19th Brazilian Congress of Thermal Sciences and Engineering
November 06th-10th, 2022, Bento Gonçalves - RS - Brazil

ENC-2022-0249
STUDY OF NONAQUEOUS DRILLING FLUIDS AS A BARRIER ELEMENT

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Abstract. *The drilling fluid exerts the role of a primary safety barrier in drilling operations, since by exerting hydrostatic pressure against the drilled formation, it prevents the unwanted influx of hydrocarbons into the well. Initially, water-based drilling fluids were applied, but with technological and operational advances and environmental needs for deep and ultradeep drilling, it became necessary to replace such fluid with synthetic-based ones. Despite the numerous benefits associated with synthetic drilling fluids it is difficult to handle natural gas solubility in the nonaqueous phase during a kick event. Until reaching the saturation pressure of the fluid, the influx is almost completely solubilized, becoming practically undetectable at the surface, what is the most critical scenario from an operational safety point of view. The main objective of the present work is to analyze the effect of methane solubility in n-paraffin based fluid, as well as to discuss the consideration of such fluid as a barrier element in two situations: (i) pit gain evaluation for a given amount of gas entering bottomhole; (ii) calculation of the amount of gas that enter downhole for a given kick alarm.*

Keywords: *drilling fluids, n-paraffin, barrier element, influx, solubility*

1. INTRODUCTION

According to Santos (2013) well control is considered one of the main drilling fluid objectives. In a situation where the pressure exercised by the drilling fluid is lower than the pressure found in the drilled formation, the well primary control may be lost. In addition, the fluid also has the functions of removing the cuttings from under the drill, carrying the cuttings to the surface, preventing collapse and closing the well, among others.

At the oil wells drilling beginning, the industry used water as a drilling fluid that had its composition improved, by the use of additives, year after year to adapt to the wells drilled at the time. Aiming at operational safety, regulatory standards were created, with NORSOK D-010 being the most relevant after becoming an international standard, to ensure the well integrity throughout its life cycle including recommendations and guidelines and classify an aqueous fluid as barrier element. Over the years, due to the challenges related to drilling in challenging scenarios, it became necessary to replace the aqueous fluid by the oily fluid which, despite its numerous benefits, presents a problem that cannot be disregarded or neglected, as it directly influences the natural gas kick detection: the solubility. Oily fluids tend to interact with the gas present in the drilled formation, solubilizing it under temperature and pressure conditions at the bottomhole.

In an aqueous fluid, the gas solubility is very low in water and in other additives necessary to improve its formulation, which can be disregarded, unlike what is observed in an oily fluid, where the gas tends to solubilize completely or partially, which can compromise the drilling safety, which in the most serious case can cause a blowout.

In order to present the late natural gas kick detection severity (most of which is composed of methane) when using a synthetic oil-based drilling fluid, it is necessary to know the gas/fluid mixture thermodynamic behavior, therefore, the main objective of this article can be stated as follows: to analyze the methane solubility effect in n-paraffin based fluid, as well as discussing the consideration of such fluid as a barrier element in two situations: (i) pit gain evaluation for a certain gas amount entering in the well bottom; (ii) gas amount calculation entering in the downhole for a given kick alarm.

2. LITERATURE REVIEW

Gas solubility in oil-based fluids studies began in the early 1980s with O'Brien (1981). The author was one of the pioneers to study the problems involving the use of oily fluids and, even without an experimental study, he realized the solubility of the gas in the oily fluid could be 10 to 100 times greater than in an aqueous one.

Thomas et al. (1984) studied the consequences of gas solubility in oil-based fluids through experimental measurements of saturation pressure in methane/pure diesel oil and methane/diesel-based drilling fluid systems. They found that there is greater gas solubility in pure diesel compared to drilling fluid. Such behavior was due to the low gas solubilization in brine and in emulsifier present in the fluid.

Lima (1998) was one of the pioneers in the synthetic fluids studies with tests conducted in Brazil presenting results similar to those obtained by Thomas et al. (1982). The n-paraffin-based drilling fluid was used to study the methane solubility. Eight methane/synthetic fluid mixtures with variable gas-oil ratio (GOR) were used to measure saturation pressures at temperatures of 38, 65, 93 and 120°C. The data obtained experimentally by the author were used in the pressure/volume/temperature (PVT) simulator calibration so that the synthetic fluid swelling with dissolved gas was calculated.

Silva (2004) experimentally analysed the methane gas solubility in synthetic fluids based on n-paraffin and ester with varying methane concentrations at 70 and 90 °C temperatures. When comparing the results obtained for the two synthetic bases used, it was noted that the gas solubility in n-paraffin was clearly higher than in the ester at both temperatures.

Monteiro (2007) obtained correlations to predict the methane/n-paraffin mixture behavior, including emulsions. The results were achieved using a PVT cell pressurized by mercury injection with a maximum pressure and temperature of 70 MPa and 175 °C, respectively. Regarding the fluid composition, an increase in the gas solubility was observed with the increase in the oil fraction of the mixture. Regarding temperature, significant effects were observed in relation to solubility only at pressures greater than 35 MPa. The volume formation factor, in turn, was influenced by the temperature at all studied pressures due to the liquid thermal expansion at high temperatures.

Atolini (2008) analysed the methane/n-paraffin and methane/emulsions system PVT behavior with methane mole percentages ranging from 12 to 95%, a temperature ranges from 70 to 130 °C and a maximum pressure of 103 MPa. The author observed in both systems a behavior directly proportional between saturation pressure and temperature for molar percentages of up to 63%. From 63% the saturation pressure became inversely proportional to the temperature. The author also concluded that the solubility increases with increasing gas molar fractions and becomes infinite at pressures greater than 35 MPa. Three case studies applied to well control were analysed where the gain in the mud tanks considering a kick situation in a methane/emulsions system was determined through the correlations previously found by the author. When compared to an aqueous fluid, the gain in the tanks for synthetic fluid was lower due to the gas solubility in the oil phase of this fluid.

Monteiro et. al (2010) discussed the PVT properties applicability in a methane/emulsion system in well control operations considering pressures and temperatures up to 70 MPa and 150 °C, respectively. From the experimental results and correlations found for solubility and volume formation factor, the authors analysed two cases applied to well control. In the first case, two wells with different depths were studied in order to compare the gains in mud tanks during an influx of methane gas in a drilling operation. The gain in the mud tanks in both wells was smaller considering a drilling carried out with an n-paraffin based emulsion than it would be if an aqueous fluid was considered. It has also been proven that as the depth increases, the difference between the gains for synthetic and aqueous fluids decreases significantly. In the second case, the same wells were studied in order to compare the volume of gas present in the system considering a fixed gain in the mud tanks, the authors observed that the volume of methane present in the system was greater when using the synthetic fluid compared to the aqueous fluid in both wells.

Marques (2016) experimentally analysed the linear methane/olefin system with tests carried out in a temperature range of 25 to 80°C with gas molar percentages between 30 and 50%. The author observed an inversion of solubility behavior at pressures greater than 35 MPa due to the temperature influence. The volume formation factor behavior was also analyzed, concluding that, in a single-phase region, the factor increases due to the expansion of the gas solubilized in the fluid, reaches its peak in the saturated region and decreases at pressures below the saturation pressure due to the lightest component detachment present in the mixture, the gas.

Chagas et al. (2020) presented a well control simulator for ester and n-paraffin based synthetic fluids whose objective was to estimate choke pressure, pit gain, gas and liquid outflows behavior during a methane kick circulation by the Driller’s method. The semi-analytical model presented by the authors responded in agreement with the results measured experimentally, where they reached the conclusion that the methane solubility is lower in the ester than in the n-paraffin, facilitating the gas detection, in addition, the ester has a lower capacity to keep the gas in solution during the kick circulation.

Duarte et al. (2021) analysed the PVT (pressure – volume – temperature) properties in three synthetic fluids based on glycerin, namely: pure fluid with 100% glycerin and two mixtures of 50% glycerin and 50% brine and 40% glycerin and 60 % brine. Given a methane kick with a molar mass between 10 and 50%, it was possible to analyse the synthetic fluid thermodynamic behavior with the mentioned gas in the temperature ranges from 20 to 80 °C and pressure from 0 to 55 MPa. The author noticed during the tests that the two phases present in the system remained separate throughout the experiment, which can be confirmed by the data collected. Therefore, considering the parameters temperature, molar percentage of methane and pressure, it can be concluded that methane does not dissolve in the glycerin-based drilling fluid.

Knowing the synthetic gas/fluid system PVT properties becomes fundamental for well control operations, and through the properties it is possible to determine the swelling of the fluid with solubilized gas, the gas expansion in the system and also the maximum gas amount which the fluid is able to solubilize through the solubility ratio.

3. GAS INFLOX ANALYSIS METHODOLOGY

The methodology had the following works as a contribution: Atolini (2008) who obtained correlations of emulsion solubility ratio (RSm) and emulsion volume formation factor (Bm) from experimentally collected data for the methane/n-paraffin emulsion system and Monteiro et al. (2010) who considered two different situations when analyzing the behavior of the gas/liquid mixture in well control operations: (i) pit gain evaluation for a given amount of gas entering bottomhole; (ii) calculation of the amount of gas that enter downhole for a given kick alarm.

3.1. Situation 1

The methodology was divided into aqueous fluid and n-paraffin based ones taking into account the following assumptions: a) There is a gas methane influx present inside the well; b) The drilling fluids are considered incompressible; c) Methane does not dissolve in aqueous base; d) Methane is only solubilized in the synthetic fluid oil phase, since the low gas solubility in brine and emulsifiers present in the fluid can be disregarded; e) Reservoir pressure (Pres) and temperature (Tres), drilling flow and compressibility factor (Zres) are considered constant; f) In the undersaturated/saturated condition, the volume increment in the surface mud tanks due to fluid swelling is small so it can be considered constant; g) In the supersaturated condition, the gas comes out of solution in the form of a single bubble, not mixing again with the drilling fluid; h) The gas mass is calculated by the Real Gas Law.

3.1.1. Aqueous fluid

Due to the low methane solubilization in aqueous fluid, the pit gain (PG) measured at the surface is equivalent to the product between the gas volume under standard conditions (Vg,sc) and the gas volume formation factor (Bg), as seen in Eq. (1).

$$PG = Vg, sc \times Bg \tag{1}$$

The gas volume formation factor (Bg), represents the methane expansion along the system and can be calculated by Eq. (2).

$$Bg = (1/Pres) \times (Tres/288.65) \times (Zres/1) \times (1/5.615) \tag{2}$$

3.1.2. Synthetic fluid

The synthetic fluid, unlike the aqueous one, solubilizes much of the influx present in the system until the fluid solubility ratio (RSm) is reached. After reaching the solubility ratio, all gas that enters the well will be free in the system. Therefore, the methodology was divided into undersaturated/saturated and supersaturated conditions.

The gas and liquid volumes present in the system are calculated by the gas and liquid flows and the kick exposure time.

In the undersaturated/saturated condition the pit gain und, sat (PG und,sat) is determined by the fluid pumped volume (Vfp,sc) and the emulsion volume formation factor (Bm) that represents the fluid welling due to the gas presence, as observed in Eq. (3).

$$PG\ und, sat = Vfp, sc \times (Bm - 1) \tag{3}$$

In the supersaturated one, pit gain super (PG super) can be defined by the pit gain sum found in the undersaturated/saturated condition and the free methane volume under reservoir conditions (Vfg, res) that corresponds to the product of difference between the maximum gas volume that the fluid can solubilize (Vg sat, sc) and the gas excess present in the system (Vg super, sc) in standard condition and Bg factor, as seen in Eq. (4) and (5).

$$PG\ super = PG\ sub,sat + Vfg, res \tag{4}$$

$$Vfg,\ res = (Vg\ super,\ sc - Vg\ sat,\ sc) \times Bg \tag{5}$$

3.2. Situation 2

In addition to assumptions presented in situation 1 there is: the mass conservation principle is applied. Then, the fixed pit gain will be distributed into the system in the liquid and/or vapor phase, depending on the gas/liquid ratio (GOR) analysed.

3.2.1. Aqueous fluid

Due to the low gas solubilization in aqueous base, the inflow amount under downhole conditions is equivalent to the pit gain measured at the surface. Therefore, the methane volume present in the system can be calculated by the ratio between the pit gain (PG) and the gas volume formation factor (Bg) which represents the gas expansion on its way to the surface, as shown in Eq. (6).

$$Vg,\ sc = Vfg,\ sc = PG/Bg \tag{6}$$

3.2.2. Synthetic fluid

In order to respect the system mass conservation, the increase in volume observed in the surface mud tanks must correspond to the inflow volume fully solubilized in the fluid under downhole conditions for the undersaturated/saturated case. Therefore, the methane total volume present in the system (Vg, sc) is equal to methane dissolved volume in the drilling fluid (Vdg, sc) as observed in Eq. (7).

$$Vg,\ sc = Vdg,\ sc \tag{7}$$

Since the gas/liquid ratio (GOR) is the ratio between the gas and fluid amounts present in the system, the gas dissolved volume (Vgd, sc) can be expressed by the product between the fluid pumped volume (Vfp, sc) and the gas/liquid ratio (GOR), as observed in Eq. (8).

$$Vdg,\ sc = Vfp,\ sc \times GOR \tag{8}$$

The fluid pumped volume (Vfp, sc), in turn, can be calculated by the ratio of the pit gain (PG) and the difference between the emulsion volume formation factors with (Bm) and without dissolved gas, where the latter is equal to 1 due to the fluid incompressibility hypothesis, as seen in Eq. (9).

$$Vfp,\ sc = PG/(Bm - 1) \tag{9}$$

Due to mass conservation, in the supersaturated case, the volumetric increase observed in the surface mud tanks must correspond to the saturated methane volume sum (Vdg, sc) in the drilling fluid and the methane volume excess in the system (Vfg, sc), presented in the free form, as shown in Eq. (10).

$$Vg,\ sc = Vdg,\ sc + Vfg,\ sc \tag{10}$$

The methane dissolved volume (Vdg, sc), represented by Eq. (11) is determined considering that the fluid is fully saturated, so it will depend on the fluid pumped volume (Vfp,sc) and the solubility ratio (Rsm).

$$Vdg,\ sc = Vfp,\ sc \times RSm \tag{11}$$

To calculate the free methane volume represented by the Eq. (12), it is necessary to know the pumped fluid volume (Vfb, sc) and the ΔGOR (surplus gas within the system).

$$Vfg,\ sc = Vfp,\ sc \times \Delta GOR \tag{12}$$

The volume pumped fluid calculation (Vfp, sc), for the supersaturated condition, is given by adding one more element to Eq. (9) denominator, which represents the free gas expansion of inside the well, as can be seen in Eq. (13).

$$Vfp,\ sc = PG/[(Bm - 1)+(\Delta GOR \times Bg)] \tag{13}$$

4. RESULTS AND DISCUSSIONS

The analyses were carried out considering an exploratory well ESS-107 conventional drilling, located in Espírito Santo, with a 1,286m water depth. The well design, as well as the depth at which the kick was taken and the pore gradient corresponding to this depth were based on Lage et al. (2002). Note in Figure 2 that the gas entered inside the well at 4,719m which corresponds to a pore gradient of 12.3 lb/gal. For the input data available in Table 1, values were assumed based on a Brazilian pre-salt well.

Nineteen RGLs ranging from 1000 to 10000 scf/stb were previously defined, with the interval between them equivalent to 500 scf/stb, except for that corresponding to the fluid solubility ratio, which differs from this stipulated interval.

As previously presented, the study was divided into situations 1 and 2 and for each one, sensitivity analyses were performed for the input parameters: kick detection time, pore gradient and pit gain. All analyzes were performed using the equations presented in the gas inflow analysis methodology.

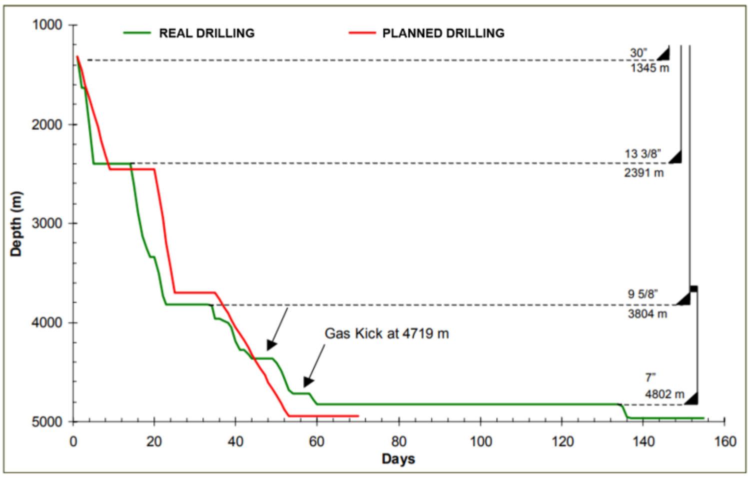

Figure 1. Drill advance curve (adapted from Lage et al., 2002)

Table 1. Exploratory well ESS-107 input data

Pres (psi)	9,891	Pit gain (bbl) – Situation 2	10
Tres (°F)	249.8	Oil percentage (%)	20
Kick detection time (min) – Situation 1	10	Drill pipe diameter (m)	0.127
Zres	1.370	Riser diameter (m)	0.533
Drilling flow (stb/min)	10	Rsm (scf/stb)	4,027
Bm (bbl/stb)	1.2644	Bg (bbl/scf)	0.00050

4.1. Situation 1

Given 10 min kick detection time, the pit gain must be determined for each presented GOR.

Figure 2a shows the pit gain for aqueous and n-paraffin based fluids. By setting the GOR at 4,027 scf/stb corresponding to synthetic fluid solubility ratio, it can be seen that the pit gain observed in aqueous fluid is 7.5 times greater than that one in synthetic fluid for the same amount of gas into the system. Therefore, the same gas volume that caused a 200 bbl pit gain in aqueous fluid would be all solubilized in synthetic fluid, causing an increase of only 27 bbl. The behavior observed in the curves shows how the gas solubility in the oil phase can mask the gas, making its detection more complex.

To understand the kick detection time influence, a sensitivity analysis was performed by changing the time in 5, 10, 15, 20 min in order to obtain pit gain value as a GOR function. The results obtained can be seen through Figure 2b and 2c, respectively. The pit gain presented an expected behavior since longer kick detection time lead to higher gas volumes inside the system, increasing the pit gain. By setting the time at 5 min, an increase in pit gain by 2, 3 and 4 times was observed for 10, 15 and 20 min, respectively.

In order to understand the pressure influence on pit gain, an analysis was performed by altering the pore gradient in 10, 12.3 and 13.5 lb/gal, since it has a direct influence on the reservoir pressure. Note in Figures 2d and 2e that pit gain decreases with increasing pore gradient, such behavior occurs because of the gas and oil volume formation factors are inversely proportional to the reservoir pressure. Besides that, the solubility ratio is directly proportional to pressure, so lower pressures lead to lower solubility ratios, such behavior leads more free gas than dissolved in the system, resulting in greater pit gains. By setting the GOR at 4,027 scf/stb and the pore gradient at 10 lb/gal an increase in pit gain was observed for the aqueous fluid from 21 and 31 bbl to 12.3 and 13.5 lb/gal respectively. In the synthetic fluid, an increase in pit gain of 161 and 165 bbl was observed, respectively.

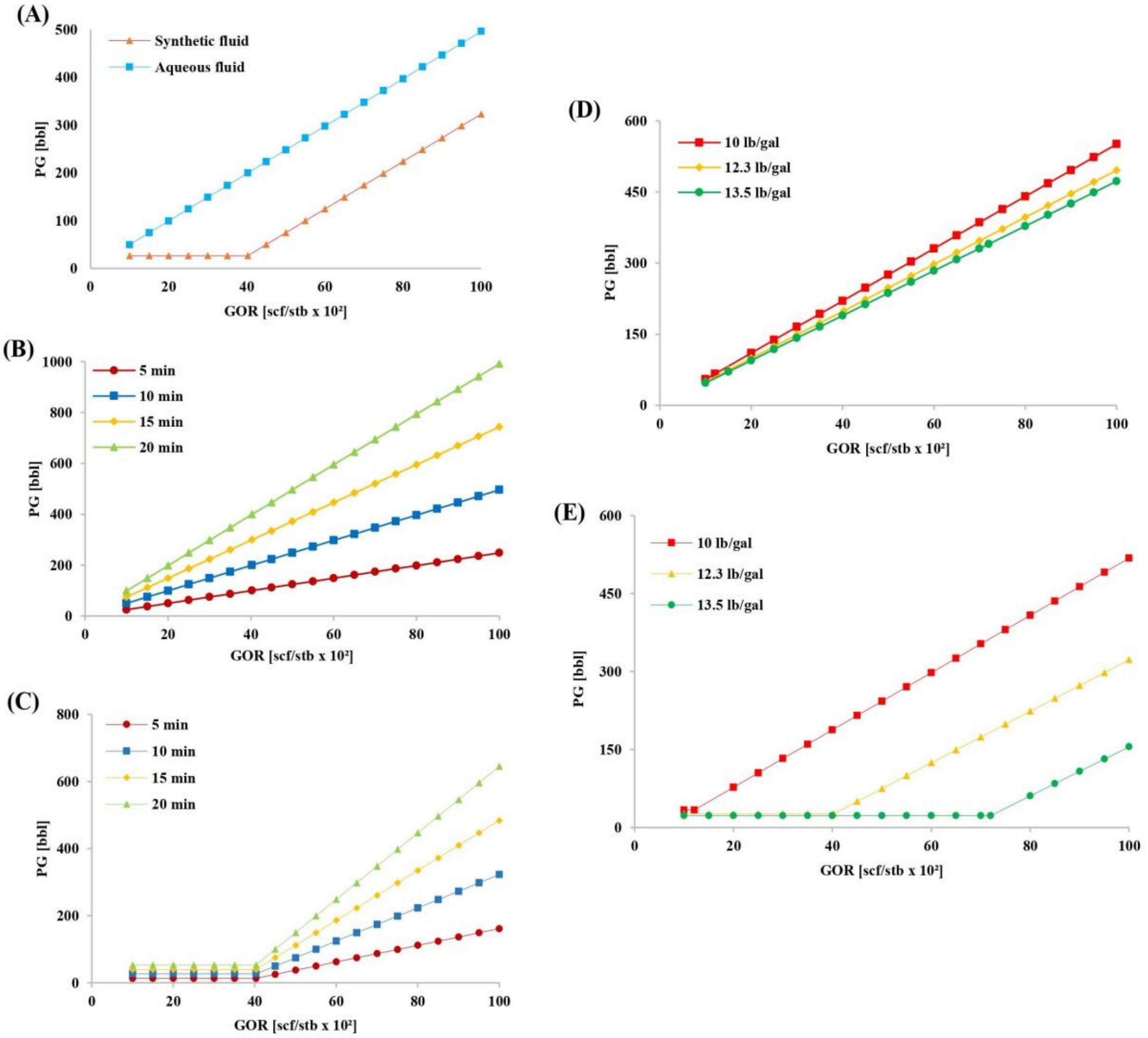

Figure 2. (A) Pit gain as GOR function for aqueous and n-paraffin based fluids; (B) Pit gain as GOR function for different kick detection times in aqueous fluid; (C) Pit gain as GOR function for different kick detection times in synthetic fluid; (D) Pit gain as GOR function for distinct pore gradients given an aqueous fluid; (E) Pit gain as GOR function for distinct pore gradients given a synthetic fluid.

4.2. Situation 2

Considering a pit gain corresponding to 10 bbl kick detection alarm, the methane total amount can be determined for each GOR. In this case, two sensitivity analyses were performed: pit gain and the pore gradient changes.

The methane total volume present in the system can be calculated using Eq. (6) when considering an aqueous fluid. In order to understand how the fixed pit gain influences the gas amount present into the well, a sensitivity analysis was performed for the gains: 10, 15, 20, 25 and 30 bbl as seen in Figure 3a. As expected, given the low gas solubility in aqueous fluid, the gas amount increased linearly with pit gain.

The methane amount calculation present in gas/synthetic fluid system was carried out respecting the mass conservation in the system. Therefore, from the fixed pit gain, the fluid can be undersaturated, saturated or supersaturated by the gas depending on the GOR analyzed. The same sensitivity analysis can be observed given the synthetic fluid in Figures 3b and 3c.

It can be seen that methane amount present in the system increases linearly with GOR until reaching fluid saturation where GOR is equal to RSm. Such behavior happens because until reaching saturation, the fluid is solubilizing the most part of gas that enters into the well, causing a volumetric swelling in the fluid. Since the pit gain is fixed, it is observed that as free gas amount increases with the GOR, the dissolved gas amount decreases with the GOR, respecting the mass conversion for supersaturated condition.

By setting the alarm at 10 bbl it was noticed, for both fluids, an increase of 1.5, 2, 2.5 and 3 times in gas total amount when increasing the pit gain to 15, 20, 25 and 30 bbl, respectively.

The same analysis performed for situation 1 was applied to situation 2 to understand the influence of pressure on gas total amount by changing the pore gradient in: 10, 12.3 and 13.5 lb/gal. The results were obtained by plotting the gas total amount as a pit gain function as observed in Figures 3d and 3e.

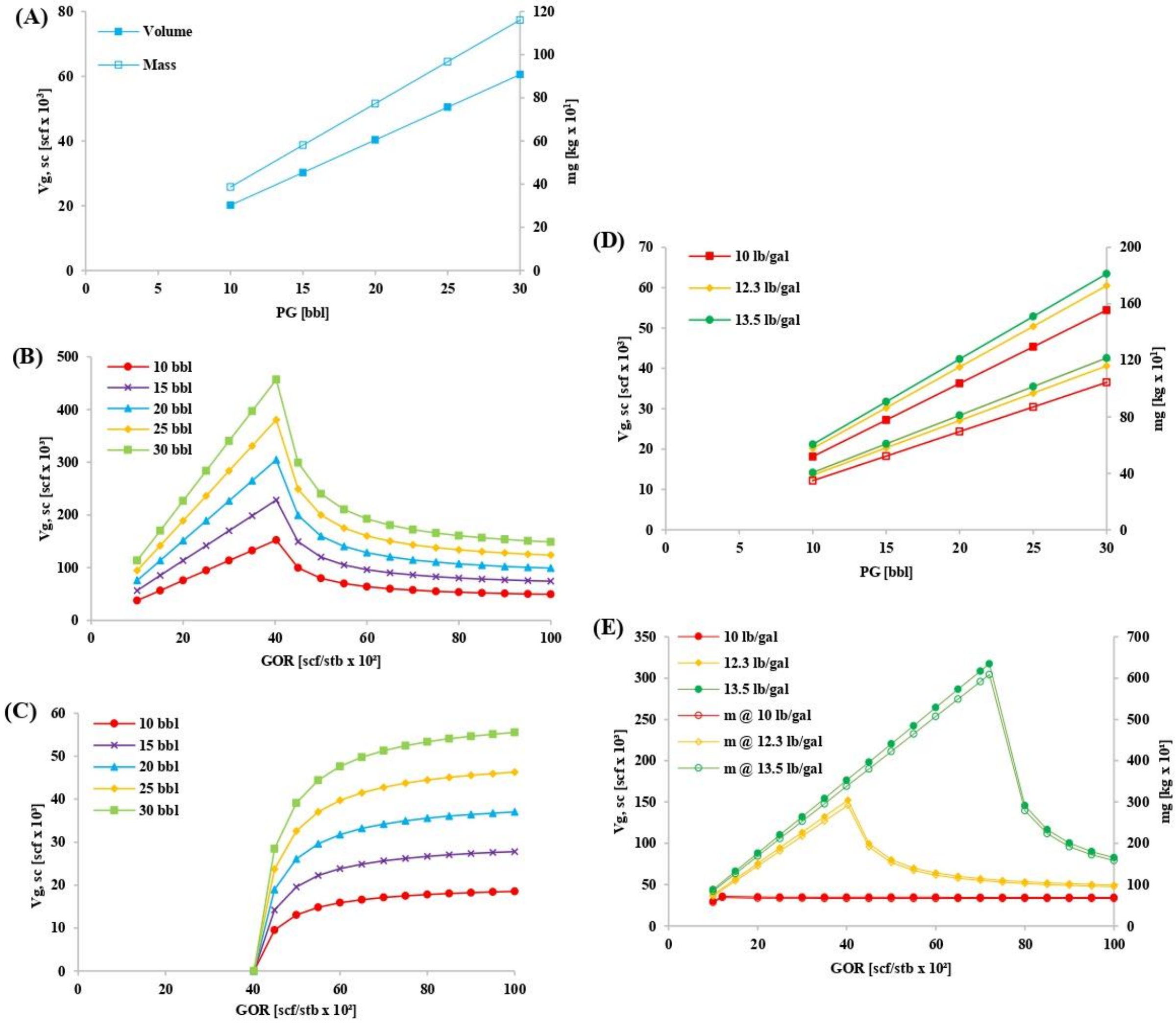

Figure 3. (A) Gas total amount as pit gain function for an aqueous fluid; (B) Gas total volume as GOR function for distinct pit gain in synthetic fluid; (C) Free gas mass as GOR function for distinct pit gain in synthetic fluid; (D) Gas total amount as pit gain function for different gradients in an aqueous fluid; (E) Gas total amount as pit gain function for different gradients in synthetic fluid.

The increase in gas amount was directly proportional to the increase in pit gain and pore gradient. As already stated, the gas and emulsion volume formation factors behavior are inverse to the reservoir pressure, but the latter is directly proportional to gas and fluid volume into the well.

By setting the pit gain at 10 bbl and the pore gradient at 13.5 lb/gal (largest amount of gas found) it was noted: in the aqueous fluid, an increase of 3,000 scf in gas amount compared to that found in 10 lb/gal and an approximate 1,000 scf increase in gas amount compared to that found at 12.3 lb/gal. In synthetic fluid, given the 10 bbl pit gain and GOR equivalent to 4027 scf/stb, an increase of 141 x 10^3 was noticed when comparing the total volume of gas observed in the pore gradients 13.5 and 10 lb/gal and an increase of 24 x 10^3 for 13.5 and 12.3 lb/gal ones.

Regarding the influence of the pore gradient on solubility, it can be observed that the greater the solubility ratio due to high pressures, the greater gas dissolved amount of in synthetic base fluid, which can be extremely dangerous, as the gas becomes masked in the fluid until the solubility ratio is reached. After saturating the fluid, there will be an excess of free gas in the system, making detection easier.

5. CONCLUSIONS

Given situation 1 (fixed gas amount) it is observed that the longer the kick detection time, the greater the gas amount present in the well. Due to the gas low solubility in aqueous fluid, it does not take much time for a significant volume to be observed in the pit gain. In synthetic fluid, the situation is more critical, since the increase in pit gain will only be significant when reaching the solubility ratio, due to the free gas presence inside the well.

When analyzing the pit gain in the aqueous and synthetic fluids (Figure 2a) for the GOR equal 4,027 scf/stb (solubility ratio), it is observed that pit gain found in aqueous fluid is 7.5 times greater than that one in synthetic fluid for the same amount of gas into the system. Comparing the pit gain for the same GOR (4,207 scf/stb) in 10 and 20 minutes, an increase in 200 bbl pit gain in aqueous fluid and 26 bbl in synthetic fluids can be seen (Figures 2b and 2c).

Regarding the pore gradient, it is possible to see that solubility increases linearly with the reservoir pressure. Therefore, the gas amount needed to saturate the synthetic fluid is smaller (Figure 2d and 2e). Note in Figure 2e that for 10 lb/gal, the pit gain found is 165 bbl greater than that observed at 13.5 lb/gal, this result can be explained by setting the GOR at 4,000 scf/stb, because under this condition, there will be free gas in the system for the 10 lb/gal pore gradient and only dissolved gas for the 13.5 lb/gal.

According to situation 2 (fixed pit gain) it is noted that the higher the alarm set for the pit gain, the greater the gas amount inside the well (Figure 2a and 2b). As expected, given a fixed pit gain, the gas amount was higher for the synthetic fluid than that observed for the aqueous fluid. As there is little gas solubilization in the aqueous fluid, the kick present in the system will be instantly detected on the surface, triggering the inflow detection alarm.

The synthetic fluid volumetric swelling until the solubility ratio is reached is minimal, making kick detection difficult. If there is excess gas in the system (supersaturated condition), the volume needed to trigger the alarm is quickly reached, making detection easier, however, in addition to the free gas, there will be a drilling fluid totally saturated by the gas.

By setting the pit gain at 10 bbl and the pore gradient at 13.5 lb/gal (largest gas amount found) it was noted: in the aqueous fluid, an increase of 3,000 scf in gas amount compared to that found in 10 lb/gal (smallest gas amount found). In synthetic one, for a GOR equivalent to 4,027 scf/stb, an increase of 141 x 10^3 was noticed when comparing the gas total volume observed in the pore gradients 13.5 and 10 lb/gal (Figures 2d and 2e).

The study shows how operational safety becomes more critical when using a synthetic fluid, as the gas is masked by solubility. In this case, extra care needs to be taken, since in many cases, the well tolerated a significant gas amount before the alarm was triggered. Therefore, it is necessary that the alarm is set at lower levels than those usually considered for aqueous fluid, the flow sensor must be able to detect any flow anomaly and there must be trained professionals available so that any irregularity is quickly detected to control procedures are initiated.

The drilling fluid stops to be a barrier element when control over it is lost and/or when it no longer exerts sufficient pressure against the drilled formation. In aqueous fluid, it is easy to define barrier failure as the gas is quickly detected at the surface. In synthetic fluid, most of the time, the kick will only be detected when reaching the solubility ratio that can be located above the BOP, compromising the secondary safety barrier, making it impossible to close the well. If the inflow is detected in time to trigger the secondary barrier, there may be so much gas inside the well that it will exceed the capacity of the surface gas separator, requiring, in more serious cases, the platform abandonment.

Safety standards are written with aqueous fluids in mind, with no mention of synthetic fluids. The study presented in this article can complement the existing standards, mainly in relation to the severity of gas kick non-detection situations. In addition to showing the need to insert synthetic fluids in the fluid column as a barrier element criteria and acceptance, since the inflow is unknown until the alarm is triggered, making the detection and control of the well complex. All the analyses carried out in this work showed the exorbitant difference in the kick behavior observed in the aqueous fluid to that obtained in the synthetic fluid, therefore, if there are different behaviors, it is necessary that different recommendations are attached, improving operational safety so that there are no more losses of human life during well drilling operations.

6. ACKNOWLEDGEMENTS

The authors of this work are grateful for the technical support offered by the Division of Petroleum Engineering (DEP) located at the School of Mechanical Engineering at Unicamp (FEM) and financial support offered by the Coordination for the Improvement of Higher Education Personnel (CAPES).

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