Angolan Mineral, Oil and Gas Journal 4 (2023) 06–12

Contents lists available at Amogj

Angolan Mineral, Oil and Gas Journal

journal homepage: www.amogj.com

Transient Pressure Techniques for Identifying Condensate-Banking

Edgar Chiquito[a], Nazaré Hebo[b] and Tommaso De Pippo[b]

[a]Azule Energy, Torres Atlântico, Av. 4 de Fevereiro 197, Luanda, Angola

[b]Institute of Minerals Resources, Environment and Technologies, Catholic University of Angola, Av. Pedro de Castro Van-Dúnem Loy 24, Luanda, Angola

ARTICLE INFO

Keywords:
Reservoir,
Well,
Pressure,
Temperature,
Condensate-Banking,
Skin.

Gas-condensate reservoirs represent a large part of the gas reserves in the world containing large amounts of hydrocarbons, but due to thermodynamic aspects and dynamic behaviour of fluids in these reservoirs, the production of resources presupposes a very complex activity that requires a broad understanding and mastery of various recovery mechanisms and reservoir engineering practices. In these reservoirs, when the pressure drops below the dew point pressure due to the production of its fluids, some liquid components emerge from the gas in the reservoir in condensate form and which over time accumulate in the vicinity of the well making the production activity very challenging for engineers. This accumulation of saturation of condensate decreases the relative permeability of the gas and intensifies in the vicinity of the well causing a block to the gas flow to the surface. Given the importance and the impact of this phenomenon on the productive capacity of the reservoir, becomes it imperative to predict its occurrence to provide the control mechanisms and/or mitigation. This research is dedicated to studying transient pressure techniques as a way of identifying the condensate-banking phenomenon. To perform the experiments of this study it was necessary to use two types of software. The first software was the reservoir simulation, Eclipse, in the compositional model (E300), where the reservoir and well tests were carried out, then, the pressure transient test software, KAPPA-Saphir. With this study, it was possible to prove that by doing an analysis from the derivative curves of pressure the moment and circumstances in which Condensate-Banking occurs can be predicted.

1. Introduction

As exploration drilling finds conditions of greater depths, high pressures and high temperatures, many gas reservoirs of condensate have been discovered worldwide and in increasing numbers. It is known that much of the 6,183 trillion cubic feet of gas reserves worldwide can be found in condensed gas reservoirs (Zhang & Wheaton, 2000; Mohammed Sayed; Ghaithan Al-Muntasheri, 2016). These reservoirs represent an important part of the reserves because they contain large volumes of hydrocarbons and as examples of the largest condensate gas reservoirs in the world, we have the case of the Arun field (Indonesia), the Cupiagua field (Colombia), the Karachanak field (Kazakhstan), the northern field (Qatar) and the Shtokmanovskoye field (Russia). However, unfortunately, the production of these resources involves major challenges related to the thermodynamic aspects of its fluids and the dynamic behaviour in the reservoir.

Understanding and modelling the behaviour of the phases and flow of fluids in the reservoir are great challenges (Ursin, 2016). The condensed gas tanks provide some of the most difficult problems in reservoir engineering practice because when the pressure drops below the dew pressure, they present a complex dynamic and in these circumstances, liquid condensation occurs near the well's gas producers. This phenomenon is known as *Condensate Banking* and identifying such a phenomenon is not always an easy process, especially when there are other factors of additional complexity like Skin, Hydraulic Fractures, sand production etc.

As the pressure in the region close to the well drops below the dew point, the condensate accumulates forming a ring around the well and this accumulation of condensate causes a reduction in the relative permeability of the gas hence, the productivity declines dramatically. For example, the productivity of the Lime Fiel Cal Canal in California decreased significantly due to the double effect of the bank condensate and high-water saturation. The recovery of

* Corresponding author: Edgar Chiquito, E-mail: support@amogj.com
Received 10 March 2022; Received in revised form 10 May 2023; Accepted 15 June 2023

this field was only 10% of the original gas on the site (Amani & Nguyen, 2015; Fan, et al., 2005/2006).

This paper focuses on the study of transient pressure techniques as a method to identify the occurrence of liquid condensates in the reservoir to subsequently allow the elaboration and application of containment mechanisms and/or mitigation of the problem.

2. The Research Problem

It can be seen that condensed gas reservoirs are a special type of gas reservoir, and although they are often detected as a gas phase, they have liquid components dissolved in the gas, which are then separated into surface conditions. When the reservoir pressure drops below the dew point due to reservoir fluid production, these components liquids begin to condense from the gas in the reservoir. Thus, progressive abandonment of liquid occurs with the pressure drop, which results in the accumulation of liquid saturation in the area close to the well and increases with time.

Depending on the value of the critical condensate saturation (S_{CC}), the liquid phase released can achieve sufficient mobility and considerably reduce the permeability of gas. Much of the liquid that falls into the reservoir does not flow and is considered lost. If this liquid does not condense in the reservoir, it is produced on the surface with gas and constitutes an important part of income for the company. However, as the liquid condensate restricts the gas flow path and, consequently, its supply, this considerably decreases the company's revenue (Ali, 2014).

The phenomenon of condensate banking is so relevant that, depending on the wealth of the fluid in the reservoir, the amount of condensate liquid can be very high to the point reaching 50%, especially in the area near the well, where the pressure is at its minimum in a reservoir and identifying this problem is often not easy, mainly if the reservoir in question is experiencing other factors of additional complexity. This research shows the possibility of identifying the condensate banking in the presence of *Skin* through the study of the characteristics of the derivative curves of pressure, caused by the phenomenon, using a numerical simulation model and transient pressure model.

There are several suggested methods for mitigating the effects of condensate banking. These methods can be grouped into three different approaches (Amani & Nguyen, 2015). The first approach is to keep the pressure in the reservoir above the dew point pressure by gas cycling or CO_2 Huff-n-Puff. The second is to mobilize the condensate near the well whole region to make it flow with the gas into the well. The last approach is to reduce the relegation pressure to prolong the time the reservoir reaches dew point pressure through hydraulic fracturing or horizontal wells.

After having identified the existence of condensate banking in the reservoir and its magnitude, one of the aforementioned methods can be chosen to resolve the problem. However, one must remember the particularities of the application of each one of the methods in the field.

3. Methodology

This paper results from the main author's graduation thesis and the data presented refer to a realistic condensed gas reservoir. It was possible to simulate the behaviour of the reservoir before and after the formation of condensates and observe pressure variations.

To carry out this investigation, two different types of software were used: ECLIPSE and KAPPA - Saphir. With ECLIPSE it was possible to do the Well Tests (Drawdown and Build-up) and as if comes from a condensate gas reservoir, was used the compositional model of the software (ECLIPSE 300) to respond to the particularities of the various components that make up the fluid.

On the other hand, after simulating the reservoir with the ECLIPSE software, it was also necessary to use the KAPPA-Saphir NL software to perform the Transient Pressure and through these tests observe the derivative curves of pressure to identify the presence or absence of condensate-banking.

3.1. Flow Regions

As the average pressure in a gas-condensate reservoir continues to decrease in production, the abandonment of condensate occurs throughout the reservoir. A gas condensate well in pressure decrease consists of three flow regions (Lal, 2003) (Figure 1):

- *Region 1*: A region near the well, where gas and liquid flow at the same time (at different speeds).
- *Region 2*: A condensate accumulation region, where there is only a flow of gas.
- *Region 3*: A region containing only one (original) gas phase of the reservoir. This region is the furthest from the well.

In a given production condition, one, two, or all three regions can exist. These three regions define semi-steady state flow conditions, which means that at a given time they represent steady-state conditions, but that steady-state conditions gradually change during depletion.

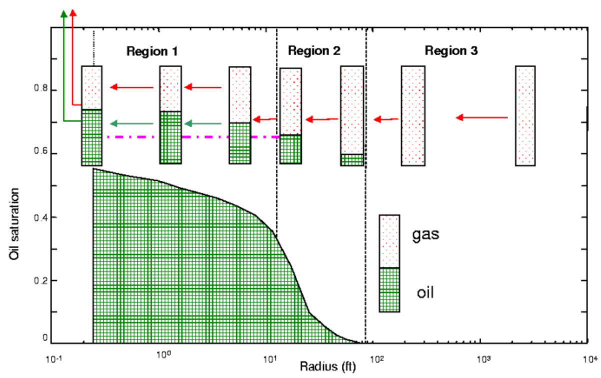

Figure 1. Scheme of the condensed gas flow behaviour

As mentioned above, region 3 is the region furthest from the well, where the reservoir pressure exceeds the dew point pressure of the original fluid in the reservoir. Therefore, in this region only gas is found, thus being the only phase mobile. The abandonment of condensate begins in Region 2, but in this region, despite being the zone that defines condensate accumulation, condensate saturation is still lower than its critical saturation (S_{CC}), and therefore, only gas flows effectively in this region, because oil mobility is zero (or very small). The size of Region 2 is greater in the first moments after the reservoir pressure drops below the dew point.

Region 1 is the main source of loss of capacity to deliver a gas-condensate well. It is in Region 1 where the condensate saturation is higher than its critical saturation and, therefore, both the gas phase and the liquid phase are already mobile. The gas's relative permeability is reduced drastically in this region, due to the condensate accumulation. The main cause of the reduction in relative permeability to gas in Region 1 is the two-phase flow. Region 1 expands over time causing a decrease in the size of Region 2. The effect of the condensate block depends on:

- PVT properties
- Relative permeability
- How the well is being produced

3.2. Relative Permeability

Relative permeability is one of the most important parameters that govern the productivity of gas-condensate reservoirs at a pressure below the dew point. Darcy's fundamental works are still the main theoretical panorama for the evaluation of relative flow permeability in a porous medium. The multiphase flow at the wellbore is a challenge for production engineers because of the difficulty in characterizing the flow regime practised that determines the type calculation of the pressure drop to be used. This is related to the problems of relative permeability in the reservoir. The flow behaviour of gas condensate systems is further complicated by the fact that, in the area close to the well, velocity and interfacial tension (IFT), depend solely on the relative permeability. The reduction of effective permeability at high speeds due to negative inertia it was first introduced by Forchhiemer in 1914. As one of the characteristics of the fluid flow in the gas-condensate reservoir is the immiscible behaviour with a low capillary number, the study of permeability can be based on Corey's model (Ali, 2014; Echenique, 2016) which presents the immiscible equations to determine the relative permeability of the gas and oil as following:

$$K_{rg} = K_{rg}\left(s_{org}\right) \times \left(\frac{s_g - s_{gc}}{1 - s_{gc} - s_{org}}\right)^{n_g} \qquad (1)$$

$$K_{ro} = K_{rog}\left(s_{gc}\right) \times \left(1 - \frac{s_g - s_{gc}}{1 - s_{gc} - s_{org}}\right)^{n_o} \qquad (2)$$

Where:
K_{rg} = gas relative permeability;
K_{ro} = oil relative permeability;
$K_{rg}\left(s_{org}\right)$ = gas relative permeability at residual saturation of oil;
$K_{rog}\left(s_{gc}\right)$ = oil relative permeability at critical saturation of gas;
s_g = gas saturation;
s_{gc} = critical saturation of gas;
s_{org} = oil residual saturation in the gas;
n_g = exponent of gas relative permeability (Corey exponent);
n_o = exponent of oil relative permeability (Corey exponent).

3.3. Well Test Analysis

The analysis of well testing in a gas-condensate reservoir is particularly complex due to the two-phase flow of gas and condensate when the bottom pressure drops below the dew point pressure. As the properties of the gas are strong functions of pressure the diffusivity equation for gas is non-linear and in an attempt to linearize the equation is defined as a pseudo-pressure of real gas in monophasic, biphasic and multiphase conditions and, in this case, the multiphase pseudo-pressure function of a gas-condensate reservoir is calculated by adding the three-part equations based on the three known flow regions.

$$\Delta P_{p_T} = \int_{P_{wf}}^{P_R} \left(\frac{k_{ro}}{\mu_o B_o} R_s + \frac{k_{rg}}{\mu_g B_{gd}}\right) dp \qquad (3)$$

$$\Delta P_{p_T} = \Delta P_{p_{R1}} + \Delta P_{p_{R2}} + \Delta P_{p_{R3}} \qquad (4)$$

$$\Delta P_{p_T} = \int_{P_{wf}}^{P^*} \left(\frac{k_{ro}}{\mu_o B_o} R_s + \frac{k_{rg}}{\mu_g B_{gd}}\right) dp + \int_{P^*}^{P_d} \left(\frac{k_{rg}}{\mu_g B_{gd}}\right) dp + k_{rg}(S_{wi}) \int_{P_d}^{P_R} \left(\frac{k_{rg}}{\mu_g B_{gd}}\right) dp \qquad (5)$$

Where,
P^* = Pressure at the border between Region 1 and Region 2 (psi);
P_{wf} = pressure flow in the well (psi);
P_d = dew point pressure (psi);
P_R = reservoir pressure (psi); K_{ro} = oil relative permeability;
K_{rg} = gas relative permeability;
$K_{rog}(s_{wi})$ = oil relative permeability in initial water saturation;
μ_o = oil viscosity (lb sec/ft^2);
μ_g = gas viscosity (lb sec/ft^2);
B_o = volumetric oil formation factor;
B_{gd} = Volumetric formation factor of dry gas;
R_s = gas-oil solution ratio (MCF/stb).

4. Condensate-Banking Investigation

The studied reservoir is a fractured reservoir of dimensions 30x47x1 in the directions X, Y and Z respectively, with double porosity and permeability, containing a single production well named PROD1 located in cell X = 1, Y = 1 and Z = 1 (Figure 2). To simulate the reservoir, the Eclipse simulation software was used in its compositional model (Eclipse 300). The well does not feel the effect of the limits or boundaries of the reservoir, so the reservoir is considered to be infinite. The reservoir properties are given in Table 1.

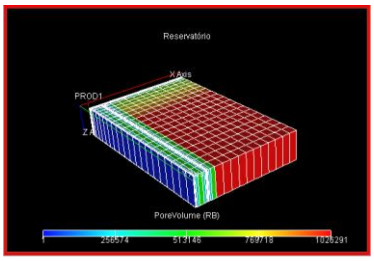

Figure 2. Distribution of pore volume in the reservoir

Table 1. Reservoir properties used in the simulation

Porosity (%) Permeability (mD)	25 1
Porosity (%) Permeability (mD)	35 1000
Reservoir Thickness (ft)	300
Irreducible water saturation	0
Rock Compressibility (psi^{-1})	4.25x10^{-6}

In this simulation, 11 components were used for the gas-condensate fluid. Such components are nitrogen (N_2), carbon dioxide (CO_2), methane (C_1), ethane (C_2), propane (C_3), i-butane (iC_4), n-butane (nC_4), i-pentane (iC_5), n-pentane (nC_5), hexane (C_6) and heptane (C_{7+}). The different properties of these components were used for the lighter and heavier mixture of condensate. The phase behaviour was simulated using the correction of the Peng-Robinson equation of state and among the various properties of each component here will only be presented those that were considered most relevant to understand issues such as the saturation profile, the good productivity and well analysis. Table 2 shows the components and the properties of the condensate fluid. It is possible to verify that the lightest component is the C_1 with about 16.04300 molar weight (MW) and the heaviest is the C_{7+} fraction with 177.7000 molar weight (MW).

4.1. Well Tests - Drawdown and Build-up

Well, tests were carried out taking into account two scenarios: when there is no condensate formation and when there is condensate. In the first scenario, the well was set to produce at a constant rate of 2000 Mscf for 2 days and then the well was shut-in for 5 days, and in the second scenario, the well-produced at a constant rate of 10 MMscf per 10 days and shut-in also for 5 days.

Table 2. Components and properties of the condensate fluid used

Components	Critical Temperature (ºR)	Critical Pressure (psi)	Weight Molar	Critical Volume	Critical Factor-Z
N_2	126.2000	492.3127	28.01300	0.8009731	0.2911514
CO_2	304.7000	1071.331	44.01000	0.8365719	0.2740778
C_1	190.6000	667.7817	16.04300	0.8721707	0.2847295
C_2	305.4300	708.3424	30.07000	1.317156	0.2846348
C_3	369.8000	45.44000	44.09700	25.15369	0.2880000
iC_4	408.1000	45.44000	58.12400	27.75885	0.2880000
nC_4	425.2000	45.44000	58.12400	28.92198	0.2880000
iC_5	460.4000	45.44000	72.15100	31.31628	0.2880000
nC_5	469.6000	45.44000	72.15100	31.94206	0.2880000
C_6	297.4017	45.44000	84.00000	20.22918	0.2880000
C_{7+}	401.7315	45.44000	177.7000	27.32566	0.2880000

As in the first scenario, the production rate is relatively low and occurs in little time, the pressure drop caused is not so much that it reaches the dew point pressure (Pdew) and forms condensates in the gas. However, in the second scenario, the effect of the production rate vs time is already more significant given the high rate and longer production time. Therefore, the pressure drop in this case is already greater and will cross the dew point line then causing the formation and accumulation of condensate as the pressure continues to drop below the dew point. The figures below show the results of the production and pressure profiles obtained for the two scenarios in the ECLIPSE software.

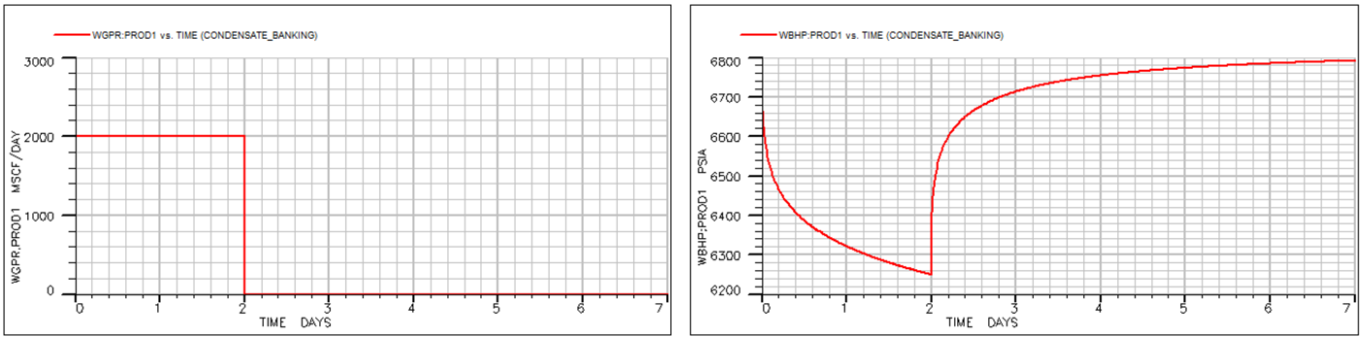

Figure 3. Production and pressure profile of the 1st scenario (P> Pdew)

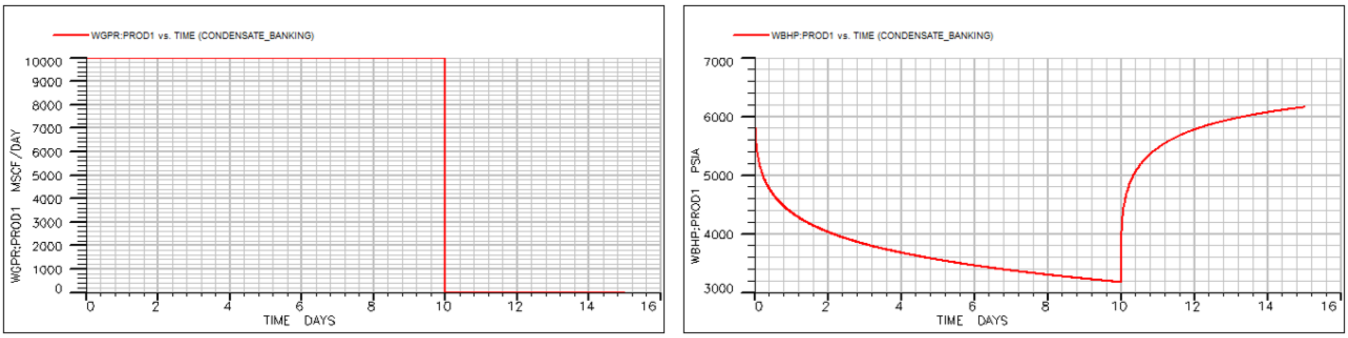

Figure 4. Profile of production and pressure of the 2nd scenario (P <Pdew)

4.2. Transient Pressure Test - Results

After simulating the reservoir for good tests on the Eclipse 300, the production and pressure data from the two scenarios over time were reported to perform the transient pressure analysis. For this other analysis was used the transient pressure analysis software, KAPPA. The results of the transient pressure analysis for the two scenarios are presented below.

- **1st Scenario: No condensate formation (P> Pdew)**

The well had 2 days of production at a constant rate of 2000 Mscf/Day and 5 days of shut-in. O time has been converted to hours. The painted zone, in Figure 5a, is the zone that indicates the period that the well was closed, that is the Buildup period, on which the transient pressure test was applied.

When carrying out the analysis, to generate the pressure curves and their derivatives, an automatic correction of the Skin factor is made beforehand by the Software itself to investigate the skin effect involved and then approximate the curves to the most real one possible. The results are presented in a log-log graph. The correction of the skin factor for this case generated curves shown

in the diagrams below with a Skin value = -1.87600. Therefore, a negative skin. This means that the well must be stimulated.

With these results, we can see that the pressure drop in the reservoir will be reduced since, in addition to the good stimulation, the production rate is low and will have little production time. There will be little impact on the pressure drop in the reservoir and therefore it will not reach the dew point pressure and the condensates will not form. The downward variation that occurs in the derivative line pressure (red line) in the logarithmic range 10 – 1 indicates that there is no formation condensate for this flow condition. Figure 5b.

To study the real effect of the Skin variation on the condensed gas reservoir, another experiment was performed assuming that the reservoir is not damaged (skin = 0). Figure 5c shows how much the skin influences the results of this analysis. The bigger the skin, the greater the pressure drop and this, consequently, generates a greater amplitude between the two curves.

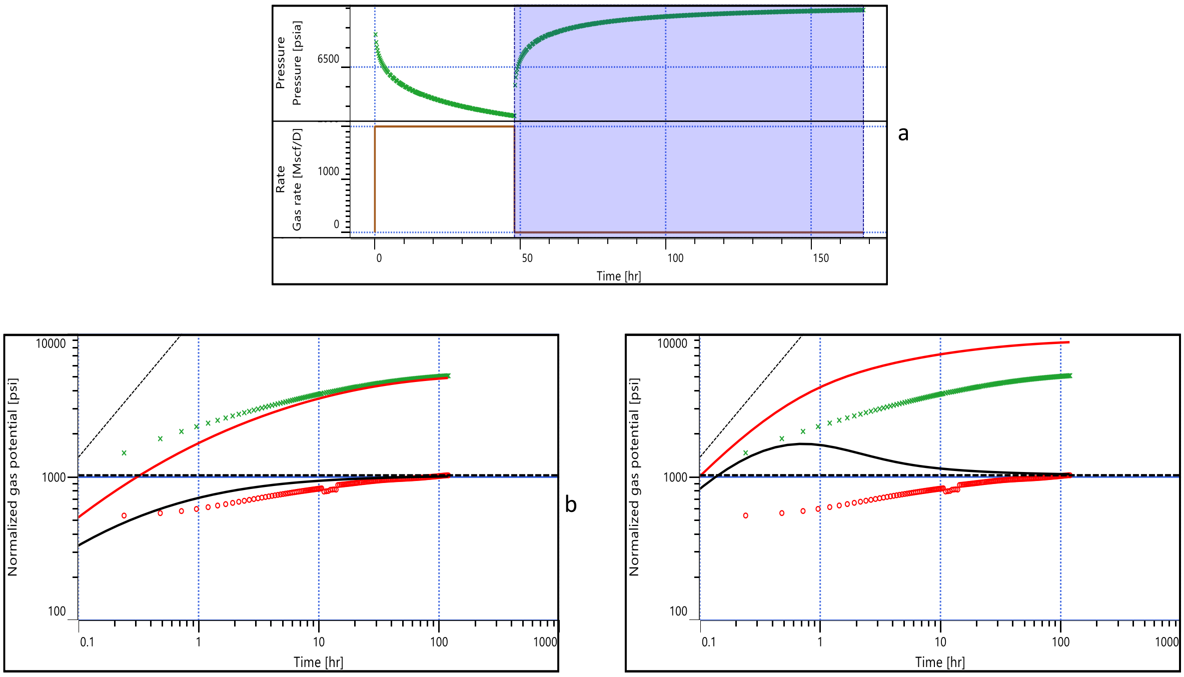

Figure 5. **1st Scenario: a - Production history without condensate; b - Log-log of the pressure curve and its derivative; c - Log-log for Skin = 0**

- **2nd Scenario - With the formation of condensates (P <Pdew)**

For this case, the well had a period of 10 days of production at a constant rate of 10000 Mscf/Day and was closed for 5 days. The shut-in period must be the same to better establish the comparisons since the analysis is made in the Buildup period (Figure 6a).

The correction of the Skin factor to investigate the skin effect and approximate the curves as real as possible found a closer approximation of the curves with Skin = - 3.23976. It is, therefore, also a negative skin which indicates conformity in conditions of well needs. The well must undergo an intervention stimulation. However, the skin is smaller which indicates that in this case, when the well is stimulated, the pressure drop will be caused mainly by the effect of the high production rate and the long period.

We can see that the effect of the high rate of production and a longer period will cause a greater effect of pressure drop in the reservoir reaching the pressure of the dew point, causing the formation of condensates and their consequent critical saturation flowing towards the area closer to the well and then form the condensate bank around it, thereby blocking the gas flow into the well to the surface (Figure 6b).

Assuming that the reservoir is not damaged, skin = 0, for this scenario, it was found that different from the 1st scenario, when the skin tends to a positive value, the pressure drop in the drawdown period tends to remain stable and increase pressure in the Buildup period. This is due to the presence of the condensate. The condensate will fill the porous spaces in the zone that is isolating the pressure regime in the well. This reasoning can be confirmed by looking at the results shown in Figure 6c.

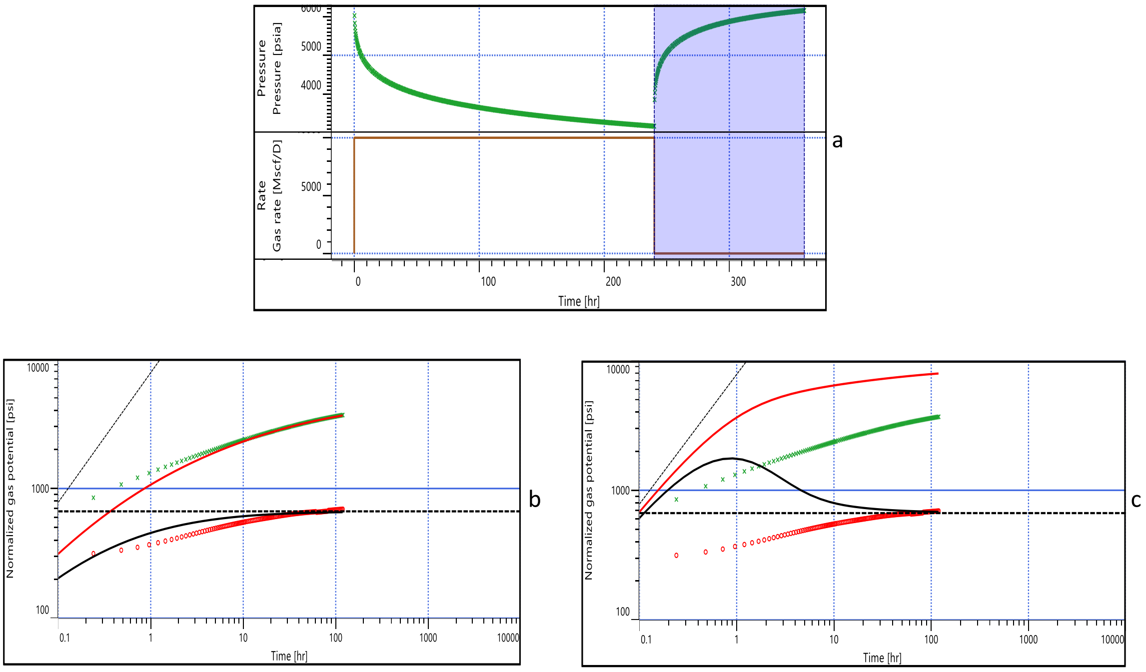

Figure 6**. 2nd Scenario: a - Production history with condensate; b - Log-log of the pressure curve and its derivative; c - Log-log for Skin = 0**

5. Conclusions

The investigation and development of this study on the application of transient pressure analysis techniques for the identification of condensate banking gave the possibility to understand the phenomenon and provide the mechanisms for its prevention and/or mitigation. From this study, it was possible to conclude that:

- The continuous formation of condensate increases its relative permeability causing a reduction in the relative permeability of the gas, which makes it difficult to flow capacity into the well to the surface, however, the reduction in size of the condensate-banking and its relative permeability depends on the rate of production.

- Well tests are very useful for determining well properties and for interpreting data. It is necessary to use some techniques and/or methods of interpretation and one of these techniques is that of transient pressure analysis.

- Transient pressure techniques are effective in identifying condensate banking to the extent that the pressure derivative curves generated in the tests clearly describe

- the behaviour of the fluids in the reservoir as well as the variation of the curve profiles as condensates form and accumulate in the reservoir.

- High production rates and very long times also contribute to the reservoir pressure reaching the dew point more quickly, causing the formation of condensate in the reservoir and the consequent condensate banking in the vicinity of the well with the continuous decrease in pressure.

- The presence of skin contributes a lot to the rapid pressure drop and consequent formation of condensates. The bigger the Skin, the bigger and faster will be the pressure drop in the reservoir thus accelerating the accumulation of condensate approximately the well.

References

Afidick, D., Kaczorowski, N., & Bette, S. (1994). Production Performance of a Retrograde Gas Reservoir: A Case Study of the Arun Field. *SPE*.

Ali, F. (2014). *Importance of water Influx and waterflooding in Gas condensate reservoir.* Obtido em 5 de Abril de 2018

Amani, M., & Nguyen, N. (2015). An Overview of Methods to Mitigate Condensate Banking in Retrograde Gas Reservoirs. *CSCanada, 9*, 1. Obtido em Mar de 2018, de httpciteseerx.ist.psu.eduviewdocdownloaddoi=10.1.1.852.5604&rep=rep1&type=pdf

Echenique, E. A. (2016). *Gas Condensate Banking – Application of Pressure Transient Analysis to Determine Production Impairment and Compositional Effects.* OMV.

Fan, L., Harris, B. W., Jamaluddin, A., Kamath, J., Mott, R., Poppe, G. A., . . . Witson, C. H. (2005/2006). *Understanding Gas-Condensate Reservoirs.*

Houzé, O., Viturat, D., & Fjaere, O. S. (2008-2018). *Dynamic Data Analysis - Pressure Transient Analysis, Rate Transient Analysis, Formation Testing, Production logging and the use of Perfomanent Dawnhole Gauges.* KAPPA.

Kgogo, T. (2011). *WELL-TEST ANALYSIS OF LOW PERMEABILITY MEDIUM-RICH TO RICH GAS CONDENSATE HOMOGENEOUS AND LAYERED RESERVOIRS.* London: Imperial College - Centre for Petroleum Studies.

Lal, R. (2003). *WELL TESTING IN GAS-CONDENSATE RESERVOIRS.* STANFORD: PETROLEUM ENGINEERING OF STANFORD UNIVERSITY. Obtido em 5 de Abril de 2018

Lee, J., & Wattenbarger, R. (1996). *Gas Reservoir Engineering* (Vol. 5). Texas: Society of PPetroleumEngineers - SPE.

Lloyd, P. (2011). *Productivity of Gas Condensate Fields Below The Dew Point: A North Sea Case Study.* Department of Earth Science and Engineering Centre for Petroleum Studies.

Miller, N. (2009). *INCREASING WELL PRODUCTIVITY IN GAS CONDENSATE WELLS IN QATAR'S NORTH FIELD.* Office of Graduate Studies of Texas A&M University, Texas.

Mohammed Sayed; Ghaithan Al-Muntasheri. (2016). Mitigation of the Effects of Condensate Banking: A Critical Review. (SPE, Ed.) (Petroleum Engineers), 1. Obtido em Mar de 2018, de https://pt.scribd.com/document/297265933/Mititigation-of-the-Effect-of-Condensate-Banking-A-Critical-Review

Mott, R., Cable, A., & Spearing, M. (1999). A New Method of Measuring Relative Permeabilities for Calculating Gas-Condensate Well Deliverability. *SPE*.

Nagarajan, N., Honarpour, M., & Sampath, K. (2004). COMPARISON OF GAS-CONDENSATE RELATIVE PERMEABILITY USING LIVE FLUID vs. MODEL FLUIDS.

Rahimzadeh, A., Bazargan, M., Darvishi, R., & Mohammadi, A. H. (24 de May de 2016). Condensate blockage study in gas condensate reservoir. (Elsevier, Ed.)

Safari-Beidokhtil, M., & Hashemi, A. (November de 2015). Condensate blockage effects in well test analysis of dual porosity/dual-permeability, naturally fractured gas condensate reservoirs: a simulation approach. *Cross Mark*.

Shi, C. (2005). *FLOW BEHAVIOUR OF GAS - CONDENSATE WELLS.* THE DEPARTMENT OF PETROLEUM ENGINEERING OF STANFORD UNIVERSITY.

Singh, K., & Whitson, C. (2008). Gas Condensate Pseudopressure in Layered Reservoirs. *SPE*.

SPE. (2007). Identifying Condensate Banking With Multiphase Flowmeters—A Case Study. *Reservoir Characterization & Simulation Conference.* SPE.

Ursin, J. R. (2016). *GAS-CONDENSATE BANKING AND WELL DELIVERABILITY. A COMPARATIVE STUDY USING ANALYTICAL - AND NUMERICAL MODELS* (Vol. 33). University of Stavanger, 4036 Stavanger, Norway. Obtido em Mar de 2018, de http://dx.doi.org/10.7494/drill.2016.33.2.259

Whitson, C. (1999). Gas Condensate Relative Permeability for Well Calculations. *SPE*.

Zhang, H., & Wheaton, R. (2000). Condensate Banking Dynamics in Gas Condensate Fields: Changes in Produced Condensate to Gas Ratios. *SPE*(Petroleum Engineers), 1. Obtido em Mar de 2018