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GAS HYDRATES IN OFFSHORE HYDROCARBON EXPLOITATION: REVIEW AND CASE ANALYSIS

Hariel Udi Santana Mendes
Paulo Roberto Ribeiro
Nilo Ricardo Kim
José Ricardo Pelaquim Mendes
University of Campinas, Campinas-SP
h263146@dac.unicamp.br
ribeiro@fem.unicamp.br
nilo@cepetro.unicamp.br
jricardo@fem.unicamp.br

Nara Angélica Policarpo
University of São Paulo, Santos-SP
npolicarpo@usp.br

Abstract. *Gas hydrates are ice-like crystalline solids formed when gas molecules are trapped by water molecules in a low-temperature, high-pressure environment. In the explotatory industry of offshore oil and gas wells, there is hydrate formation evidence in drilling, logging, formation testing, completion, and well intervention activities, causing huge losses and delays for the companies operating these fields. In this work, a literature review was carried out on the industry cases where there was evidence of that issue in exploitation activities. The main causes for the hydrate formation in each of these cases and the consequences that occurred were commented on. To better discuss hydrate prevention techniques during well drilling, a phase behavior software was used, which provides hydrate equilibrium curves using thermodynamic inhibitors in drilling fluids. In addition, a description was carried out of the main techniques used for hydrate dissociation after it was formed: hydrate inhibitors circulation, depressurization through nitrogen circulation to relieve hydrostatic pressure, and assembly of a special column for hydrate jetting and removal.*

Keywords: *Gas hydrates, offshore exploitation, hydrate prevention, hydrate dissociation, drilling fluids.*

1. INTRODUCTION

In recent years, the oil industry has been challenged to exploit oil and gas fields in complex areas, as in the case of deep and ultra-deepwater depths. In those places, environmental conditions on the mudline (high hydrostatic pressure up to 4,000 psi and low temperatures close to 4°C) might promote the hydrate formation, rigid ice-like structures that trap gas molecules, as natural gas and their components: methane, ethane, propane, and carbon dioxide (Hale and Dewan, 1990).

Two phenomena occur in the hydrate formation: hydrate nucleation, which is a stochastic and microscopic process and is characterized by the growth of small agglomerates of water and gas; and hydrate growth, in which the development and multiplication of stable nuclei occur. The stochastic nature of the formation process is a result of the degree of metastability, that is, the ability of a non-equilibrium state to remain for a long period. In the metastable zone, between the thermodynamic spinodal curve and the hydrate equilibrium curve (Fig. 1), the system still does not have enough energy to overcome the entropy/enthalpy barrier for the creation of critical-sized nuclei, however, depending on the mixing conditions and components composition, the hydrate nuclei could form (Lal and Nashed, 2019). Therefore, the hydrate-free zone is the right side region of the equilibrium curve, which is the workplace for the oil and gas industry, from an operational point of view.

Pressure and temperature hydrate formation conditions may be especially found in drilling activities, mainly in gas kick situations. According to Santos (2006), the following problems could occur during drilling (Fig. 2a): (a) choke and kill lines plugging; (b) wellbore annular space obstruction; (c) drillstring sticking due to the crystal formation along the BOP (Blowout Preventer) region (Fig. 2b); and (d) difficulty in opening and closing the BOP rams. Because of those problems, drilling operations have to be stopped altogether to remove the gas hydrates, resulting in monetary losses, damage to equipment, and safety issues.

During formation testing activities hydrate could be formed within the test column, throttling the produced fluid flow. That produced fluid often contains formation water and gas with hydrocarbon mixtures from the reservoir, in addition to the completion fluid inside the well. Well intervention situations are using coiled tubing, where there is the hydrate plug formation between the column and the coiled tubing, trapping it and impeding its removal from the well (Fig. 2c). This same problem might occur during cable logging, with the cable becoming trapped and making its release impossible. There is also the hydrate formation possibility in the wellhead during its cleaning for completion or after a perforation operation.

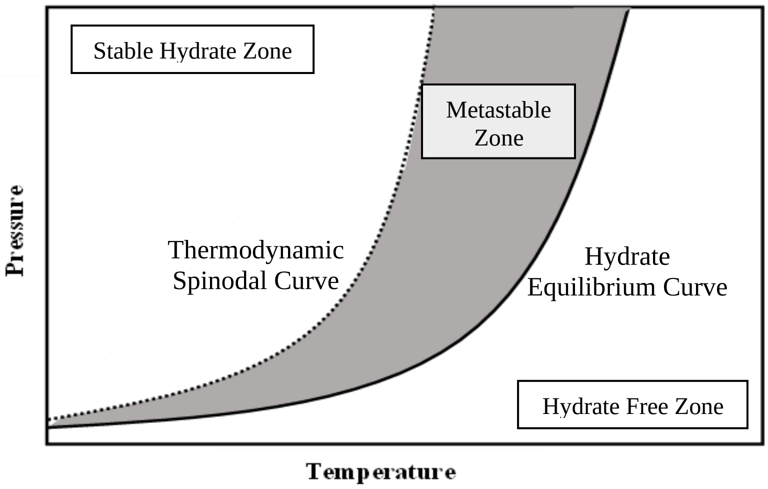

Figure 1. Hydrate phase envelope.
Adapted from: Lal and Nashed (2019).

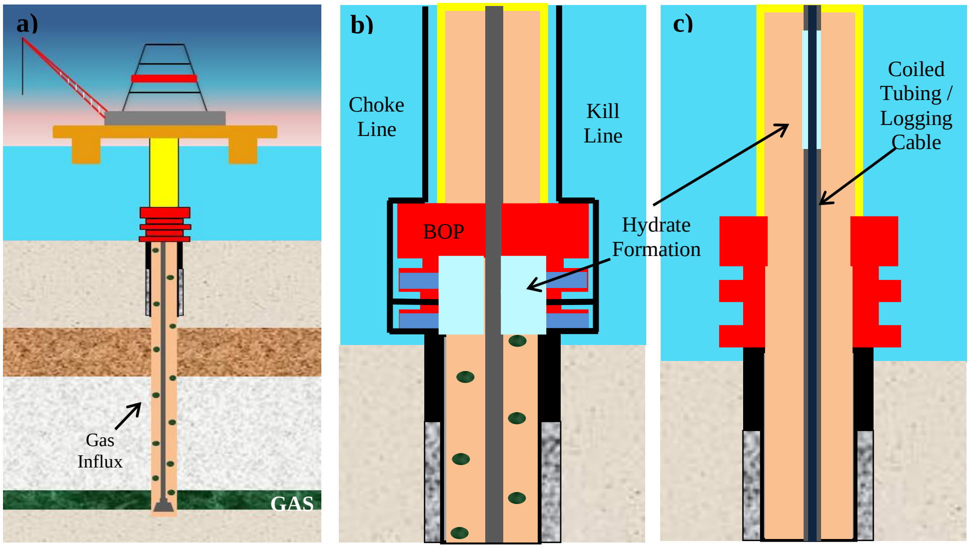

Figure 2. a) Gas kick during an offshore well drilling operation; b) Hydrate formation in the BOP region during drilling; c) Hydrate plug between column and coiled tubing/logging cable during formation testing.

The objective of this work was to identify the cases in the oil exploration and production industry where there was hydrate formation evidence in drilling, logging, formation testing, completion, and well intervention activities. Prevention techniques for hydrate inhibition in well drilling activities were examined, through simulations in a phase behavior software that applies thermodynamic equations of state. The causes and consequences of hydrate occurrence in the other situations were described and the hydrate dissociation/removal techniques in these cases were examined.

2. LITERATURE REVIEW

Barker and Gomez (1989) were the first to report hydrate incident cases during two wells drilling in geographically separated areas. The first case was from a well located at 350m water depth on the USA West Coast, where the seafloor temperature was 7ºC. The second well was located in the Gulf of Mexico at 945m water depth and 4°C mudline temperature. In both cases, gas kicks were detected, which resulted in choke and kill lines blockage. In the second case, BOP issues arose due to ram obstruction.

Peavy and Cayias (1994) exhibited the project stages for three gas wells completions in deepwaters up to 640 m in the Gulf of Mexico. The temperature on the seafloor varied between 7ºC and 13ºC. Even with the project being implemented, there was a failure in a hydrate inhibition injection pump in one of the wells, which caused the hydrate formation at the wellhead.

Davalath and Barker (1995) reported a hydrate blockage formed within a formation test column in a well at 181m water depth, located in a South America offshore area, with a 7°C seabed temperature. During pulling out the downhole wireline pressure gauges, there was a blockage due to the crystal formation. In an attempt to pull the wireline, the cable was broken. A fishing assembly was set up to retrieve the wireline tools and it was also stuck due to other hydrates formed above the subsea BOP.

Reyna and Stewart (2001) described a case of 244m long hydrate plug formation inside a well testing column, used to perforate a well, in the seafloor region, when the temperature was -0.2°C. The well located in deepwater (838 m) on the UK Atlantic Margin, Shetland Islands West, was perforated using Tubing Conveyed Perforating (TCP) guns. During a well clean-up attempt, a production flow rate drop was identified. The authors assigned the fact to the poorly well cleaning during the flow black period.

Lage et al. (2002) presented the gas influx events during an exploratory drilling in the Espírito Santo basin - Brazil, at 1,286 m water depth. Several inflow events were detected which resulted in the choke and kill lines hydrate plugging, impairing well control procedures.

Barros Filho et al. (2004) faced a hydrate situation during a well formation evaluation, in the offshore Sergipe-Alagoas basin at 1,164 m water depth. After the test end, when the electric logging cable was pulling up from the well, it got stuck close to the subsea well-test tree (SSTT), due to the hydrate. It was found that the reverse circulation was also prevented and that the formation test column withdrawal under operational safety conditions could not be carried out.

Freitas et al. (2005) had problems with hydrates during a formation test carried out at 1,402 m water depth in the Espírito Santo basin - Brazil. During the drill stem test (DST), after pre-flow 11 h, it was noticed that the pressure was stabilizing and that the flow rate was reducing, indicating hydrate formation. To prevent this problem, they opted to run a coiled tubing (CT) for hydrate inhibitor injection at a high flow rate. The CT was lowered to a certain depth, but during its withdrawal, it became stuck due to a massive hydrate agglomeration, preventing its retrieval.

Arrieta et al. (2011) reported a case during a gas well testing operation located in Mexico at 1,735 m water depth, and approximately 4.2°C mudline temperature. A DST column was assembled with a packer and tubing-conveyed perforating (TCP) gun. The column was run into the hole, and after the packer was set, a CT injector was rigged up. The well was perforated without any problem and the injector was lowered into the well to perform jet lifting with nitrogen. After some time, diesel was also pumped through the tubing. When trying to pull the CT out of the hole, it was trapped by a massive hydrate plug at the mudline.

Assis et al. (2013) presented another hydrate blockage case within a column during a choked DST with very limited drawdown. This case was in Campos Basin - Brazil, at 2,788 m water depth. During the formation test, wellhead pressure and flow rate drop were observed, indicating a hydrate event. That plug was formed in the riser region, between the surface and the wellhead and it was 83 m long.

Hamid (2013) faced an issue with hydrates in Canada when carrying out a CT operation in a tight gas producer well, with high water cut. After the perforation of two intervals, isolated by a retrievable bridge plug, it was made a CT intervention operation, to pull out the bridge plug isolating the perforations set, and commingle production from both intervals. Hydrates trapped the CT when it was pulled out from the hole.

3. CASE ANALYSIS

For hydrate formation in drilling activities, the occurrence cases will be described and a hydrate prevention analysis will be carried out, by simulations using a phase behavior software of hydrate equilibrium, through thermodynamic equations of state. Regarding the hydrates occurrence during completion activities, formation testing, or well intervention, the cases will also be described and the main remediation techniques used in each one of them will be highlighted.

3.1 Drilling activities

In case 1 of Barker and Gomez (1989) the main causes for the hydrate formation that clogged the choke and kill lines were: i) seabed low temperature (7ºC); ii) gas influx from a 2,362 m depth sand; iii) high density of the kill mud (14.2 lbm/gal), which was pumped 3,100 psi surface pressure; iv) lack of sufficient hydrate inhibitors in the mud. To unplug the choke and kill lines, were applied pressure surges at the surface, but were unsuccessful. They had to make cementing operations to secure the wellbore and recover the BOP from the sea bottom to hydrate dissociation in the rig.

To analyze this case, it is necessary to understand the system operating pressure and temperature. To calculate the fluid hydrostatic pressure in the BOP region (P_{BOP}), Eq. (1) can be used.

$$P_{BOP} = 0.1704 * \rho_{mud} * WD + P_{SUR} \quad (1)$$

where P_{BOP} is the BOP pressure (psi), ρ_{mud} is the drilling fluid density (lbm/gal), WD is the water depth (m), and P_{SUR} is the surface pressure (psi).

For this case, the calculated operating pressure on the BOP was 3,946.9 psi. With the operational information, simulations might be performed by a phase behavior software (Multiflash, Version 7.1) using the van der Waals and Platteeuw model, combined with the Cubic-plus-Association equation of state with electrolytes, to evaluate different scenarios. However, it is worth mentioning that simulations were not performed with the drilling fluid complete composition, a simplified analysis was performed to try to get closer to what was reported in the field by the authors.

Figure 3 illustrates the methane hydrates equilibrium curves simulated with the aid of the software, for drilling fluid situations without the use of hydrate inhibitors and with the most common thermodynamic hydrate inhibitors (THIs): sodium chloride (NaCl), monoethylene glycol (MEG), triethylene glycol (TEG), and methanol. The glycerol effectiveness as a hydrate inhibitor was also tested, since it promotes other advantages for the drilling fluid, such as fluid weight increase, with fewer solids addition; avoids salts solubility and clays swelling; it is biodegradable; and possesses low toxicity level (Correa et al., 2017). The simulations were carried out considering a mass fraction of 5% of NaCl (concerning the water-based fluid mass), entering as a water-based drilling fluid constituent, since the salt is a weighting agent for the fluid and also prevents shales swelling, but a large amount of salt in the mud could affect its rheological properties (Caenn et al., 2011).

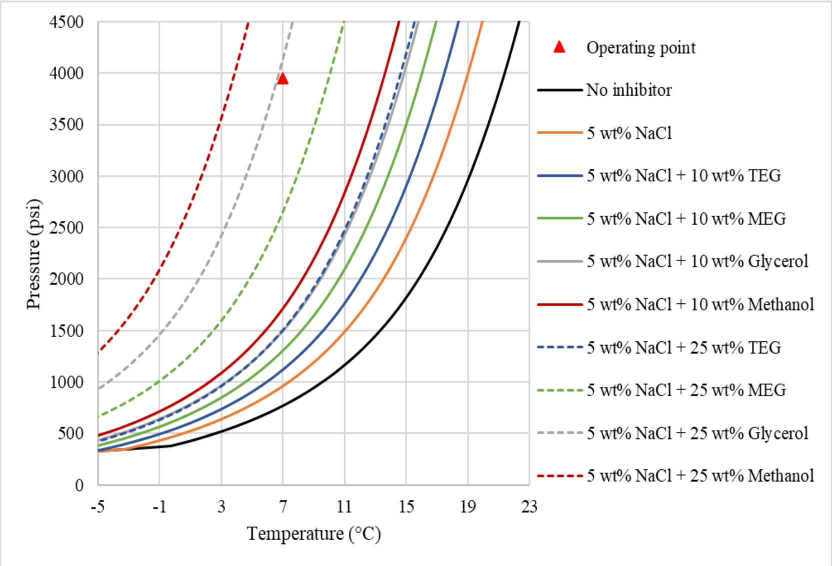

Figure 3. Barker and Gomez (1989): Case 1 - Simulated methane hydrates equilibrium curves in drilling fluids.

Inhibition by organic solvents, such as methanol, glycols, and glycerol, is attributed to the presence of the hydroxyl group (OH^-), which interrupts the activity of water via hydrogen bonding ability with water molecules. Salts are also induced by this behavior due to ions' presence, resulting from the Coulombic effect, in which positively charged particles (cations) and negatively charged particles (anions) overcome the hydrogen bonds present among water molecules. Increasing the THIs concentration implies a greater break between the hydrogen bonds of the water with the gas, which causes a shift to the left of the hydrate equilibrium curve (Lal and Nashed, 2019).

For the operational point to be outside the hydrate envelope, fluids containing 5 wt% NaCl + 25 wt% Methanol or 5 wt% NaCl + 25 wt% Glycerol were needed, according to the simulations performed. The liquid/gas simulated composition was 80 mol% of drilling fluid and 20 mol% of gas inside the well.

In case 2 of Barker and Gomez (1989), the causes were: i) low seabed temperature (4ºC); ii) gas kick occurred during drilling at 2,340 m; iii) lack of hydrate inhibitors in the drilling fluid. To unplug the choke and kill lines, there were applied pressure surges at the surface but were unsuccessful. Through neutron decay and unfocused density logging, hydrate evidence was obtained in the casing and drillstring annulus, below the BOP, and in the annulus between the riser and drillstring, above the BOP. To ensure the well safety, perforation and cement squeezing were carried out to isolate the open well from the cased well.

Then, a 2⅜'' tubing was run to circulate heated freshwater mud (43°C) in the drillstring/riser annulus, dissociating part of the hydrate from that region. To hydrate removal below the BOP, it was necessary to perforate the drillstring about 122 m above the annular gas/liquid contact and hot mud was circulated, through a CT lowered into the drillstring. Another three sets of shallower perforations were performed to dissociate all hydrate from the annulus. To remove the crystal at the BOP and the choke and kill lines, it was necessary to withdraw the BOP.

For this case, drilling fluid densities, surface pressures, or shut-in casing pressure (SICP) were not provided. Therefore, three different situations were analyzed: P_{BOP} = 2,500 psi, P_{BOP} = 3,500 psi and P_{BOP} = 4,500 psi, for some drilling fluid compositions without and with hydrate inhibitors. The formation gas composition sample was informed and used to simulate natural gas hydrates equilibrium curves (Tab. 1).

Table 1. Recovered gas composition during well control events reported in case 2 of Barker and Gomez (1989).

Component	**mol%**	**Component**	**mol%**
N	0.37	iC_4	0.73
CO_2	0.19	nC_4	0.69
C_1	86.73	iC_5	0.23
C_2	5.88	nC_5	0.20
C_3	3.60	C_{6+}	1.38

The simulations indicated that for each of the three situations analyzed, a larger inhibitor amount would be necessary to provide a total hydrate inhibition according to the operational needs, concerning case 1, due to the lower temperature and reasonable amounts of ethane and propane that favor hydrate formation.

In two of the three cases, P_{BOP} = 2,500 psi and P_{BOP} = 3,500 psi, a composition of 5 wt% NaCl + 50 wt% Glycerol would be sufficient to prevent hydrate development in the BOP region. While considering pressures up to 5,000 psi, the inhibition would be achieved with 5 wt% NaCl + 35 wt% Methanol in the drilling fluid or 5 wt% NaCl + 50 wt% MEG. These simulations were also performed considering the composition of 80 mol% of drilling fluid and 20 mol% of gas inside the well. Figure 4 shows the hydrate equilibrium curves for natural gas in situations without and with the use of some inhibitors and the operational points chosen for analysis.

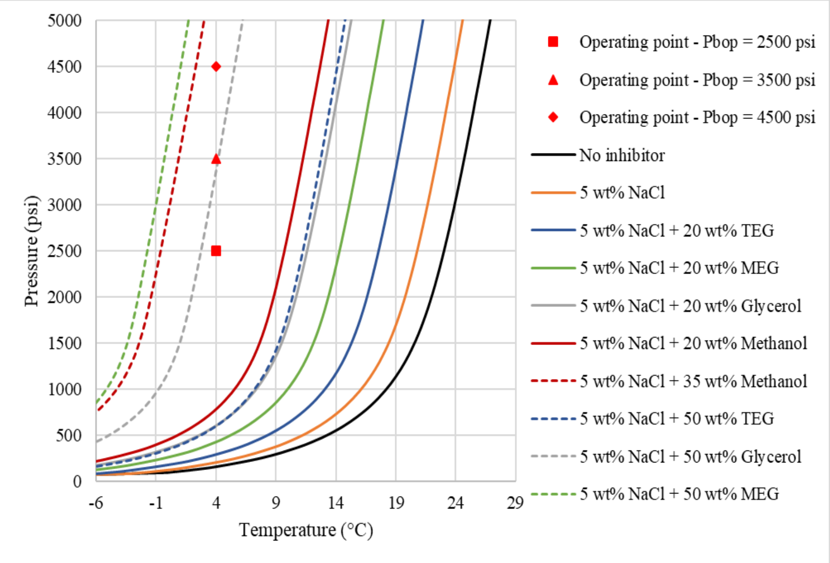

Figure 4. Barker and Gomez (1989): Case 2 - Simulated natural gas hydrates equilibrium curves in drilling fluids.

During the ESS-107 well drilling, reported by Lage et al. (2002), two inflow situations affected the activity. This well was drilled without any problems until the end of phase 12¼''. The 9⅝'' casing was set at 3,804 m and a formation integrity test was performed with a result of 13.8 lbm/gal. Phase 8 ½'' drilling started with an 11 lbm/gal water-based drilling fluid. At a depth of 4,719 m, already with an 11.3 lbm/gal mud, a sudden increase of 10 bbl in the mud tanks and a drop in pump pressure of 250 psi was noticed, indicating a gas kick. The well was closed and well control was initiated using the driller's method, increasing the fluid weight to 12.5 lbm/gal. However, a few days after the well control attempts, the kill line became clogged due to hydrate formation. To unblock it, it was necessary to increase the line pressure to 8,500 psi, in stages of 1,000 psi.

The second inflow occurred during drilling from 4,719 m to 4,826 m, coming from an overpressure sandstone reservoir, after increasing the fluid weight to 13.7 lbm/gal, both choke and kill lines were blocked by the presence of hydrate. Even with the pressure increasing in the lines to 9,000 psi, it was not possible to unblock them. Because it was no longer possible to circulate fluid in the well due to both choke and kill lines being blocked, a temporary well abandonment was planned by a cement plug set. After this operation, the BOP was removed from the seabed, and maintenance was carried out. The lines were unblocked, but no plugs were found, which is assumed that the obstruction cause was hydrate that was dissociated after the BOP removal from the seabed to the surface.

The main causes that were responsible for that issue during the drilling were: i) the seafloor low temperature in the region, of 4ºC (Bergmann, 2011); ii) two gas influxes caused by the swap-out process between the wellbore and the reservoir in 4,719 m – 4,789 m and an overpressure sandstone reservoir from 4,790 m to 4,826 m; iii) use of water-based drilling fluid without hydrate inhibitor or with insufficient hydrate inhibitor; iv) high hydrostatic pressure of the fluid due to its high weight to kill the influx (12.5 lbm/gal in the first well control and 13.7 lbm/gal in the second well control). Drilling was expected to be completed in 70 days during the planning phase. Due to the problems that arose, it was only completed in approximately 155 days, consequently, delaying 85 days.

Three situations of choke and kill lines hydrate occurrence were reported, in chronological order. Table 2 summarizes the drilling fluid properties and pressures that caused this problem. To calculate the pressure in the BOP region (P_{BOP}), an equation similar to Eq. (1) was used, but with the use of SICP instead of P_{SUR}.

Table 2. Pressures that caused hydrate formation in the BOP region for the events reported in Lage et al. (2002).

Situation	**SICP (psi)**	ρ_{mud} **(lbm/gal)**	P_{BOP} **(psi)**
(1)	250	12,5	2989,18
(2)	400	13,7	3402,14
(3)	200	13,7	3202,14

For a composition of 80 mol% of drilling fluid and 20 mol% of gas inside the well, Fig. 5 presents the methane hydrates equilibrium curves for drilling fluid formulations with some inhibitors. It was noticed that the addition of 5wt% NaCl + 25wt% MEG/Glycerol/TEG was not sufficient to stay out of the hydrate envelope. Formulations containing 5 wt% NaCl + 25 wt% Methanol, 5 wt% NaCl + 30 wt% Glycerol, 5 wt% NaCl + 35 wt% MEG or 5 wt% NaCl + 65 wt% TEG would be required in this case to provide the required inhibition under operating pressures and temperatures.

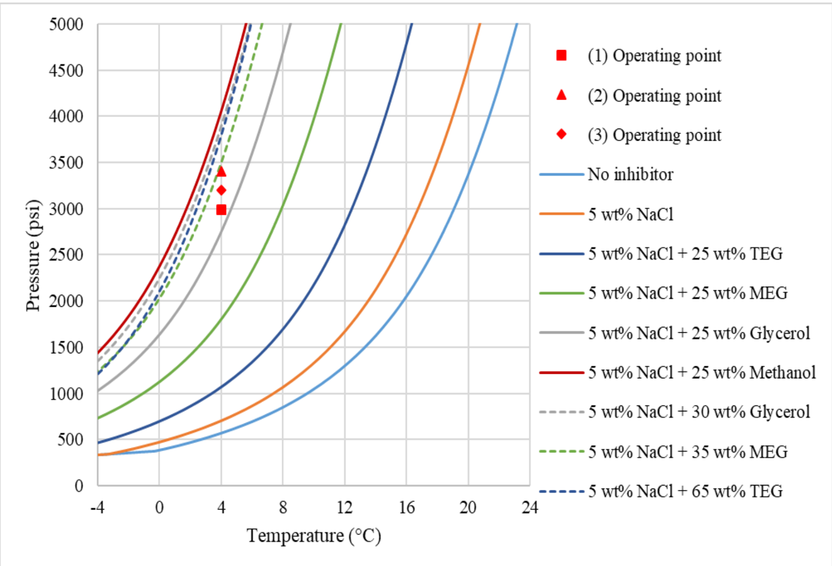

Figure 5. Lage et al. (2002) - Simulated methane hydrates equilibrium curves in drilling fluids.

Among the hydrate event cases in drilling activities, it was noted that water-based drilling fluids without inhibitors are favorable to hydrate formation in the offshore environment. It was recommended the use of phase behavior software to help with the best techniques that might be used to prevent the phenomenon. It was observed that methanol has the greatest potential to inhibit hydrates, but its use on platforms must be carried out with care, as it could form explosive atmospheres at low temperatures, for having low vapor pressure and flash point, it is highly flammable, requiring special storage tanks on offshore rigs and good planning for logistics and transport to avoid possible spills, and very toxic to humans if there is inhalation or contact (National Center for Biotechnology Information, 2022).

One of the alternatives that could be used is glycols, but the glycerol application showed better results, for the same percentage by mass, according to the phase behavior software used in both cases the simulations were performed considering only methane as the influx gas. The use of synthetic fluids is preferable in an environment favorable to hydrate formation, as they have the power to inhibit and minimize the problem.

Interesting work has been performed about hydrate management, in which hydrate crystals are allowed to form, but the apply of antiagglomerants prevents their particles from aggregating and they can be transported through a flowable hydrate slurry (Kakitani et al., 2019). That slurry formed in the drilling fluid could be considered a time-dependent elastoviscoplastic material with higher apparent viscosity, statically stronger than under dynamic conditions (lower yield stress) and with a more fragile structure, which reduces its yield strain (Mulhsted et al., 2021). However, new techniques and protocols for flow startup and steady flows of the hydrate slurries in water-based drilling fluids need to be studied.

After choke and kill lines hydrate clogging or hydrate development in BOP rams, preventing them from opening or closing, the hydrate removal is very difficult, as shown in the cases in this section, requiring the temporary well abandonment and BOP recovery to hydrate dissociation at the surface, resulting in lost time several days to perform this procedure.

3.2 Well completion activities

Wellhead hydrate formation, described by Peavy and Cayias (1994) was mainly due to the low temperatures in the mudline (7-13ºC). Another factor that caused this problem was the failure of an inhibitor injection pump during the activity. Non-productive time of 13 days was required to remove the gas hydrate. The project in the other two wells worked well, without hydrate presence. Three organic inhibitors were tested as hydrate inhibitors: methanol (but with limited use because of its flammability); MEG, which did not cause precipitate problems with the brines (calcium bromide and calcium chloride) used as the completion fluid; and isopropanol (IPA), used in all of the acid stages. These inhibitors were injected above the Subsea Test Tree, through injection lines that allowed a 4 gal/min flow rate.

For a good hydrate inhibition project during well completion some steps must be considered: a) one must know the operating pressure near the wellhead and produced fluids temperature history of the, using a transient simulation wellbore temperature program; b) calculation of hydrate equilibrium conditions, knowing the gas composition and water production rate, using phase behavior software; c) choosing the inhibitor type to be used and its required amount; d) pump selection for inhibitors injection, depth and lines diameter (two lines are generally chosen, one installed in the subsea tree and the other below the seafloor to mitigate the possibility of hydrate formation downhole); e) material type for lines (sufficient to withstand collapse and burst pressures), valves and accessories (with elastomeric seals compatible with the inhibitor type to be used); f) thermal insulation around the tubing string, reducing heat losses to the environment, near and above the seafloor; g) salt precipitation, since the presence of alcohols, such as methanol or MEG, generally decreases the most inorganic salts solubility in water, and these salts could be present in the formation water or in the completion fluids.

3.3 Formation test activities

In the case reported by Davalath and Barker (1995), even at a low 181 m water depth, the seafloor temperature at this location was 7°C. There was a lack of hydrate inhibitors during the production test. The water cut detected during the production of 15 h was 6%. After the shut-in period (it lasted 25 h), two problems occurred: i) in an attempt to recover downhole wireline pressure gauges, they were blocked by hydrates inside the tubing string, and when pulling the wireline, it broke; ii) to try to dissociate this hydrate near the surface, glycol was poured into the column and a fishing assembly was run in the tubing to retrieve the wireline tools, however, while pulling the fishing assembly out of the hole, it was trapped probably by hydrates formed above subsea BOP.

The following actions were taken to handle those problems: i) an attempt was made to hydrate dissociation by circulating heated seawater for several days, but the heat loss that occurred from the riser to the sea was extreme and did not allow the hydrates to dissociate; ii) increase in pressure up to 7,000 psi to try to break the hydrate and push it to the bottom of the well, but increasing pressure on the hydrate only makes it more stable, which did not work either; iii) coiled tubing string application stripped inside the tubing string and 79°C MEG circulation, which managed to dissociate the hydrate plugs. After those events, production test operations were able to continue, but more than 13 days were lost due to this issue.

During the cleanup period, in Reyna and Stewart (2001), the main reasons that led to the hydrate formation were: i) water production higher than expected (there was a water invasion from outside the production range due to poor primary cementation in the production liner); ii) the seafloor temperature was -0.2°C, and its rapid heat transfer caused the maximum flowing temperature recorded at the SSTT to be 7.8°C, much lower than expected (13.3°C – 18.3°C); iii) lack of sufficient hydrate inhibitor (estimates performed later indicated that the methanol injection rate should have been 5 times higher than the 1.5 L/min rate that was applied).

CT was applied to remove the hydrate from the string, circulating a fluid containing 25% BV glycol and 75% BV brine. This fluid was heated by applying a closed-loop system with a steam heater to temperatures ranging from 37.8ºC to 52.2°C on its return to the surface. Surface backpressure (1,000 psi) was also maintained to prevent damage to equipment as the hydrate dissociates and releases small pieces. The hydrate top was located at approximately 518.2 m and its jet washing took place at 673.9 m. At this depth, it was necessary to change the jetting BHA (Bottom Hole Assembly) for a milling one, since this was the most consolidated hydrate section. The hydrate base was located at 824.5 m. After those operations to remove the obstruction, it was possible to proceed with the formation test.

In Barros Filho et al. (2004), well conditioning was performed with 10.8 lbm/gal drilling fluid. The perforation was carried out in the production range from 3,674 m to 3,682 m and the well was equipped for formation testing. During the test, this well produced gas and condensate with 52º API, however, the water present in this fluid was not detected in the drilling rig, but it is believed that there could be a small water content. After the second static period, which lasted 12 hours, during the logging cable removal, it was arrested at 1,257 m, near the SSTT head.

The actions implemented to remove the hydrate plug were: i) to relieve the pressure above the plug (to take it out of the hydrate envelope), the fluid was replaced for nitrogen; ii) logging cable tensioning and n-paraffin circulation with CT, jetting the hydrate; iii) drilling fluid circulation through the booster line above the BOP, and methanol and butyl glycol injection through the chemical line.

In Freitas et al. (2005), two formation tests would be carried out in the well, at two different intervals, and an injectivity test. The first formation test and the injectivity test went without any problems. In the second formation test, more water was produced than expected and the cleaning was not effective, even with ethanol injection at a 220 L/h flow rate. After a pre-flow of 11 hours, the pressure was stabilizing and reducing the fluid flow that was being produced, indicating hydrate formation. To increase the ethanol injection flow rate, as SSTT limited this injection to 300 L/h, it was decided to run a CT in the well. The CT was positioned at 1,360 m, finding resistance between 1,087 m and 1,294 m and the total ethanol injection rate reached 650 L/h. This circulation took place for a few hours, with no blockage sign, but the flow had to be interrupted due to a leak in the CT near the injector.

It took 29h for repair and the CT was repositioned to 1,742 m, resuming the ethanol flow. After 50 min, the pressure began to drop and it was decided to remove the CT from the well. The tube became stuck when it reached 1,607 m, due to the hydrate formation between the annulus of the test string and the CT. The first strategy to combat this issue was based on thermal methods. Hydrate simulation software was used and for the 1,885.5 psi operating pressure, the hydrate dissociation temperature was 20°C.

The following actions were taken: i) hot fluid injection (50°C) at 2,300 psi pressure on the surface and 0.4 bbl/min flowrate for two days and 30,000 lb over pull application, without success; ii) temperature increase from 50°C to 70°C and circulation for three days, without result; iii) reactant fluids use: $NaNO_2$ (sodium nitrite) and NH_4Cl (ammonium chloride), to try to increase the temperature to 140°C in two attempts of 30 minutes each, without success; iv) annulus depressurization, using a chemical cutter to cut the CT approximately 50 m above the hydrate top. Then nitrogen was injected to completely remove the completion fluid. After a depressurization of approximately 19 h, the hydrate began to dissociate.

In Arrieta et al. (2011), the main reasons that led to hydrate formation were: i) diesel and brine mixture apply as a cushion before the TCP, which increased the hydrostatic pressure; ii) there was liquid segregation/accumulation during the cleanup period, due to the restricted flow rate; iii) water production greater than anticipated during the cleanup period, made the glycol injection insufficient for hydrate inhibition; iv) the CT restricted the flow area and increased the hydrostatic pressure.

The actions taken to remove the hydrate plug and its consequences were: i) tension applied to the CT top up to 32,000 lbf and 7,360 psi: did not work; ii) kill the well by pressurizing the annulus to 4,100 psi to open the rupture disk (RD) valve (RD was set to 4,000 psi): RD valve could no longer be closed; iii) brine injection 77 bbl, 1.27 g/cm^3 with 10% glycol at 110°F (43.3ºC) through the CT: partially dissociated the hydrate near the CT wall; iv) hot brine injection with 10% glycol at 2,000 and 6,500 psi: ineffective; v) CT perforation with explosives to define the hydrate plug top by using reverse circulation: the hydrate top was found below 750 m; vi) glycol displacement 15 bbl: unsuccessful attempt; vii) nitrogen circulation to relieve hydrostatic pressure above the hydrate top: after 4h, the hydrate started to dissociate and the gas burned at the flare; viii) 35,000 lbf steady application of tension on the CT; ix) nitrogen injection processes through reverse circulation and tension application: after 11 days, there was a partial CT movement; x) the CT was perforated at 875 m: more hydrate dissociated and burned; xi) CT perforation at 1,780 m, below the hydrate plug: trapped gas found and injected into formation by bullhead; xii) 1,400 psi pressure applied to the annulus: upward force generated on the CT that helped in its release with drag 6,000 lbf.

After those operations, the entire CT was recovered. There was also retrievable packer release and the coiled-tubing lift-frame injector was laid down. It was possible to change the well fluid. The string was removed until 2,645 m, but gas was still present due to hydrate dissociation. The CT and lift frame were reinstalled to remove this remaining hydrate. The CT was run in the hole with a 2.3'' bit, a 1-11/16'' mud motor, and a 1.37 synthetic drilling fluid. With no further gas problems in the well, the DST could be pulled out.

In Assis et al. (2013), to solve the hydrate problem within the DST string, the CT Company proposed to the Operator a high-pressure rotating nozzle (HPRN) application, together with the CT and an oil-based mixture combined with a hydrate inhibitor. The main advantages of applying HPRN are the possibility of cleaning the entire well (360º), jetting control, rate of penetration (ROP) control, and nonmetal cutting or gridding action, resulting in minimal damage to completion installations. To optimize the jetting head and nozzle selection performance, according to the well conditions and surface pressure limitations, jetting hydraulics modeling was performed. The CT equipped with the HPRN was run in the well using a MEG/oil-based fluid composition, 25/75 by volume. The hydrate top was located at 1,715 m and with an average 68.5 ft/h ROP it was possible to remove the hydrate in 4 h at 0.8 to 0.9 bbl/min fluid pump rate (its base was located at 1,798 m). The total intervention time was 86 h (approximately 3.5 days), including rig up, operations, and rig down.

It is observed that when there was hydrate formation inside string during formation testing, the most effective ways to remove were the application of the special column using CT for jetting or milling the hydrate, combined with fluids containing hydrate inhibitors. The most critical cases analyzed were hydrate blockages that trapped the CT or logging cable. For those situations, the most effective techniques are the attempt to locate the hydrate top through perforations and reverse circulation. Once this point is located, depressurization using nitrogen for hydrate dissociation is recommended. Washing the hydrate top employing a hot fluid is ineffective, since the heat loss that the fluid will have along the riser until it reaches the hydrate top is very high, due to the low temperatures reached by seawater. In addition, pressure increases most of the time are also inefficient as they make the plug even more stable.

3.4 Well-intervention activities

In Hamid (2013), the wellbore was a tight gas producer with high water cut, S-shaped deviated, completed with 5½'' production casing and casing shoe at 3,440 m. A retrievable bridge plug set at 3,000 m isolated the two perforated zones. The intervention operation consisted of bridge plug recovery through a CT. When the CT was run in the hole, a first plug hydrate was found at 358 m and dissolved with methanol pumping for 60 min. The bridge plug top was reached at 3,000 m and started to be pulled out. Close to the surface, the CT was stuck several times and after pulling and slacking attempts it was released in 90 min, however, several column components were defective: the overshot cracked, the CT pipe had a permanent deformation in a helical profile, and its portion above the coil connector was bent and parted. The further analysis performed defined that the excessive over pull activated the jarring assembly, this upward jarring force coupled with the hydrate plug applied upward acting compressive force, approximately three times greater than the catastrophic buckling limit (CBL), which caused this catastrophic bending of the tube.

4. CONCLUSIONS

There are several cases in the industry where there was hydrate formation in different oil and gas wells exploitation phases. In drilling, it is important to act preventively, through hydrate inhibitors application when working with water-based drilling fluids. Synthetic-based fluids are also recommended, as they minimize this type of problem.

It is advised the use of software that provide hydrate equilibrium curves, based on certain known information, such as the composition of the gas and the drilling fluid, for better support of the techniques to be used for prevention. Currently, the most effective inhibitor is methanol, but its flammability risk, especially in offshore drilling rigs, and its toxicity level mean that new alternatives are sought for use. As with other alternatives, other alcohols could be applied, such as glycols and glycerol. According to the simulations performed, glycerol showed better inhibition results.

The following aspects should be taken into account in a hydrate inhibition project during well completion: tubing string operating pressure and temperature knowledge; hydrate equilibrium conditions for the produced gas composition; inhibitor type and amount to be applied; injection depth; flow capacity and injection lines material; pipe insulation; and salt precipitation.

For hydrate removal within a formation test column it is recommended to apply special columns using CT for jetting or milling the plug, combined with fluids containing hydrate inhibitors. If CT or logging cable is trapped due to hydrate blockage, the hydrate top must be located through perforations and reverse circulation. Then, depressurized by nitrogen injection. Over-pull attempts are not recommended, as they could cause equipment physical integrity loss.

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