Optimizing Recovery in Gas Condensate Fields

By

Yong Han Seah

A report submitted in partial fulfilment of the requirements for the MSc and/or the DIC.

September 2013
DECLARATION OF OWN WORK

I declare that this thesis

Optimizing Recovery in Gas Condensate Fields

is entirely my own work and that where any material could be construed as the work of others, it is fully cited and referenced, and/or with appropriate acknowledgement given.

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Abstract

Well deliverability impairment resulting from liquid drop-out in gas condensate fields has been the central issue in gas condensate study over the past 60 years. Gas condensate fields usually exhibit complex flow behaviours due to phase behaviour and compositional changes, resulting in the production of gas and liquid condensates below the dew point pressure. Condensate bank gradually evolves and accumulates around the wellbore when the well bottom-hole pressure drops below the dew point pressure as production time progresses, forming a “condensate ring” around the wellbore which effectively reduces the relative permeability to gas flow. As a result, gas production decreases and liquid condensate which is a valuable resource of the field is now left behind in the reservoir.

Previous studies have demonstrated various solutions to remediate this productivity loss, including drilling horizontal wells to substitute for vertical wells, acid stimulation after the condensate bank has developed and hydraulically fracturing vertical wells before or after the formation of the condensate bank. To date, however, there has been little discussion about the importance of reservoir management in terms of operational decisions in the study of gas condensate fields. Good operational decisions yield higher field recovery efficiency.

In this study, compositional reservoir simulation cases have been constructed, using representative condensate fluid models, to predict condensate drop-out under typical operating conditions and to quantify the effectiveness and productivity increase from different production methods and remediation solutions below the dew point pressure. Sensitivity studies and optimization workflows have been used to test different methods to improve productivity, including well production control mode, well configuration and well stimulation study to minimize condensate build-up. Velocity-dependent relative permeability models have been incorporated into the simulation models to estimate the well deliverability accurately. Compositional analysis has been performed to distinguish between rich and lean gas condensates by examining the condensate-gas-ratios and phase diagrams. A single-well model was used at the initial stage of the study to investigate the different control modes that can be implemented for the production from the gas condensate field. The same methodology has been extended to the full field model in which the performance of employing 6 vertical wells was compared to that of the 2 horizontal wells in low permeability and tight gas condensate fields.

Overall, horizontal wells and well stimulation both improve well productivity to different extents. Nonetheless, the degree of productivity enhancement depends greatly on well and reservoir parameters such as horizontal well lengths, well placement, reservoir permeabilities and gas condensate compositions. In a low permeability gas condensate reservoir, the 6 vertical wells have a slightly better performance than the 2 horizontal wells for the same amount of field gas production. On the contrary, the performance of the 2 horizontal wells in a tight gas condensate reservoir is superior to that of the 6 vertical wells; generating 47% more gas recovery than the 6 vertical wells. Well stimulation increases the productivity of the vertical wells in tight gas condensate reservoir; however, it is not as effective when compared to the use of horizontal wells. The significance of the use of horizontal wells in tight gas condensate fields must not be overlooked. Consequently, recommendations for further studies have been proposed.
Acknowledgements

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I am grateful to Schlumberger Abingdon Technology Center for generously providing me with a great working environment and with all the resources necessary for this project to be successful. I would also like to thank all the Schlumberger interns for providing a fun and cheerful environment to work in.

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Finally, I would like to dedicate this thesis to my grandmother and my parents for their love, support, encouragement and unconditional sacrifice throughout my life.
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Overall, horizontal wells and well stimulation both improve well productivity to different extents. Nonetheless, the degree of productivity enhancement depends greatly on well and reservoir parameters such as horizontal well lengths, well placement, reservoir permeabilities and gas condensate compositions. In a low permeability gas condensate reservoir, the 6 vertical wells have a slightly better performance than the 2 horizontal wells for the same amount of field gas production. On the contrary, the performance of the 2 horizontal wells in a tight gas condensate reservoir is superior to that of the 6 vertical wells; generating 47% more gas recovery than the 6 vertical wells. Well stimulation increases the productivity of the vertical wells in tight gas condensate reservoir; however, it is not as effective when compared to the use of horizontal wells. The significance of the use of horizontal wells in tight gas condensate fields must not be overlooked. Consequently, recommendations for further studies have been proposed.

Introduction

The continuous development in drilling and logging technologies has allowed for more deep and high pressure, temperature gas condensate reservoirs to be discovered and developed. In addition, most mature gas condensate fields worldwide are at the later stage of their field life, gradually approaching their dew point pressure below which liquid condensate drops out. Globally, the increasing demand for natural gas supply on world markets in recent years has stimulated interest in developing gas reservoirs (BP Statistical Review of World Energy 2013). Companies now proactively explore new ways to optimize their gas-condensate resources.

Gas condensate reservoirs exhibit complex flow behavior due to the existence of a two-fluid system, reservoir gas and liquid condensate, as a result of retrograde condensation when the bottomhole flowing pressure drops below the dew point pressure. The past 60 years have seen increasingly rapid advances in the study of gas condensate flow behaviour. It was discovered that three concentric regions with different liquid saturations emerge around a gas condensate well producing below the dew point pressure (Kniazeff and Naville 1967). Away from the well, an outer region contains the initial liquid saturation; next, an intermediate region having a rapid increase in liquid saturation and a corresponding reduction in gas relative
permeability. Liquid in this region is still immobile because the critical saturation has not been reached yet. Nearer to the well, an inner region forms where liquid saturation exceeds the critical saturation and both the reservoir gas and liquid condensate flow into the well with constant composition.

A fourth region in the immediate vicinity of the well with low interfacial tension resulting from high flow rate yields lower liquid saturation and higher gas relative permeability (Gringarten et al. 2000). The existence of this fourth region is important because it counters the productivity loss caused by liquid dropout. This region is where the capillary number effect is dominant over the inertial resistance effect, contributing to higher gas productivity/recovery. As a result, it affects the final decision made in the production planning of a gas condensate field. Gas condensate dropout near the wellbore must be considered, as changes in fluid saturations affect relative permeabilities.

**Background and Theory**

In 1949, Muskat first suggested that liquid condensate builds up around the wellbore when bottomhole pressure drops below the dew point pressure in his research on gas cycling and explained mathematically the condensate saturation profile around a producing well in a gas condensate reservoir. Eilerts et al. and Kniazeff and Naville each published a paper in 1965 in which they modeled gas condensate well deliverability numerically with respect to time and radial distance respectively and studied the effects of non-Darcy flow on well deliverability. Two years later, Gondoin et al. (1967) extended the work by Kniazeff and Naville (1965) and demonstrated the significance of non-Darcy flow effects and condensate blockage by applying their formulations to the results data of backpressure tests from Hassi Er R’Mel field, Algeria. O’Dell et al. (1967), on the other hand, applied Muskat’s solutions and presented a pseudo-pressure function to describe the gas condensate blockage.

In 1973, Fetkovich developed a rate and time dependent skin based on Muskat’s results and incorporated it into the standard gas flow equation. Subsequently, Fevang and Whitson (1996) applied the modified form of the Evinger-Muskat pseudopressure to calculate gas-condensate well deliverability and provided a simple method for calculating bottom-hole flowing pressure in coarse-grid models. A more recent study by Gringarten et al. (2000) established the use of 3-region composite model to analyze gas condensate well tests data.

Well productivity index, i.e. the relationship between pressure drop and flow rate, is complicated in gas condensate reservoirs below the dew point pressure due to the existence of the “fourth region” with lower interfacial tension and higher gas relative permeability. The two velocity-dependent relative permeability effects contributing to the existence of the near wellbore region are the Capillary Number effect, also referred to as “velocity stripping”, “viscous stripping” or “positive coupling” effect, and the non-Darcy flow or inertial resistance effect introduced by Forchheimer (Belhaj et al. 2003). A compositional reservoir simulator has been used to model the complex flow behavior of gas condensates, with very fine grids near to the well as pressure drawdown predominantly occurs within 10 ft of the wellbore (Mott et al. 2000).

**Velocity-dependent Relative Permeability effects**

**Capillary number effect**

Previous studies have reported that gas deliverability increases as a result of an increase in the gas relative permeability at high velocity when the Capillary Number is high (Danesh et al. 1994; Henderson et al. 1995 and 2000; Ali et al. 1997; Gringarten et al. 2000). Danesh et al. (1994) was the first to address the improvements of relative permeability to gas flow in condensate systems with increases in velocity or decreases in interfacial tension through their laboratory experiments results. Miscibility between the flowing phases due to reduced interfacial tension at high velocities, which increases mobility for oil and gas, can be modeled in the compositional simulator using various different options for velocity-dependent relative permeability.

Capillary Number is basically the ratio of viscous to capillary forces and can be represented by a single parameter, $N_c$. The $N_c$ effect is limited only to compositional simulations below the dew point pressure with systems that exhibit retrograde condensation. Several field production data have revealed that the deliverability is higher than the conventional simulated data because of the positive effect of capillary number (Mott 2003). It is essential to incorporate the capillary number model into the simulation model for compositional runs below the dew point pressure. Otherwise, well productivity will be underestimated whereas pressure drops and condensate dropout will be overestimated.

The capillary number formulations applied in this study to compute the capillary number effects on residual saturations and relative permeabilities were after Henderson et al. (1995) as shown below. In their model, the capillary number for both phases depends only on the gas properties.

$$N_{cp} = \frac{v_g \mu_g}{\sigma}$$

(1)

The “Base Capillary Number” $N_{cpb}$ is defined as the lower threshold value below which the $N_c$ has no effect on phase relative permeabilities. This number is taken from input data and used to calculate a “Normalized Capillary Number” $N_{cn}$:

$$N_{cn} = \frac{N_{cp}}{N_{cpb}}$$

(2)
At higher capillary numbers, the residual saturation is reduced by multiplying the phase residual saturation $S_{rP}$ by a factor $X_p$:

$$X_p = 1 - e^{-\gamma m_p n_{cnp}} \quad \text{...}$$  

(3)

The Capillary Number is also used to define the interpolation between the “immiscible” relative permeability curves defined by input tables and the “miscible” curves that are constructed internally as straight lines.

$$k_{rmp} = f k_{rP} + (1 - f) k_{rmp} \quad \text{...}$$  

(4)

The immiscible relative permeability is $k_{rP}$ and the miscible relative permeability is calculated as follows, giving a straight line with endpoints defined by the adjusted phase residual saturation:

$$k_{rmp} = \frac{(S_p - X_p S_{rP})}{(1 - X_p S_{rP})} \quad \text{...}$$  

(5)

where $X_p$ is defined in Equation (3) above. The interpolation factor $f$ is calculated as:

$$f = n_p^{1/n_{cnp}} \quad \text{...}$$  

(6)

$$n_p = n_{1p} S_{p}^{n_{2p}} \quad \text{...}$$  

(7)

**Non-Darcy flow effect**

Darcy’s law does not explain gas flow accurately when the flow rate is high, especially near the wellbore. At high gas rate, the pressure drop between average reservoir pressure and well bottomhole pressure is no longer proportional to the flow rate due to turbulence effect, which is contradictory to Darcy’s law. Turbulence, which causes increased pressure drop, can be modeled in the simulator using the Forchheimer correction. Forchheimer (1901) proposed the following equation to account for inertial effects:

$$\frac{dp}{dL} = \left(\frac{\mu}{k}\right) v + \beta \rho v^2 \quad \text{...}$$  

(8)

Non-Darcy flow effect is typically modeled as a rate-dependent skin in most numerical simulators. $\beta$ can be determined from multi-rate pressure test analysis or from theoretical or empirical correlations (Li et al. 2001). A typical empirical correlation for single-phase is:

$$\beta = \frac{a}{k^b \phi^c} \quad \text{...}$$  

(9)

Geertsma (1974) proposed an empirical correlation for two-phase flow, relating $\beta$ to the fluid saturation and relative permeability:

$$\beta_p = \frac{a}{\phi^b S_p^{d}(k k_{rP})} \quad \text{...}$$  

(10)

In the case of two-phase gas condensate flow, inertial effects generate extra condensate drop-out, because the inertial resistance in one phase is affected by the presence of the second phase.

**Parameters affecting productivity of horizontal wells**

The performance of horizontal wells can be expressed by the ratio of horizontal to vertical productivity indices (Joshi 1988):

$$J_h = \frac{\ln(r_c/r_w)}{\ln\left[\frac{a + \sqrt{a^2 - (L/2)^2}}{L/2}\right] + \frac{h\sqrt{k_h/k_p}}{L \ln(h\sqrt{k_h/k_p}/2r_w)} \quad \text{...}$$  

(11)

where
\[ a = \left( \frac{L}{2} \right) \left[ 0.5 + \sqrt{0.25 + \left( 2r_{eh}/L \right)^4} \right]^{0.5} \]

Equation 12 implies that the productivity of horizontal well depends on the producing horizontal length \( L \) and the permeability ratio \( k_v/k_h \).

**Methodology, Analysis and Discussion**

**Basic Assumptions**

The research study was carried out in three stages. First stage, gas condensates compositional analysis and base models design; Second stage, base models study; Third stage, full field model (FFM) design and sensitivity studies. Assumptions made for the study are as follows:

1. The near well phase equilibrium and fluid flow interactions are accurately represented using a fine Radial grid model and a fine Tartan grid model, with phase equilibrium/fluid properties calculated from an EOS.
2. There is no limit on the tubing head flowing pressure and only well bottomhole pressure limits are considered.
3. The pressure drop due to condensate blockage is significant compared to the pressure drop in the tubing.
4. There is no aquifer support in the gas condensate fields.

**Gas Condensate Compositional Analysis**

Four gas condensate mixtures with different compositions have been studied to distinguish between rich and lean gas condensates and are shown below in Table 1. According to reservoir engineering studies, a lean gas condensate generates a small volume of the liquid phase, i.e. 30-50 bbl/MMscf, whereas a rich gas condensate generates a larger volume of liquid, i.e. 50-300 bbl/MMscf (Zheng et al. 2006). There is no established boundary in the definitions of lean and rich gas condensates as they are fundamentally relative to each other, so these figures are taken merely as indicators of a range.

Gas condensate “B” has been selected to be used for the rest of the simulation studies because it represents a gas condensate with a CGR in between that of A and C, D, i.e. not too rich and not too lean. These four gas condensates were used in the “Gas Condensate Composition Sensitivity Study” section at the later stage of the full field model study.

<table>
<thead>
<tr>
<th>Gas Condensate</th>
<th>Condensate-gas-ratio (bbl/MMscf)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>161</td>
</tr>
<tr>
<td>B</td>
<td>87</td>
</tr>
<tr>
<td>C</td>
<td>48</td>
</tr>
<tr>
<td>D</td>
<td>27</td>
</tr>
</tbody>
</table>

**Table 1: Condensate-gas-ratio for Gas Condensate A, B, C and D.**

**Figure 1:** Phase diagrams of Gas Condensate A (left) and B (right). Gas Condensate B is leaner than Gas Condensate A and therefore its phase diagram appears to be shifted to the left when compared to Gas Condensate A.

**Single-Well Model gridding and description**

Compositional gas condensate simulation cases have been constructed to simulate fluid flow behavior and to predict condensate dropout under typical operating conditions using single well models. The simulation models used in this study are
Radial grid and Tartan grid models. They consisted of five-layer homogeneous reservoir of 100 ft thickness with a drainage area of 891 acres, a 10% porosity, a horizontal permeability of 1 mD and a vertical to horizontal permeability ratio \( (k_v/k_h) \) of 0.1 (typical of sandstone reservoirs).

A finely gridded 1D radial, fully compositional model was used, with no wellbore storage, mechanical skin effect, or flow within the producing string. A large outermost grid size of 1335 ft has been designed to avoid boundary effects. (Figure 2; Table 1)

![Figure 2: Single-well Radial grid model](image)

A Tartan grid model was then designed to represent the Radial grid model in order to be utilized in the full field model studies at the later stage of the project. Tartan grid was chosen over the Cartesian grid with local grid refinements due to the fact that Tartan grid greatly improves the runtime performance of the models whilst providing enhanced grid definition. Tartan grid model with very fine grids near the well enables us to model the true geometry and behaviour of condensate dropout around the wellbore. (Figure 3; Table 2)

In order to achieve this, the field properties (i.e. Field Pressure, Field Gas in Place, Field Oil in Place, Field Gas Production Rate and Field Oil Production Rate) and the well property (i.e. Well Bottomhole Pressure) of the single-well Tartan grid model were compared and validated against that of the Radial grid model. The initial Field Gas in Place for both models was kept constant at 79 Bscf.

![Figure 3: Single-well Tartan grid model](image)

### Table 2: Single-well Radial grid model - Grid properties.

<table>
<thead>
<tr>
<th>Grid properties</th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Grid number</td>
<td>20</td>
<td></td>
</tr>
<tr>
<td>Innermost grid radius</td>
<td>0.15</td>
<td>ft</td>
</tr>
<tr>
<td>Outermost grid radius</td>
<td>1335</td>
<td>ft</td>
</tr>
<tr>
<td>Cell size (ft)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
|                           | Cell sizes increase geometrically in radial direction away from the centre where the well is located.

### Table 3: Single-well Tartan grid model - Grid properties.

<table>
<thead>
<tr>
<th>Grid properties</th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Grid number</td>
<td>28125</td>
<td></td>
</tr>
<tr>
<td>Innermost grid size</td>
<td>2</td>
<td>ft</td>
</tr>
<tr>
<td>Grid density (x-direction)</td>
<td>Cell No.</td>
<td>Aver. Cell Size (ft)</td>
</tr>
<tr>
<td>Uniform</td>
<td>30</td>
<td>101.35</td>
</tr>
<tr>
<td>Logarithmic, Central</td>
<td>15</td>
<td>10</td>
</tr>
<tr>
<td>Uniform</td>
<td>30</td>
<td>101.35</td>
</tr>
<tr>
<td>Grid density (y-direction)</td>
<td>Cell No.</td>
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<td>10</td>
</tr>
<tr>
<td>Uniform</td>
<td>30</td>
<td>101.35</td>
</tr>
</tbody>
</table>

**Velocity-dependent Relative Permeability Effect**

In this project, the velocity-dependent relative permeability models (i.e. Capillary Number model and Forchheimer’s Non-Darcy model) were applied and incorporated into all the simulation cases for the compositional simulation runs. The Capillary Number model introduced by Henderson *et al.* (1995) has been used to interpret the difference between the base relative permeability and the miscible relative permeability models. A multi-rate drawdown (200 Mscf/D for 1 day, 400 Mscf/D for 2 days, 800 Mscf/D for 3 days and 1600 Mscf/D for another 4 days) followed by 10 days of build up were simulated to observe the positive effect of the velocity-dependent relative permeability phenomenon.

The high capillary number and non-Darcy flow effects are both rate-dependent functions acting in opposite directions. Figure 4 shows a stronger capillary number effect over the inertial effect, resulting in a positive velocity-dependent relative permeability effect. The pressure drawdown for the simulation case incorporated with velocity-dependent relative permeability models is lower than that without velocity-dependent relative permeability models at the same designated flow rates.

![Figure 4](image)
Optimizing Recovery in Gas Condensate Fields

Effect of different gas production rate

The single-well Radial grid model has been used to examine the condensate dropout effect as production goes below the dew point pressure at 4298 psia by operating at different specified rates. Various scenario cases were run for 10 days of drawdown followed by another 10 days of build up to achieve an optimum balance between gas production rate and well bottomhole pressure. This is important to minimize the condensate dropout effect in the reservoir.

Final operational decision was made after analyzing the results obtained from the scenario cases at high (e.g. quick depletion at 10 MMscf/D) and low rates (e.g. 10 Mscf/D at a BHP limit of 4350 psia to maintain above dew point pressure) whilst also taking into account the initial reservoir conditions. It is important for the well to achieve an optimum balance between its production rate and its bottom-hole pressure due to the fact that the initial reservoir pressure is just slightly above the dew point pressure.

Figure 4: Effect of Velocity-dependent Relative Permeability models on well bottomhole pressure.

**Effect of different gas production rate**

<table>
<thead>
<tr>
<th>Well Bottomhole Pressure vs. Time</th>
</tr>
</thead>
<tbody>
<tr>
<td>Without Velocity-dependent</td>
</tr>
<tr>
<td>Relative Permeability Effect</td>
</tr>
<tr>
<td>With Velocity-dependent Relative</td>
</tr>
<tr>
<td>Permeability Effect</td>
</tr>
<tr>
<td>Difference in pressure drop</td>
</tr>
</tbody>
</table>

Time Elapsed (days)

Figure 5: Gas production rate (GRAT) Control Mode at 1 MMscf/D and 2 MMscf/D respectively with a limiting bottomhole pressure (BHP) target or lower limit at 3000 psia.

Figure 5 shows the two operational decisions that can be executed on this gas condensate reservoir. The well can either produce at a rate of 1 MMscf/D or 2 MMscf/D, yielding different amount of condensate dropout as the bottomhole pressure drops below the dew point pressure. For the well producing at 2 MMscf/D, an oil saturation as high as 37% was observed around the wellbore at the end of the 10-day drawdown. On the other hand, about 26% of the oil saturation was found around the well producing at 1 MMscf/D.

There exists a trade-off between high production rate and small liquid dropout effect. As the production rate increases, the pressure drawdown increases, leading to higher amount of condensate dropout, as in the case of the 2 MMscf/D gas productions. However, reducing liquid dropout requires production at a lower rate.

The two operating scenarios shown in Figure 5 are both producing at reasonable rates, yielding 26% and 37% of liquid dropout respectively at the end of the drawdown period. Thus the final operational decision can be made, either aiming at reducing condensate dropout and therefore a lower production rate; or aiming at producing at a higher rate and accepting a higher liquid dropout around the wellbore.
For the next stage of the study, it was decided that in order for the well to produce at a reasonable rate the pressure drawdown will be allowed to go below the dew point pressure.

**Full field model study**

The simulation models used in this study consisted of a 5-layer homogeneous reservoir of 300 ft thickness with a drainage area of 4768 acres, a 10% porosity, a horizontal permeability of 1 mD and a vertical to horizontal permeability ratio of 0.1 (typical of sandstone reservoirs). Tartan grids were incorporated into the full field model for better runtime performance. The Tartan grid full field model was constructed to be logarithmic, central fine grids near the well for enhanced grid definition to capture the fluid flow movement, which then increases logarithmically away from the well. All the models have the same initial gas in place of \(1.3 \times 10^{12}\) scf. *(Figure 6)*

6 vertical producing wells were placed equally apart from each other in the gas condensate field. Capillary number and non-Darcy flow effects were taken into account in the full field model study whereas frictional losses in the wellbore, wellbore storage and skin were neglected. Sensitivity studies were performed to study the gas condensate fields in further details. The four main sensitivity studies conducted are Gas Condensate Composition, Reservoir Permeability, Well Configuration and Well Stimulation. In addition, sensitivity study on rates was also performed on the FFM and it has been decided to produce at a field production Daily Contracted Quantity (DCQ) of 12 MMscf/D from the field; with each well produces at 2 MMscf/D in order to minimize the condensate dropout effect around the wellbore. For the 6 vertical wells, the condensate saturation profiles around Well 1, Well 2 and Well 3 were plotted against the radial distance from the wellbores, i.e. along Distance A from Well 1, Distance B from Well 2 and Distance C from Well 3. *(Figure 7)* Different radial directions from the wells gave distinct condensate saturation plots; however, their saturation profiles generally follow the same trend and agree well with each other.

**Phase Diagram**

As the well bottomhole flowing pressure falls below the dew point pressure, lighter components of gas condensate “B” are being produced as gas phase whereas the heavier components drop out as immobile liquid as time progresses from the start to the end of the drawdown period. As a result, the produced gas becomes leaner as the near wellbore region becomes richer in...
heavier components (liquid condensate). As can be seen in Figure 8 (right), the phase diagram of the gas condensate near the wellbore has shifted to the right at the end of the drawdown, indicating that condensate dropout has occurred around the well.

![Comparison of Phase Diagrams](image)

**Figure 8:** Comparison of Phase Diagrams at the start and the end of the 5-year production from the full field model using 6 vertical wells.

**Figure 9** further confirms that the produced reservoir gas in the gas condensate field has become leaner at the end of the drawdown period as gas condensate has dropped out in the reservoir. It can be observed that the CGR decreases rapidly from 87 bbl/MMscf to approximately 72.5 bbl/MMscf during the first year of production; then remains relatively constant at a plateau CGR of 72.5 bbl/MMscf until the end of the production.

![Changes of Condensate-Gas-Ratio](image)

**Figure 9:** Changes of Condensate-Gas-Ratio in the gas condensate field with respect to producing time.

**Sensitivity Study Simulation Results**

**Rich vs. Lean Gas Condensate**

A first objective of the simulation runs was to compare the condensate saturation profile around the wellbore for different gas condensate compositions, with all other parameters kept constant. The four gas condensates discussed in the “Compositional Analysis” section were used in this study. Compositional simulation runs were made with capillary number and inertial effects at a constant gas flow rate of 2 MMscf/D per well.

A Cartesian plot of condensate saturation profile against distance from Well 1 at the end of the 5 year drawdown is shown in Figure 10. As predicted, Gas Condensate A (the richest gas condensate) exhibits the highest amount of liquid dropout near the wellbore; whereas on the other hand, Gas Condensate D (the leanest gas condensate) exhibits the least amount of liquid dropout around the wellbore.

Gas Condensate B, which has been used for all the simulation models, has about 31% of liquid saturation within 2 ft of the wellbore, and increases gradually up to approximately 35% 10 ft away from the wellbore, then eventually tails off from there...
as the distance gets further away from the wellbore. This could be due to the existence of the “fourth region” mentioned earlier where low interfacial tensions at high flow rate yields lower liquid saturation and higher gas relative permeability (Gringarten et al. 2006).

**Figure 10: Comparison of condensate saturation profiles for different gas condensate compositions (A, B, C and D)**

**Tight vs. High Permeability Gas Condensate Reservoir**

A series of simulation runs was performed to compare the condensate saturation profile and gas and liquid production rates for different reservoir permeabilities. Four different reservoir permeabilities were studied, with each representing different types of gas condensate reservoir, i.e. ultra-tight reservoir (0.001 mD), tight reservoir (0.1 mD), low permeability reservoir (1 mD) and high permeability reservoir (1200 mD). All the four reservoirs have a vertical to horizontal permeability ratio \( k_v/k_h \) of 0.1 and a porosity of 10%. Gas Condensate B was used in this study.

It was found that the condensate dropout effect is the most significant in tight reservoir, even more than that in ultra-tight reservoir. In the ultra-tight reservoir, gas condensate production is the lowest because of the very tight nature of the reservoir, which ultimately inhibits the flow of the gas and condensates. There is no liquid dropout in the high permeability reservoir due to the very good reservoir/formation connectivity which enables both the gas and liquid phases to flow easily into the producing wells and eventually up to the surface. (Figure 11 and Figure 12)

Additional sensitivity study on reservoir heterogeneity has also been performed, but was found not significant in this model. It was observed that the main parameter that affects the condensate dropout and gas condensate production is the reservoir permeability of the formation near the wells. Therefore, in this study, layered reservoir and other types of reservoir heterogeneity distributions will be disregarded; only reservoir permeability will be considered.

**Figure 11: Comparison of Condensate B saturation profiles in ultra-tight, tight, low permeability and high permeability gas condensate reservoirs.**
Optimizing Recovery in Gas Condensate Fields

Figure 12: Comparison of pressure drawdown, well gas cumulative production volume, well gas and liquid production rates in ultra-tight, tight, low permeability and high permeability gas condensate reservoirs.

Well Configuration

2 horizontal wells vs. 6 vertical wells

Horizontal well enhances reservoir contact and therefore improves well deliverability. The simulation model used in this study is exactly the same as the full field model with 6 vertical wells discussed earlier, except that 2 horizontal wells have been used to replace the 6 vertical wells. (Figure 13) The 2 horizontal producing wells were placed equally apart from each other in the gas condensate reservoir to minimize boundary effects. Both of the horizontal wells are fully cased and perforated over their entire horizontal length. Frictional losses in the wellbore, wellbore storage and skin were neglected.

In this section, sensitivity studies were performed in the low permeability gas condensate field (1 mD) and the tight gas condensate field (0.1 mD) respectively. A series of simulation runs were performed to compare the pressure drawdown and the condensate saturation profile when the flowing bottom-hole pressure drops below the dew point pressure. In order to match the field production DCQ at a rate of 12 MMscf/D, each of the two horizontal wells was produced at 6 MMscf/D respectively.

Figure 13: Full field model with 2 horizontal wells producing from the gas condensate field. Tartan grid (right) was used for better runtime performance and enhanced grid definition.
In Low-permeability gas condensate field (1 mD)

The full field model was operated for 5 year drawdown followed by 500 days of build up period in the low permeability gas condensate field. The liquid dropout effect is shown in Figure 14. A plot of pressure against time is shown in Figure 15 (left) for the 2 horizontal wells with different completion lengths (1000 ft, 2000 ft and 3000 ft) and for the 6 vertical wells with 300 ft of completion length. Compositional runs were made with capillary number and inertial effects at a constant gas flow rate of 6 MMscf/D, starting at an initial reservoir pressure of 4356 psia, just 58 psi above the dew point pressure.

As can be seen in Figure 15 (left), the 6 vertical wells (producing a total of 12 MMscf/D) yield a smaller pressure drop than the 2 horizontal wells (producing the same total amount) whereas the pressure drop in horizontal wells decreases as the horizontal well length increases. The horizontal well length of 3000 ft has been selected because it yields a lower pressure drawdown, thus reducing the condensate dropout around the wellbore. Nonetheless, this has to be justified against the cost of using a longer horizontal well length. Figure 15 (right) reveals that at a constant field gas cumulative production volume of 21.9 Bscf, the 6 vertical wells (1.59 MMstb) produce approximately 0.14 MMstb more of liquid condensate than that of the 2 horizontal wells (1.45 MMstb) at the end of the drawdown ($t_p = 5$ years).

The condensate saturation profile around the vertical and horizontal wells in the field at the end of the 5 year drawdown is illustrated in Figure 16. For the two horizontal wells, the condensate saturation is plotted against the distance from the heel in the x-direction (perpendicular to the well). In this particular reservoir, condensate saturation is fairly uniform because of the 1 mD isotropic horizontal permeability throughout the field. Figure 16 also indicates that, as the horizontal well length increases from 1000 ft to 3000 ft, the condensate saturation decreases at a constant flow rate. It was found that the horizontal wells ($L_H = 3000$ ft), even producing at a rate of 6 MMscf/D each (i.e. higher drawdown per well than that of per vertical well), has similar condensate saturation to that of the vertical wells producing at 2 MMscf/D per well; both yielding a maximum condensate saturation of 35% near the wellbores.

Thus, it can be concluded that drilling 2 horizontal wells could potentially substitute the use of 6 vertical wells for the same amount of field gas production in the low permeability gas condensate field. In addition, the costs of using 6 vertical wells and 2 horizontal wells have to be evaluated and justified against the revenue generated from the gas production.
In Tight Gas Condensate field (0.1 mD)

In order to compare well productivities between vertical and horizontal wells and to quantify the effectiveness of horizontal wells in tight gas condensate field, compositional simulation runs of 5 year duration were made for different horizontal well lengths (1000 ft, 2000 ft and 3000 ft). Similarly, the runs were made with capillary number and inertial effects at constant gas flow rate of 6 MMscf/D per well, starting at an initial reservoir pressure of 4356 psia, 58 psi above the dew point pressure.

A plot of pressure against time for a 5 year drawdown followed by a 500 day build-up is shown in Figure 17 (left) for the two horizontal wells with different completion lengths (1000 ft, 2000 ft and 3000 ft) and for the 6 vertical wells with 300 ft of completion length in the tight gas condensate field. Due to the very low permeability of the reservoir, it is difficult for the gas condensate to flow from the field into the wells. As can be seen in Figure 17 (left), the bottomhole pressure limit of 400 psia for the vertical and horizontal wells has been reached once the production was started.

By referring to Figure 17 (right), it was observed that the 2 horizontal wells (14.7 Bscf) produce approximately 4.7 Bscf more of gas than that of the 6 vertical wells (10.0 Bscf) at the end of the drawdown (t = 5 years). In addition, it was found that the 2 horizontal wells (600 Mstb) produce approximately 85 Mstb more of liquid condensate than that of the 6 vertical wells (515 Mstb).

The difference in well productivity between horizontal wells and vertical wells is very significant in a tight gas condensate field. The cumulative field gas production increases with the horizontal well length. A clearer picture is given in Figure 18, which shows the increase in cumulative field gas production for each horizontal well length compared to the cumulative production from the vertical wells. The 2 horizontal wells (L_H = 2000 ft) were found to be almost equivalent to the 6 vertical wells in Figure 18 in terms of field gas cumulative production volume. Figure 19, on the other hand, compares the cumulative field liquid production for each horizontal well length and the vertical wells.

The condensate saturation profile around the vertical and horizontal wells in the tight gas condensate reservoir at the end of the 5 year drawdown is illustrated in Figure 20. It can be seen that, in the tight gas condensate reservoir, the different horizontal well lengths yield similar condensate saturation profile around the wellbore. The vertical and horizontal wells showed a maximum saturation of about 48% at the end of the drawdown period, which eventually tails off as it gets further away from the wellbore.
In a tight gas condensate field, horizontal wells yield higher field gas recovery than vertical wells. As can be seen in Figure 17 (right), the 2 horizontal wells were capable of producing 47% more of gas than that of the 6 vertical wells. On the other hand, this was not the case in the low permeability gas condensate field as discussed above. Therefore, in a tight gas condensate reservoir, the option of drilling 2 horizontal wells was heavily favoured over drilling 6 vertical wells.

![Comparison of Field Gas Cumulative Production for different Horizontal Well Lengths](image1)

**Figure 18:** Comparison of field gas cumulative production for vertical and horizontal wells in the tight gas condensate reservoir.

![Comparison of Field Liquid Cumulative Production for Vertical and Horizontal Wells](image2)

**Figure 19:** Comparison of field liquid cumulative production for vertical and horizontal wells in the tight gas condensate reservoir.

Condensate Saturation vs. Distance from Horizontal and Vertical Wells

![Condensate Saturation vs. Distance from Horizontal and Vertical Wells](image3)

**Figure 20:** Comparison of condensate saturation profile for vertical and horizontal wells in the tight gas condensate reservoir.

**Well spacing between horizontal wells**

Well spacing is generally defined as the maximum area of a reservoir that can be efficiently and economically drained by one well (Keungoua et al. 2011). Sensitivity study has been performed to study the effects of well spacing between the horizontal wells. In this study, the low permeability gas condensate field was used to examine the boundary effects caused by the neighbouring well when the two horizontal wells were placed closer to each other. **Figure 21** shows another full field model having exactly the same size and fluid properties as the original FFM but with different well location and smaller well spacing whereby the two horizontal wells were designed to be parallel to the x-axis. As a result, the two horizontal wells acted as no-flow boundaries against each other, leading to an increase in the pressure drawdown at a constant flow rate. **(Figure 22)**
Optimizing Recovery in Gas Condensate Fields

Figure 21: Horizontal wells being placed closer to each other to observe boundary effects whereby each well acts as a no-flow boundary against each other.

Figure 22: Comparison of pressure drawdowns for the two horizontal wells being placed closer to each other and the two horizontal wells in the original FFM.

Well Stimulation on vertical wells

In this study, sensitivity analysis of well stimulation was performed to study the well productivity/deliverability enhancement upon stimulating the 6 vertical wells in the tight gas condensate reservoir. Well (acid) stimulation enhances the productivity index and reduces the pressure drawdown at a constant flow rate, thus minimizing the condensate dropout effect in the tight gas condensate reservoir as the production goes below the dew point pressure. Well stimulation on horizontal wells was not conducted in this study.

By referring to Figure 23 (right), it was observed that well stimulation does not have a major impact on the productivity of the vertical wells compared to the use of 2 horizontal wells. In addition, the difference between a productivity increment of three-times and of five-times is insignificant. A three-time productivity index increment upon well stimulation yields an incremental field gas recovery of 600 MMscf compared to the unstimulated vertical wells. However, the 2 horizontal wells (14.6 Bscf) still produce 4 Bscf more of gas than the 6 stimulated vertical wells (10.6 Bscf).

Figure 23: Productivity index enhancement after well stimulation (left) and the comparison of field gas cumulative production volume in vertical and horizontal wells (right).
Discussion

In this study, well deliverability impairment due to liquid dropout in gas condensate fields was successfully represented in the compositional simulation models. In order to model the gas condensate field, sensitivity study on gas condensate compositions (rich vs. lean) has been conducted to take into account different fluid characteristics. As predicted, a richer gas condensate yields higher liquid dropout in the field than a leaner gas condensate. Sensitivity study on reservoir permeability was also performed to study the effects of formation permeability around the wellbore on the gas recovery and liquid dropout. In real life, gas condensate reservoirs are complex and highly heterogeneous, resulting in more complicated flow behaviour into the wells. This study assumes a homogeneous reservoir, with a $k_h/k_v$ ratio of 0.1 (typical of sandstone reservoirs). Additional sensitivity studies on more representative gas condensate reservoir properties would be required to confirm the best production method.

The gas condensate field has initial conditions just above the dew point pressure. Naturally, the pressure drawdown goes directly below the dew point pressure once the production was started. Good operational decisions in managing the gas condensate field yield higher recovery efficiency. The operational methods conducted in this study were production rates, well configuration and well stimulation. The operational decision made from this study is to produce the field at a well production rate of 2 MMscf/D for the 6 vertical wells and of 6 MMscf/D for the 2 horizontal wells respectively in order to meet the field gas production DCQ of 12 MMscf/D. In a low permeability gas condensate reservoir, the 6 vertical wells have a slightly better performance than the 2 horizontal wells ($L_H = 3000$ ft), with both producing at the same DCQ. Nonetheless, this has to be justified against the cost of using 6 vertical wells versus only drilling 2 horizontal wells. On the other hand, the performance of 2 horizontal wells in a tight gas condensate reservoir is superior to that of the 6 vertical wells; recording 47% more gas recovery than the 6 vertical wells. Well stimulation (e.g. acid treatment) enhances the productivity of the vertical wells and yields 6% more gas recovery than the unstimulated vertical wells for a three-time productivity index increment in the tight gas condensate reservoir. Hydraulic fracturing study was not conducted in this project due to time constraint. Hashemi and Gringarten (2005) demonstrated that both horizontal well and hydraulically fractured well improve well productivity and reduce pressure drop. From their study, it was found that hydraulically fractured wells are comparable to horizontal wells. The final choice between a horizontal well and an equivalent vertical well with a fracture can only be determined from economic evaluation.

In practice, particularly in mature gas condensate reservoir at a later stage of the field life where its reservoir pressure is close to its dew point pressure, there are two extremes which the field operator can decide on how to operate the field: (1) Allow for very quick depletion to produce most of the gas and condensates out of the field within the next few years of production, without considering the effect of liquid dropout. Then, shut in the well for pressure buildup for some time and produce from the field again when/if the reservoir pressure builds up above the dew point pressure. (2) Produce the field at a very low rate by limiting the pressure drawdown above the dew point pressure. The former assumes that the resulting pressure buildup plateau is above the dew point pressure and the revaporization of the condensate bank developed around the wellbore. The later produces the field at an unreasonably low rate, which certainly does not justify the operation in economics terms. The optimum operating decision for a specific field is likely to be between these two extremes and it will require more simulation studies to determine the best operating rates.

Conclusions

The main conclusions from this paper are as follows:

1. The effect of liquid dropout in a gas condensate field is of critical importance. Well Productivity Index impairment due to liquid drop-out in a gas condensate field will be overestimated if the compositional simulation model ignores the velocity-dependent relative permeability effects in the immediate vicinity of the wellbore region.
2. For a gas condensate production below the dew point pressure, it is possible to achieve an optimum balance between the gas production rate and the pressure drawdown to minimize condensate dropout effect while at the same time produce at a reasonable rate from the field.
3. The optimum well configuration and selection of vertical or horizontal wells for a gas condensate field depend on the type of reservoir (low permeability vs. tight reservoirs).
4. Horizontal well length affects gas production in gas condensate fields. A longer horizontal well reduces condensate dropout and increases reservoir contact, thus is favourable to be employed in gas condensate fields operated below the dew point pressure.
5. Well stimulation enhances the productivity of the vertical wells in the tight gas condensate reservoir; however, it is not as effective when compared to the use of horizontal wells.

Recommendations for Further Study

1. This work focuses on the operational decision and reservoir management of gas condensate fields. It is recommended that a comprehensive study on hydraulic fracturing effect (before and after the formation of condensate bank) should be performed.
2. An in-depth study of Gas Cycling effect in a low-permeability or tight gas condensate field is recommended for the continuation of this project. Gas Cycling can be used to maintain reservoir pressure above the dew point pressure while producing at a reasonably high rate, thus avoiding condensate dropout in the reservoir.
3. For this study, reservoir models with fine grids near the wellbore were successful and the simulation models ran in reasonable timescale. For a bigger FFM, it would be necessary to use coarser grids whereby methods of upscaling, i.e. generalized pseudopressure model, proposed by Feyang and Whitson (1996) would need to be incorporated and thoroughly studied.

4. It is recommended that more study should be done as a follow up on the economic benefits of using horizontal wells to substitute vertical wells or vice versa, in the specific gas condensate fields.

5. The impact of aquifer drive and water encroachment was not considered in this project. Further study on the gas condensate full field model with an aquifer support would be a path to explore.

Nomenclature and Abbreviation

\[ \begin{align*}
  a, b, c, d & \quad \text{Non-Darcy coefficients (Experimental)} \\
  \beta & \quad \text{Forchheimer's non-Darcy coefficient} \\
  p & \quad \text{Pressure (psia)} \\
  k & \quad \text{Absolute permeability (mD)} \\
  k_v & \quad \text{Vertical permeability (mD)} \\
  k_h & \quad \text{Horizontal permeability (mD)} \\
  L_H & \quad \text{Horizontal well length (ft)} \\
  \phi & \quad \text{Porosity} \\
  S & \quad \text{Saturation} \\
  \phi_c & \quad \text{Capillary Number} \\
  \nu & \quad \text{Intertitial velocity in the reservoir (ft/d)} \\
  \mu & \quad \text{Viscosity (cp)} \\
  \rho & \quad \text{Density} \\
  scf & \quad \text{Standard Cubic Feet} \\
  stb & \quad \text{Stock Tank Barrel} \\
  WBHP & \quad \text{Well bottomhole pressure (psia)} \\
  DCQ & \quad \text{Daily Contracted Quantity} \\
  FFM & \quad \text{Full field model} \\
  \rho_{dew} & \quad \text{Dew point pressure (psia)} \\
  GPP & \quad \text{Generalized Pseudo-pressure} \\
  \text{Subscript } g & \quad \text{Gas phase} \\
  \text{Subscript } p & \quad \text{Phase (Oil, Gas)} \\
  \text{Eos} & \quad \text{Equation of state} \\
  \text{P1} & \quad \text{Productivity Index (Mcscf/dpsi)} \\
  \text{PI} & \quad \text{Equation of state} \\
  \text{dp/dL} & \quad \text{Pressure drop along distance L} \\
  \text{mdp, n1p, n2p} & \quad \text{User-defined input parameters} \\
  t_p & \quad \text{Production time (year)}
\end{align*} \]

References


## Appendix A: Literature Review

### Table A-1: Key milestones related to this study

<table>
<thead>
<tr>
<th>Paper no</th>
<th>Year</th>
<th>Title</th>
<th>Authors</th>
<th>Contribution</th>
</tr>
</thead>
<tbody>
<tr>
<td>Physical Principles of Oil Production, Chapter 13, Pages 738-800</td>
<td>1949</td>
<td>Condensate Reservoirs</td>
<td>M. Muskat</td>
<td>Introduction of condensate blockage in a gas condensate reservoir. Describe mathematically the saturation profile around the wellbore of gas condensate reservoir.</td>
</tr>
<tr>
<td>SPE 962</td>
<td>1965</td>
<td>Two-Phase Flow of Volatile Hydrocarbons</td>
<td>V.J. Kniazeff, S. A. Naville</td>
<td>First to model radial gas condensate well deliverability numerically with respect to time and radial distance. First to describe three different zones around the well.</td>
</tr>
<tr>
<td>SPE 1478</td>
<td>1967</td>
<td>An Attempt to Predict the Time Dependence of Well Deliverability in Gas Condensate Fields</td>
<td>M. Gondouin, R. Iffly, J. Husson</td>
<td>First to demonstrate the significance of non-Darcy flow effects and condensate blockage by performing backpressure tests.</td>
</tr>
<tr>
<td>SPE 1495</td>
<td>1967</td>
<td>Successfully Cycling a Low-Permeability, High-Yield Gas Condensate Reservoir</td>
<td>H.G. O’Dell, R.N. Miller</td>
<td>First to present a pseudo-pressure function to describe the gas condensate blockage.</td>
</tr>
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<td>SPE 4529</td>
<td>1973</td>
<td>The Isochronal Testing of Oil Wells</td>
<td>M.J. Fetkovich</td>
<td>First to develop a rate and time dependent skin to be included in the standard gas inflow equation to describe behaviour of a condensate well.</td>
</tr>
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<td>SPE 21704</td>
<td>1991</td>
<td>Long Term Testing of Vertically Fractured Gas Condensate Reservoirs</td>
<td>S. Sognesand</td>
<td>First publication on productivity loss due to condensate blockage in vertically fractured wells.</td>
</tr>
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<td>SPE 62920</td>
<td>2000</td>
<td>Well Test Analysis in Gas-Condensate Reservoirs</td>
<td>A.C. Gringarten, A. Al-Lamki, S. Daungkaew, R. Mott, T. M. Whittle</td>
<td>First to use 3-region composite model to analyse gas condensate well tests.</td>
</tr>
<tr>
<td>SPE 68175</td>
<td>2001</td>
<td>Optimization of Gas Condensate Reservoir Development by Coupling</td>
<td>A.M. Aly, A.H. El-Banbi</td>
<td>Present the results of a study that use both compositional reservoir simulation and</td>
</tr>
<tr>
<td>Publication Code</td>
<td>Year</td>
<td>Title</td>
<td>Authors</td>
<td>Abstract</td>
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<td>----------------------------------------------------------------------</td>
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<tr>
<td>SPE 94178</td>
<td>2005</td>
<td>Comparison of Well Productivity Between Vertical, Horizontal and Hydraulically Fractured Wells in Gas-Condensate Reservoirs</td>
<td>A. Hashemi, A.C. Gringarten</td>
<td>Discussion of the treatment of vertical well by hydraulic fracturing and the use of horizontal well in order to improve well productivity in a gas condensate reservoir.</td>
</tr>
<tr>
<td>SPE 103433 (Distinguished Author Series JPT, 2007)</td>
<td>2007</td>
<td>Deliverability of Gas-Condensate Reservoirs – Field Experiences and Prediction Techniques</td>
<td>J. Kamath</td>
<td>Outline a five-step approach to predict deliverability loss in gas condensate reservoir due to the formation of condensate bank when bottom-hole pressure near wellbore drops below the dew point pressure.</td>
</tr>
</tbody>
</table>
Integration of Partial Differential Equation for Transient Radial Flow of Gas-Condensate Fluids in Porous Structures

Authors: Eilerts, C.K., Sumner, E.F. and Potts, N.L.

Contribution to the understanding of gas condensate reservoirs:
First to develop and program the solution for the partial differential equation in order to compute the accumulation and flow of liquid condensates using numerical method.

Objective of the paper:
To apply finite-difference equations and use electronic computers to integrate the second-order, nonlinear, partial-differential equation representing the transient radial flow of gas-condensate fluids in reservoirs.

Methodology used:
- Establish a mass balance to represent a distribution of multi-component systems. Calculate the saturation increase at equal intervals implicitly by using the available experimental information/data and subsequently use an existing program to calculate the pressure. The two calculations were then combined to calculate the saturations and pressures respectively over multiple iterations.
- Other factors included are liquid vapour volume ratio, compressibility factor, viscosity, saturation dependent mobility and pressure dependent permeability.
- Utilize dimensionless parameters (e.g. recovery rate) in the integration calculation.

Conclusions reached:
1. Condensate accumulation and its radial flow in a porous medium have been described by developing a mass balance and solving the partial different equation.
2. Determined the liquid vapour volume ratio empirically.
3. Performed the integrations for different recovery rates and/or constant recovery rates with different gas/heavier components mole fractions.
4. The use of five-term instead of three-term finite derivative forms to represent derivatives of the partial differential equation led to the development of a five-diagonal matrix solution that could be useful for the integration of complex equations.

Comments:
Combined an existing mathematical method for pressure calculation with a new implicit method for saturation calculation.
SPE 962 (1965)

Two-Phase Flow of Volatile Hydrocarbons

Authors: Kniazeff, V.J. and Naville, S.A.

Contribution to the understanding of gas condensate reservoirs:
First to numerically model radial gas condensate well deliverability.

Objective of the paper:
To solve the second-order non-linear partial differential equations numerically in the case of radial two phase flow around a well by taking into account both the thermodynamical fluid properties and the mechanical properties of the reservoir.

Methodology used:
Develop a computer program to work out the numerical solution of the equations for pressure and saturation distributions as a function of the radial distance from the well and time.

Conclusions reached:
1. Demonstrated theoretically that condensate saturation builds up when bottomhole pressure drops below the dew point pressure and this in turn reduces gas deliverability.
2. In order to meet the case of non-Darcy flow of gas in condensate wells, a quadratic relationship between the velocity of the gas phase and the pressure gradient is used, incorporating parameters which are measured by a newly designed laboratory experiment on field cores.
3. The problem of unsteady-state condensate-gas flow through porous media leading to a set of second-order non-linear partial differential equations has been solved numerically in the case of radial two-phase flow around a well, taking into consideration both the thermodynamical properties of the fluid and the mechanical properties of the reservoir.

Comments:
The numerical solutions developed in their research have been applied in commercial reservoir simulators today.
SPE 1478 (1967)

An Attempt to Predict the Time Dependence of Well Deliverability in Gas Condensate Fields

Authors: Gondouin, M., Iffly, R. and Husson, J.

Contribution to the understanding of gas condensate reservoirs:
First to numerically model and to study the flow behaviour of gas condensates in the gas condensate wells through radial black oil simulation.

Objective of the paper:
To investigate the flow behaviour of gas condensates in the gas condensate wells and factors affecting the well’s deliverability.

Methodology used:
- Extended the work by Kniazeff and Naville (1965) and developed flow equations with boundary (assuming thermodynamic equilibrium between the two co-existing phases in the pore scale) and solved the equations numerically by developing a computer program.
- Demonstrated the significance of non-Darcy flow effects and condensate blockage by applying their formulations to the results data of backpressure tests from Hassi Er R’Mel field, Algeria.

Conclusions reached:
Showed that the main features of the flow phenomena, including radial extension of liquid build up around the well, non-Darcy flow into the well and simultaneous flow of the liquid and gas phases.

Comments:
Mobility increase is due to capillary number effect and not due to non-Darcy flow effect.
SPE 1495 (1967)

Successfully Cycling a Low-Permeability, High-Yield Gas Condensate Reservoir

Authors: O’Dell, H.G. and Miller, R.N.

Contribution to the understanding of gas condensate reservoirs:
First to develop a method to calculate the volume of retrograde liquid around the producing wellbore and present the gas rate equation incorporating the pseudo-pressure function to describe condensate blocking.

Objective of the paper:
To investigate the behaviour of gas condensate well by conducting gas cycling operations.

Methodology used:
- Study the performance of gas condensate Headlee Devonion field, West Texas undergoing pressure maintenance by gas injection (Gas Cycling).
- Show that velocity (of gas and liquid phases) is proportional to its relative permeability and inversely proportional to its viscosity and volume fraction.
- Apply the concept of equilibrium saturation in their formulation.

Conclusions reached:
The deliverability of gas condensate reservoir with flowing bottomhole pressure below dew point pressure does not significantly affect the ultimate liquid recovery providing that the reservoir pressure is maintained (Gas Cycling) and that the reservoir exhibits favourable relative permeability characteristics.

Comments:
Applied the concept first described by Muskat (1949) and was later used by Fevang and Whitson (1996).
SPE 4529 (1973)

The Isochronal Testing of Oil Wells

Authors: Fetkovich, M.J.

Contribution to the understanding of gas condensate reservoirs:
Used Muskat’s results to develop a rate dependent skin in a gas inflow equation for gas condensate reservoirs.

Objective of the paper:
To use isochronal and flow after flow multi-point backpressure tests and demonstrate that gas wells and oil wells behave very similarly and should be described and analysed using the same basic flow equation.

Methodology used:
- Analyze isochronal and flow after flow multi-point backpressure tests conducted on oil wells.
- Developed equation for flow in oil well which is similar to that of a gas well.
- Developed flow equation which incorporates rate- and time- dependent skin for gas condensate wells.

Conclusions reached:
Developed equations for gas and oil reservoirs (saturated to undersaturated) which also incorporated the rate dependent skin factor (non-Darcy flow).

Comments:
Applied the concept first described by Muskat (1949) to derive the rate dependent skin (non-Darcy flow behaviour).
SPE 21704 (1991)

Long Term Testing of Vertically Fractured Gas Condensate Reservoirs

Author: Sognesand, S.

Contribution to the understanding of gas condensate reservoirs:
First publication on productivity loss due to condensate blockage in vertically fractured wells.

Objective of the paper:
To examine the effect of retrograde condensate blockage on long-term well performance of vertically fractured gas condensate wells.

Methodology used:
Conduct scenario simulations.

Conclusions reached:
1. Condensate buildup/blockage in the vicinity of vertically-fractured gas condensate wells depends mainly on richness of the gas condensate, relative permeability characteristics and production mode. A constant pressure production yields the largest near fracture condensate blockage.
2. Condensate buildup around the gas condensate wells can be modeled as a condensate blockage skin factor.
3. The effect of vertical fracture on the condensate blockage is most significant in tight formations due to large inflow area to the wellbore, yielding higher productivity than in an unfractured well.
Optimizing Recovery in Gas Condensate Fields

SPE 30714 (1996)

Modeling Gas-Condensate Well Deliverability

Authors: Fevang, Ø. and Whitson, C.H.

Contribution to the understanding of gas condensate reservoirs:
First to apply the modified form of the Evinger-Muskat pseudopressure (originally proposed for solution-gas-drive oil wells) to calculate gas-condensate well deliverability. Provide a simple method for calculating bottom-hole flowing pressure (BHFP) in coarse-grid models.

Objective of the paper:
To apply pseudo-pressure approach for modeling gas condensate well deliverability.

Methodology used:
- Develop a simple method to calculate the pseudopressure integral by breaking it into three parts corresponding to the three regions of flow behavior in a gas-condensate well undergoing depletion. The approach is an extension of the pseudopressure method proposed by Evinger and Muskat for solution-gas-drive oil wells.
- Verify the proposed pseudopressure method with fine-grid simulation.
- Study the relative permeability effects on well deliverability by finding the relationship between krg and the ratio krg/kro.

Conclusions reached:
1. Three flow regions emerged as gas-condensate wells produce at well bottom-hole flowing pressure below the dew point pressure. The multiphase pseudopressure function is calculated in three parts, based on the three flow regions.
2. The proposed pseudopressure method calculates well deliverability accurately in coarse-grid models, without the need of near-well local grid refinement.
3. The primary relative permeability relationship affecting condensate blockage (in region 1), and thus the primary cause of reduced well deliverability, is krg as a function of krg/kro and is independent of saturation.
4. Critical oil saturation has no direct effect on gas-condensate well deliverability whereas gas/oil interfacial tension dependence of relative permeability has little or no effect on gas-condensate well performance.
5. Show that the proposed pseudopressure method is readily calculated for each well grid cell on the basis of only grid-cell pressure and saturation (i.e. producing GOR). Local grid refinement near wells is not necessary, and relatively large well grid cells can be used and still provide an accurate description of well deliverability.

Comments:
Showed that the key parameter in determining well deliverability is the relationship between krg and the ratio krg/kro.
SPE 59773 (2000)

Investigation of Well Productivity in Gas-Condensate Reservoirs

Authors: El-Banbi, A.H., McCain, W.D. (JR) and Semmelbeck, M.E.

Contribution to the understanding of gas condensate reservoirs:
Good history match between simulated results from a compositional reservoir simulator and actual field data.

Objective of the paper:
An advancing step towards better understanding of the dynamics of condensate buildup around the wells in gas condensate fields and its negative effect on well productivity.

Methodology used:
History match with a compositional simulation model to investigate the productivity of gas condensate wells.

Conclusions reached:
1. Production rate of gas condensate wells in low permeability reservoirs declines because of liquid drop out around the wellbore, once the near wellbore pressure drops below the dew point pressure.
2. Condensate builds up in the reservoir as the reservoir pressure drops below the dew point pressure. As a result, the gas moving to the wellbore becomes leaner.
3. The gas production rate may stabilize, or possibly increase, after the period of initial decline. This is controlled primarily by the condensate saturation near the wellbore.
4. Both the liquid and gas around the wellbore change in composition. The liquid becomes heavier and the gas becomes leaner.
5. Viscosity of the liquid becomes higher and viscosity of the gas becomes lower with production. This improves the mobility of the gas with respect to the oil.

Well Test Analysis in Gas-Condensate Reservoirs

**Authors:** Gringarten, A.C., Al-Lamki, A., Daungkaew, S., Mott, R. and Whittle, T.M.

**Contribution to the understanding of gas condensate reservoirs:**
First to use a 3-zone radial composite model to analyse gas condensate well test data.

**Objective of the paper:**
To investigate the existence of a velocity stripping zone in the immediate vicinity of the well with high capillary number which increases the gas relative permeability by analyzing well test data.

**Methodology used:**
- Well test analysis of gas condensate well test data by using a 3-zone radial composite model complemented with numerical compositional simulations studies to verify the presence of a velocity stripping zone in the immediate vicinity of the well.
- Discuss the challenges on identifying the zone of increased gas mobility around the wellbore in well tests data due to the impact of wellbore dynamics (i.e. wellbore phase redistribution effects) at early times.

**Conclusions reached:**
1. Phase redistribution is a major problem in analysing well tests data (early time behaviour).
2. Examples shown have confirmed the presence of three stabilizations on the derivative corresponding to three mobility zones: an outer zone away from the well, a zone nearer to the well with reduced gas mobility and a velocity stripping zone in the immediate vicinity of the well.

**Comments:**
Good demonstration of proving the existence of a velocity stripping zone in the immediate vicinity of the well with high capillary number.
Optimization of Gas Condensate Reservoir Development by Coupling Reservoir Modeling and Hydraulic Fracturing Design


Contribution to the understanding of gas condensate reservoirs:
Present the results of a study that utilize both compositional reservoir simulation and hydraulic fracture modeling to compare alternative development plans for a low permeability, rich gas condensate reservoir.

Objective of the paper:
- To investigate the possibility of enhancing productivity from the reservoir and to increase gas recovery.
- Use both compositional reservoir simulation modeling and hydraulic fracture treatment modeling to improve original fracture treatment designs and develop the field more efficiently.
- Use compositional reservoir model to study alternative completions and estimate the size of optimal hydraulic fracture treatments.

Methodology used:
- Compositional reservoir modeling of three types of wells: vertical wells, vertical wells with multiple fractures, and horizontal wells.
- Investigate the effects of condensate dropout around the well and/or the fracture, change of relative permeability around the wellbore and non-Darcy flow.

Conclusions reached:
1. Hydraulic fracturing increased the production rate and extended the production plateau period which will delay drilling of new wells to maintain the field production rate at the Daily Contracted Quantity (DCQ).
2. Hydraulic fracturing resulted in cost savings of about 40% on the overall cost of the development plan, because fewer wells could be used to reach the required field deliverability.
3. The technique of using both a reservoir simulation model and a fracture propagation model to optimize gas production was a successful way to design efficient fracture treatments and decrease the project overall costs.
4. Reservoir modeling of the horizontal well indicated that the additional benefits to be recognized from fracturing the horizontal well did not justify performing the operation with high risks.
SPE 94178 (2005)

Comparison of Well Productivity Between Vertical, Horizontal and Hydraulically Fractured Wells in Gas-Condensate Reservoirs

Authors: Hashemi, A. and Gringarten, A.C.

Contribution to the understanding of gas condensate reservoirs:
Discussion of the treatment of vertical well by hydraulic fracturing and the use of horizontal well to increase well productivity as compared to a non-stimulated vertical well (base case) in a gas condensate reservoir.

Objective of the paper:
To quantify the well productivity enhancement from different remediation solutions (i.e. hydraulic fracturing and horizontal wells) and assess their effectiveness.

Methodology used:
- Discuss the main parameters affecting flow in gas condensate reservoirs (i.e. Capillary Number and Non-Darcy flow effects); and study the parameters affecting productivity of horizontal and hydraulically fractured wells.
- Compare well productivities between non-fractured vertical, horizontal and hydraulically fractured wells in gas condensate reservoirs by running 5.5 year durations compositional simulations above and below the dew point pressure.

Conclusions reached:
1. Well test data can be used to calibrate the parameters of empirical correlations in well performance models when experimental data are not available.
2. Horizontal wells increase productivity in dry gas systems and their performance is even better in gas-condensate reservoirs below the dew point pressure compared to that of vertical wells.
3. Hydraulically fractured vertical wells is comparable to horizontal wells at improving well productivity in gas-condensate reservoirs below the dew point pressure.
4. The final decision to select between a horizontal well and an equivalent vertical well with a fracture can only be determined from economic evaluation.
Productivity Evaluation of Hydraulically Fractured Gas-Condensate Reservoirs

Authors: Zheng, S.Y., Zhiyenkulov, M. and Yi, T.C.

Contribution to the understanding of gas condensate reservoirs:
Perform multi-phase flow simulations in a fractured gas-condensate reservoir and evaluation of hydraulic fractured well productivity through simulation of variable rate well testing.

Objective of the paper:
To describe an application of a compositional single well simulator to analyse well tests in gas-condensate reservoirs. The simulator is used to understand the impact of liquid drop-out and fracture flow on fluid productivity.

Methodology used:
- Compositional simulation of a single well in a tight-gas condensate reservoir to generate transient pressure data for well test analysis and interpretation to predict multi-phase flow behavior, and to analyse productivity impairment due to condensation.
- Simulation models were then further modified to study the impact of various hydraulic fractures on the well productivity index (PI). PIs for fractured cases are compared with respect to the non-fractured base case.
- Streamline simulation of fractured gas-condensate reservoir to visualize the flow profile in and around the hydraulic fracture.

Conclusions reached:
1. Well PI impairment due to liquid drop-out in a gas-condensate reservoir will be overestimated if the simulation model ignores the non-Darcy flow effect in the near-well region.
2. A hydraulic fracture does not need to be very long to result in a higher PI increase (as long as it passes through the condensate banking radius, which is usually very close to the well).
3. Fracture width is a more important fracture parameter than fracture length in tight gas-condensate reservoirs. The benefit from increasing fracture half-length diminishes after the length has reached a certain value.
4. Wide/short fractures provide higher PI than narrow/long fractures in a tight gas-condensate reservoir.
SPE 103433 (Distinguished Author Series JPT, 2007)

Deliverability of Gas-Condensate Reservoirs – Field Experiences and Prediction Techniques

Authors: Kamath, J.

Contribution to the understanding of gas condensate reservoirs:
Outline a five-step approach to predict deliverability loss in gas condensate reservoir due to the formation of condensate bank when well bottom-hole pressure near-wellbore drops below dew point pressure.

Objective of the paper:
To predict deliverability loss caused by condensate banking using a five-step approach and discuss integrated laboratory/simulation field studies used to validate these steps.

Methodology used:
- Discuss impact of condensate banking and its adverse effects on well deliverability.
- Discussion of a five-step approach to predict well deliverability loss due to condensate banking.
  - Appropriate Laboratory Measurements – To conduct pseudosteady-state experiments with carefully designed synthetic fluids that allow the experiments to be conducted at lower temperatures without the need for saturation measurements.
  - Fitting Laboratory Data (of the form \( k_{rg} = f(k_{rg}/k_{ro}, N_c) \) or \( k_{rg} = f(S_g, N_c) \)) to Relative Permeability Models
  - Use of Spreadsheet Tools – To evaluate well performance rapidly. The spreadsheet uses a material-balance model for reservoir depletion and a two-phase pseudopressure integral for well-inflow performance, and it can use laboratory data in the form \( k_{rg} = f(k_{rg}/k_{ro}, N_c) \).
  - Simulation of Single-Well Compositional Models to understand compositional effects, heterogeneity, differential depletion, and time-varying boundary conditions.
  - Full-Field Models (FFMs) – To capture the effects of condensate banking on well deliverability in three ways:
    i. PI multipliers
    ii. Local grid refinement (LGR) around wells
    iii. Use of generalized pseudopressure (GPP) model
- Discuss ways to improve deliverability by well stimulation including hydraulic fracturing and chemical treatments.

Conclusions reached:
1. A five-step approach using practical laboratory techniques and modeling approaches can predict deliverability loss caused by condensate banking reasonably.
2. Continued extensive testing of existing relative permeability models and more measurements in the high-\((k_{rg}/k_{ro})\) and -capillary-number region will increase confidence in predictions.
3. Productivity improvement by fracturing in gas-condensate wells is not as well understood as in dry-gas systems and could benefit from additional work.
4. Chemical treatments to change wettability and improve deliverability are in the laboratory phase, and field trials are still needed to evaluate their effectiveness.

Comments:
Good discussion and systematic approach to predict the gas condensate well deliverability.
SPE 117930 (2010)

Gas-Condensate Pseudopressure in Layered Reservoirs

Authors: Singh, K. and Whitson, C.H.

Contribution to the understanding of gas condensate reservoirs:

Objective of the paper:
To verify for the first time that the gas-condensate pseudopressure method as proposed by Fevang and Whitson (1996) is valid and accurate for layered systems with significant heterogeneity (permeability variation), with and without crossflow, with and without capillary number modification of relative permeabilities, and for widely ranging fluid compositions in each layer.

Methodology used:
Use commercial compositional reservoir simulator to study the examples from several field studies (which include rich- and lean- condensate reservoirs) and from two synthetic systems.
- Construct three-dimensional multilayer, fine-grid (radial and Cartesian) models and equivalent coarse-grid models were used.
- Both depletion and gas-injection cases were simulated for a wide range of reservoir fluids.
- Reservoir performance of fine-grid models and coarse-grid models was compared using the gas-condensate pseudopressure method and showed comparable results in all cases studied, including relative permeabilities with capillary-number dependence and high-velocity ($\beta$) flow treatment.

Conclusions reached:
1. The accuracy of the pseudopressure method is somewhat dependent on the well grid size, generally requiring $\Delta x = \Delta y \approx 50 - 100 m$ for lean gas condensates and $\Delta x = \Delta y \approx 100 - 200 m$ for rich gas condensates.
2. The effect of condensate blockage is most prominent for low-$kh$ (i.e. permeability-thickness) reservoirs.
3. The effect of condensate blockage is greater at higher production rates because of the large difference between well bottom-hole pressure (BHP) and reservoir pressure.
4. The effect of condensate blockage is smaller with velocity-dependent relative permeability where condensate blockage is offset by an increase in relative permeability resulting from capillary-number effect.
5. For all simulated cases, coarse-grid models without pseudo-pressure well treatment give optimistic reservoir performance compared to fine-grid models, which capture well treatment and blockage correctly.
## Appendix B: Main keywords used in the compositional simulation models

<table>
<thead>
<tr>
<th><strong>Eclipse 300 simulator keyword</strong></th>
<th><strong>Description</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>ISGAS</td>
<td>The run is gas condensate</td>
</tr>
<tr>
<td>VELDEP</td>
<td>Activates the Capillary Number and the Forchheimer models for both the oil and gas phase</td>
</tr>
<tr>
<td>VDKRO</td>
<td>The data comprises of a set of tables for the Capillary Number and Forchheimer models of oil velocity dependent relative permeability data.</td>
</tr>
<tr>
<td>VDKRG</td>
<td>The data comprises of a set of tables for the Capillary Number and Forchheimer models of gas velocity dependent relative permeability data.</td>
</tr>
<tr>
<td>SGFN</td>
<td>Gas saturation functions</td>
</tr>
<tr>
<td>SOF3</td>
<td>Oil saturation functions (three-phase)</td>
</tr>
<tr>
<td>SWFN</td>
<td>Water saturation functions</td>
</tr>
<tr>
<td>HWELLS</td>
<td>Horizontal well completion option</td>
</tr>
<tr>
<td>TUNING</td>
<td>Sets simulator control parameters</td>
</tr>
<tr>
<td>LSCRIT</td>
<td>Linear solution convergence criteria</td>
</tr>
<tr>
<td>WPIMULT</td>
<td>Multiplies well connection factors by a given value</td>
</tr>
</tbody>
</table>
Appendix C: Main Operational Control Mode Study

Table C-1: Gas Production Rate Control Mode Study

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Gas Production Rate Control Mode (GRAT)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Gas rate target <em>without</em> limiting a bottom-hole pressure target or lower limit; Well Gas Production Rates at different Report Steps are specified as follows:</td>
</tr>
<tr>
<td></td>
<td>i. 200 Mscf/D from 1&lt;sup&gt;st&lt;/sup&gt; Jan 2014 to 2&lt;sup&gt;nd&lt;/sup&gt; Jan 2014 (1 day)</td>
</tr>
<tr>
<td></td>
<td>ii. 400 Mscf/D from 2&lt;sup&gt;nd&lt;/sup&gt; Jan 2014 to 4&lt;sup&gt;th&lt;/sup&gt; Jan 2014 (2 days)</td>
</tr>
<tr>
<td></td>
<td>iii. 800 Mscf/D from 4&lt;sup&gt;th&lt;/sup&gt; Jan 2014 to 7&lt;sup&gt;th&lt;/sup&gt; Jan 2014 (3 days)</td>
</tr>
<tr>
<td></td>
<td>iv. 1600 Mscf/D from 7&lt;sup&gt;th&lt;/sup&gt; Jan 2014 to 11&lt;sup&gt;th&lt;/sup&gt; Jan 2014 (4 days)</td>
</tr>
<tr>
<td></td>
<td>v. Shut in well from 11&lt;sup&gt;th&lt;/sup&gt; Jan 2014 to 21&lt;sup&gt;st&lt;/sup&gt; Jan 2014 (10 days)</td>
</tr>
<tr>
<td>2</td>
<td>Gas rate target <em>without</em> limiting a bottom-hole pressure target or lower limit; Well Gas Production Rates at different Report Steps are specified as follows:</td>
</tr>
<tr>
<td></td>
<td>i. 1000 Mscf/D from 1&lt;sup&gt;st&lt;/sup&gt; Jan 2014 to 6&lt;sup&gt;th&lt;/sup&gt; Jan 2014 (5 days)</td>
</tr>
<tr>
<td></td>
<td>ii. 2000 Mscf/D from 6&lt;sup&gt;th&lt;/sup&gt; Jan 2014 to 11&lt;sup&gt;th&lt;/sup&gt; Jan 2014 (5 days)</td>
</tr>
<tr>
<td></td>
<td>iii. Shut in well from 11&lt;sup&gt;th&lt;/sup&gt; Jan 2014 to 21&lt;sup&gt;st&lt;/sup&gt; Jan 2014 (10 days)</td>
</tr>
<tr>
<td>3</td>
<td>Gas rate target <em>without</em> limiting a bottom-hole pressure target or lower limit; Well Gas Production Rates at different Report steps are specified as follows:</td>
</tr>
<tr>
<td></td>
<td>i. 2000 Mscf/D from 1&lt;sup&gt;st&lt;/sup&gt; Jan 2014 to 6&lt;sup&gt;th&lt;/sup&gt; Jan 2014 (5 days)</td>
</tr>
<tr>
<td></td>
<td>ii. Shut in well from 6&lt;sup&gt;th&lt;/sup&gt; Jan 2014 to 11&lt;sup&gt;th&lt;/sup&gt; Jan 2014 (5 days)</td>
</tr>
<tr>
<td></td>
<td>iii. 2000 Mscf/D from 11&lt;sup&gt;th&lt;/sup&gt; Jan 2014 to 16&lt;sup&gt;th&lt;/sup&gt; Jan 2014 (5 days)</td>
</tr>
<tr>
<td></td>
<td>iv. Shut in well from 16&lt;sup&gt;th&lt;/sup&gt; Jan 2014 to 21&lt;sup&gt;st&lt;/sup&gt; Jan 2014 (5 days)</td>
</tr>
<tr>
<td>4</td>
<td>Gas rate target <em>with</em> a limiting a bottom-hole pressure target or lower limit at 400 psia; Well Gas Production Rates at different Report steps are specified as follows:</td>
</tr>
<tr>
<td></td>
<td>i. 5000 Mscf/D from 1&lt;sup&gt;st&lt;/sup&gt; Jan 2014 to 11&lt;sup&gt;th&lt;/sup&gt; Jan 2014 (10 days)</td>
</tr>
<tr>
<td></td>
<td>ii. Shut in well from 11&lt;sup&gt;th&lt;/sup&gt; Jan 2014 to 21&lt;sup&gt;st&lt;/sup&gt; Jan 2014 (10 days)</td>
</tr>
<tr>
<td>5</td>
<td>Gas rate target <em>with</em> a limiting a bottom-hole pressure target or lower limit at 400 psia; Well Gas Production Rates at different Report steps are specified as follows:</td>
</tr>
<tr>
<td></td>
<td>i. 10000 Mscf/D from 1&lt;sup&gt;st&lt;/sup&gt; Jan 2014 to 11&lt;sup&gt;th&lt;/sup&gt; Jan 2014 (10 days)</td>
</tr>
<tr>
<td></td>
<td>ii. Shut in well from 11&lt;sup&gt;th&lt;/sup&gt; Jan 2014 to 21&lt;sup&gt;st&lt;/sup&gt; Jan 2014 (10 days)</td>
</tr>
</tbody>
</table>

Table C-2: Bottom-hole pressure Control Mode Study

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Bottom-hole pressure Control Mode (BHP)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Bottom-hole pressure target <em>without</em> limiting gas rate target or upper limit, specified at different Report steps as follows:</td>
</tr>
<tr>
<td></td>
<td>i. Set WBHP target at 400 psia (lowest possible for this system) from 1&lt;sup&gt;st&lt;/sup&gt; Jan 2014 to 11&lt;sup&gt;th&lt;/sup&gt; Jan 2014 (10 days)</td>
</tr>
<tr>
<td></td>
<td>ii. Shut in well from 11&lt;sup&gt;th&lt;/sup&gt; Jan 2014 to 21&lt;sup&gt;st&lt;/sup&gt; Jan 2014 (10 days)</td>
</tr>
<tr>
<td>2</td>
<td>Bottom-hole pressure target <em>without</em> limiting gas rate target or upper limit, specified at different Report steps as follows:</td>
</tr>
<tr>
<td></td>
<td>i. Set WBHP target at 4000 psia (below $P_{dew} = 4298 \text{ psia}$) from 1&lt;sup&gt;st&lt;/sup&gt; Jan 2014 to 11&lt;sup&gt;th&lt;/sup&gt; Jan 2014 (10 days)</td>
</tr>
<tr>
<td></td>
<td>ii. Shut in well from 11&lt;sup&gt;th&lt;/sup&gt; Jan 2014 to 21&lt;sup&gt;st&lt;/sup&gt; Jan 2014 (10 days)</td>
</tr>
<tr>
<td>3</td>
<td>Bottom-hole pressure target <em>without</em> limiting gas rate target or upper limit, specified at different Report steps as follows:</td>
</tr>
<tr>
<td></td>
<td>i. Set WBHP target at 4350 psia (above $P_{dew} = 4298 \text{ psia}$) from 1&lt;sup&gt;st&lt;/sup&gt; Jan 2014 to 11&lt;sup&gt;th&lt;/sup&gt; Jan 2014 (10 days)</td>
</tr>
<tr>
<td></td>
<td>ii. Shut in well from 11&lt;sup&gt;th&lt;/sup&gt; Jan 2014 to 21&lt;sup&gt;st&lt;/sup&gt; Jan 2014 (10 days)</td>
</tr>
</tbody>
</table>
Figure C-1: Gas Production Rate Control Mode (GRAT) – Scenario 1

Figure C-2: Gas Production Rate Control Mode (GRAT) – Scenario 2
Figure C-3: Gas Production Rate Control Mode (GRAT) – Scenario 3

Figure C-4: Gas Production Rate Control Mode (GRAT) – Scenario 4
Figure C-5: Gas Production Rate Control Mode (GRAT) – Scenario 5

Figure C-6: Bottom-hole pressure Control Mode (BHP) – Scenario 1
Figure C-7: Bottom-hole pressure Control Mode (BHP) – Scenario 2

Figure C-8: Bottom-hole pressure Control Mode (BHP) – Scenario 3