AADE-17-NTCE-132

The Effects of Gas Kick Migration on Wellbore Pressure

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Abstract

It is critical to understand the dynamic behavior and consequences of undesired reservoir influxes that triggers well control emergencies. In contrast to liquid kick, gas influx migration in water based mud and solubility in oil based mud represents exceptionally hazardous conditions. Operation delay time would result in a pressure build-up at the surface with increasing risk of fracturing the casing shoe.

In this study, critical factors affecting gas bubble rise velocity in a closed wellbore are studied. These factors are influx size, annulus clearance, reservoir pressure, oil/water ratio, drilling fluid density, plastic viscosity and yield point. Three different well types (vertical, directional and horizontal) and wellbore configurations are considered. Gas rise velocity and pressure changes at the surface and bottomhole are monitored at different well shut-in periods of time. A commercial multiphase dynamic well control simulator utilized with a common well configuration.

Preliminary results show that higher gas rise velocities and wellbore pressures are experienced as the severity of the encountered conditions increase due to high reservoir pressure as well as the influx size. In comparison to vertical and directional wells, horizontal wellbore trajectory experiences the lowest surface and bottomhole pressures. The average gas rise velocity in WBM is 82.2 ft/min, while in OBM the average gas rise velocity is 31.96 ft/min. In addition, in OBM while the gas is migrating to the surface, wellbore pressure increases then free gas dissolves completely and stays stationary.

Introduction

A kick is defined as an undesired liquid or gas influx from the drilled formations into the wellbore which interrupts the drilling operations. This flow is driven by pressure underbalance between the drilled formation and the dynamic bottom hole pressure. Meanwhile, if allowed to expand, gas results in an additional drop in the bottom hole pressure, which in turn induces more gas invasion. Additionally, lack of crew awareness, delayed or improper actions and equipment failure initiate uncontrolled surface or underground blowouts (Adams and Kuhlman 1994). In fact, most of the fatal accidents in the oil and gas industry occur due to the lack of proper training and awareness of well control. Hence, unexpected well control emergencies still arise as what happened in Gulf of Mexico -Macondo Blowout- in 2010 (Turley 2014).

Gas blowouts are more hazardous in comparison to liquid blowouts since gas bubbles either percolate in a closed wellbore filled with water based mud or dissolve in oil based mud under bottom hole conditions (Tarvin et al. 1991). Well control philosophy is based on maintaining a constant bottom hole pressure throughout kick handling procedures. Once an influx is detected at the surface, the BOP is closed to minimize influx volume. Then, upon shutting-in the wellbore and stabilizing the shut-in drill pipe and casing pressures, a proper kick circulating method is applied. This includes circulating the influx and displacing higher mud density around the wellbore to overbalance the kicking zone (Watson et al. 2003). If the crew fails to start influx circulation, gas bubbles percolate in a closed wellbore to the surface due to density difference. While gas bubbles migrate in water based mud, the wellbore pressures increase (Guner et al. 2016).

Consequently, if the formation fracture pressure or surface equipment rating pressure is exceeded, an inevitable blowout will be triggered. Drilling crew sometimes is forced to wait on kick circulation as a result of pump failure or drill string is outside the hole during well control situation. Therefore, Matthews and Bourgoyne (1983) proposed the implementation of constant drill pipe pressure with static and dynamic volumetric methods when normal well control methods are delayed to minimize gas migration consequences. Moreover, gas is highly soluble in oil-based mud and as a result surface pressure and volume measurements are not representative of the actual downhole measurements (Elshehabi and Bilgesu 2015). Therefore, it is necessary to investigate critical factors affecting gas bubble rise velocity in water and oil based drilling fluids.

Gas Rise Velocity in Water Based Mud

Gas percolation in a closed wellbore is a critical parameter in kicks and blowout control practices. During gas migration, the position of the gas bubble specifies downhole/surface pressures. Typically, casing shoe depth is the weakest point in a closed wellbore. Matthews and Bourgoyne (1983) proved that the assumption of gas kick remains as a continuous slug during migration is invalid. In addition, experimental study by Rader et al. (1975) showed that the most essential factors affecting the velocity of gas bubbles are drill pipe/annulus configuration, deviation angle, gas and liquid viscosities and densities. They concluded that gas bubbles migrate upwards from one side of the hole while the liquid flows downwards on the opposite side.

However, surface tension and pipe eccentricity had insignificant influence on gas rising velocity. Skalle et al. (1991) investigated a broad range of air and liquid related flow properties. They concluded that dispersed two-phase flow pattern dominates. Also, they found that Findlay correlation (Zuber and Findlay 1965) gives the best results for holdup estimation to distinguish between bubble and slug flow. In addition, Johnson and White (1991) concluded that gas rise velocity in viscous drilling fluids is higher than water. This can be contributed to the large slug-type bubbles at low void fraction flow regime. Hovland and Rommetveit (1992) studied gas migration velocity in a full-scale research well. They concluded that gas rises faster at high concentrations compared to low and medium concentrations. However, they derived a gas rise velocity correlation that does not depend on a void fraction, mud density, rheology, surface tension, and deviation angle. Johnson and Cooper (1993) extended their studies to deviated wells. They concluded that with deviation angles up to 45°, bubble slip velocity insignificantly changes. Furthermore, gas migration velocity is underestimated if mud compressibility, fluid loss, and wellbore elasticity are neglected.

Field cases reported gas migration resulting with the surface pressure build-up at a high rate of 50 psi/min. Meanwhile, experimental results showed that gas migrates at a rate of 100 ft/min. There is always a high uncertainty about the influx volume and composition in the drilling industry, while it is widely believed that gas can rise at a rate of 1000 ft per hour or less (Tarvin 1994). This disagreement between field reports and experimental results can be contributed to a higher gas fraction in experiments than field reported data. Johnson et al. (1995) reviewed the inconsistent gas migration values reported in the previous studies. They concluded that when gas concentration is higher than 10% of the void fraction, gas migrates at a rate of 100 ft/min and leaves a trail of suspended stationary gas bubbles. In contrast, field cases reported bubble migrates at a slower rate of 15 ft/min or less and in some cases gas bubbles remains stationary. In addition, the suspended gas bubbles increase mud compressibility and reduce surface pressure build-up.

Spoerker and Tuschl (2010) stated that sour gas influxes in a high pH drilling fluid migrate and create a chemical buffering reaction that damages high strength steel pipes. Hauge et al. (2012) developed a two-phase dynamic model to estimate gas percolation rate in a vertical partially evacuated riser. They estimated a gas rise velocity of 95 ft/min (Hauge et al. 2012). Shen et al. (2013) derived a model that consider the downhole temperature impact in estimating gas rise velocity and associated forces. Moreover, Gruber et al. (2014) concluded that hydrogen sulfide influx into high pH mud creates sulfide stress cracking (SSC) to drill string. This can be contributed to the chemical reaction-kinetic effects during well shut-in period. Upward gas migration is accompanied by a potential change in flow pattern and corrosion severity, and the amounts of dissolved H_2S gas. In developing their 1D multiphase drift-flux model, Varadarajan and Hammond (2015) employed a gas migration velocity of 0.5 m/s for void fractions between 10% and 40%.

Also, annular pressure variations caused by gas kick/injection was studied by Meng et al. (2015). They concluded that bottomhole pressure significantly impacted by the gas and liquid mass flow rates and well depth. Also, gas kick in shallow wells represents a higher risk because of a larger degree of underbalance and short arrival time at the surface. Velmurugan et al. (2016) studied the dynamic behavior of gas expansion and concluded that buoyancy and slip cause gas migration in marine risers. Also, decreasing the hydrostatic pressure triggers gas expansion until enough back pressure is applied at the surface. Fjelde et al. (2016) estimated the gas rise velocity as 45.3 ft/min. In addition, they discussed the accuracy of kick slippage models and the result of pressure buildup misinterpretation because of gas suspension. They defined two causes of errors, one as the uncertainty of gas slip parameters, and the other as the numerical diffusion and numerical solver discretization. Furthermore, they concluded that gas migration velocity depends on the type of flow regime that could be bubble, slug, dispersed, churn, or annular flow.

Gas Solubility in Oil Based Mud

Previous studies argued about the factors impacting the degree of gas solubility in oil-based drilling fluids. For instance, O'Bryan et al. (1988) concluded that the gas solubility in water is less than 1% compared to oil and therefore, it could be neglected. Also, gas liberation occurs at the bubble point pressure which mostly happens in the upper 2,000 ft section of a wellbore. Gas solubility increases with wellbore pressure and gas specific gravity. However, increasing temperature, solid content and water/oil ratio decreases gas solubility (O'Bryan et al. 1988). Adams and Kuhlman (1994) concluded that gas kick dissolves and surface pit gain do not represent the actual downhole kick size. Therefore, massive influx sizes could invade the wellbore without significant surface warning signs. For instance, a 20 bbls kick might only be recognized at the surface as 4-6 bbls pit gain (Adams and Kuhlman 1994). Schilhab and Rezmer (1997) stated that in HPHT wells significant gas fraction remains trapped by mud yield stress at the bottom of the hole until circulated out.

Berthezene et al. (1999) studied the solubility of methane in diesel, mineral, synthetic, and ester oils. They concluded that methane dissolves completely when the downhole pressure is above the miscibility pressure (Berthezene et al. 1999). Monteiro et al. (2010) claimed that 45% more methane can enter the wellbore in oil based mud compared to water based mud at high temperatures. Elshehabi and Bilgesu (2015) and (2016) studied the impact of gas solubility on well control operations for horizontal shale gas wells. They concluded that gas solubility introduces uncertainty about surface/downhole measurements. In addition, single slug model overestimates surface pressures and volumes. This can be contributed to underestimating the mud/gas mixture density. In comparison, the multiphase flow model predicts realistic surface/downhole measurements with lower mud/gas mixture density values. According to Velmurugan et al. (2016) influx detection in oil based mud is complicated due to complete dissolution of gas and relative delay in surface kick indicators.

Methodology

In this paper, a two phase dynamic well control commercial software is used to investigate the factors that affect gas bubble rise in a closed well drilled with water or oil based drilling fluids. Choke, casing shoe, and bottomhole pressures are monitored to avoid fracturing the casing shoe after the well has been shut-in. The parameters that were studied are kick size, wellbore annulus clearance, reservoir pressure, drilling fluid density, wellbore geometry (for vertical, directional and horizontal wells), oil/water ratio, mud yield point and mud plastic viscosity.

Kick sizes of 10, 20, and 30 barrels for oil based mud and 5, 10, and 15 barrels for water based mud are used to determine the impact of kick sizes on wellbore pressures and gas rise velocity. Three different wellbore annular areas with 5.0”, 6.276’’, and 8.0’’ casing inside diameters and 3 ½’’ drill pipe outside diameter are used to find out the influence of wellbore geometry. Reservoir pressures of 5,500 psi, 6,500 psi, and 7,500 psi are used for investigating the influence of reservoir pressures on wellbore annular pressures. 11.20 lbm/gal, 13.35 lbm/gal, and 15.52 lbm/gal water and oil based muds are used to compare the impacts of drilling fluid density on wellbore annular pressure and gas rise velocity. Vertical, horizontal and deviated wells are used as types of wellbore geometry to determine their impact. True vertical depth (TVD) of 6,824 ft is used for each type of well as a reference depth for the reservoir and casing shoe depth was 5,708 ft. The measured depths (MD) of horizontal and deviated wells were 14,928 ft and 7,098 ft respectively. Average gas rise velocity is calculated based on migration time and final measured depth reached after gas percolation. In order to see the impact of the oil-water (O/W) ratio for OBM; 50/50, 70/30 and 90/10 O/W ratios were used. In addition, the Bingham Plastic model was used with yield points of 5 lbm/100ft^2, 10 lbm/100ft^2, 15 lbm/100ft^2. Also, plastic viscosities of 12 cp, 19 cp, and 26 cp with 13.35 lbm/gal WBM were used to see the impact of drilling fluid’s rheological properties on wellbore pressures and gas rise velocity.

Results and Discussion

The pressure variation on surface choke, bottomhole and at the casing shoe for each case are shown in the following figures. The average gas rise velocities for each case are shown in table 2.

1- Effect of Kick Size

The impact of different kick sizes is studied with OBM and WBM in a vertical well. For OBM, the kick sizes are measured as the surface pit gain of 10 bbl, 20 bbls, and 30 bbl. While, for WBM, kick sizes were 5 bbl, 10 bbl, and 15 bbl. Figure-1 shows the impact of kick size on the surface and downhole pressures in OBM. Gas solubility takes place when OBM is used as the drilling fluid. A certain amount of gas dissolves in OBM depending on OBM composition, temperature, and pressure. For instance, 10 bbl gas kick migrated to 4,000 ft and increased the wellbore pressures then it completely dissolved and stayed stationary (Figure-1). The pressure related solubility is similar to the drill cuttings entrapment in mud due to yield point. When approximately 80% of the 20 bbl and 30 bbl kick sizes dissolve in the mud while migrating, the rest of the gas is in the free gas form and migrates and reaches to top of the well with different velocities. In comparison to the bottomhole and casing shoe pressure, the choke experiences the highest pressure difference as shown in Figure-1. For instance, the choke pressures were 1064 psi, 1533 psi and 1812 psi for 10, 20, and 30 bbl kick sizes, respectively. The average gas rise velocities were 14.1 ft/min, 14.22 ft/min and 30.96 ft/min for 10 bbl, 20 bbl, and 30 bbl kick. The gas kick arrives at the top of the well around 220 min for 30 bbl kick size, which was 260 minutes earlier than 20 bbl kick size. Therefore, the average gas rise velocity for 30 bbl kick size was more than two folds of the average gas rise velocity for 20 bbl. It was concluded that greater the kick size, higher the gas rise velocity and wellbore pressures.

Figure-2 compares pressure variations as a result of changing kick size in WBM. Since gas solubility in WBM is insignificant, smaller kick sizes were used for WBM in comparison to OBM. In WBM, the whole influx was in the free gas form which migrates and reaches the surface. Therefore, 5 bbl, 10 bbl, and 15 bbl kick sizes were simulated in WBM. The average gas rise velocities were 64.8 ft/min for 15 bbl, 55.8 ft/min for 10 bbl, and 46.8 ft/min for 5 bbl kick size. This means gas arrives at surface 40 minutes earlier for 15 bbl kick size than for 5 bbl kick size for a vertical well, which had a 6824 TVD. It is obvious that gas migrates faster in bigger kick sizes. This observation was consistent with the results observed in OBM. Not only gas rise velocity was higher for bigger kick sizes, but wellbore pressures were also greater for bigger kick sizes. For example, 15 bbl kick size created 4310 psi at the choke pressure, which was 440 psi greater than pressure created by 10 bbl kick size. Also, in comparison to 5 bbl kick size, 15 bbl created 1210 psi additional choke pressure.

2- Effect of Wellbore Annulus Clearance

The effect of annular area on surface/downhole pressures and gas rise velocity was investigated using the three different annular clearances shown in Table-1. For all the configurations, 13.35 lbm/gal WBM was used. Figure-3 presents bottomhole, casing shoe and wellhead choke pressures for three different annular areas. The smaller the annular clearance, the higher the pressure variations. In smaller annulus clearance, the gas kick column occupies longer height compared to larger annulus clearance. For example, surface choke pressure was 4433 psi for the narrowest annulus size used in this study. While the choke pressure was 3783 psi for the middle and 2393 psi for the largest annulus clearance. These results are in agreement with the earlier study by Rader et. al. (1975). Tight annular clearance also affects the gas rise velocity in the same way for each configuration. The gas rise velocity in the smallest annulus clearance was 70% higher compared to the largest annulus clearance. The gas rise velocities were 82.2 ft/min, 54.6 ft/min, and 48.6 ft/min for small, medium and large clearances, respectively. The observed pressure fluctuations shown in Figure-3 were attributed to different annular areas in the wellbore. This includes annular area between DC and open hole, DP and open hole, DP and previous casing.

3- Effect of Reservoir Pressure

The influence of reservoir pressure on annular wellbore pressures in a vertical well drilled with WBM is illustrated in Figure-4. The change in reservoir pressure had a remarkable impact on surface and downhole pressures. The higher reservoir pressure resulted in a larger influx size into the wellbore. Even though the surface pit gain was maintained constant at 6.2 bbl, the downhole total influx values were 5.9 bbl, 6.8 bbl, and 8.3 bbl with reservoir pressures of 5500, 6500, 7500 psi, respectively. Thus, the bigger total influx sizes create higher annular wellbore pressures. The maximum surface choke pressure difference was 2408 psi for reservoir pressures of 5500 psi and 7500 psi. Also, the maximum bottomhole pressure difference observed was 2448 psi. This significant pressure increase may exceed casing burst pressure or fracture pressure at the shoe.

4- Effect of Drilling Fluid Density

Figure-5 shows the influence of mud weight change on wellbore pressures and gas rise velocity. This includes using 11.20 ppg, 13.35 ppg and 15.52 ppg mud weights for OBM in a vertical well. The surface pit gain was maintained at the level of 6.2 bbls for each case. However, downhole gas influx volume was different since the hydrostatic pressure was different for each mud weight. For example, 14.4 bbl, 12.5 bbl, and 10.8 bbl were recorded at 11.20 ppg, 13.35 ppg, and 15.52 ppg. Pressure stabilized after 115 minutes when gas influxes were completely dissolved.

Choke pressure was greater for a low mud weight due to the fact that bigger volume of kick enters the wellbore. For 11.20 ppg OBM, the maximum choke pressure and gas rise velocity were 2650 psi and 12.7 ft/min as shown in Table-2. Figure-6 shows wellbore pressure variation for a WBM with different mud weights. Since gas solubility in WBM was insignificant, gas kick migrated to the top of the well. For 11.20 ppg WBM, the maximum choke pressure and gas rise velocity were 4575 psi and 49.2 ft/min, respectively. Figure-7 compares pressure variation of WBM with OBM both with 11.20 ppg density. The pressure variation and gas rise velocity were much higher in WBM compared to OBM. For instance, gas migrated approximately 3.8 times faster in WBM. Also, the observed choke pressure for 11.20 ppg of WBM was 1934 psi greater than the value in OBM.

5- Effect of Wellbore Geometry

The results for pressure variations are presented in Figure-8 for three different wellbore trajectories when WBM is used. Vertical and directional wellbores experience similar pressure increases whereas the pressure increase for the horizontal well is delayed for a duration equal to the gas travel time in the horizontal section. For the horizontal case, the delay time was approximately 200 minutes. The pressure increase for the horizontal well occurs when the gas kick reaches the end of kick of point (KOP). Among the three wellbore trajectories, horizontal wellbore experienced the lowest surface and bottomhole pressures. Gas rise velocities slightly changed in each wellbore trajectories. The highest gas rise velocity was seen in the vertical well, which was 49.8 ft/min, and the lowest velocity of 44.4 ft/min was seen in the horizontal well.

6- Effect of Oil/Water Ratio

The ratio of oil to water percentage in the drilling fluid is defined as the Oil/Water Ratio (OWR). The change of OWR can affect the degree of gas solubility in OBM. In this paper, an OBM with 13.35 ppg mud weight was used with three different OWR. These are 90/10, 70/30 and 50/50 oil water ratios. The results of the runs are shown in Figure-9. Free gas influx started dissolving immediately at highest OWR of 90/10. However, while migrating, gas influx dissolved completely in all three compositions. Although pressure varitions were insignificant for the different OWR values, gas influx dissolved at different well depths. Hence, the gas reached upper parts of the well when the OWR of mud was at the lowest value of 50/50. The dissolution depths in the wellbore were 3600 ft for 50/50 OWR, 4500 ft for 70/30 OWR, and 4900 ft for 90/10 OWR. Clearly, higher the OWR, higher was the degree of gas solubility in the OBM.

7- Effect of Mud Yield Point and Mud Plastic Viscosity

The impacts of mud yield point (YP) and mud plastic viscosity (PV) in WBM were investigated using Bingham plastic model. By definition, YP of the drilling mud is used to evaluate cutting carrying capacity of the mud. Three different YP values of the mud (5-10-15 lbm/100 ft^2) were used to evaluate YP effect on wellbore pressures and gas rise velocity while keeping plastic viscosity and mud weight constant. PV indicates the solid content of the drilling fluid and system friction losses. Impact of PV values of 12 cp, 19 cp, and 26 cp were examined while keeping YP and mud weight constant. The results are shown in Figure-10 and Figure-11. PV and YP had insignificant impact on wellbore pressures and gas rise velocity since in a closed wellbore there was no circulation and the drilling fluid was in a static condition.

Conclusions

Based on the observed results, the following conclusions are presented:

- The major factors affecting gas rise velocity are kick size, wellbore annulus clearance, reservoir pressure, wellbore geometry, drilling fluid type, and mud density.
- The range of average gas rise velocity for a WBM was between 44 ft/min and 82.2 ft/min, and the range of average gas rise velocity for OBM was between 12.3 ft/min and 31.96 ft/min.
- Wellbore annular area had the greatest impact on the surface choke pressure and gas rise velocity because smaller annular area created longer gas bubble height. It caused higher surface pressures with gas rise velocity of 82.2 ft/min.
- The effect of kick size has to be considered as a vital parameter on well control operations since the higher kick size causes higher choke pressure at the surface and higher gas rise velocity, which shortens the time of kick migration to the top of the well.

- With gas going into solution in OBM, pressure builds up until all the gas was dissolved and there was no further gas migration. However, gas kick migrates in WBM, and it builds up the pressure until gas reaches the surface. Therefore, the type of drilling fluid employed has a great impact on annular wellbore pressures.
- Properties such as Oil/Water ratio, the yield point and plastic viscosity of the drilling fluid had a minor impact on wellbore pressures and gas rise velocity in the wellbore annulus configurations used in this study.

Nomenclature

Avg = Average
Bbl = barrel
BHA = bottom hole assembly
Cp = centipoise
Ft = feet
ft^2 = square feet
gal = Galon
lbm = pound
Min = minute
OWR = Oil/Water Ratio
PV = Plastic Viscosity
YP = Yield Point

Table 1 Wellbore annulus clearance values.

PROPERTY	Well#1	Well#2	Well#3
Casing OD, in.	5.5''	7.0''	8 5/8''
Casing ID, in.	5''	6.276''	8''
Drillpipe OD, in.	3.5''	3.5''	3.5''
Drill collar OD, in.	4.0''	4.5''	4.5''
Bit Diameter, in.	4.5''	6.0''	7.0''

Table 2 Gas migration times and average gas rise velocity values.

Parameters	Variables	Migration time to Surface/ Dissolution minute	Where It Reaches ft	Avg. Gas Rise Velocity ft/min
Kick Size OBM	10 bbl	200 min	4000 ft	14.1
	20 bbl	480 min	Top of the well	14.22
	30 bbl	220 min	Top of the well	30.96
Kick Size WBM	5 bbl	145 min	Top of the well	46.8
	10 bbl	123 min	Top of the well	55.8
	15 bbl	105 min	Top of the well	64.8
Wellbore Size WBM	5'' ID Casing	83 min	Top of the well	82.2
	6.276'' ID Casing	125 min	Top of the well	54.6
	8'' ID Casing	140 min	Top of the well	48.6
Reservoir Pressure WBM	5500 psi	144 min	Top of the well	47.4
	6500 psi	142 min	Top of the well	48
	7500 psi	140 min	Top of the well	48.6
Mud Weight OBM	11.20 ppg	128 min	5200 ft	12.7
	13.35 ppg	130 min	5200 ft	12.5
	15.52 ppg	132 min	5200 ft	12.3
Mud Weight WBM	11.20 ppg	138 min	Top of the well	49.2
	13.35 ppg	142 min	Top of the well	48
	15.52 ppg	144 min	Top of the well	46.8
Wellbore Geometry WBM	Vertical	137 min	Top of the well	49.8
	Horizontal	336 min	Top of the well	44.4
	Deviated	147 min	Top of the well	48
Oil/Water Ratio	50/50	240 min	3600 ft	14.33
	70/30	172 min	4500 ft	13.5
	90/10	154 min	4900 ft	12.49

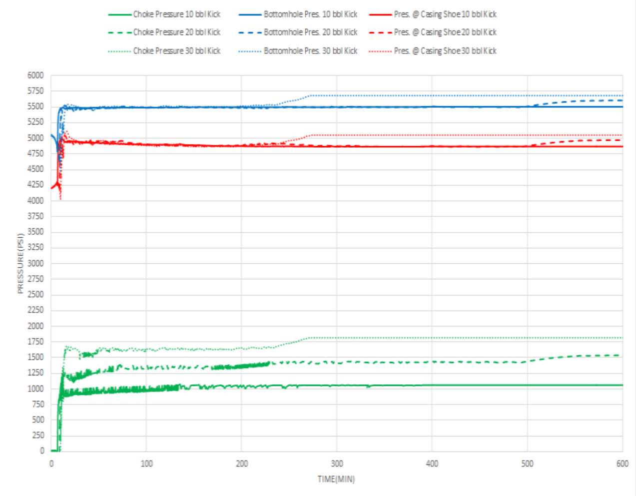

Figure 1 Variation of pressures with time in a vertical well for kick size effect with OBM.

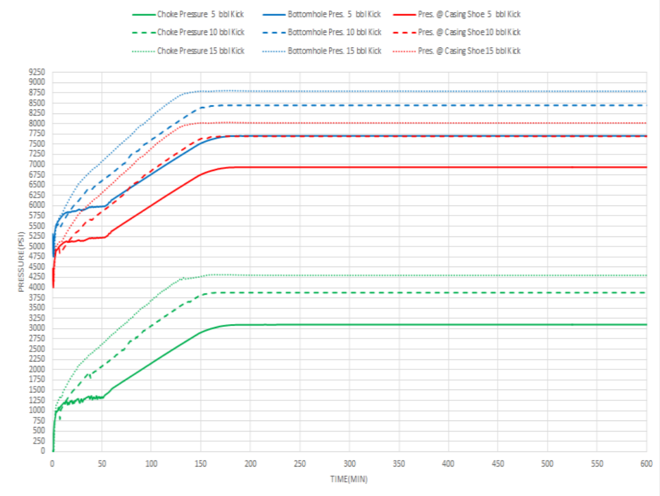

Figure 2 Variation of pressures with time in a vertical well for kick size effect with WBM.

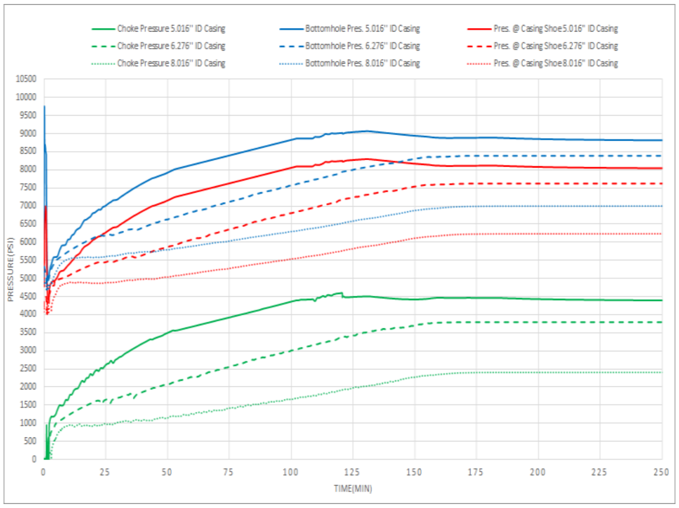

Figure 3 Variation of wellhead choke, bottom-hole and casing shoe pressures as a function of time for three different annular sizes.

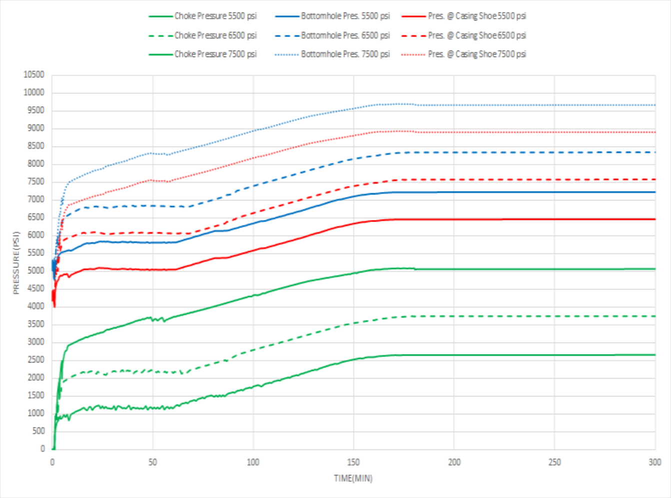

Figure 4 Variation of surface and bottomhole pressures for three different reservoir pressures in a vertical well with WBM.

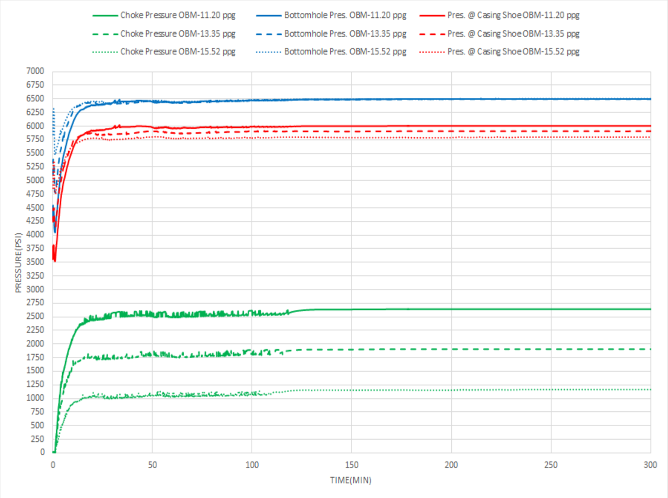

Figure 5 Variation of pressures with time in a vertical well for Oil Based Mud Density.

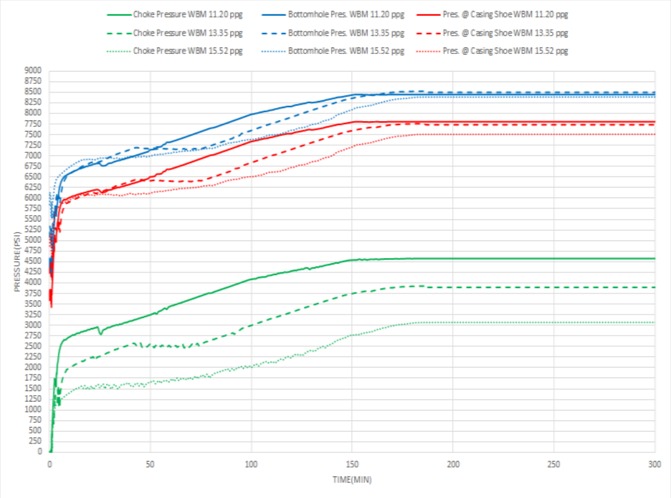

Figure 6 Variation of pressures with time in a vertical well for Water Based Mud Density.

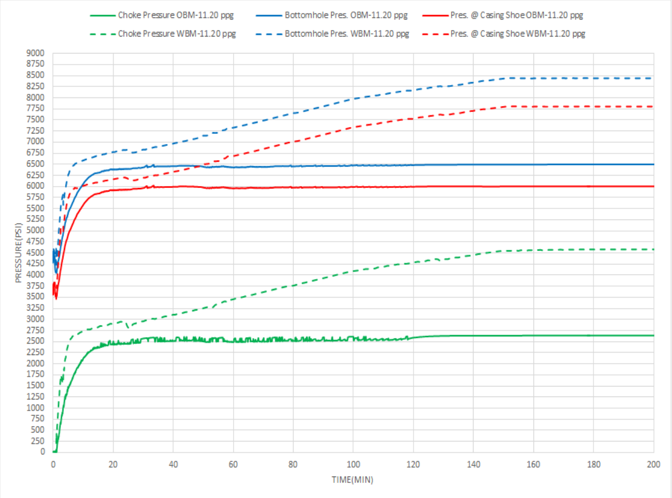

Figure 7 Variation of pressure with time in a vertical well for comparison of OBM and WBM.

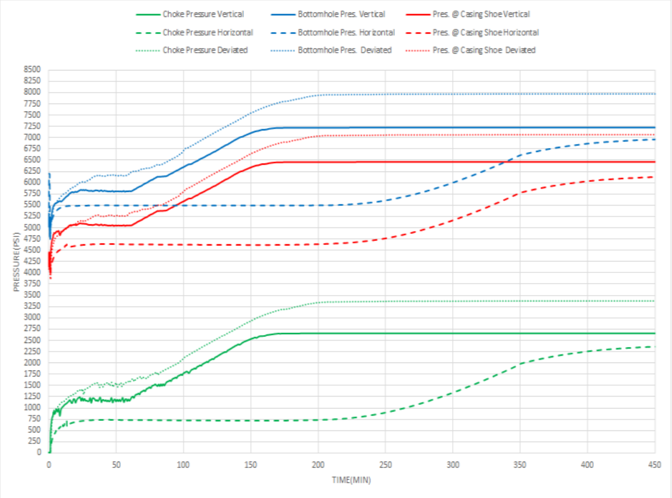

Figure 8 Variation of pressure with time in a well with WBM for three different wellbore trajectories.

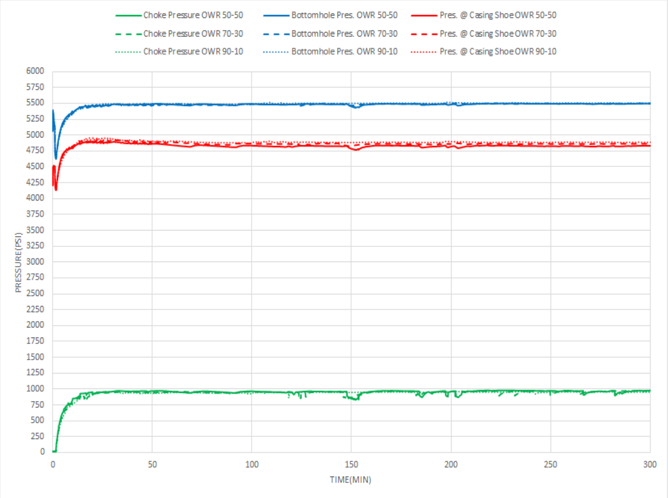

Figure 9 Variation of pressure with time in a vertical well for three different Oil/Water ratios.

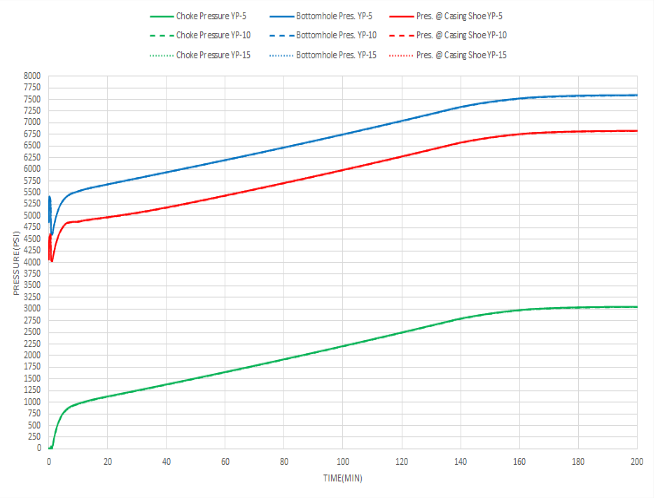

Figure 10 Variation of pressure with time in a vertical well for three different yield point values.

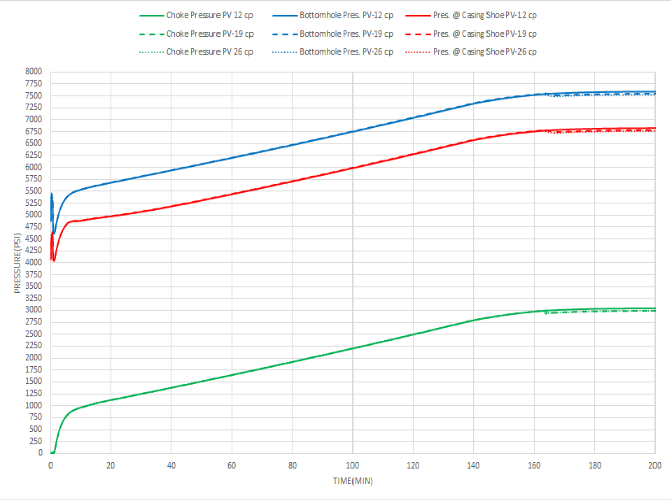

Figure 11 Variation of pressure with time in a vertical well for three different plastic viscosity values.

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