram with a line of isothermal reduction of reservoir pressure of volatile oil.

2.1.1.5 Black oil

Black oil (also called "low shrinkage" oil) contains a large fraction of heavy components. The two-phase envelope is widest of all hydrocarbon reservoir fluids. The critical temperature is much higher than the reservoir temperature. The bubble-point pressure of the black oil is low. The isovolume lines are broadly spaced at reservoir conditions, and the separator condition lies on a relatively high isovolume line, so a large reduction of the pressure below the bubble-point pressure (at constant temperature) results in vaporization of only a small amount of liquid. Hence, the oil is called "low shrinkage" (Figure 2.5).

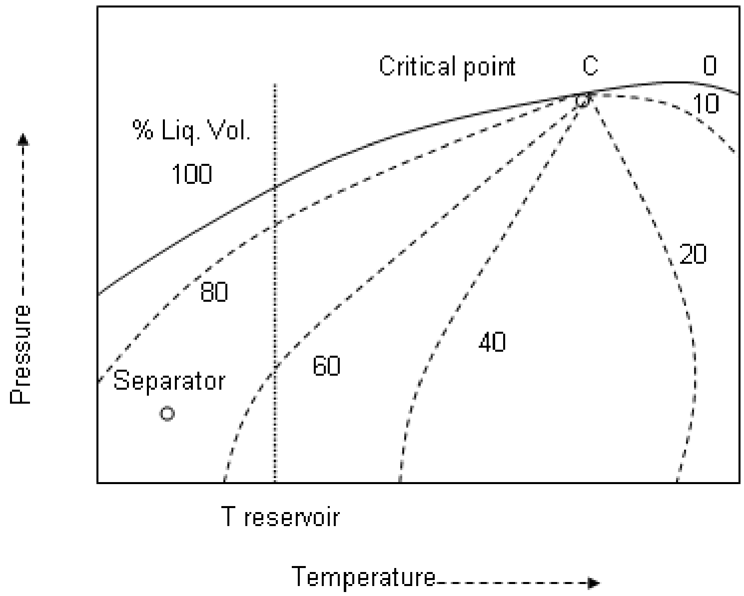

Figure 2. 5: Phase diagram with a line of isothermal reduction of reservoir pressure of black oil.

Another type of classification which is based on the surface-determined properties is listed in Table 2.1. Gas condensate reservoirs produce condensate and gas both in the reservoir and at the surface with producing gas-liquid ratio from 3,200 to 150,000SCF/STB, and the stock tank oil density changes throughout the life of the reservoir. This is different from the wet-gas reservoir where the liquid is formed only at the surface, and the density of the stock tank oil does not change. McCain (1994) further distinguished the difference between volatile oil and gas condensate based on a cut-off composition of12.5% C_{7+}.

Table 2. 1: Summary of guidelines for determining fluid type from field data

	Black Oil	Volatile Oil	Retrograde Gas	Wet Gas	Dry Gas
Initial producing gas/liquid ratio (scf/STB)	<1,750	1,750 to 3,200	>3,200	>15,000	1000,000
Initial stock-tank liquid gravity (°API)	<45	>40	>40	Up to 70	No liquid
Color of stock-tank liquid	Dark	Colored	Lightly colored	Water white	No liquid

McCain,(1994).

2.2 PHASE BEHAVIOR OF GAS CONDENSATE

Figure 2.6 shows a phase diagram with isovolume lines of the gas condensate. When the pressure is above the dew-point (B1) the fluid is single-phase gas. Isothermal depletion leads to the dew-point where the first drop of condensate occurs. If the pressure is reduced further to abandonment pressure (B1→B2→B3), the amount of condensate dropout will increase to a maximum value, then decrease due to revaporization. This characteristic is shown in Figure 2.7. However, this process assumes that liquid and gas remain immobile in the reservoir and hence that the composition is constant. In reality, because the gas is produced more from the reservoir than liquid condensate because of its higher mobility, the overall composition will change, and the two-phase envelope will shift. The critical point moves to a higher temperature and the two-phase envelope moves right and downwards.

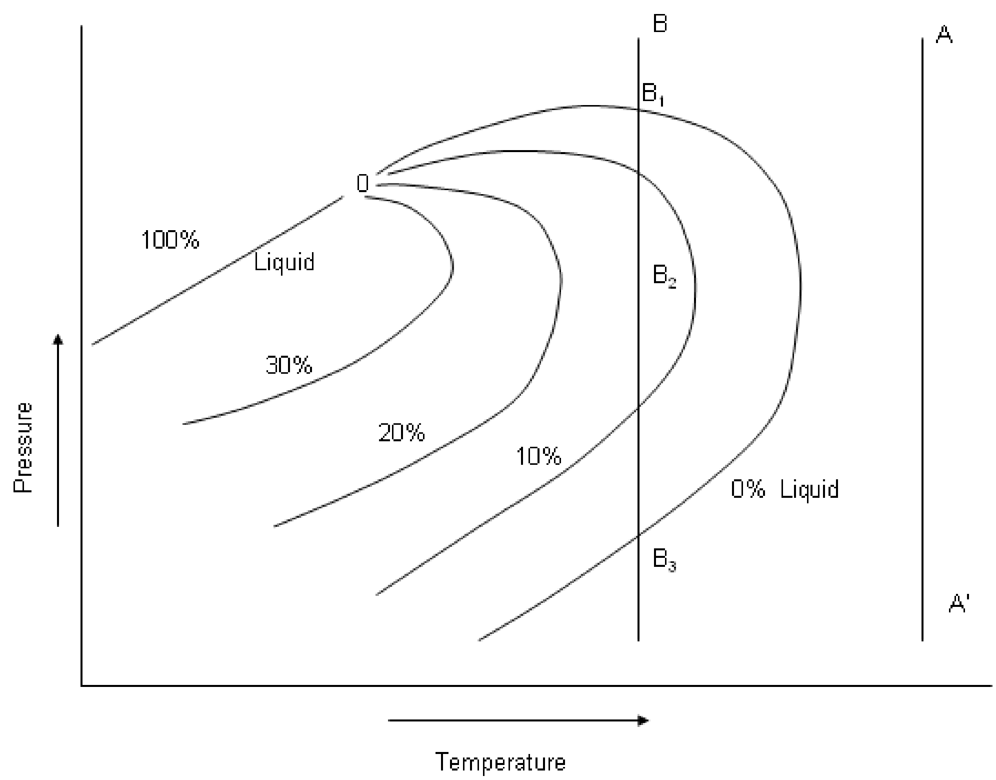

Figure 2. 6: Phase diagram with an isovolume line of gas condensate.

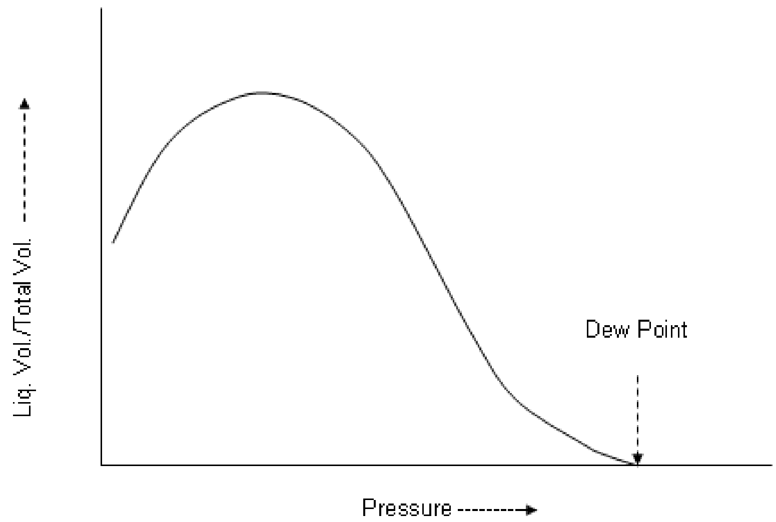

Figure 2. 7: Liquid dropout behavior of gas condensate.

To quantify the phase behavior and properties of gas condensate at reservoir conditions, two PVT tests normally done on gas condensate are Constant Composition Expansion (*CCE*) and Constant Volume Depletion (*CVD*).

2.3 FLOW BEHAVIOR OF GAS CONDENSATE

2.3.1 Drawdown Behavior

Reservoir performance during the production of a condensate well can be described as (Economides *et al.*, 1987 and Ali *et al.*, 1997):

Stage 1: Single-phase gas reservoir

For *BHP >pd*, the reservoir fluid exists as single-phase gas.

Stage 2: Mobile gas, immobile liquid

As *BHP* declines below *pd*, a condensate bank develops around the wellbore with the saturation below the critical saturation, hence the liquid is immobile.

Stage 3: Mobile gas and liquid

As production continues, condensate accumulates until the condensate saturation exceeds the critical condensate saturation in the zone near the well. Condensate liquid will flow in the reservoir.

As the liquid saturation profile continues to increase in magnitude and radial distance, eventually a steady-state is reached in which liquid dropout is equal to the liquid production.

Stage 4: Both reservoir pressure and *BHP* are below the dew-point.

The liquid condensation will occur throughout the whole reservoir.

Based on previous studies, Fevang and Whitson (1996) proposed a simple but accurate model for the flow of gas condensate into a producing well from a reservoir undergoing depletion once steady-state flow is reached. Based on this model, the fluids flow can be divided into three main flow regions (Figure 2.8):

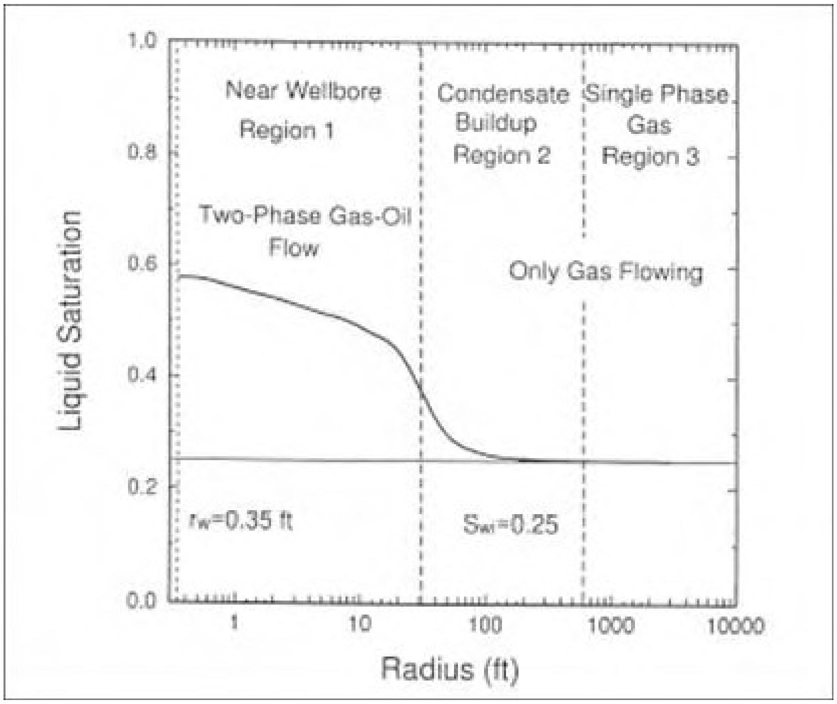

Figure 2. 8: Three regions of flow behavior in a well condensate well (from Fevang and Whitson, 1996).

Region 1: An inner near-well region where the condensate saturation exceeds the critical condensate saturation hence both gas and condensate flow (although with different velocities). In this region, the flowing composition is constant; hence the fluid properties can be approximated by the *CCE*. Region 1 is the main source of deliverability loss in a gas condensate well. Gas permeability is reduced due to the liquid blockage. The size of region 1 increases with time. Region 1 exists only if the *BHP* is below the dew-point pressure *Pd*.

Region 2: A region of condensate buildup where only gas is flowing. In this region, the pressure is below the dew-point pressure, but the condensate saturation is below the critical condensate saturation hence only gas flows in region 2. In other words, region 2 is the region of net condensate accumulation. Due to the condensate dropout, the flowing gas phase becomes leaner.

Condensate dropout in region 2 can be approximated by the *CVD* experiment corrected for water saturation. The consequence of region 2 is that the producing wellstream is leaner than calculated by the *CVD* experiment. The size of region 2 decreases with time as region 1 expands over time. Region 2 always exists together with region 1.

Region 3: An outer region where pressure is above the dew-point. Only the original gas phase is contained in this region. The composition is constant in region 3 and equal to the composition of the original reservoir gas. The fluid properties in this region can be calculated by the *CCE* experiment. Region 3 can only exist if the pressure is above the dew-point pressure.

2.3.2 Buildup Behavior

During production, as we mentioned previously, the overall composition of the gas condensate changes, as it becomes richer in heavier components. If the well is shut in, the liquid bank that is formed around the production well may not revaporize to the gas phase. In a theoretical derivation, Economides *et al.* (1987) determined conditions under which a hysteresis in condensate saturation will occur. Although a pressure buildup would indicate a revaporization based on the original gas condensate *PVT* properties, condensate accumulation in the reservoir may preclude the reverse process. Roussennac (2001) showed by simulation that if the production period is longer than a certain threshold, the fluid near the well can switch from gas condensate behavior to a volatile oil behavior. Novosad (1996) also showed in numerical simulations that during depletion of lean gas condensate, the fluid near the wellbore changes from gas condensate to near critical retrograde gas and later to volatile oil (Figure 2.9). For a rich gas condensate fluid, the fluid will change from a retrograde gas to near critical retrograde gas, a volatile oil, black oil then reverse to near critical oil and finally a dry gas. Furthermore, if the gas condensate system is near critical, the behavior during the pressure depletion is even more complicated. Double retrograde condensation, with two liquids rather than the usual single liquid phase, can occur (Shen *et al.*, 2001). In short, the thermodynamic and flow behaviors of the gas condensate during the buildup period depend on the overall composition, condensate saturation and pressure at the moment of well shut in. Hence shutting in the well after having condensate banking is not a good strategy to mitigate the condensate blockage effect because the saturation of a volatile oil will increase with pressure increase.

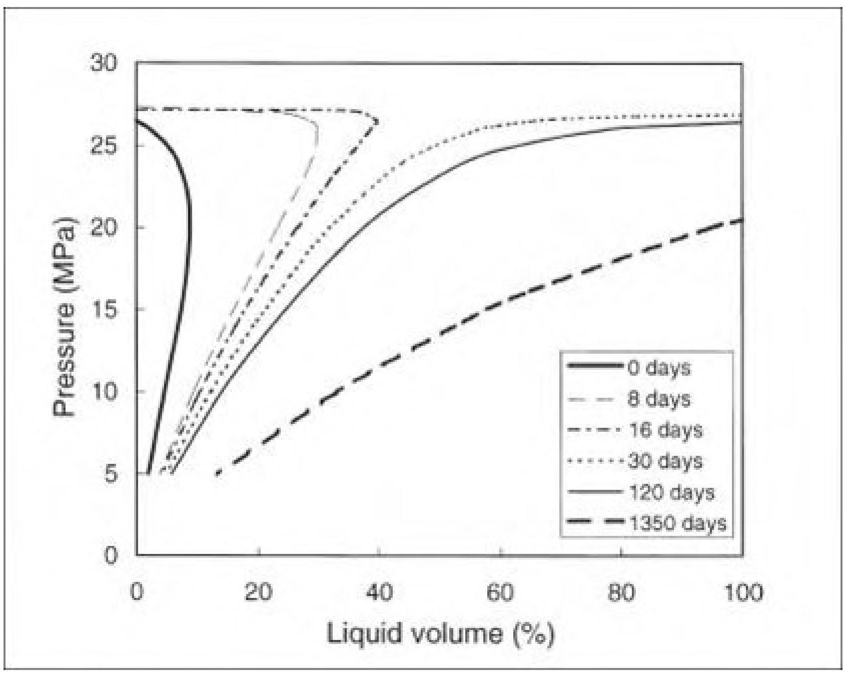

Figure 2. 9: Evolution of fluid compositions in the innermost grid block for a lean gas condensate at dew-point pressure (Novosad, 1996).

2.4 EFFECT OF FLOW VELOCITY AND INTERFACIAL TENSION ON RELATIVE PERMEABILITY

The effects of flow velocity and (gas-oil) interfacial tension are not independent and are expressed through a dimensionless capillary number defined by:

$$N_C = \frac{v_g \mu_g}{\sigma} \quad \text{.......} 1$$

Note that the same value of N_C is used for both phases.

If the capillary number is less than a threshold value, Ncb, the base relative permeability curve (Krb) is used. A low capillary number corresponds to low-velocity conditions encountered in the bulk of the reservoir and to the low-velocity/high interfacial conditions under which relative permeability curves are conventionally measured.

Once the capillary number exceeds the threshold, an interpolation between the base relative permeability curve and a "miscible" curve (Krm) is used:

$$K_r = r^{\frac{1}{n}} K_{rb} + \left(1 - r^{\frac{1}{n}}\right) K_{rm} \quad \text{.......} 2$$

Here the interpolation parameter, r, is given by:

$$r = \frac{N_{cb}}{N_c} \quad \text{.......} 3$$

and the "miscible" relative permeability curve is a straight line with a residual saturation that reduces its base value (Srb) to zero as the capillary number increases:

$$K_{rm} = \left(\frac{S^{\square} - S_r}{1 - S}\right) \quad \text{.......} 4$$

$$S_r = \left(1 - e^{-mr}\right) S_{rb} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 5$$

$$S^{\square} = \frac{S}{1 - S_w} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 6$$

The model thus has three parameters, Ncb, m, and n which may be different for each phase (gas and condensate). More generally, n may vary with saturation, but we do not use this feature.

2.4.1 Non-Darcy Flow

Reservoir simulation models are generally based on Darcy's law, which states that pressure gradient is proportional to flow rate. This is valid at a sufficiently low rate, but at a slightly higher rate, the pressure gradient is observed to increase more rapidly than the flow rate. This can be described by adding a quadratic term to obtain the well-known Forchheimer equation:

$$\frac{dp}{dx} = \frac{\mu_g v_g}{K} + \beta \rho_g v_g^2 \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 7$$

Non-Darcy flow effects are usually negligible, except in the vicinity of wells in some gas reservoirs. Where such effects are seen, they are often referred to as "turbulence," though the flow remains laminar and the extra pressure drop is due to inertia effects. In full field simulation models, non-Darcy flow effects are often modeled simply as rate dependent skin.

The Forchheimer or non-Darcy flow coefficient is usually measured for single-phase flow (in the presence of irreducible water saturation), or inferred from multi-rate well tests. When condensate is deposited in the reservoir, it is necessary to account for the variation of the Forchheimer coefficient with gas saturation. In the Velocity Dependent Relative Permeability (VDRP) model developed by Heriot-Watt University, this dependence is expressed as:

$$\beta\left(S_g\right)=\beta^{\square} S_g^c\left(K K_{rg}\right)^d \quad \text{......} 8$$

Note that the value of the Forchheimer coefficient for single-phase flow is given by:

$$\beta_{sp}=\beta^{\square}\left(1-S_{w,irr}\right)^c K^d \quad \text{......} 9$$

assuming that the end-point relative permeability to gas is equal to unity.

2.5 PREVIOUS RELATED WORKS

Table 2. 2: Previous related works

Author	Aim	Conclusion
Cho *et al.*, 1985	Presented a correlation to predict maximum condensation for retrograde condensation fluids, it is used in pressure depletion calculations.	The correlation presented was a function of the reservoir temperature and the heptanes' plus mole fraction only.
Sognesand, 1991	Discussed condensate buildup in vertically fractured gas condensate wells.	He showed that the condensate buildup depends on the relative permeability. Increased permeability to gas yield reduced the amount of condensate accumulation, and constant pressure production yields the largest near fracture condensate buildup.
Afidick *et al.*, 1994	Studied the decline in productivity of the Arun gas Condensate reservoir as a result of condensate accumulation.	The decline in the productivity of wells by a factor of around 2 as the pressure falls below the dew-point pressure was attributed to the accumulation of condensate around the wellbore.
Baguette *et al.*, 2005	Developed a novel approach for calculating representative field relative permeability based on a physical model that takes into account the various mechanisms of the process: bubble nucleation, phase transfer, and displacement.	In the model, they have identified a few neither invariant parameters that are not sensitive to depletion rate and are specific to the rocks/fluid system. These invariants are determined by history, matching one experiment at a given depletion rate.
Jamiolahmady *et al.*, 2006	Used a larger data bank of gas condensate relative permeability to develop general correlation accounting for the combined effect of coupling and inertia as a function of fractional flow.	The result shows that the correlation can provide reliable information on variations of relative permeability near wellbore conditions with no requirement for expensive

		measurement.

CHAPTER THREE

METHODOLOGY

A single-layer, radial, 3D reservoir model was used to investigate the effect of Velocity Dependent Relative Permeability (VDRP) on productivity from gas condensate reservoir with the aid of Eclipse 300 reservoir simulation software. A fully perforated vertical well was located at the center of the reservoir model. The reservoir model consists of 30 grid blocks increasing logarithmically with radius away from the wellbore. The use of high-resolution gridding near the wellbore was undertaken to ensure that changes in condensate saturation are accurately simulated. The reservoir description, properties and reservoir grid distribution of the gas condensate reservoir model are listed in Table 3.1 and Table 3.2 respectively.

Table 3. 1: Reservoir Grid Dimension and Description

Grid Dimension	30 x 1 x 1
Datum Depth (ft)	13200
Gas/Water Contact	13201
Initial Pressure at Contact (psia)	8000
Water Density at Contact lm/ft^3	63
Water Compressibility psi^{-1}	3.0 x 10^{-6}
Capillary Pressure at Contacts (psi)	0
Porosity	0.2
Thickness (ft)	100
K_x (md), K_z (md)	100

Table 3. 2: Grid size Distribution of the 3D, Radial Reservoir Model Used in Simulations

Innermost Grid Radius (ft)	0.2917
Reservoir Grid Cell Size in Radial Direction, (ft)	1.75 1.72 1.73 1.74 1.75 1.76 1.77 1.78 1.79 1.80

	1.9541 2.4544 3.0827 3.8719 4.8631 6.1081 7.6718 9.6358 12.1026 15.2009 19.0924 23.9802 30.1192 37.8299 47.5146 50.55 109.21 235.92 509.68 1101.08

Figures 3.1 and 3.2 show the 3D view and the TOP view respectively of the reservoir model described in the Tables 3.1 and 3.2.

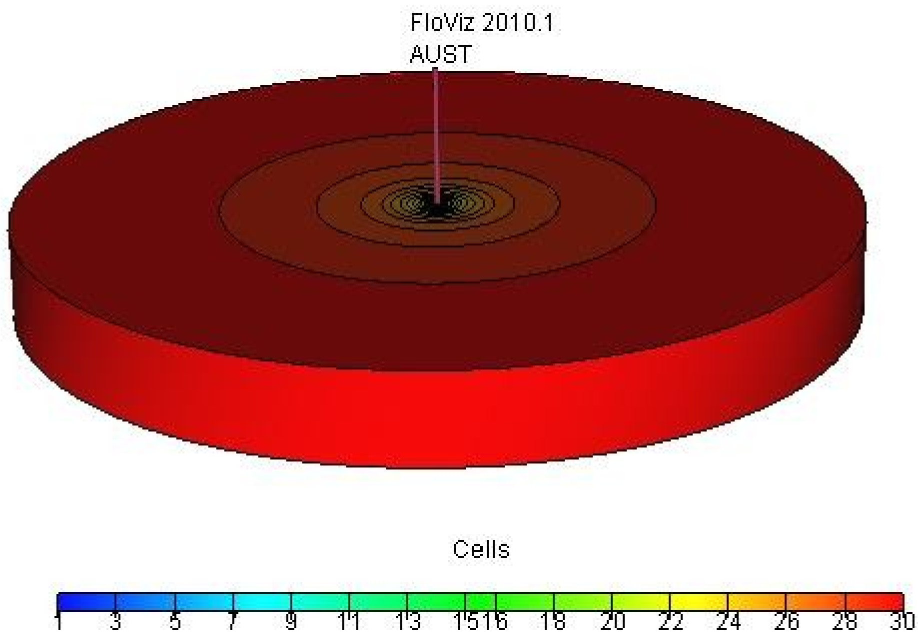

Figure 3. 1: 3D view of the radial compositional gas condensate reservoir model used in the simulations

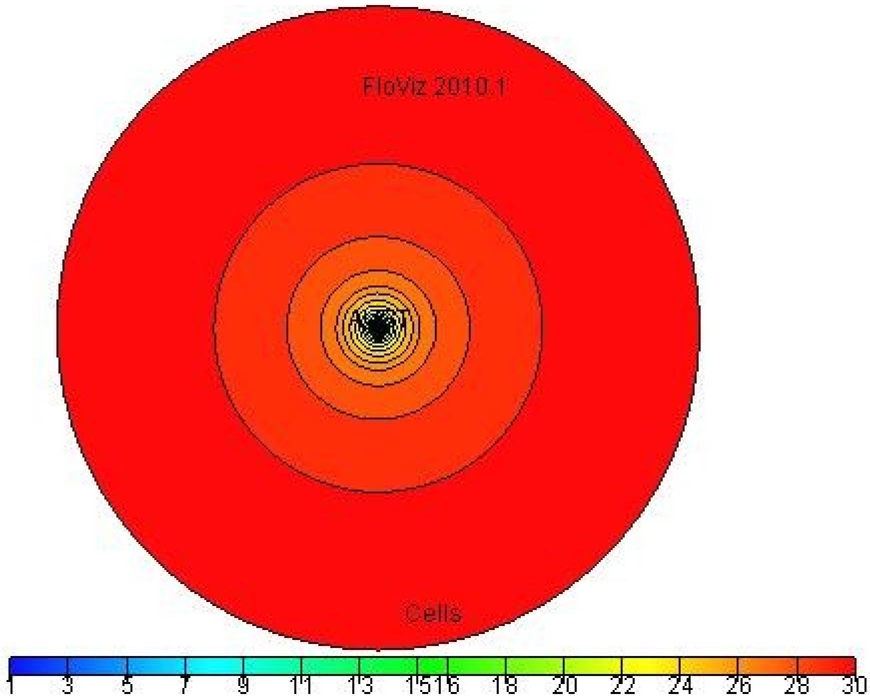

Figure 3. 2: Top view of the radial compositional gas condensate reservoir model used in the simulations

CHAPTER FOUR

4.0 RESULTS AND DISCUSSION

In order to evaluate the condensate banking phenomena and velocity effects on production from gas condensate reservoir, the gas relative permeability (Krg) of the innermost cell was compared between two cases for different volume flow rates and velocities; one was the simulated Krg with Velocity Dependent Relative Permeability (VDRP) option and the second was "base Krg" that assumed a no-VDRP option. According to Bang *et al.* (2006), the implementation of VDRP parameters alter relative permeability properties and hence the Productivity Index (PI) depending on rate.

Figure 4.1 shows the comparison of "simulated Krg with VDRP option" and "base Krg without VDRP option" in case 1 and case 2 for volume flow rate of 10 Mscf/day. It was evaluated that the "simulated Krg with VDRP option" and the "base Krg" did not show any difference as the gas relative permeability decreased at a constant rate for the two cases. As can be seen from Figure 4.1, the gas relative permeability remained unchanged for the two simulation cases due to the low volume flow rate.

Under steady-state production conditions (VDRP enabled) and unsteady state condition (VDRP disabled), it was found that a volume flow rate of 10 Mscf/day resulted in no difference in the PI for the two simulation cases as can be seen in Figure 4.2. This is because of the low volume flow rate.

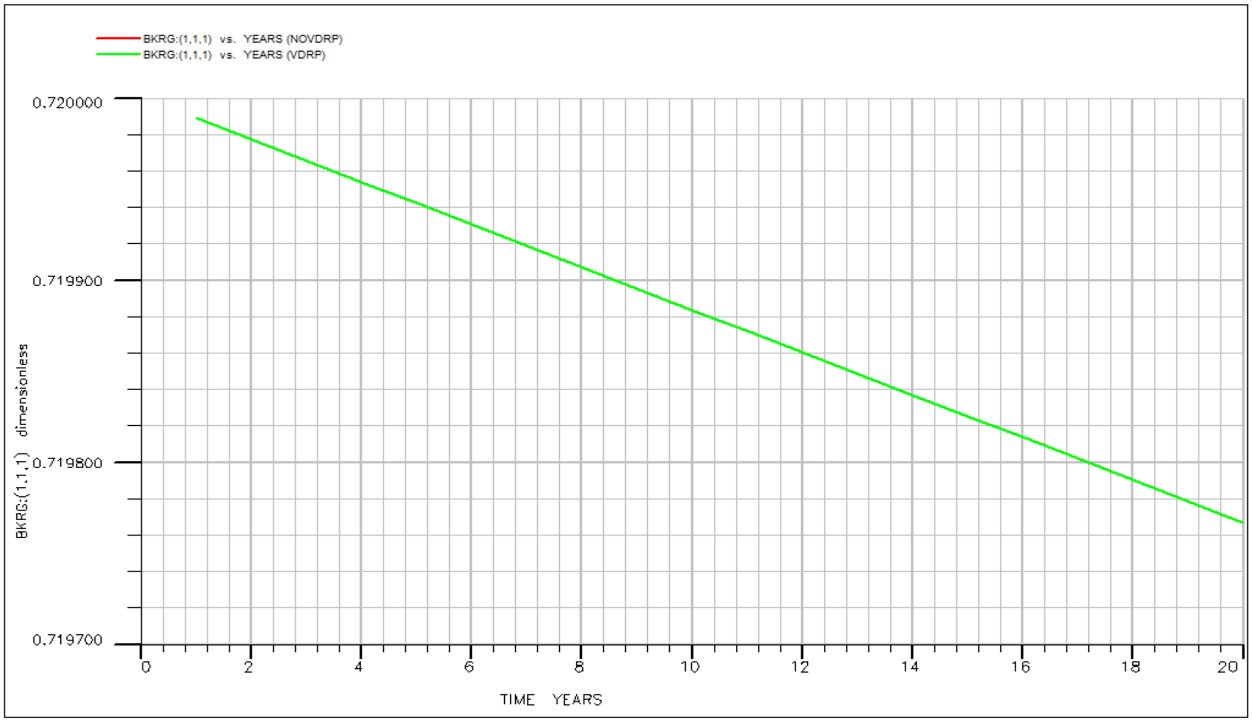

Figure 4. 1: Block Relative Permeability for 10Mscf/Day

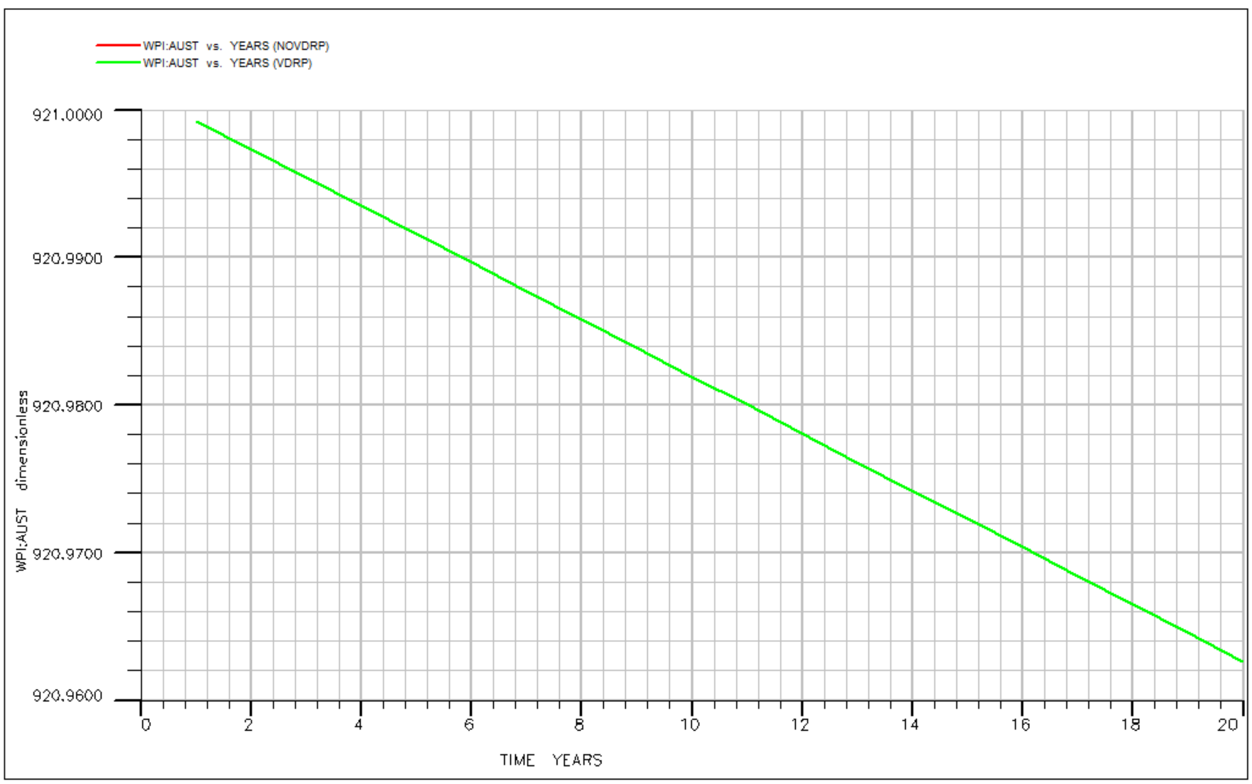

Figure 4. 2: Well Productivity Index for 10Mscf/Day

Figure 4.3 shows the near wellbore relative permeability for the two cases. The first simulation neglects the VDRP, and the other includes VDRP. It was observed that the simulated Krg with Velocity Dependent Relative Permeability option reduced by 36.1% due to condensate dropout after the first 12 years of production. However, the reduction of Krg, in this case, was not as severe as the case that neglects the VDRP option which accounts for 72.2% reduction in the gas relative permeability after 12 years of production. The difference in the near wellbore gas relative permeability for the two cases was as a result of the increased volume flow rate from 10 Mscf/day to 1000 Mscf/day which in agreement with the work of Bang *et al.* (2006)

Figure 4. 3: Block Relative Permeability for 1000Mscf/Day

Similarly, Figure 4.4 shows the PI for the same volume flow rate of 1000 Mscf/day. It was observed that the PI only dropped by 34.8% when the VDRP option was used. This is due to the positive effect of velocity. However, the reduction in PI reached 71.7% when the Velocity Dependent Relative Permeability option was neglected.

Figure 4. 4: Well Productivity Index for 1000Mscf/Day

Figure 4.5 shows the comparison of "simulated Krg with VDRP option" and the "base Krg neglecting VDRP option." It was observed that the gas relative permeability with VDRP option reduced by only 23.6% for volume flow rate of 2000 Mscf/day but this time after 6 years of production due to condensate dropout. However, when the VDRP option was neglected for the same flow rate, the reduction in Krg reached 72.2%. Under steady-state production conditions (VDRP enabled), it was found that a volume flow rate of 2000 Mscf/day resulted in only a slight drop in PI of 21.7%. When the VDRP is disabled, simulating unsteady state, a far more profound impact was observed as the PI dropped by 71.7% after 6 years of production as can be seen from Figure 4.6.

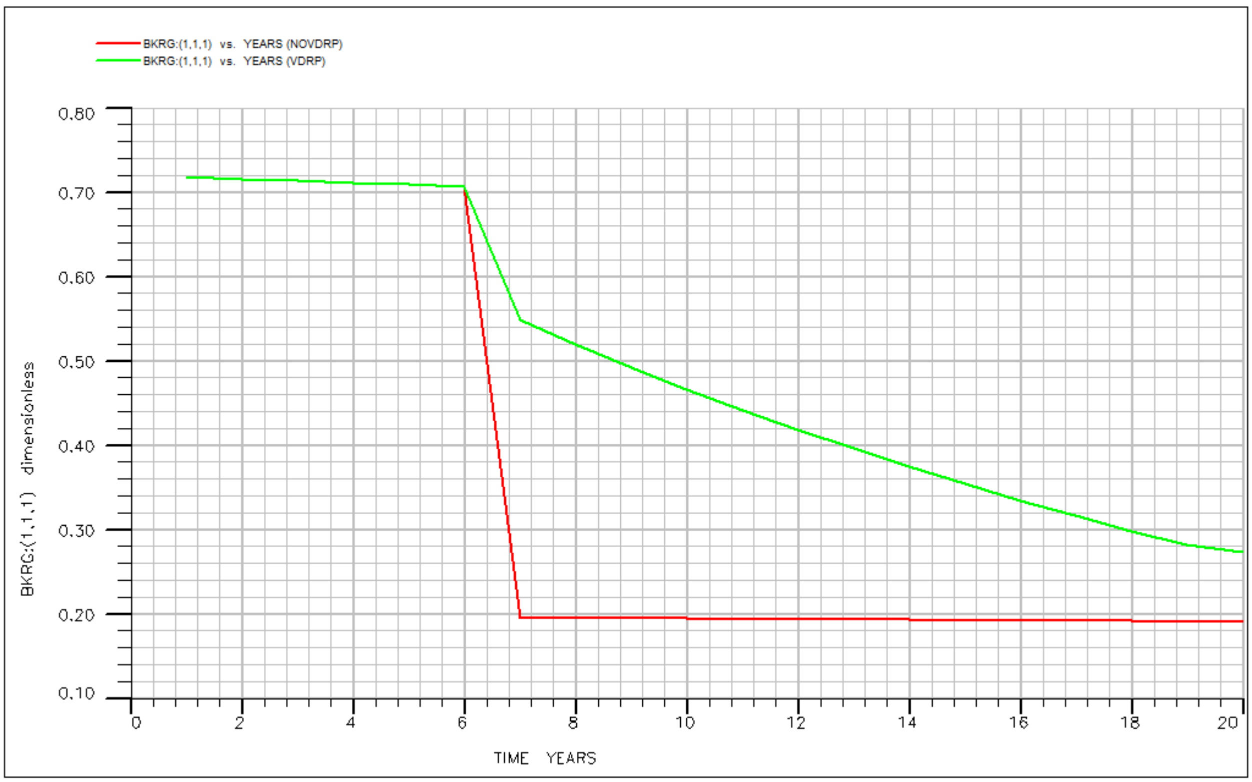

Figure 4. 5: Block Relative Permeability for 2000Mscf/Day

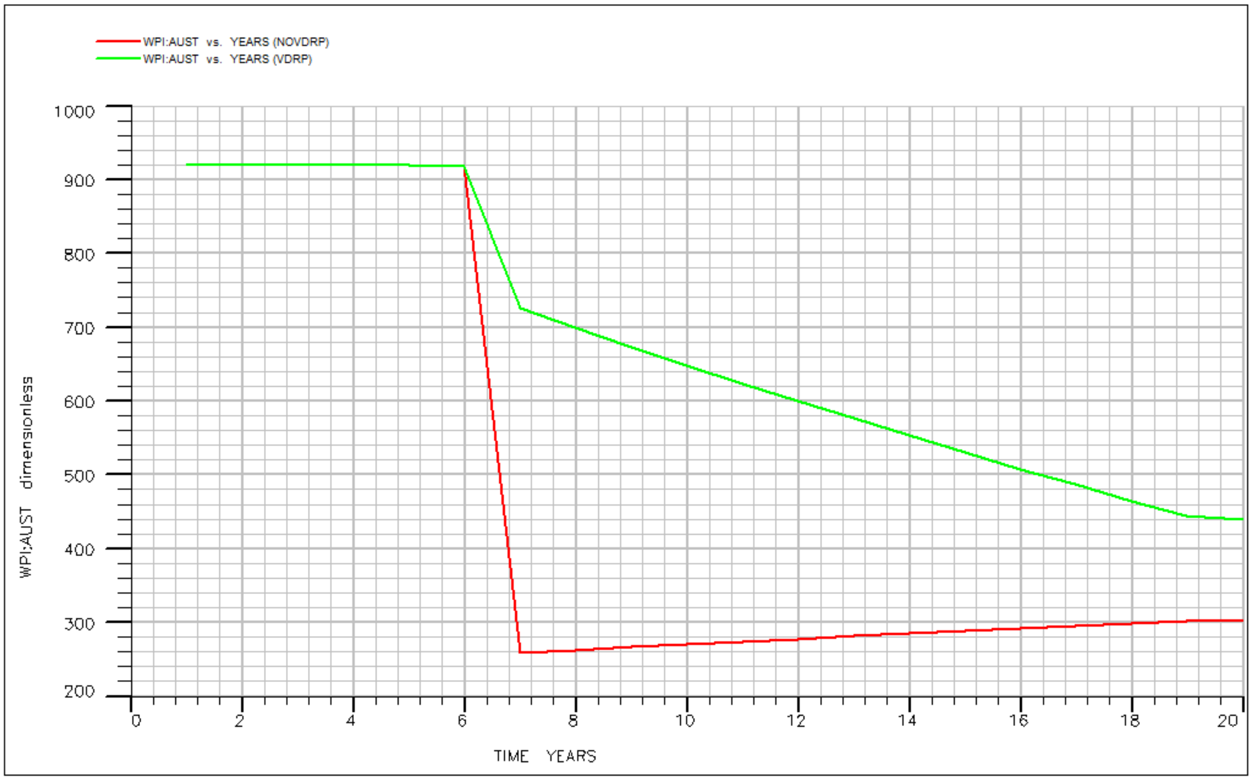

Figure 4. 6: Well Productivity Index for 2000Mscf/Day

The volume flow rate was further increased to 5000 Mscf/day (see Figure 4.7) in the absence of the VDRP option; the gas relative permeability dropped by 72.2% as in the previous cases. However, when the VDRP option was introduced for the same flow rate, it was observed that the drop in the gas relative permeability was no longer stable. This is probably due to the fact that a volume flow rate greater than or equal to 5000 Mscf/day would no longer result in an improved gas relative permeability and hence poor productivity.

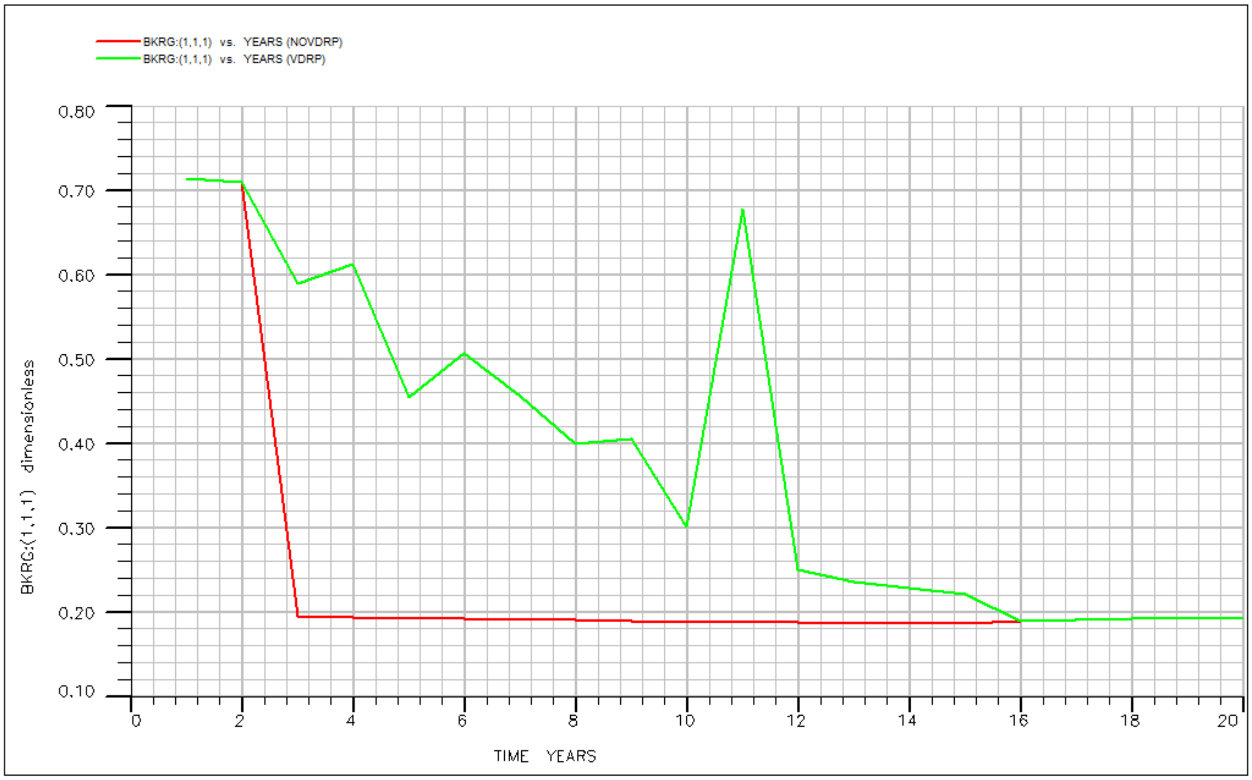

Figure 4. 7: Block Relative Permeability for 5000Mscf/Day

Bang *et al.*, (2006) studied the general correlation of Relative Permeability of Gas Condensate Fluids. They concluded that at high flow rate typical of many gas condensate wells, the relative permeability is rate dependent and that such rate dependence can be modeled using a capillary number to calculate the decrease in residual saturation and the corresponding increase in relative permeability as viscous forces become dominant over the interfacial forces.

To achieve this, *Bang et al.,* (2006) showed the gas relative permeability data as a function of capillary number for different Krg/Kro ratios along with the work of Henderson *et al.,* Cable *et al.,* Kumar *et al.,* and Berea as depicted by Figure 4.8.

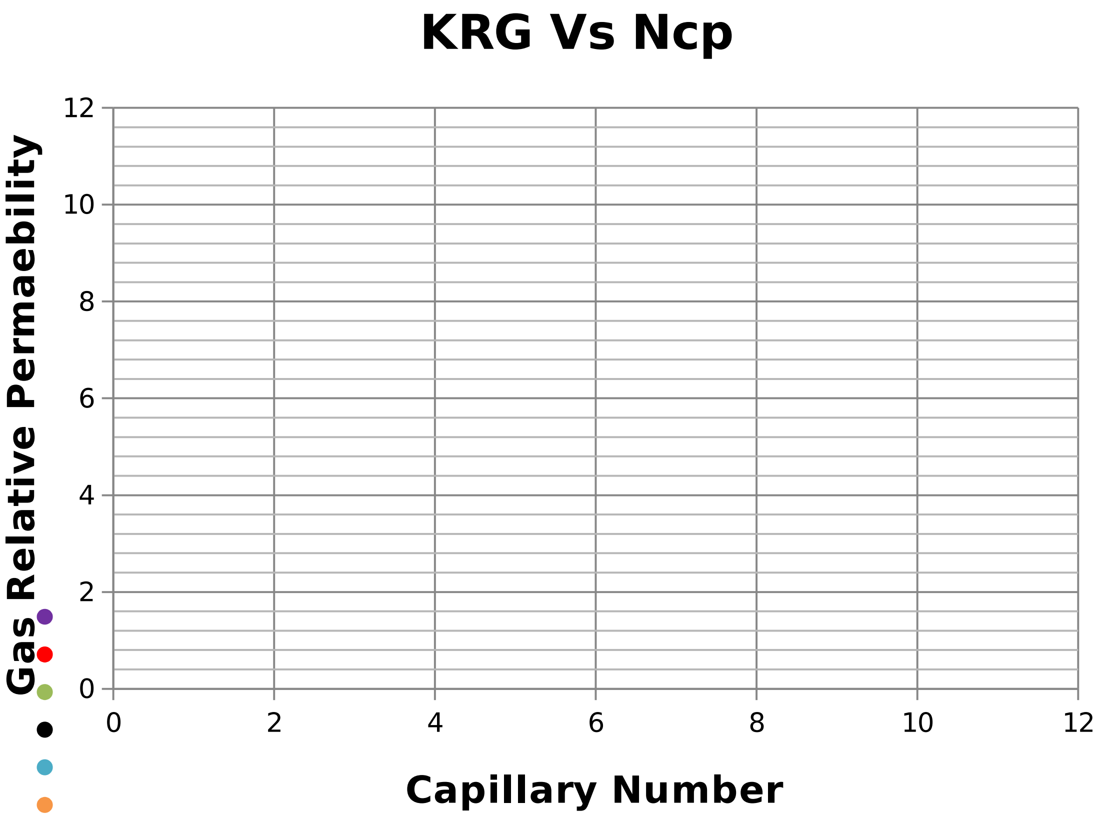

Figure 4. 8: Comparison of Findings with Established Experimental Results

From Figure 4.8, the purple bubbles are the result we obtained by adopting the VDRP option which is in agreement with the work of Bang *et al.*, Henderson *et al.*, Cable *et al.*, Kumar *et al.* and Berea. The figure shows that the gas relative permeability is improved by increasing the flow rate when VDRP is adopted in simulating gas condensate reservoirs since the capillary number is directly related to flow rate by Equation 1.

It has been established that adopting VDRP improves gas relative permeability when simulating gas condensate reservoirs, but it is not clear from literature if this improvement results in improved condensate recovery.

Figures 4.9, 4.10 and 4.11 show the trend of condensate recovery when VDRP is adopted and when it is neglected for different flow rates (10 Mscfpd, 1000 Mscfpd, and 5000 Mscfpd)

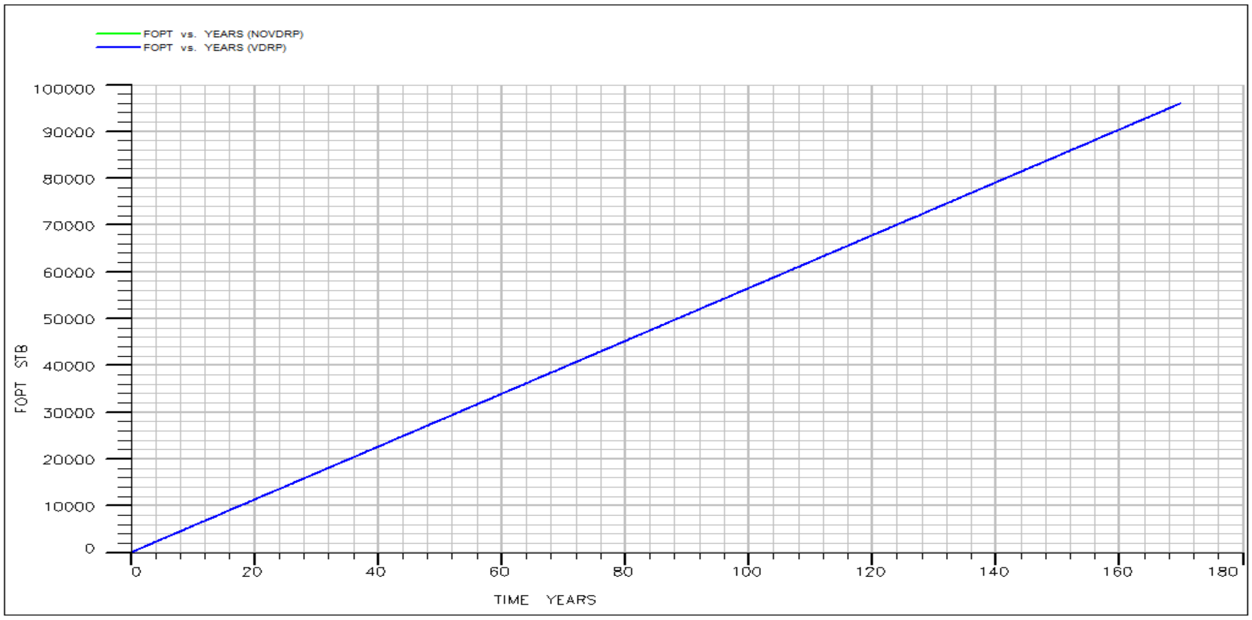

Figure 4.9: Condensate Recovery for Flow Rate of 10 Mscf/Day

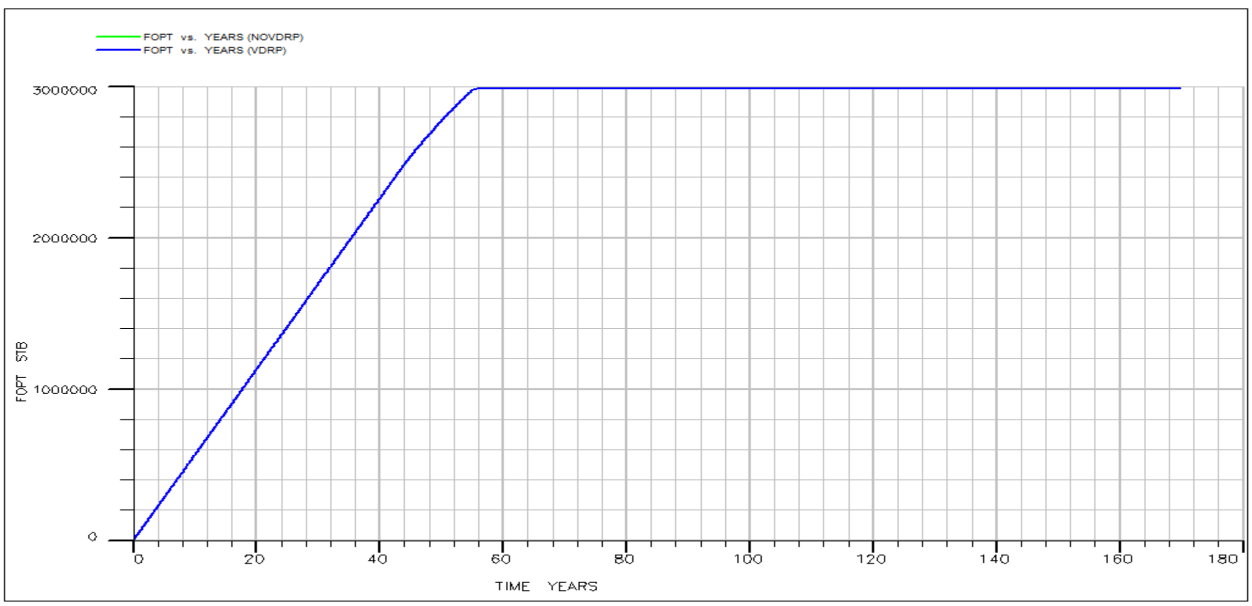

Figure 4.10: Condensate Recovery for Flow Rate of 1000 Mscf/Day

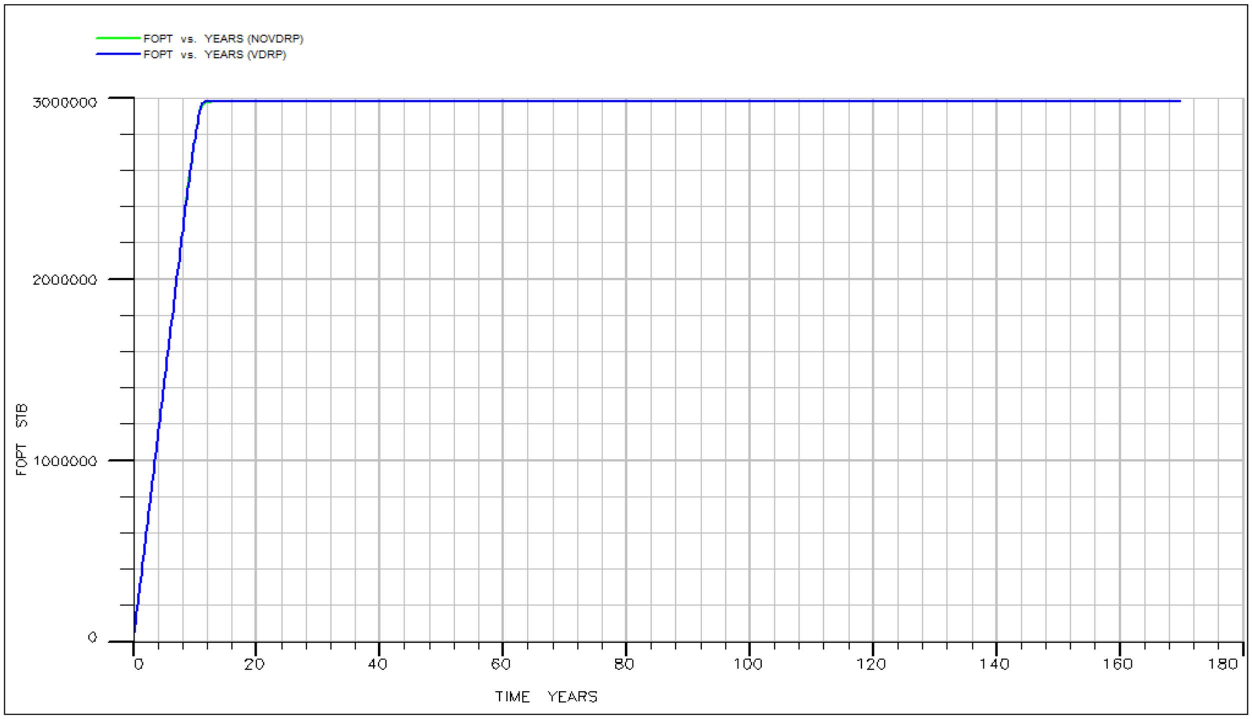

Figure 4.11: Condensate Recovery for Flow Rate of 5000 Mscf/Day

From Figures 4.9, 4.10 and 4.11, it can be observed that adopting VDRP when simulating gas condensate reservoir does not improve the condensate recovery as expected. This may be as a result of large uncertainty in VDRP parameters due to lack of core experimental data.

CHAPTER FIVE

CONCLUSION

The concept of Velocity Dependent Relative Permeability (VDRP) was adopted to evaluate the impact of condensate banking phenomena and velocity effect using field data from literature, and the following conclusions were made:

1. Adopting VDRP improves KRG and PI with increasing flow rate.
2. Neglecting the VDRP option leads to a large drop in KRG and PI.
3. Adopting the VDRP model does not improve condensate recovery probably due to the low range of flow rate and gas composition.
4. Large uncertainty in VDRP parameters due lack of core experimental data.
5. Adopting the VDRP concept would improve the accuracy of the performance prediction for a similar gas condensate reservoir.

Recommendation

1. The Velocity Dependent Relative Permeability (VDRP) model should be adopted to better model and simulate gas condensate reservoirs, but the model parameters should be calibrated with actual measured core data for more accurate results.
2. Rich gas condensate should be used for the simulation to see if there will be a difference in the condensate recovery.
3. A wider range of flow rate up to 2BSCF/Day should be used in the simulation if that will result in a change in the condensate recovery.

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