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Modelling the Effect of Composition Change during Condensate Dropout in a Horizontal Gas Well

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Abstract

This paper presents a mathematical model describing the behavior analysis for a two-phased gas-condensate system narrowing down on the three zone method.

The three zone method accounts for the composition change in the reservoir and is based on modeling the depletion by three main flow regions:

- A near wellbore region (Region 1) where the oil saturation is important allowing both phase, vapor and liquid to be mobile.
- Region 2 where condensate and gas are present but only the gas is mobile.
- An outer Region 3 exists when the reservoir pressure is greater than the initial gas dew point and contains only gas.

This research proposed a fourth region (Region **I**) which is the immediate vicinity of the well where accumulation of liquid buildup at high rates which yielded from an increase of liquid saturation and a probable decrease in gas relative permeability. The existence of the fourth region or flushed zone is particularly important as it represent the total skin effect: mechanical skin, rate dependent two-phase skin and skin due to gas condensate blockage. The calculated well deliverability rate using the modeled equation for gas condensate reservoir showed a relatively high difference when compared to other known equations. This significant difference is as a result of the effects of the proposed Region **I**. The developed correlation confirms that as the pressure drops below dew point there occurs condensate banking which when the critical saturation is reached becomes mobile and leads to a reduction in gas flow rate in the reservoir

INTRODUCTION

Gas condensate exhibit complex phase and flow behaviors due to the appearance of condensate liquid when the bottom-hole pressure drops below the dew point pressure. The accumulated condensate in the vicinity of the wellbore causes a blockage effect and reduces the effective permeability appreciably, depending on a number of reservoir and well parameters, and also causes the loss of heavy components at surface (Chunmei, 2005).

Productivity loss resulting from the condensate buildup is alarming, most often, the decline could get to factors of two to four, considering the work of Afidick *et al.*, (1994) and Barnum *et al.*, (1995). "A maximum liquid drop out of only 1%, may reduce the productivity in very lean gas-condensate reservoirs by a factor of about two as the pressure drops below the dew-point pressure" (Afidick *et al.*, 1994).

In order to have a near accurate figure for well deliverability and calculate gas and liquid recovery, it is mandatory to acquire a comprehensive data set of the relative permeability and liquid banking of gas-condensate wells.

Fluid properties and flow process are important factors linked with Gas-condensate relative permeabilities, and are affected by both viscous and capillary forces.

The impact of condensate blockage is very sensitive to the gas-oil relative permeabilities in the region around the wellbore. Several laboratory experiments have demonstrated an increase in mobility for gas-condensate fluids at the high velocities typical of the near-well region, a mechanism that would reduce the negative impact of condensate blockage. There is also some evidence from well test results to suggest that this effect occurs in the field. Forecasting of condensate well productivity usually requires fine grid numerical simulation to model near-well effects and the improvement in relative permeability at high velocity. However, it is also possible to use 2-phase pseudo pressure methods to provide a simpler and faster method of estimating condensate well productivity. Pseudo pressure methods have been extended to model high-velocity effects and can also be applied to fractured and horizontal wells. These methods are suitable for rapid calculations to examine sensitivities to different input parameters. .Simultaneous flow of two fluid phases in porous media is a highly non-linear process due to the complex relations between the capillary pressure, phase saturations and conductivities. Typical examples of two-phase flow include gas flow in gas condensate reservoirs.

Majority of worldwide gas reservoir assets are constituted in gas condensate fields and have become a major trend of focus for the energy industry in recent times. Efficient and cost-effective reservoir management of gas-condensate fields requires meeting the unique accurate well deliverability and liquid recovery predictions challenges posed by these assets (Nagarajan *et al*., 2004).

For example, the number of wells and the size of the surface facilities required are dictated by the well deliverability and liquid recovery of a particular gas reservoir. Fundamental to making near accurate predictions of well deliverability and liquid recovery over the life of the reservoir is a clear understanding and accurate knowledge of the flow characteristics of both gas and condensate phases through reservoir rocks (Fevang & Whitson 1996).

Typically, gas condensate reservoirs are discovered as single-phase gas reservoirs. As the reservoir pressure drops below the dew point pressure, isothermal condensation occurs and produces a "ring" of liquid condensate, which is mainly composed of intermediate and heavier components. The "buildup" of the condensate ring generates a reduction in gas deliverability, due mainly to the reduction in gas relative permeability. This condition leaves a substantial portion of the condensed liquid in the reservoir due to the high liquid-to-gas viscosity ratio (and relative permeability effects). Ultimately, the buildup of condensate in the reservoir affects the economic value of the project. Characterization of gas condensate reservoirs is often an uphill task because multiphase flow exists in the reservoir and during production the fluid changes its overall composition in both time and space. This situation complicates well deliverability analysis, well testing, evaluation of productivity and the sizing of surface facilities (Yanil, 2003). Various flow regimes associated with gas and condensate phases below the fluid dew point pressure are briefly discussed. During the production of a gas-condensate reservoir, heavier hydrocarbon components in the gas drop out as liquid when the reservoir pressure declines below the fluid dew point pressure (Nagarajan *et al*., 2004).

There are various flow regions encountered in a gas-condensate reservoir, along with the pressure profile and the liquid dropout curve as the pressure declines below the dew point pressure. Farthest from the wellbore, the reservoir may still experience a single gas-phase flow because the reservoir pressure is still above the dew point pressure (Nagarajan *et al*., 2004).

The flow regions to be considered are:

- Region 1: An inner near-wellbore region where both gas and liquid flow simultaneously (at different velocities).
- Region 2: A region of condensate buildup where only gas is flowing.
- Region 3: A region containing single-phase (original) reservoir gas. This region is the farthest away from the well. 9

In region 2 where the reservoir pressure is just below the dew point pressure, condensation of heavier components and subsequent liquid buildup occur. If the liquid saturation has not exceeded a threshold value known as the "critical condensate saturation" (Scc), the liquid does not flow. However, increasing condensate saturation, even if it is not flowing, could impede the gas flow, thus reducing the well deliverability. Further to the left of this region and closer to the wellbore the condensate accumulation is accelerated due to the large influx of gas in this region. This results in liquid saturation above (Scc) and leads to two phase flow and further loss of well productivity (Nagarajan *et al.*, 2004).

LITERATURE

The ability to predict well deliverability is a key issue for the development of gas condensate reservoirs. Cho *et al.,* (1985) presented a correlation to predict maximum condensation for retrograde condensation fluid its uses in pressure depletion calculations. The correlation presented is a function of the reservoir temperature and the heptane's plus mole fraction only *(*Cho *et al.,* 1985*).*

Sognesand, (1991) discussed condensate built up in vertical fractured gas condensate wells. He showed that the condensate build up depends on the relative permeable characteristic and production mode, increase permeability to gas yields reduced amount of condensate accumulation, and constant pressure production yields the largest near fracture condensate build-up.

Afidick *et al.,* (1994) studies the decline in productivity of Arun gas condensate reservoir as a result of condensate accumulation. Experimental PVT analysis fluids show that the reservoir fluid was a lean gas condensate with maximum liquid dropout of 1.1%. The decline in the productivity of wells by a factor of round 2 as the reservoir pressure fall below the dew point pressure was attributed to accumulate of condensates around the well bore. The accumulation of the condensate around the well bore was confirmed by well test and the analysis done on the well bore well confirmed by well test and the analysis done on the reservoir cores. *(*Afidick *et al.,* 1994*)*

Barnum *et al.,* (1995) found that production loss is severe for low productivity reservoir i.e. those with a K_h less than 1000md-ft. they reported that the critical condensate saturation ranged from 10-30% and can decrease the productivity by a factor up to five due to condensate accumulation near the well bore. Volatile oil modes were used in preference to more complex compositional simulation which might be needed to understand condensate recovery and gas quality resulting from gas quantity resulting from gas cycling or more displacement processes *(*Barnum *et al., 1995).*

In furtherance to gas condensate productivity studies, Robert Mott (1999-2002) reviewed recent developments in the understanding of near-well bore behavior in condensate reservoir, and in estimating well productivity through numerical simulation. Three different approaches for calculating condensate well productivity in full field reservoir simulation well consider- using single well calculations to estimate skin factors, local grid refinement and pseudo methods *(*Robert Mott *1999-2002).*

Cable *et al.,* (2002) considered the issue affecting gas condensate production and how special core analysis data for near-well relative permeability may be to model productivity in a full field model for evaluating gas condensate reservoir development. They argue that though some aspects of gas condensate reservoir be studies using standard techniques from dry gas reservoir engineering, it is also important to issues such as liquid recovery and change in yield during field life, compositional gradients, and the reduction in well deliverability caused by condensate blockage *(*Cable *et al., 2002).*
Gozalpour *et al.,* (2007) investigated the impact of sample contamination with oil-based-mud filtrate on different types of reservoir fluids, including condensate and volatile oil smiles. Two samples method are suggested to retrieve the uncontaminated composition from a contaminated sample in which mud filtrate is totally dissolved in the formation fluid (i.e. reservoir – oil sample). A tracer-based technique is also developed to determine the composition of an uncontaminated reservoir-fluid sample from a sample contaminated with oil-based-mud filtrate, particularly for those cases in which the two fluid are partially miscible. The tracer are added to the drilling fluid, the additional cost to drilling-mud preparation being negligible. The capability of the developed techniques was examined successfully against deliberately contaminated reservoir-fluid sample under controlled conditions in the laboratory *(*Gozalpour *et al*., *2007)*

Since the most important and complex phenomena associated with condensate banking and productivity reduction is relative permeability, there have been many investigation of gas condensate relative permeability and a few of this are reviewed below.

Hinchman & Barrel, (1985) showed how the choice between ambitions and drainage relative permeability curves could dramatically alter the productivity forecast below the saturation pressure for gas condensate reservoirs. Productivity above the dew point pressure is controlled by reservoir permeability and thickness, and by the viscosity of the gas. Below the dew point the degree of productivity reduction will be controlled by critical condensate saturation and the shape of the gas and condensate relative permeability curves *(*Hinchman & Barrel, *1985).*

Gringarten *et al.,* (2000) found that when reservoir pressure around a well drops down the dew point pressure, retrograde condensate occurs and three regions are created with different liquid saturations. Away from well, an outer region has initial liquid saturations; next there is immobile. Closer to the well, an inner regions form where the liquid saturation researches a critical value, and the effluent travel as a two phase fluid with constant composition (the condensate is deposited as pressure decrease of the liquid saturation and an increase of the gas relative permeability) *(*Gringarten *et al.,* 2000*).*

Baguette *et al.,* (2005) developed a novel approach for calculating representative field relative permeability: This is based on physical model that takes into account the various mechanisms of the process: bubble nucleation (pre- existing bubbles model), phase transfer (volumetric function), and displacement (bubble flow). 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 invariant are determined by history matching one experiment at a given depletion rate *(*Baguette *et al., 2005).*

Jamiolahmady *et al.,* (2006) used a larger data bank of gas/condensate relative permeability to develop general correlation accountings for the combined effect of coupling and inertia as a function of fractional flow. The parameters of the new correlation are either universal applicable to all types of rocks, or can be determined from commonly measured petrochemical data. They examined the developed correlation by comparing its predictions with gas condensates relative permeability values measured at near well bore conditions on reservoir rocks not used in the development. The result shows that their correlation can provide reliable information on variations of relative permeability near – well bore conditions with no requirement for expensive measurement *(*Jamiolahmady *et al.,* 2006*).*

Bozorgzadah & Gringarten, (2007) show in their paper that well deliverability depends mainly on the gas relative permeability at both the end point and the near well bore saturation as well as on the reservoir permeability. The demonstrate how these parameters and the base capillary number can be obtained from pressure build up data by using single-phase and two – phase pseudo-pressures simultaneously. These parameters can in turn be used to estimate gas relative permeability curves. The approach was illustrated with simulated pressure buildup data and an actual field case (Gozalpour *et al.,* 2007).

MATHEMATICAL MODEL

Using pseudo pressure analysis, the general volumetric rate equation for a gas condensate well of any geometry (e.g. radial, vertically fractured or horizontal) for a compositional formulation is given by Fevang’s equation (1995):

$$q_g = C\frac{RT_{sc}}{P_{sc}}\beta\int_{P_{wf}}^{P_R}\frac{\rho_o K_{ro}}{M_o\mu_o} + \frac{\rho_g K_{rg}}{M_g\mu_g}dP \;\ldots\ldots (3.6)$$

$$\text{Where } C = \frac{2\pi\alpha_1 Kh}{ln\frac{r_e}{r_w} - 0.75 + s} \ldots\ldots (3.7)$$

Fevang’s equation is strictly applied to vertical wells and does not compensate for the Non-Darcy effect which is an important parameter in natural gas flow. For very low permeability reservoirs in mature environments, it is sufficient to assume that gas flow obeys Darcy’s law, but for newly drilled wells with moderate to high permeability ranging from 1-100md, the above equation would be modified to predict effectively the well deliverability for a horizontal well considering the three (3) regions of flow, reservoir length, turbulence and the reservoir fluid properties as they influence deliverability.

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We assume that $\beta = 0$
Introducing Non-Darcy flow coefficient D

$$\text{Where } C = {2\pi\alpha_1 kh}\Big/{\ln\left(\frac{r_e}{r'_w}\right) - 0.75 + s + Dq} \quad (3.7)$$

$$\alpha_1 = \frac{1}{2\pi * 141.2}$$

$$D = \frac{2.22X10^{-15}(K_X K_Y K_Z)^{\frac{1}{3}}\gamma_g}{\mu h r'_w}\beta_H \ldots \quad (3.8)$$

$$\beta_H = \frac{5.5X10^9}{(K_X K_Y K_Z)^{5/12}\emptyset^{3/4}} \ldots (3.9)$$

$$K = \sqrt[3]{k_H^2 k_V}\text{ , where kxky} = k_H^2 \text{ and } K_Z = k_V$$

Considering an anisotropic reservoir, the effective wellbore radius is given by

$$r'_w = \frac{r_{eh}(L/2)}{a(1 + \sqrt{1 - (L/2a)^2})\left(\frac{\beta h}{2r_w}\right)^{\beta h/L}} \ldots\ldots (3.10)$$

$$a = \left(\frac{L}{2}\right)[0.5 + \sqrt{0.25 + (\frac{2r_{eh}}{L})^4}]^{0.5} \ldots (3.11)$$

Taking the fluid properties of the reservoir into consideration, noting that the gas phase of the reservoir fluid consist of various properties that would respond to a change in horizontal length, temperature, pressure, and turbulent flow experienced at region 1 closest to the wellbore.

The fluid properties are derived using various correlations as they respond to the reservoir and wellbore parameters stated

$$\rho_g = {PM_g}/{ZRT} \ldots\ldots\ldots (3.12)$$

$$\mu_o = A\mu_{od}^B \ldots\ldots\ldots\ldots\ldots (3.13)$$

$$\mu_g = (10^{-4})Kexp(X\rho^Y) \ldots\ldots (3.14)$$

$$M_o = {42.43\gamma_o}/{1.008 - \gamma_o} \ldots (3.15)$$

$$M_g = \sum \gamma_{iM_i} \ldots\ldots\ldots\ldots\ldots\ldots\ldots (3.16)$$

The gas flow rate in region 1 (near wellbore region) where the gas and condensate are both flowing from the dew point pressure to the last flowing well pressure can be calculated using

$$q_g = \frac{2.6962Kh}{\ln\left(\frac{r_e}{r'_w}\right) - 0.75 + s + Dq_g}\beta\int_{P_{wf}}^{P_R}\frac{\rho_o K_{ro}}{M_o\mu_o} + \frac{\rho_g K_{rg}}{M_g\mu_g}dP \ldots (3.17)$$

$$\text{Where } \lambda_o = \frac{\rho_{ok_{ro}}}{\mu_o} \ldots\ldots 3.18)$$

$$\lambda_g = \frac{\rho_g k_{rg}}{\mu_g} \;\ldots\ldots (3.19)$$

Substituting equation (3.18) & (3.19) into equation (3.17)

$$q_g = \frac{2.6962Kh}{\ln\left(\frac{r_e}{r_w'}\right) - 0.75 + s + Dq_g} \beta \int_{P_{wf}}^{P_R} \lambda_o/_{M_o} + \lambda_g/_{M_g}\, dP \ldots (3.20)$$

Applying the basic quadratic principle to equation (3.20), we eliminate the q_g term from the RHS,

$$q_g = \ln(\frac{r_e}{r_w'}) - 0.75 + s \pm \frac{\sqrt{\{(\ln {r_e}/_{r_w'}) - 0.75 + s\}^2 + 4D}\,(2.6962kh\beta \int_{Pwf}^{Pr} \lambda_o/_{M_o} + \lambda_g/_{M_g})}{2D}$$

RESULT ANALYSIS

Calculated Flow Rate Using Discussed Equations

The equations which were considered in the previous chapter are all well deliverability equations for horizontal well i.e. Equations (3.1, 3.3 and 3.4), but does not capture the effect of Non-Darcy flow factor, variation of well length and reservoir fluid properties. The flow rates calculated using the discussed gas flow rate equation for the reservoir at different bottom-hole flowing pressures is shown in Table 1 below;

- Joshi's Equation
- Borisov's Equation
- Geiger's Equation

Table 1: Calculation Summary for Discussed Equations

P(psia)	qgj	qgb	qgg
4500	35.0107	31.1107	34.8783
4200	36.1180	32.2180	35.9856
4100	43.1020	39.2020	42.9696
3400	46.6820	42.7820	46.5496
3100	52.1430	48.2430	52.0106
2900	59.2180	55.3180	59.0856
2800	60.8100	56.9100	60.6776
2761	62.2430	58.3430	62.1106
2200	68.5730	64.6730	68.4406
1000	71.7630	67.8630	71.6306

Effect of Relative Permeability

When computing the two-phase pseudo pressures (either using steady-state or three-zone method), a pressure-saturation is needed. The pressure-saturation relationship is determined by relating the ratio *krg*/*kro* with functions of pressure only, hence this ratio can be written as *krg*/*kro* (*p*).

The two-phase pseudopressure is given by:

$$m(p) = \int_{P_{wf}}^{P_R} \frac{\rho_o K_{ro}}{M_o \mu_o} + \frac{\rho_g K_{rg}}{M_g \mu_g}\, dP$$

Recalling that in the two-phase pseudopressure integral, only the gas term has a significant contribution (ρg*krg/μg) the value of the integral will then only depend on the relationship *krg* = *f*(*krg*/*kro*(*p*)). Therefore, sensitivities on relative permeabilities should be evaluated on different sets of curves that have different relationship *krg* = *f*(*krg*/*kro*) as Fevang (1995) advised.

Calculated Flow Rate Using Developed Equation

The equation is derived to compensate for the effect of skin, turbulent flow coefficient, variation in length of horizontal producing well and reservoir fluid composition. The modeled equation would introduce the effect of the reservoir fluid property as it changes with pressure difference. The gas flow rate is calculated and compared to flow rates as resulting from the previous discussed models.

Table 2: Calculation Summary for Reservoir Fluid Properties with Pressure Change

P(psia)	ρ_o	So	Sg	Swc	S'o	k_{ro}	M_o	u_o	ρ_g	k_{rg}	M_g	u_g
4500	0.1369	0.7000	0.0503	0.2497	0.9330	0.812062	0.01886495	1.008	0.5612	0.000301	0.746688	0.1695
4200	0.1685	0.6500	0.1003	0.2497	0.8663	0.650182	0.02487164	0.912	0.5902	0.002389	0.800023	0.1611
4100	0.2360	0.5500	0.2003	0.2497	0.7330	0.393898	0.03568171	0.823	0.7032	0.019026	0.819535	0.1589
3400	0.2792	0.4500	0.3003	0.2497	0.5998	0.215741	0.05091386	0.612	0.8321	0.064115	0.988263	0.1522
3100	0.3375	0.3500	0.4003	0.2497	0.4665	0.101508	0.06749749	0.524	0.9112	0.151863	1.083902	0.1471
2900	0.4570	0.2500	0.5003	0.2497	0.3332	0.036993	0.09770109	0.401	1.2303	0.296474	1.158654	0.1143
2800	0.5240	0.2000	0.5503	0.2497	0.2666	0.01894	0.11602581	0.321	1.3322	0.394542	1.200034	0.0911
2761	0.5802	0.1500	0.6003	0.2497	0.1999	0.00799	0.13029092	0.236	1.5098	0.512154	1.216985	0.0887
2200	0.9104	0.1000	0.6503	0.2497	0.1333	0.002368	0.25655381	0.102	1.6421	0.651083	1.527316	0.01695
1000	2.4489	0.0500	0.7003	0.2497	0.0666	0.000296	1.51833201	0.05	1.8231	0.813107	3.360095	0.01695

Table 3: Calculation Summary for the Two-Phase Pseudopressure

P(psia)	$\frac{\rho_o K_{ro}}{M_o \mu_o}$	$\frac{\rho_g K_{rg}}{M_g \mu_g}$		$\lambda_o/M_o + \lambda_g/M_g$	qgn(D,s,Fp)
4500	5.847222	0.001336		5.84855787	17.2433
4200	4.829454	0.01094		4.840393095	18.3506
4100	3.165013	0.102737		3.267750073	25.3346
3400	1.933163	0.35469		2.287853487	28.9146
3100	0.968586	0.867887		1.8364724	34.3756
2900	0.431496	2.754215		3.185711589	41.4506
2800	0.266469	4.807853		5.074322065	43.0426
2761	0.150776	7.163262		7.314037462	44.4756
2200	0.082362	41.2988		41.3811605	50.8056
1000	0.009546	26.02776		26.03730358	53.9956
			TOTAL=	101.0735621	
D	β	K	Kh	(2.6962khβ)	
0.0000	8.49E+09	0.136929	15.0622	3.4477E+11	

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The calculated well deliverability rate using the modeled equation for the gas condensate reservoir showed a relatively high difference when compared to other equations (3.1, 3.3 and 3.4). The results are shown below.

Table 4: Computation of Well Deliverability Results

P(psia)	qgj	qgb	qgg	qgn	qgn(D,s,Fp)
4500	35.0107	31.1107	34.8783	32.8907	17.2433
4200	36.1180	32.2180	35.9856	33.9980	18.3506
4100	43.1020	39.2020	42.9696	40.9820	25.3346
3400	46.6820	42.7820	46.5496	44.5620	28.9146
3100	52.1430	48.2430	52.0106	50.0230	34.3756
2900	59.2180	55.3180	59.0856	57.0980	41.4506
2800	60.8100	56.9100	60.6776	58.6900	43.0426
2761	62.2430	58.3430	62.1106	60.1230	44.4756
2200	68.5730	64.6730	68.4406	66.4530	50.8056
1000	71.7630	67.8630	71.6306	69.6430	53.9956

The calculated flow rate from equations 3.1, 3.3, 3.4 and 3.21 all show similar trends when related to the effective wellbore radius as affected by a variation in the horizontal well length.

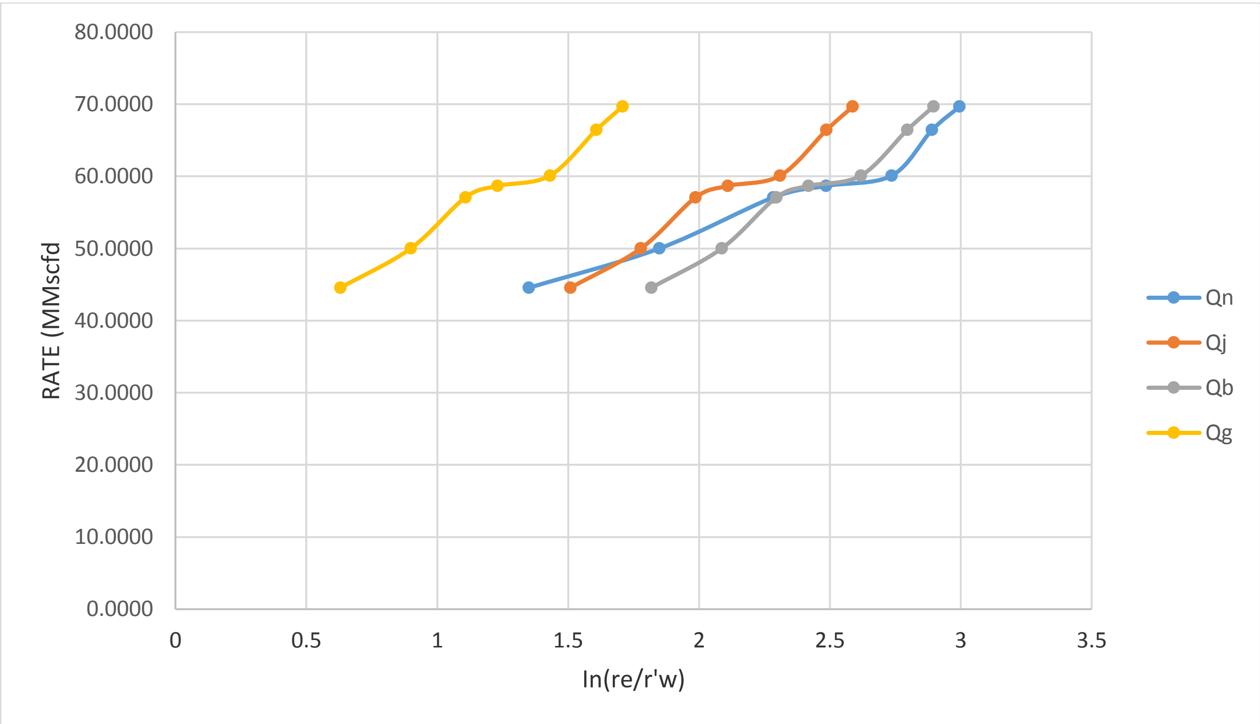

Figure 1: Plot of the Well Flow Qg (MMscfd) Against the Effective Wellbore Radius

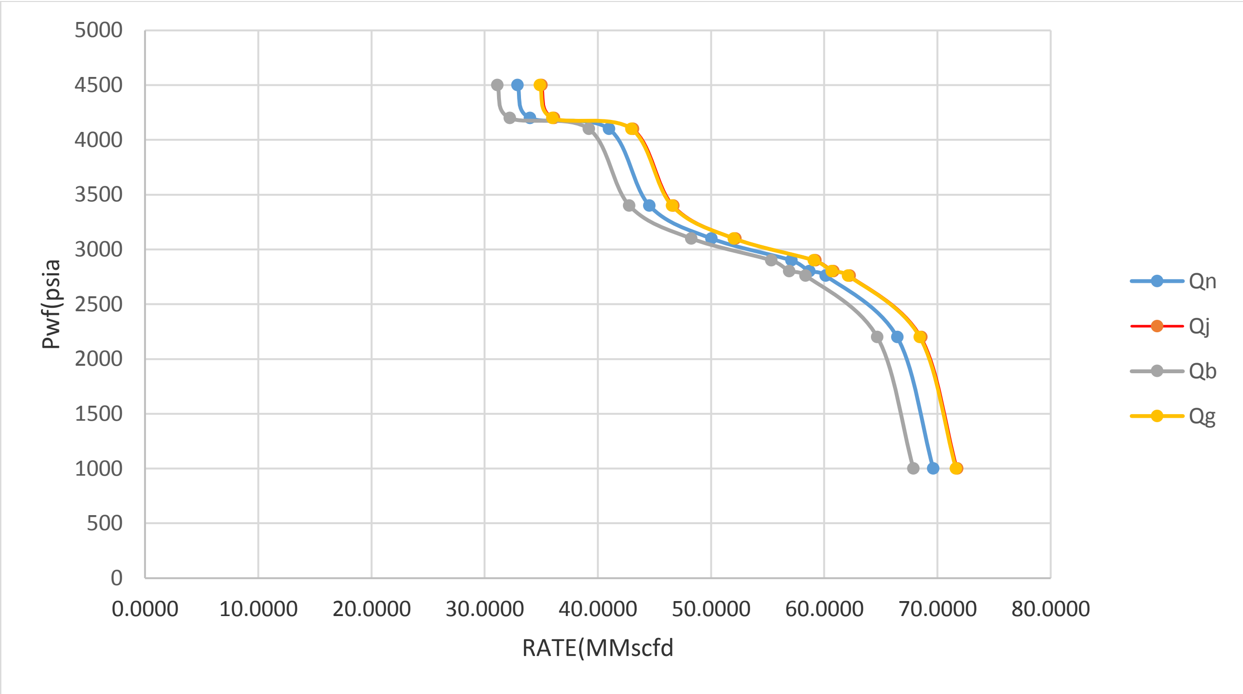

Figure 2: Shows The Result of Discussed Models and Developed Model (without the effect of D, s and Rfp).

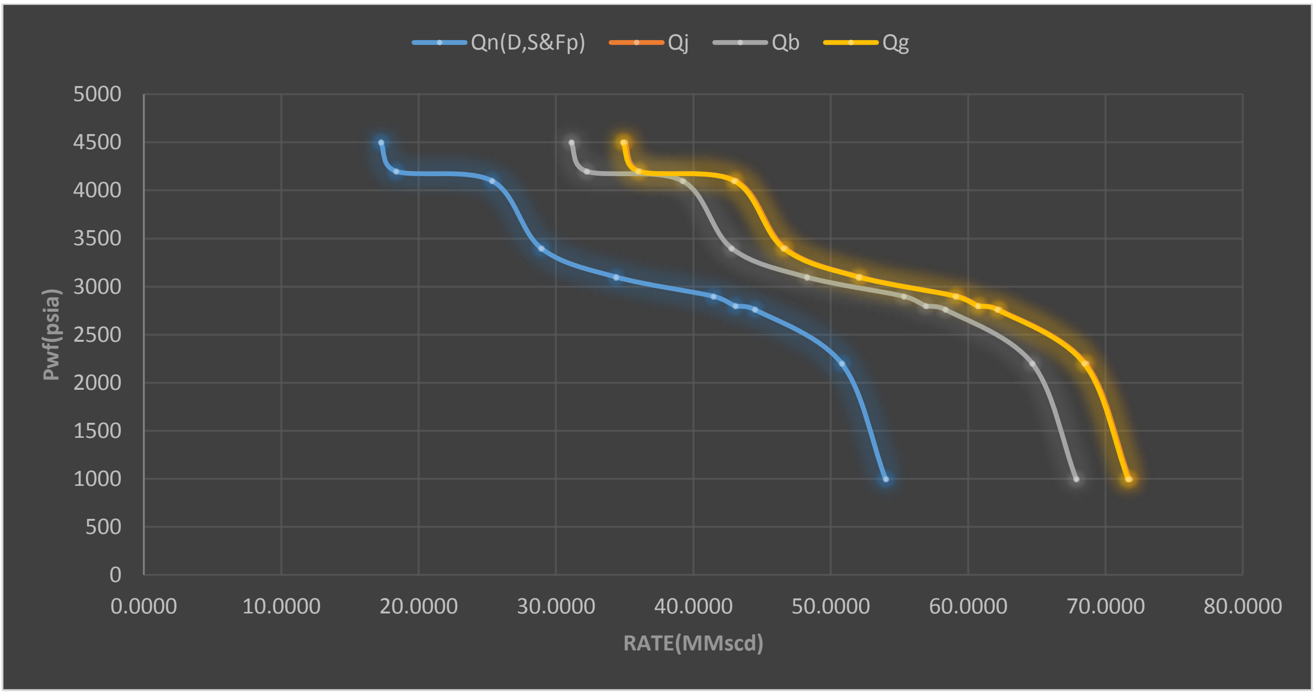

Figure 3: Shows The Result of Discussed Models and Developed Model (with the effect of D, s, Rfp)

The inflow performance curve follows the regular trend of an IPR curve, the flow rate increases as pressure drops. Although the rate at which the flow rate increases is not as large as if it were purely a gas reservoir, this is as a result of condensate drop out and accumulates to form liquid buildup around the wellbore. This reduces the well deliverability for a gas condensate reservoir.

For the optimum flow rate of a gas condensate reservoir to be maintained, the well flowing pressure must be maintained above bubble point pressure to reduce the formation of liquid drop out and buildup.

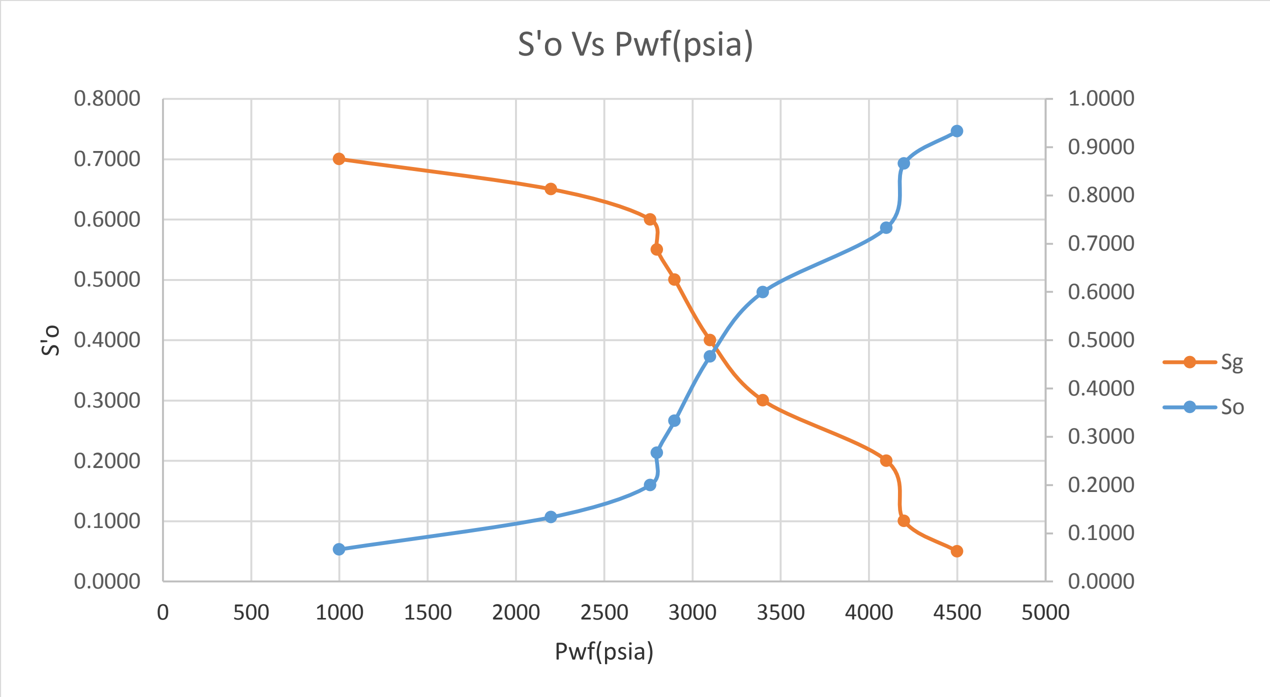

Figure 4: Show the Relationship between the Well Flowing Pressure and Liquid Saturation (So & Sg).

CONCLUSION

For a Gas condensate wells producing with a bottom hole pressure below the dew point develop up to three flow regions in the reservoir. Region 1 has a constant flowing composition (constant producing gas-oil ratio) where both gas and oil flow simultaneously. Most of the flow resistance that complicates the well deliverability interpretations comes from the reduced gas mobility in Region 1. Region 2 is a zone of condensate accumulation with no mobility, the composition of the flowing mixture changes in this region. Region 3 is the outer region where the reservoir pressure is greater than the dew point and only gas is present.

The developed correlation confirms that as the pressure drops below dew point there occurs condensate banking which when the critical saturation is reached becomes mobile and leads to a reduction in gas flow rate in the reservoir.

The condensate drop-out will hinder the flow capability, due to relative permeability effects.

Conclusion made using the gas flow rate calculated with the developed correlation shows that:

Composition and condensate saturation change significantly as a function of producing sequence. The higher the BHP, the less the condensate banking and a smaller amount of heavy-component is trapped in the reservoir. The lower the producing rate, the lower the amount of heavy-component left in the reservoir.

Gas flow rate starts declining with pressure when the condensate saturation is above the critical saturation.

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