

Potency of starch in hydrate inhibition in a field within Gulf of Guinea Using Aspen Hysys

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Abstract

Hydrocarbon industry is now moving from onshore to offshore environments in search of black gold, since the world's energy demand is growing astronomically. Exploitation of this black gold in an offshore environment is quite very capital intensive but not exonerated from flow assurance and intervention challenges. This is due to the fact that the black gold is produced alongside with BSW, associated gas, without which the black gold will be termed dead oil; also, there is restricted accessibility in an offshore environment. The result of hydrate formation includes blockage of flow lines, plaguing downstream equipment and flow line's appurtenances such as Valves, Tees, Elbows. The current methods of preventing hydrate formation by the industry are highly limited and the chemicals used are harsh to the ecosystem. This study investigated the potency of Starch from *Manihot Esculenta* in hydrate inhibition using Aspen Hysys V11.0. The performances of considered hydrate inhibitors in a modeled flow line system with diameter 355.6mm, length of 12.095 km in deep water hydrocarbon field within the Gulf of Guinea, were based on actual condition and production data. The simulation results at 40% and 80% water cuts were plotted for both steady state and dynamic state using Mat lab. At steady state, simulation results disclosed that there will be no hydrate formation. However, at dynamic state, simulation results disclosed that hydrates will form. HCF's pressure declines from 61bar to 40.52bar, 32.43bar respectively, for the different water cuts, in induction time of 240 minutes. Likewise, HCF's temperature declined suddenly and sharply rose again indicating hydrate formations. Starch at 0.05, 0.1, 0.15, 0.2 mole fractions prevented hydrates from forming but best at 0.2 mole fractions. Starch was therefore, recommended for field-pilot test and further developed, utilized as an ecofriendly hydrate inhibitor.

Keywords: Black gold (Hydrocarbon); Starch; *Manihot Esculenta*; Basic Sand Water (BSW); Hydrocarbon Fluid (HCF)

1. Introduction

Natural gas hydrates are crystalline, ice-like substances formed at low temperatures and high pressures when low molecular weight hydrocarbon (gases) comes in contact with water molecules [1]. Gas hydrate formation and agglomeration is an unwanted process in the Oil and Gas industry, be it at the upstream, midstream and even downstream. This is because; gas hydrate plugs flow lines, undermines the integrity of downstream equipment, causes significant downtime and operational expenditures (OPEX), jeopardizes the safety of personnel on board or within the milieu, and in some cases, results to enormous environmental degradation [4]. The control, prevention or moreover, the management of hydrate is of paramount importance and critical issue in flow assurance in every Oil and Gas business, most especially in the deep and ultra-deep water projects. Deep water and ultra-deep water flow lines are very susceptible to hydrate formation due to its cold and high pressured environment. Gas hydrate are non-stoichiometric ice-like solid compounds which are realized when the molecules of water get themselves attached by

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hydrogen bonding, forming cavities that are occupied by guest molecules which are either hydrocarbon gases (e.g Methane, Ethane, Propane e.t.c) and/or non-hydrocarbon gases (e.g Carbon dioxide, Hydrogen Sulphide, Nitrogen e.t.c) [1]. The cavities are spherical but irregular, containing at least a guest molecule trapped within it by repulsive force. Therefore, the guest molecule(s) stabilizes the structure of the cavities, nevertheless spectrometry reveals that it is not steadfastly attached but allowed to rotate within the cavity [1, 6].

Gas hydrate formation incorporates four different stages and they are; gas-liquid mass transfer, nucleation, crystal growth and agglomeration [11]. Three types of hydrates, known as type I, type II and type H. They are also termed structure I, structure II, and structure H. The difference among them lies on the composition of the guest molecules. Structure I is composed of any of these; Methane, Ethane, Hydrogen Sulphide (H₂S), Carbon dioxide (CO₂) as guest molecule. Structure II is composed of any of these; Propane, Butane, Isobutane, Nitrogen. Structure H is striking to researchers in its composition. This is because, it is composed of more than one guest molecule, without which it will not form. The guest molecules for structure H are not limited to 2-methylbutane; 2,2-dimethylbutane; 2,2-dimethylpentane; 3,3-dimethylpentane; 2,3-dimethylbutane; 2,2,3-trimethylbutane; Methylcyclopentane, Ethylcyclopentane; Methylcyclohexane; Cycloheptane, Cyclooctane. Most of these guest molecule compositions for structure H, are rarely found in natural gas [1]. It is therefore, safer to state that most analysis do not test for hydrates whose guest molecules are that of structure H.

Flow assurance challenges in the production, handling and transport of hydrocarbons, more especially natural gas fluids are not limited to hydrates alone. There are also; Asphaltene, Paraffin and Wax depositions but hydrates poses the major concern and costs the industry the most to prevent, manage [3, 19]. Nevertheless, despite the nostalgia attached to gas hydrate as a threat to flow assurance in the Oil and Gas conventional industry, gas hydrates also offers uncountable potential benefits. These benefits lies on carbon capture and sequestration; non-conventional natural gas exploitation such as Coal-bed Methane; water desalination and seperation of undesirable (toxic or incombustible) species from biogases [9, 12, 14, 20, 27].

The prevention of gas hydrates is achievable by the removal of free water in the gas stream; heating; depressurization of the system and chemical injection. The injection of chemicals comprises of thermodynamic inhibitors (THIs) and low dosage hydrate inhibitors (LDHIs). Preventing gas hydrate by removal of water is achieved by the adsorption of water onto Silica gel, hygroscopic salts or alcohol, glycol, subsea seperation. The use of glycol is limited due to its significantly less effectiveness under very cold conditions, especially below -40F. At this temperature (-40F), if the removal of water is exceedingly required, molecular sieves, solid dessicants are preferable, but they are quite exorbitant to implement [18]. Heating is limited by the amount of power generated on the floating platform.

The injection of chemicals is termed to be economically more feasible, especially in deep and ultra-deep offshore environment, because of the environments' peculiar nature which is not limited to restricted accessibility. Two broad chemical methods are in existence to prevent, control or manage gas hydrate. They are; thermodynamic (THIs) and low dosage hydrate inhibitors (LDHIs) [28]. Thermodynamic hydrate inhibitors prevent the formation of hydrates by the effects of its inherent anti-freeze agents to the hydrocarbon fluid stream. The utilization of the thermodynamic inhibitors in order to achieve hydrate formation inhibition are at enormous concentrations (10-60 wt.%). Their efficacy can be best described, that it alters potential of aqueous or hydrate phase, in such a way that the hydrate dissociation curve is displaced to lower temperatures or higher pressures. Methanol, Mono-ethylene glycol (MEG), Di ethylene glycol (DEG), Ethanol are examples of thermodynamic inhibitors. The low dosage hydrate inhibitors are of different types, namely; Kinetic and Anti-Agglomerants (AA) hydrate inhibitors. The LDHIs are added at low concentrations, therefore the reason for her name [28]. Kinetic hydrate inhibitors (KHIs) act by delaying the onset of the nucleation and growth of hydrates. Its examples include Poly Vinyl Pyrrolidone (PVP), Poly Vinyl Caprolactum (PV Cap), Poly ethyleneoxide (PEO), Poly (N-Vinyl Caprolactum), Poly (N-Vinyl acetamide) (VIMA), Poly (N-Vinylalrolactum) (PV Vam), and Poly (acryoylprrolidone) (PAPYD). The evaluation of the kinetics of KHIs is quite problematic and herculean [21, 24]. This is because of the dynamics and complexity of its evaluation process [15]. Anti-Agglomerants (AA) are surface acting chemicals which modify the crystals of hydrate, therefore preventing the agglomeration of hydrates. An example of AAs is Berol 26 [18, 28].

Imidazolium based ionic liquids have been subjected to tests as gas hydrate inhibitors and have been found to be also, very efficient when used alongside KHIs and THIs. The ionic liquids are also found to be dual functional in nature [5]. Ionic liquids are molten state salt which has the ability of exhibiting electrostatic interactions, forming hydrogen bond with molecules of water, therefore enhancing their crystalline surface adsorption capacity, concomitantly the hydrate nucleation process [5]. The utilization of high pressured cell such as Autoclaves and Rocking cells for the evaluation of Pyrrolidinium and Morpholinium based ionic liquids of which includes N-hydroxyethyl-N-methyl pyrrolidinium tetrafluoroborate ([HEMP][BF₄]), N-butyl-N—methyl pyrrolidinium bromide ([BMP][Br]), N-hydroxyethyl-N-methyl

pyrrolidinium chloride ([HEMP][Cl]) and a host of others has been extensively undertaken [22]. It was discovered that the time for hydrate nucleation was quite delayed by the ionic liquids, better than the Poly Vinyl Pyrrolidone (PVP). The effectiveness of the ionic liquids is greatly affected by the cation and anion present in them [16]. Comparison of ionic inhibitors; Potassium chloride, Calcium chloride, Sodium chloride salts and thermodynamic inhibitors; methanol and mono-ethylene glycol combination on inhibition of gas hydrate was undertaken through depression of temperature using Hammerschmidt and Ostegard equations [17]. The dosage of THI was observed to reduce by a significant amount of 34%. Odotola et al. (2014) [17], concluded that this approach will drastically reduce the volume/concentration of Methanol and Glycol usage based on water salinity. Synthetic based gas hydrate inhibitors were utilized in all these studies. These synthetic gas hydrate inhibitors, though have been proven and deemed effective, pose environmental concern and or health risks to human, terrestrial and aquatic lives. There is, therefore, an unquantifiable need for the use of local materials that are readily available in the environment and which poses less or no threat to the ecosystem. This has triggered insatiable researches to meet the need for a better and safer environment [5, 18].

Guodong et al. (2018) [7], undertook an experimental study on hydrate anti-agglomeration in the presence of Rhamnolipid. The study was carried out using Autoclave at constant high pressure of 10MPa, different water-cuts and mass fractions of Rhamnolipid. The torque measurements from the experimental results disclosed that Rhamnolipid prevented the agglomeration of hydrates at all concentrations used, especially at 0.5wt%. It was seen from visual inspection of the hydrates formed in the course of the experimental runs that Rhamnolipid could make the surface of the hydrate smooth. Carlos et al (2018) [2], undertook experiments to investigate the effectiveness of a non-synthetic substance termed KHI 530 in hydrate inhibition. The experiments were ran using Rocking cells and the experimental results revealed that KHI 530 at concentrations > 1.0 wt% can protect against hydrate formation for 48hours in a subcooling of 6-7oC. The experimental results also revealed that the performance of KHI 530 was quite satisfactory as that of Poly (N-Vinylpyrrolidone). The experimental results of blends of KHI 530 and MEG at various ratios disclosed that KHI 530 is a good additive to MEG, reducing the amount of MEG needed.

Saikia et al. (2018) [23], undertook an experimental study to evaluate Soy Lecithin as an eco-friendly bio-surfactant clathrate hydrate anti-agglomerant additive. The performances of Soy Lecithin were compared with that of Cetyltrimethylammonium bromide (CTAB) and the experimental results disclosed that Soy Lecithin's performance was very satisfactory. 0.001 wt%, 0.1 wt% of Soy Lecithin increased the time for hydrate crystals agglomeration by 1000 min and 1440 min, respectively. Soy Lecithin's effect on the rheology and filtration properties of drilling fluid was studied by Siakia et al [23]. The experimental results disclosed that at a temperature of 1°C, the highest concentration (1.0 wt%) of Soy Lecithin considered, still had the drilling fluid's rheology and filtration properties within permissible limits. Okon et al. (2018) [18], undertook an experiment using a mini flowloop to study the effectiveness of a locally formulated inhibitor from agro waste based starch in gas hydrate inhibition. The performances of the locally formulated hydrate inhibitor was compared to those of N-Vinyl Caprolactam (N-VCap) and 2-(Dimethylamino) ethylmethacrylate (2-DMEM) at different concentrations of 0.01, 0.02 and 0.03 wt%. The experimental results on pressure-time, temperature-time plots disclosed that the locally formulated inhibitor had pretty satisfactory performance compared to the other hydrate inhibitors considered.

There are different tools utilized in the experimental study of hydrate, which includes: Rocking cell apparatus, Autoclaves, Wheel loop and Flow loop [3]. However, studies on hydrates could be carried out using softwares such as Equi-phase, PVTsim, OLGA, Multiflash, CSMHYD, CSMGEM, Promax, VGMSim, Aspen Hysys, to list but a few [1].

Studies in hydrate management or prevention along subsea flowlines have been widely carried out. The efficacy of various inhibitors of hydrates ranging, ranging from Thermodynamic inhibitors (THIs) to Low Dosage Hydrate Inhibitors (LDHIs) have been extensively investigated. Nevertheless, green hydrate inhibitors such as Starch from Manihot Esculenta deduced in the tropics has not been studied for hydrate inhibition, considering hydrocarbon produced from the Gulf of Guinea. Starch from Manihot Esculenta are non-synthetic, biodegradable and eco-friendly, therefore eliminating the threats that the synthetic hydrate inhibitors poses to the ecosystem. This work is therefore tailored to the investigation of Starch from Manihot Esculenta in hydrate inhibition using Aspen Hysys (V11.0) and hydrocarbon field data from Gulf of Guinea.

2. Methodology

A model of the subsea flow line conveying reservoir fluids from wellhead to FPSO was created using Aspen Hysys process simulator. In creating the model, data of a hydrocarbon field within the Gulf of Guinea was utilized. The data did not exclude: pressure and temperature of the hydrocarbon fluid, bathymetry, flow line's diameter and roughness, flowline's conductivity and heat transfer coefficient, subsea's ambient temperature (4°C). Below are tables containing

parameters obtained from the operator of a hydrocarbon field in the Gulf of Guinea. However, due to the Operator's strict policies, her anonymity will be respected in this study.

Table 1 Fluid Compositions and their mole fractions.

Components	South Loop (% mole)	Molecular Weight (MW)
N ₂	0.01	28.01
CO ₂	1.08	44.01
C ₁	44.90	16.04
C ₂	5.63	30.07
C ₃	5.93	44.10
IC ₄	3.29	58.12
NC ₄	4.33	58.12
IC ₅	3.69	72.15
NC ₅	3.26	72.15
C ₆	5.36	85.11
C ₇	6.00	98.40
C ₈	5.89	111.74
C ₉	5.53	125.19
C ₁₀	5.07	137.83
CN ₁	0.00	191.00
CN ₂	0.00	320.00
CN ₃	0.00	475.00

Table 2 The production flowline's data and it's a pipe-in-pipe.

Inner Pipe			Outer Pipe						
Inner Diameter (ID)	Wall Thickness (WT)	Outer Diameter (OD)	Total gap	Insulation thickness (Izoflex)	Air gap	Inner Diameter (ID)	Wall Thickness (WT)	Outer Diameter (OD)	Anti-corrosion coating thickness
Mm	Mm	mm	Mm	mm	mm	Mm	mm	mm	mm
254	22.2	298.4	13.8	5.5	8.3	327	14.3	355.6	3.2
Internal roughness = 50 microns									

Table 3 Length of the production flowline and its bathymetry

Length (Km)	Water depth (m)
0.000	-955
1.587	-940
2.978	-935
5.017	-950
6.687	-948
7.421	-932
8.540	-932
9.374	-959
10.312	-910
10.868	-900
12.095	-1060

Table 4 Operating data for Production South loop (max profile), year 0.5

Well	Oil rate (Stb/d)	Gas rate (MMS cfd)	Water (Stb/d)	GOR (Scf/Stb)	Water cut (%)	WHFP (bara)	WHFT (°C)
1	14615	15.8	1	1080	0.0	104	112
2	8492	4.2	6	496	0.1	91	66
3	22434	12.6	0	563	0.0	96	65
4	11937	12.6	136	1058	1.1	93	80
5	17487	8.4	2	482	0.0	93	66
6	0	0.0	0	-	-	-	61
7	12900	7.4	2	571	0.0	93	68
Total		61.1	147				

Table 5 Additional data from South loops

Parameters	Values
Production life so far	8 yrs
GOR (sm ³ /sm ³)	101.5
Oil rate (bopd)	8855
Water cut/ rate (%/bwpd)	61.5/14145
Gas Lift Rate (MMScfd)	22
Total Liquid Rate (blpd)	23000
Inlet Temp. (far end FLET) (°C)	46
Inlet Temp. (Gas Lift at FPSO) (°C)	25
Arrival Pressure (FPSO BL) (Bara)	20

Table 6 Properties of the stabilized crude oil for export

Parameters	Values
Maximum oil density	870kg/m ³
Minimum oil density	840kg/m ³
Oil viscosity at export temperature of 35°C	13cP
Fluid's pressure at flowline's outlet for Well 1 in South loop	61bar
Fluid's temperature at flowline's outlet for Well 1 in South loop	87°C
Arrival Pressure (FPSO BL)	20bar

Figure 1 discloses the model of the subsea flow line created using Aspen Hysys process simulator. Water and hydrocarbon fluid are the feed at a pressure of 290.3bar and temperature of 254°C. The feed was meant to flow through the Mixer (Hydrocarbon-Water Mixer) for the purpose of commingling the two fluids, mimicking the real life scenario. Water as feed was created separately in order to make it easy, varying the water cuts. The commingled fluid termed

Mixed1 passed through an intercooler, which concomitantly reduced the temperature and pressure of the hydrocarbon fluid (HCF).

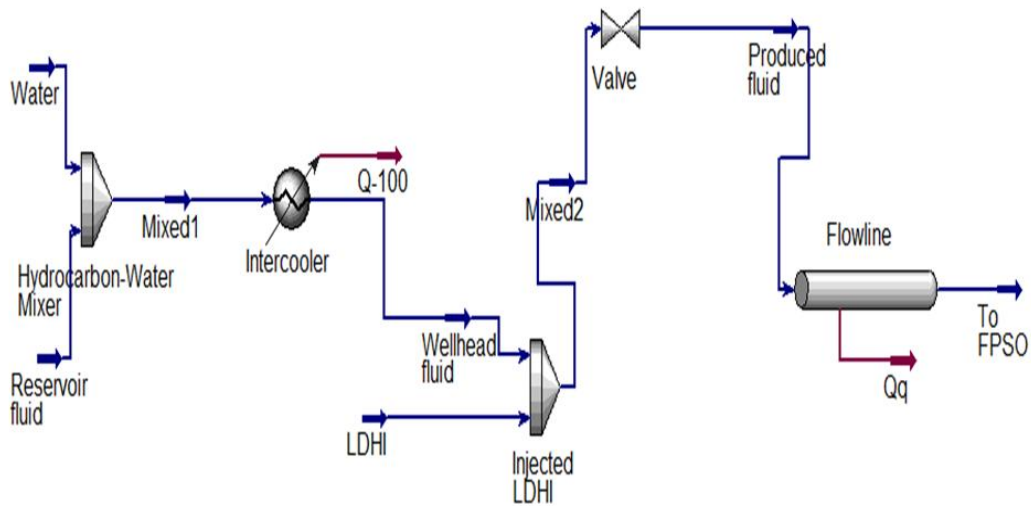


Figure 1 Aspen Hysys Model of the Flowline at Steady State

At the second Mixer (Injected LDHI), the fluid stream from the intercooler had its name changed to Wellhead fluid for easy identification. The second Mixer made it possible for the hydrate inhibitor under consideration (Starch) to be injected into the Wellhead fluid, then it commingles both fluids into one. The commingled fluid from the second Mixer termed Mixed2 passed through the Valve. This was so, in order to create Joule-Thompson's effect, further reducing the fluid stream's temperature and pressure by virtue of it passing through a constriction. As Mixed 2 passed through the Valve, it had its name changed again to produce fluid. The produced fluid stream then passed through the subsea flow line to the FPSO. The produced fluid stream's pressure and temperature were same as the Well in Table 4, below. The model created using Aspen Hysys was simulated in both steady and dynamic states, respectively. The simulation results were plotted using Matlab and analysed.

3. Results and discussion

The simulation results of the model at steady state were analyzed on different plots of Hydrocarbon fluid's temperature, pressure against flow line length for both the uninhibited system and the inhibited system. The uninhibited system means that there was no hydrate inhibitor (Starch) injected into the system, while the inhibited system means that the hydrate inhibitor was injected into the system.

It was observed that simulation results were same for both water cuts considered (40% and 80%). The plot of hydrocarbon fluid's pressure against flow line's length contained in Figure 2, disclosed that there was pressure decline in the flow line. The HCF's pressure decline was seemingly gradual in the flow line up to a length of 8095m, but became steep from 8895m to 12095m of the flow line's length. However, the HCF's pressure profile in the flow line is seen to be same with both the inhibited system and the uninhibited system. The reason for the HCF's pressure decline along the flow line is not far-fetched. It could be as a result of the HCF's friction with the internal wall of the flow line and/or HCF's viscosity.

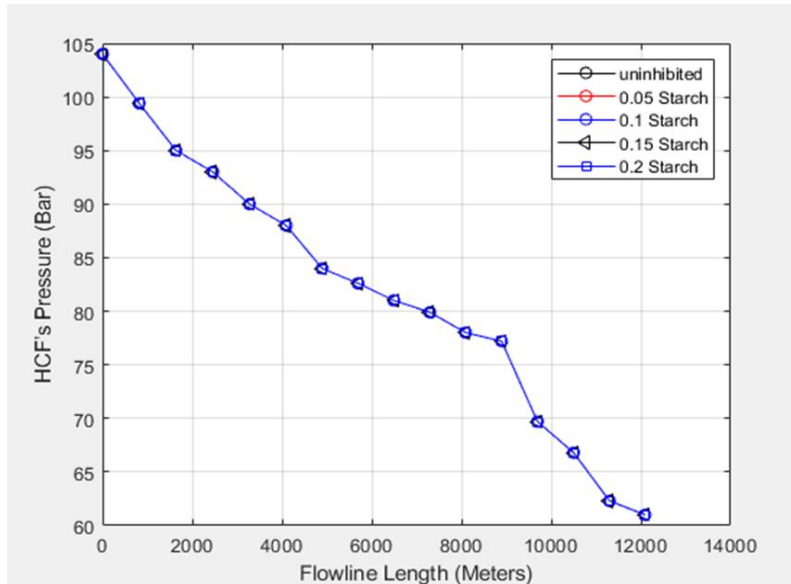


Figure 2 Hydrocarbon Fluid's Pressure (Bar) versus Flow line length (Meters) for Uninhibited System and Different Starch Concentrations at Steady State

The plot of Hydrocarbon fluid's temperature (Celsius) against flow line's length (Meters) for uninhibited system and inhibited system using Starch at different concentrations is disclosed in Figure 3. HCF's temperature is seen to reduce from 112°C to 87°C along the flow line, very gradually. It is seen from Figure 3 that the HCF's temperature profile was same for both the inhibited and uninhibited system. Nevertheless, the hydrocarbon fluid's temperature though declined but was still above the hydrate formation temperature of the system. This entails that with or without hydrate inhibitor, the system has no risk of hydrate formation.

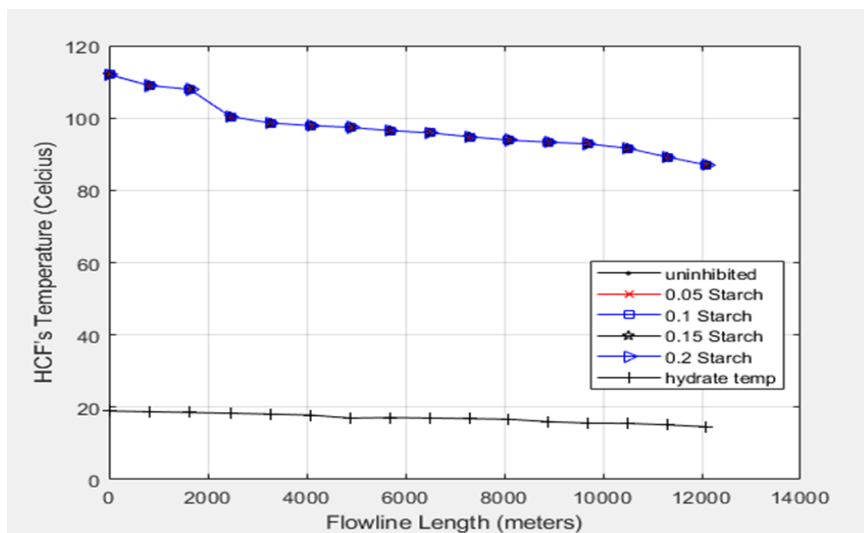


Figure 3 Hydrocarbon Fluid's Temperature (Celsius) versus Flow line's length (Meters) for Uninhibited System and Different Starch Concentrations under Steady State

Switching the simulator from steady state to dynamic state, a prompt for some adjustments popped-up in the computer. The prompt disclosed that the pressures at the Hydrocarbon-Water Mixer and that of Injected LDHI on the model be equalized. The prompt also disclosed that Valves be attached for the feed (Water and Reservoir fluid). All that the prompt demanded of as prerequisites for the dynamic state simulation of the model, were done. A pictorial rendition of the model in dynamic state simulation is seen in Figure 4.

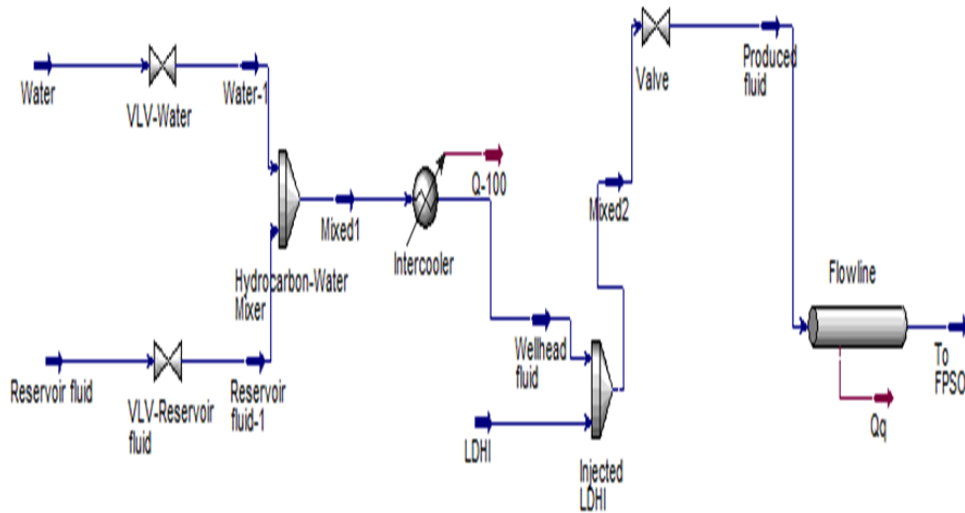


Figure 4 Aspen Hysys Model of the Flow line at Dynamic State

Figure 5, discloses the hydrocarbon fluid's pressure (Bar) against Induction time (minutes) for the uninhibited system and inhibited system (0.05, 0.1, 0.15, 0.2 mole fractions of Starch) at 40% water cut in dynamic state. It is seen in Figure 5, that in the uninhibited system, hydrocarbon fluid's pressure readily declined from 61bar to 40.52bar in 240 minutes of induction time. All the concentrations of Starch used in the inhibited system, were seen to hinder the hydrocarbon fluid's pressure drop as observed in the uninhibited system. However, it is seen from Figure 5, that the higher the concentration of Starch in the system, the better it prevents the hydrocarbon fluid's pressure drop. The hydrocarbon fluid's pressure decline observed in the uninhibited system in Figure 5, discloses that gases are encapsulated by water in the multiphase produced fluid stream heading to the FPSO [18]. In other words, there was formation of hydrates. The introduction of Starch, having prevented the drop of hydrocarbon fluid's pressure, therefore, did inhibit hydrate formations in the system.

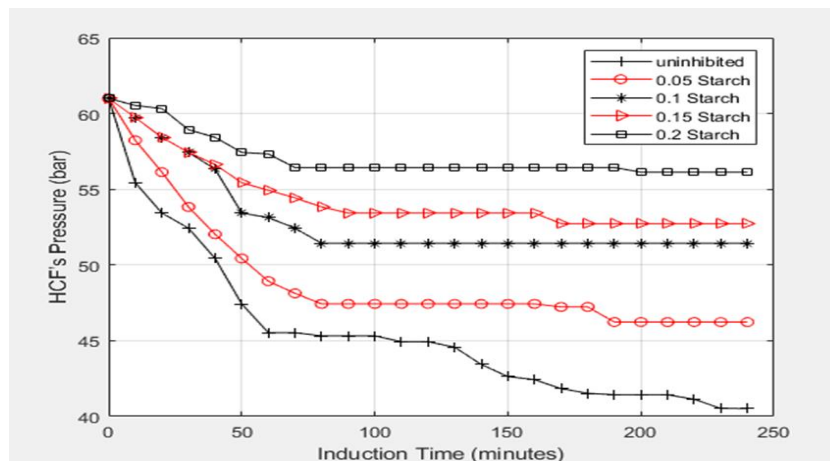


Figure 5 Hydrocarbon Fluid's Pressure (Bar) versus Induction Time (Minutes) for Uninhibited System and Different Starch Concentrations at 40% Water Cut in Dynamic State

Figure 6, discloses hydrocarbon fluid's temperature (Celsius) against Induction time (Minutes) for the uninhibited system and inhibited system (0.05, 0.1, 0.15, 0.2 mole fractions of Starch) at 40% water cut in dynamic state. It is seen in Figure 6, that in the uninhibited system, hydrocarbon fluid's temperature declined suddenly to 27°C from 87°C in 50 minutes induction time. The hydrocarbon fluid's temperature after the first 50 minutes of induction time had sudden, but sharp rise in temperature to 56.8°C and another sharp rise to 86°C at 110 minutes of the induction time. At an induction time of 120 minutes and beyond, the hydrocarbon fluid's temperature was seen to plateau. The sharp fall and rise of hydrocarbon fluid's temperature is termed to have been caused by hydrate formation. This phenomenon, agrees with the works reviewed in this study and not limited to those of Okon et al [18], Saikia et al [23], Carlos et al [2]. In these works, experiments were run, coupled with visual inspection of what was happening in the system. Figure 6,

disclosed that the different concentration of Starch introduced into the system prevented the sudden fall and rise in hydrocarbon fluid's temperature. Starch did better at higher concentration of 0.2 mole fractions.

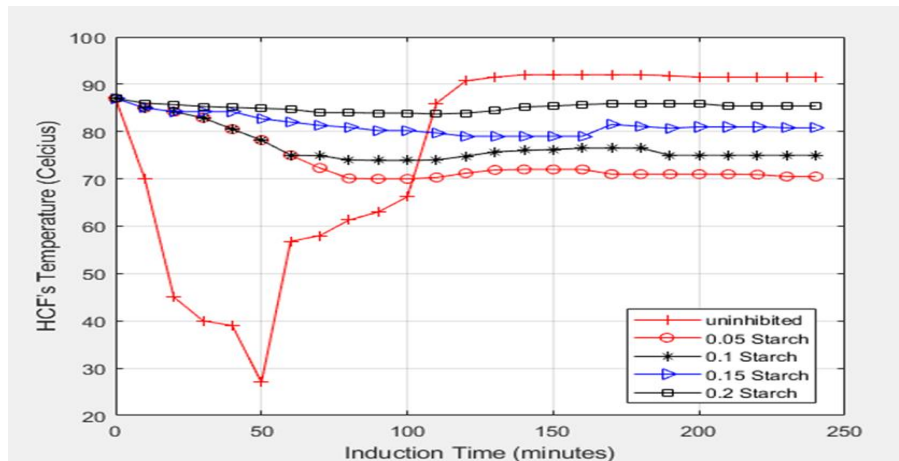


Figure 6 Hydrocarbon Fluid's Temperature (Celsius) versus Induction Time (Minutes) for Uninhibited System and Different Starch Concentrations at 40% Water Cut in Dynamic State

Figure 7, discloses the hydrocarbon fluid's pressure (Bar) against Induction time (Minutes) for the uninhibited and inhibited system (0.05, 0.1, 0.15, 0.2 mole fractions) at 80% water cut in dynamic state. It is seen in Figure 7, that the uninhibited system, hydrocarbon fluid's pressure readily declined from 61 bar to 32.43 bar for the duration of 240 minutes induction time. The rate of decline in hydrocarbon fluid's pressure was faster than that seen for 40% water cut (Figure 5), also its HCF's final pressure after 240 minutes induction time, was lower than that for 40% water cut. This could be as a result of more water being available in the produced fluid stream for the process of hydrate formation. However, Figure 7, discloses that all the concentrations of Starch used were able to prevent the decline in HCF's pressure seen in the uninhibited system. It is also seen that the higher the concentration of Starch in the system, the better it prevents the HCF's pressure drop.

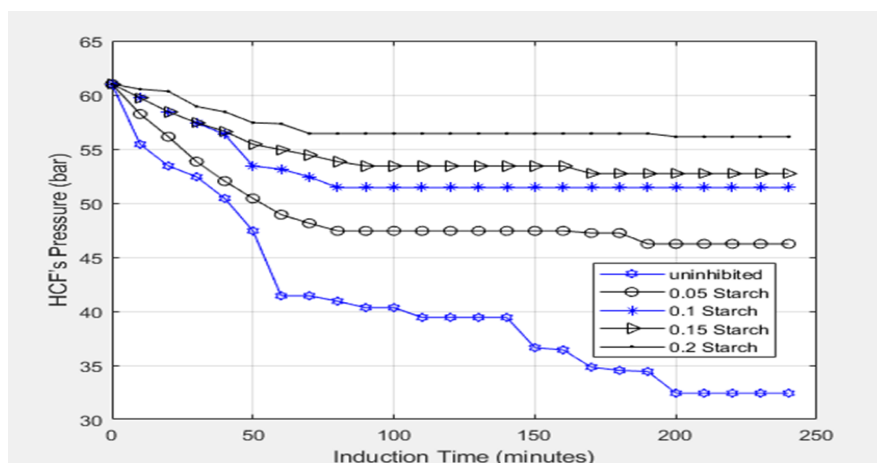


Figure 7 Hydrocarbon Fluid's Pressure (Bar) versus Induction Time (Minutes) for Uninhibited System and Different Starch Concentrations at 80% Water Cut in Dynamic State

Figure 8, discloses hydrocarbon fluid's temperature (Celsius) against Induction time (Minutes) for the uninhibited and inhibited system (0.05, 0.1, 0.15, 0.2 mole fractions of Starch) at 80% water cut in dynamic state. It is seen in Figure 8, that in the uninhibited system, hydrocarbon fluid's temperature declined suddenly from 87°C to 19°C in the first 30 minutes of induction time. It rose steeply back to 85°C in 40 minutes and further plateaued at 92°C after the initial HCF's temperature decline. At the elapse of the entire induction time of 240 minutes, hydrocarbon fluid's temperature was 91.5°C. The sudden fall and sharp rise in HCF's temperature in the uninhibited system was in concordance with the works reviewed for this study. It, therefore serves as a yardstick to ascertain the performances of the Starch in the inhibited system. The different concentration of Starch as seen injected into the system, were effective in preventing the sudden fall and rise of HCF's temperature. It is also obvious from Figure 8 that as the concentration of Starch injected

into the system increased, the better the prevention of the sudden fall and rise in HCF's temperature. The visual inspection and results of experiments ran in the works reviewed for this study, revealed that when similar sudden fall and rise in temperature seen in Figure 8, occurred, hydrates were seen to form. This therefore, means that Starch prevented hydrates from forming in this study. The work of Okon et al. (2018) [18] is therefore validated by the results from this study because the inhibitor used in their study was also starch-based.

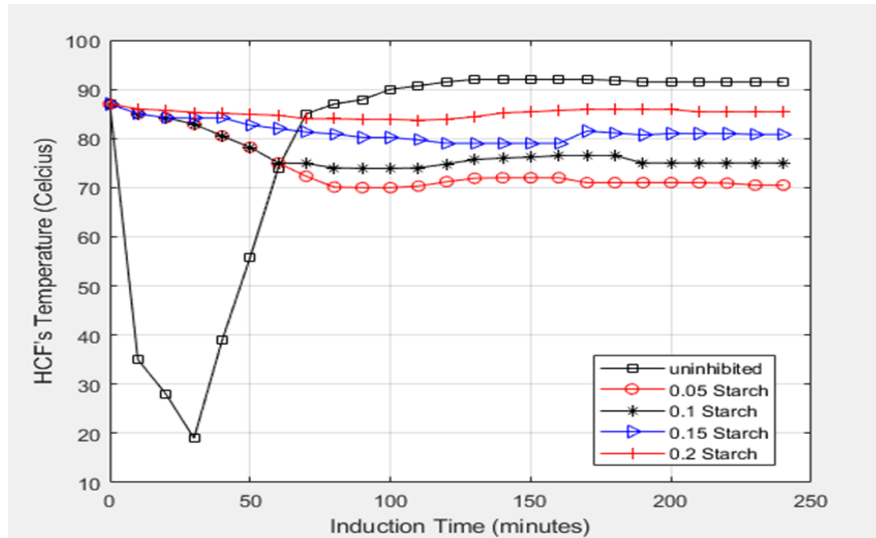


Figure 8 Hydrocarbon Fluid's Temperature (Celsius) versus Induction Time (Minutes) for Uninhibited System and Different Starch Concentrations at 80% Water Cut in Dynamic State

4. Conclusion

In this work, the potency of Starch in hydrate inhibition in a field within the Gulf of Guinea was investigated using Aspen Hysys V11.0. The performances of Starch were deduced using different plots of hydrocarbon fluid pressures and temperatures at both steady state and dynamic state. Simulation results obtained from the steady state were very dissimilar to those obtained in the dynamic state. The steady state simulation results revealed that hydrate will not form. In the steady state simulation results, the plots of temperature changes for both the inhibited and uninhibited systems along the flow line's length neither approached nor intersected with the hydrate formation temperature profile of the hydrocarbon fluid. The steady state simulation results disclosed that hydrate formation pressure 'do not exist'. It therefore, means that since one of the conditions for hydrate formation was missing, there would be zero hydrate formation in steady state.

The simulation results of the dynamic state was contained in the plots of HCF's pressure, temperature against Induction time for both uninhibited system and inhibited system at water cuts of 40% and 80%. The dynamic state simulation results, justified the use of Starch as Kinetic Hydrate Inhibitor. Starch was seen from the simulation results to delay the formation of hydrates in the different water cuts, throughout the induction time and was best at 0.2 mole fractions. This study has further disclosed that Aspen Hysys can be used in hydrate studies, considering polymers such as Starch as hydrate inhibitors. It is therefore, recommended that Starch be taken on a field-pilot test, to further ascertain its efficacy in inhibiting hydrates. Once Starch passes the field-pilot tests, it should be developed as a commercial non-synthetic hydrate inhibitor and utilized by the industry. This will not only create wealth from wastes generated when processing farm produce with high Starch content, such as Manihot Esculenta to a finished edible goods. Its eco-friendly nature, saves the ecosystem from the harsh effects, which its synthetic counterparts poses to the environment.

Compliance with ethical standards

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Disclosure of conflict of interest

All authors would like to declare that there is no conflict of interest relevant to this article

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