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TECHNICAL FEASIBILITY STUDY ON HYDRATE TRANSPORTABILITY FOR CONDENSATE PRODUCTION FLOW LINES

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ABSTRACT

Recent quest for oil and gas towards exceptionally remote ultra-deepwater areas requiring long tiebacks to link subsea wells with existing platforms renders the popular hydrate preventive method economically non-reasonable for long distances involved. This work investigated the likelihood of transporting hydrate slurry in condensate production flow line without using any heat or hydrate inhibition program. PIPESIM® was employed to simulate the transportability of hydrate slurry for flow line sizes of 0.241, 0.292, 0.343m and flow rates of 820, 1640, 2460 and 3280 sm^3/day over a distance of 10 km. Simulations results support higher rates and bigger duct diameter for hydrate-plugging avoidance. Flowrate at 3280sm^3/day for both low and high Watercut was more favourable having less outlet pressure drop hence taking out any requirement for secondary recovery techniques at the later field life. PIPESIM® predicted hydrate-temperature of above 12^{o}C was contrasted with some hydrate-temperature prediction models including the Hammerschmidt model, Towler and Mokhatab model, and Katz model. Considering the deviations in the simulated hydrate-temperature with the existing models, the Towler and Mokhatab model were prescribed here as the most suitable alternative to PIPESIM® simulation.

KEYWORDS: Hydrate-Slurry, PIPESIM Simulations, Flowrate, Hydrate-Temperature.

INTRODUCTION

To achieve economic sustainability and fluid flowing assurance of deep offshore gas-dominant products (such as condensate) transportation systems, the design, optimisation and assessing hydrate control via management like the use of hydrate particle slurry transportation is very crucial. However, this emerging technology of handling hydrate by particle slurry transportation is faced with the following difficulties.

a) Very few feasibilities/research studies on hydrate slurry transportation without adding any hydrate chemical inhibitor or heat application (and insulation) for the gas-dominant system, like the gas-condensate product. Majority of studies done on hydrate slurry solid-transport are for oil-dominant systems and for systems that involve LDHIs.

b) It is not having generally accepted and validated models that will aid in predicting hydrate-plugging in a multiphase flow of gas-condensate and associated water. Several models are being developed by researchers using different assumptions. Gong *et al*., 2014 expressed that there is no consensus or agreement on hydrate slurry transport law and how different factors contribute to plugging.

This paper centres around feasibility study on hydrate slurry transportation gas-condensate multiphase fluid composition and relevant (operating) conditions, a typical case in the Gulf of Guinea (Nigerian field in particular). Also, a comparative investigation is carried out on some of the existing/popular models, looking at their efficiency in the prediction of hydrate plugging of flow lines for gas condensate production system without using any hydrate hindering compound, chemical or heat (warmth) application.

This study aims to investigate the likelihood of transporting hydrate slurry in a typical gas-condensate production flow line without the addition of any hydrate chemical inhibitor by consideration of different operating conditions, criteria and pertinent parameters.

The Objectives are:

i. Predicting potential hydrate plugging or blockage of flow line at various flowrate, pipeline diameters and lengths for a gas-dominate system without any chemical inhibition or heat application.

ii. We are predicting whether artificial lifting will be required at high Watercut towards the end of the field's life.

iii. Predicting the temperature at which hydrate crystals are likely to appear with Simulation software and comparing the result with three hydrate formation temperature prediction models.

The natural hydrate occurrence in oil and gas transportation flow lines and its control still present severe operational and financial migraine for oil and gas producing companies all over the world till date. Feasibility studies on hydrate slurry transportation and models for anticipating hydrate crystallisation or formation is possibly advantageous to designing and assessing hydrate control via management methods, determining the probable quantity of hydrates particulate that can occur and also the possibility of transporting these solid particles for each particular scenarios, with the end goal of ascertaining the risk of hydrate blockage. A model of gas hydrate which can precisely determine the hydrating line blockage risk inflow line is a great significance not only in designing but also optimising of flow lines and operational procedures.

This study will not only investigate the likelihood of transporting hydrate slurry in a typical gas condensate production flow line without addition of any hydrate chemical inhibitor but also seeks to find a reliable model for specific conditions or criteria that will efficiently predict hydrate blockage tendency for gas-condensate flow lines to be able to proffer a superior answer to operational and cost (chemical, infrastructure, intervention, remediation, accident e.t.c.) challenges of gas condensate transportation flow lines caused by hydrate plugging.

We are utilising computer software to do detailed sensitivity analysis for hydrate slurry transportability for different flow line lengths and sizes at given conditions of operation. Here inside this work, some popular models for predicting hydrate including the Hammerschmidt model, Towler and Mokhatab model, and Katz model would be assessed based on the model correctness and deviations in comparison to the results from computer simulations, a better, more accurate and the most suitable model for manual calculations of hydrate crystallisation would be chosen or proposed from the three models. Suitable parameters for facilities design such as diameter, flow rate, temperature and pressure, etc... would also be suggested in the application of the picked or proposed model.

2. System Description

In order to get to the topside, facility recovered fluids from reservoirs in deep-water must flow through jumpers, manifolds and risers that are worked to resist deep-water pressures, temperatures and gale (currents) forces. However, long-distance tiebacks have associated difficulties. It comes with potential issues from hydrate forming, wax deposition, scales asphaltenes etc... These issues sometimes are sufficiently significant to oppose fluid transport topside facilities, the degree of issues of flow assurance is hugely determined by chemical parts of the recovered fluids and their P-T relation as they are transported from a system end to the other (Bai *et al.*, 2005). The optimal designing of a subsea pipeline system is an arduous task. Subsea productions come with such problems as pressure decline, temperature decline, etc... Which often cause chemistry-related transport issues like formations/precipitations of waxes, scales, asphaltenes, hydrates, e.t.c. Thus, the need for Flow Assurance which is the thermal-hydraulic designs of recovery and transport systems as well as the forecasts and management of these flow challenges (Baxter, 2014).

Ideally, to stop the issue of temperature decline, Flowrate must be increased. To increase Flowrate requires smaller inner pipeline diameter, but this comes with the problem of pressure decline and slugging (Yukie, 2014). In order to prevent significant pressure decline, a bigger flow line inner diameter may become necessary but also come with setbacks on cost (Max, 2013), the decline in stream rate and temperature drop because of the long distance between the Wellhead and the topside. In order to manage excessive temperature drop, an excellent insulation material is required, but this also has excellent cost implications, especially for lengthy distance flow (David, 2014). Cognizant to these, resolving one issue prompts another.

This project involves the flow assurance design of operational parameters for a subsea-to-be-used pipeline with PIPESIM®. The pipeline will be transporting recovered fluids from four (4) subsea production wells to the hosting platform without the infusing hydrate inhibitors. The four wells will produce dry gas at the highest liquid rate of 3280 sm3/day (with no significant water) expected for the initial starting (3) years.

Wellhead temperature remains constant at 50^{o}C, and experiments done by Schlumberger predicted wax appearance temperatures of 25^{o}C below which significant wax deposit appear. Furthermore, the pressure at the wellhead is set 2.41MPa (maximum) to prevent too much back pressure, the delivery (1st stage separator entry) pressure of 1.03MPa is the minimum allowable, and beneath this value, the delivery will not be accomplished. The current Stage one (1) separator is made to handle slug capacity of 8.5m^3. The various tasks required to complete the design areas presented in the base data below.

The strategies to be utilised here are the typical flow assurance methods for performing pipeline designs using simulation software. The establishment of the hydrate-forming and management conditions will be done using PIPESIM® software, and besides working with the software, efforts would be made to undertake handwritten calculations to compare the results from PIPESIM® software and the models to be used which would include K-value method using series of charts (like the dew point calculation), Hammerschmidt model and Towler. The simulations will provide us with conditions necessary to flow recovered fluids with hydrate slurries successfully without thermal insulation, heating, the addition of chemicals or pipeline plugging by hydrates. The sets of temperatures, flow rates, pressure, pipe sizes, etc... Necessary to accomplish this slurry flow will be studied.

3. Base Data

The essential data and boundary limit conditions on which this design will be based are as presented below and in Figure 1 and Table 1:

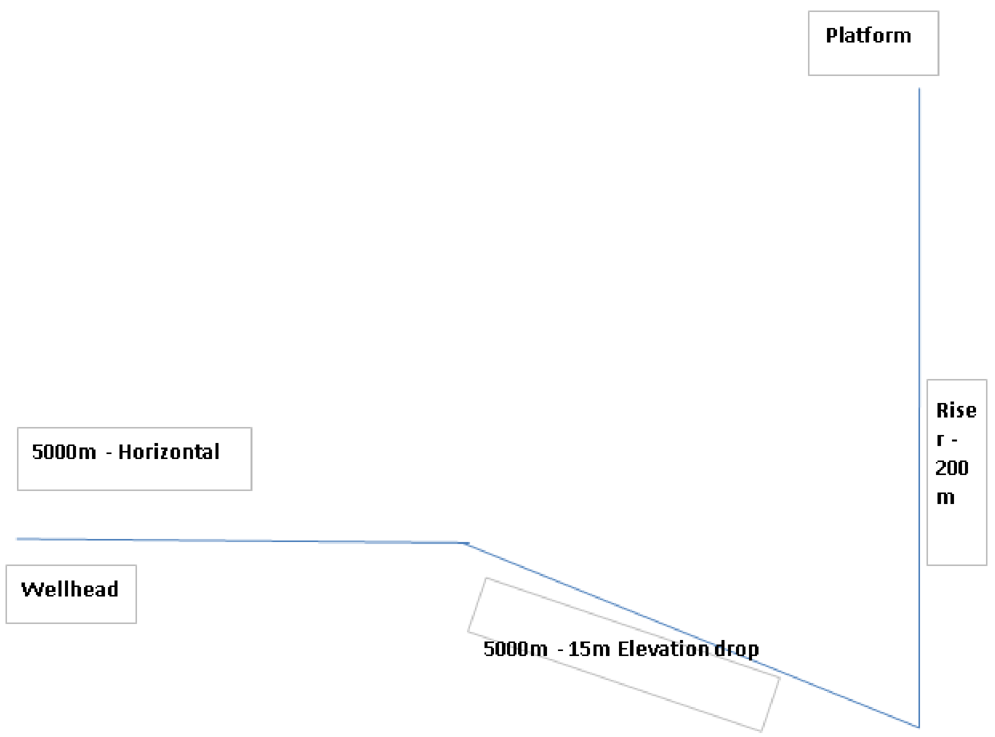

Figure 1. Schematic of Pipeline Architecture.

Table 1. Design data.

Data Description	**Value**
Fluid inlet pressure at the wellhead	2.41MPa
Fluid inlet temperature at wellhead	50℃.
4 well liquid flow rate	3280 sm^3/day
Maximum turndown	820 sm^3/day
Minimum outlet pressure at the platform	1.03MPa
Minimum outlet temperature at the platform	To be determined
wax formation temperature	25℃.
Ambient Temperature	4℃.

Boundary Conditions

Separator slug handling capacity = 8.5m^3

Wall thickness = 0.0127m

Roughness = 0.0254mm.

Line sizes to be considered are 0.241, 0.292, 0.343m internal diameter

Volume flowrates are 3280, 2460, 1640, and 820 sm^3/day, for 4, 3, 2, and 1 well flowing in the pipeline respectively

Assumptions

i. The rate of undulations is assumed zero.
ii. No thermal insulation of flowlines
iii. Constant Wellhead temperature of 50^{o}C.
iv. No addition of chemical inhibitors (only well product flowing).
v. The constant ambient temperature of 4℃.
vi. Slurry particle sizes of 1-10 micrometres
vii. Infinite K-values for hydrocarbon components heavier than butane.

Table 2. Composition of hydrocarbon and other components in the system.

Pure hydrocarbon system (Data sourced from Gulf of Guinea field)	
Components	**Mole %**
C1	64
C2	7.5
C3	4.7
C4	4.1
C5	3.0
C6+	16.7
Aqueous component (Water)	Initially zero increasing to 60%

3.1 Steps for PIPESIM® Simulation

The PIPESIM® software is an essential tool used simulating steady-state, multiphase flow throughout the oil and gas production system, extending from the reservoir to wellhead. This software also helps with the further analysis of Flowline with surface facilities to make a comprehensive producing system. According to Schlumberger, (2011) modelling and analysis of hydrate formation, gas-lift operations, flowline diameter, erosion, corrosion and pipeline insulation configurations can be done with this software using the steps below.

A. Create a physical model

B. Create a fluid model

Black oil model is typically applicable for GOR less than 2,000STB/SCF or where compositional data not available while the compositional model is used to model volatile oils, retrograde condensates accurately, and for wax, hydrate, and asphaltenes prediction (Schlumberger, 2011).

C. Choose flow correlations

D. Perform the following operations

1. Select the appropriate operation:
2. Specify known variables.
3. Specify sensitivity variable(s) and values.
4. Run model

For all operations, three key variables are needed: inlet pressure, outlet pressure and Flowrate. Supply two of these variables with the inlet temperature. The third is gotten automatically (Schlumberger, 2011).

E. View and analyses results

3.2 Hydrate Prediction Model

Hammerschmidt (1934) presented a model for gas hydrate forming, shown in Equation (1):

$$T_{(°\mathrm{F})} = 8.9P_{(psi)}^{0.285} \tag{1}$$

(Where T and P are temperature and pressure of hydrate crystallises, respectively).

Towler and Mokhatab (2005) proposed a fundamental correlation for forecasting HFT of hydrocarbon gas mixtures. Equation (2) shows an improved type of model:

$$T_{(°\mathrm{F})} = 13.47\ln P_{(psi)} + 34.27\ln\gamma - 1.675\ln\gamma\ln P_{(psi)} - 20.35 \tag{2}$$

Katz (1945) proposed a method of forecasting hydrate formation conditions in a mixture of sweet natural gas.

$$x = \frac{y}{k_{VH}} \tag{3}$$

Hydrate K_{VH} values (functions of T and P) is defined as the molar fraction for each gas component divided by the corresponding portion in the hydrate. It is used in checking the hydrate-dew point for the gas (with constant composition).

4. Results

Utilising the model configuration from PIPESIM®, shown in Figure. 2, a Phase envelope for the fluid sample was developed (zero initial Watercut).

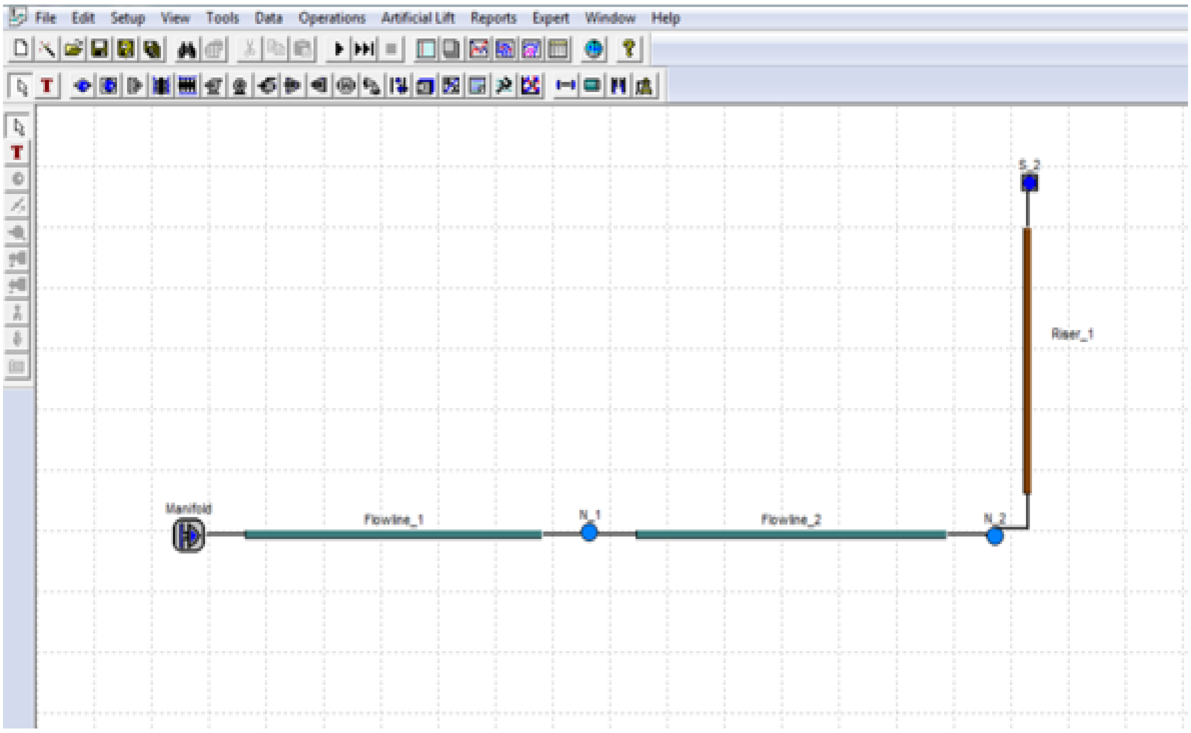

Figure 2: Results Summary.

In order to choose an appropriate flow line size, a sensitivity analysis was carried out for all flow rates against the lines sizes, and the results summarised as shown in Table 2.

Table 3: Flowline Sizes Pressure-Distance Profile for 3280, 2460, 1640 and 820 flow rates.

Flow rate (sm^3/day)	Pipeline ID (m)	Outlet Pressure (bar)
3280	0.241	1.2
	0.292	15.1
	0.343	17.4
2460	0.241	12.1
	0.292	16.8
	0.343	16.7
1640	0.241	16.2
	0.292	16.5
	0.343	13.9
820	0.241	14.6
	0.292	12.9
	0.343	12.0

From the simulation result, at temperature = 50°C, the outlet pressure for flow line size of 0.241m was very low, at 1.2 bar which below the desired output pressure of 10.3bar. As 0.241m internal diameter did not meet the set delivery pressure, the analysis has been modified using only line sizes of 0.292m and 0.343m, for each Flowrate.

Table 4: Outlet Pressures (bar) of the Pipe Line Sizes (m) at 3280sm^3/day and Watercut at 60% by Volume.

Pipeline IDs (m)	Outlet Pressure (bar)
0.241	9.4
0.292	11.3
0.343	11.9

4.1 Hydrate formation Temperature from Hammerschmidt model

Using the correlation proposed by Hammerschmidt a for gas hydrate formation shown in equation 1.

Using inlet pressure of 24.1bar, which is equivalent to 349.45psi, the HFT using Hammerschmidt model is given as 8.46°C**.**

4.2 Hydrate formation Temperature from Towler and Mokhatab model

The moderately basic and simple correlation proposed by Towler and Mokhatab (2005) for predicting HFT for mixtures of hydrocarbon with a modified form as shown in equation 2, the sum of the vapour mole fractions (γ) were determined to be equal to one from PIPESIM®, with inlet pressure equivalent to 349.45 psi, the hydrate forming temperature using Towler and Mokhatab is given as 14.74°C**.**

4.3 Hydrate formation Temperature from Katz model

According to Petroleum Engineering handbook, favourable conditions for hydrate formations are high pressures - low temperatures. Therefore, the inlet pressure of 24.1bar was used as the formation pressure. Components heavier than butane were assumed to have *K*-values of infinity. Thus, components used for the hydrate-appearing temperature calculations were *C1* (methane) to *C4* (butane). Their vapour mole fractions were obtained from PIPESIM® and utilising equation 3, then changing temperatures with pressure fixed at 24.1bar and iterating, $\sum(y/K)$ =1 was obtained at a temperature of 12.03^{o}C after Interpolation. Hence the HFT is 12.03^{o}C. 'K' and 'y' are vapours solid equilibrium constant and mole fraction of gas respectively.

5. Discussion

To identify suitable Pipeline Diameter for slurry flow with no chemical inhibitors usage

Based on the assumption of slurry particle sizes of ranging between 1-10microns and also no thermal insulation on pipe, analysis and PIPESIM® result demonstrates that the Flowline size of 0.241m resulted in hydrating plugs before getting to the delivery point and this resulted to a very low outlet pressure of 1.2bar, at which mainly, no flow occurred just at the downstream end of the Riser. Qin *et al*. (2018) stated that pressure drop could be utilised in calculating the rate of hydrate growing. Other flow line sizes of 0.292m and 0.343m were able to deliver the fluids and the slurries to the platform successfully without hydrate block forming, and also outlet pressures of 15.1bar and 17.4bar respectively were observed for the two Flowlines. These values met the minimum outlet pressure requirement of 10.3bar. Hence the selection of the suitable pipeline size for flow for this project will be based between line sizes of 0.292m and 0.343m.

However, for economic reasons, it suggested that the optimal size to use should be a pipeline diameter of 0.292m. This has to do with fact; the bigger the pipeline diameter, the higher the cost of construction and pipelay (Max, 2013). However, to flow slurries along with the produced fluids, this line size likely is not the most optimum.

Also from the simulation results, using pipe size of 0.241m led to erosional velocity (see Table 5) because its erosional velocity ratio is greater than one and this probably increased the volume of particles being flown and likely to also give rise to sites for agglomeration of hydrate crystals that contributed to Flowline plugging.

Table 5: Erosional Velocity Ratio values for the line sizes (m).

Pipeline IDs (m)	Erosional Velocity Ratio
0.241	1.66
0.292	0.35
0.343	0.23

Evaluation of Pipeline Pressure - Distance profile for flowrates of 3280, 2460, 1640 and 820 sm^3/day

The plot of pressure vs Distance at these varying flow rates for the given pipeline inner diameters indicates that higher the flow rate, the higher the outlet pressure and the lower will the pressure dropping be though the reverse is the case for the smallest diameter(0.242). Keijo *et al*. (2014) reported that the risk of hydrate plugging increases as pipe length increases and diameter decreases. Notably, a significant pressure drop is expectedly seen towards the 10km end most notably for the smallest pipe diameter size.

5.1 Suitable parameters for hydrate slurry flow

Four flow rates and three-line sizes were utilised during simulation to check the possibility of transporting the fluid with no chemicals injection and thermal insulation. Simulation results suggest that in order to have a successful flow (i.e. flow with outlet pressure greater than 10.3bar at the platform) for the stated assumptions, input data and operating conditions, the temperature needs to be kept above 12^{o}C, below this temperature there would be mainly no flow caused by hydrate plugs. Again, Song *et al*., (2018) reported that increasing flowrate would at a stage impose a steady decrease in the agglomerated particle diameter size, thereby promoting the transportation of particles. From the simulation analysis, it was also noticed that lower flow rate and smaller pipe diameter did not favour the fluids flow pushing hydrate slurries. Therefore, from the results, optimal flow parameters are flow rate of 3280sm^3/day and the pipeline inner diameter of 0.343m.

5.2 To identify if Gas-lift will be required when fluid will have 60% Watercut

The plot of Pressure vs Total distance at 3280sm^3/day and water volume ratio of 60% indicates that the outlet pressure of selected line size of 0.292m is 11.3bar which is a decrease when compared to similar case at 0% Watercut (Concerning this, Ahuja *et al.*, 2018, suggested that high Watercut will enhance interactions between the droplets of water and gas molecules thereby leading to a faster growth of hydrate particles). It can be correctly be assumed that further sensitivity analysis with flow rates below 3280 sm^3/day, the outlet pressure will fall below 10.3bar in other words, gas-lift is needed. However, at a flowrate of 3280sm^3/day, no gas-lift is required. Gainville *et al*., (2011) proposed that at extreme value of 57% for Watercut, potential for hydrate plugging of flow line will exist while Gong *et al*., (2014), stated that (although using AA of 1% by weight in their study) fewer hydrate slurry transportation problems are noticed for system with relatively low (25%) water content and also that for higher Watercut, the possibility of slurry transportation depends majorly on the actual flowing rate.

Since PIPESIM® is a simulator using the steady-state concept, steady-state analysis alone is not adequate for final design (David, 2013). Hence, hand calculations using three hydrate predicting models were done to compare the HFT obtained from the simulation. The results from hand-calculations using the hydrate predicting models are given below:

5.3 Prediction of Hydrate formation Temperature

Table 6: Hydrate formation Temperature Prediction from Models.

Models	Predicted Temperature (^oC)
Towler and Mokhatab	14.74
Katz	12.03
Hammerschmidt	8.46

From the hand calculations using the three models above, it is evident that the model proposed by Towler and Mokhatab predicted HFT is consistent with what was gotten from PIPESIM® simulation.

6. Summary

The oil industry has currently moved towards operations in the far remote and ultra-deepwater environment (such as the frigid Antarctic and arctic regions) due to the exhaustion of the conventional (onshore) resources. For economical operations and production, deepwater fields are supported with tie backs. This kind of environment provides favourable conditions for flow assurance problems of which hydrate plugging of flow line is one of the riskiest and troublesome. At the moment, the only mature and viable technologies for flow assurance in greater water depth are chemical inhibition and thermal solutions (direct heating and insulation). However, these two conventional methods are limited to short distance (approximately 200km and below) transportation (Moses, 2013; Lv *et al*., 2012). Moreover, the use of chemical methods come with a lot of environmental issues and escalating operating and capital costs incurred from the regeneration process plus the large voluminous chemicals required due to their high volatility. Hence, the transportation of hydrate-crystallized particle slurries becomes an essential technology to consider.

Despite the complex and irregular nature and behaviour of gaseous hydrate, oil and gas companies and individual researchers are channelling tremendous resources and efforts (on actual field study and laboratory experimental study, development of models and computer simulation software programs) towards understanding the various parameters, conditions, criteria and factors contributing to the hydrate forming, agglomerating growth and plugging risk in oil and gas production flow lines with aimed result of ascertaining the feasibility of transporting of hydrate slurry in a multiphase-flow.

7. Conclusion

This work looked at the feasibility of transporting hydrate particle slurry for a gas condensate (gas-dominant) production system with zero hydrate inhibition chemical addition. The effects of flow line sizes, distance, flow rates and product composition (Watercut) on hydrate-crystal slurry flow; hydrate plugging, fluid outlet temperature and pressure were investigated via PIPESIM® simulations. From the simulation results, it was observed that higher flow rate and bigger flow line diameter sizes were more favourable to hydrate slurry flow and hydrate block plugging avoidance. For this particular task, the flowrate of 3280sm3/day for water volume ratio of both zero and 60% was more favourable. At this flow rate, the outlet pressure is relatively higher with less pressure drop, thereby removing gas-lift need from the picture (or other secondary recovery techniques).

Also, from this study results, it would be proposed that in the absence of flow simulators, the best model to be employed for HFT prediction is Towler and Mokhatab, model. Moreover, for this task, the minimum allowable temperature to successfully flow the condensate fluids combined with the hydrate slurries is 12^{o}C.

8. Recommendations

For future works that are similar to this, the effects of slugging (due to pipeline architecture) on hydrate slurry flow should be considered as its likely for slugging to occur, and this may have an impact on the transport process of the condensate fluids. It is also good to note that other factors that can affect hydrate slurry transportation such as heat and mass transfer (no thermal insulation of flowline, only coated steel pipe was assumed here) sloughing, and specific fluid characteristics (wettability, gelling and natural surfactant which can assist selflubrication at pipe walls) were not looked into for this research, ought to be investigated in future works.

In addition to these, the effects of slurry sizes and hydrate particle growth (agglomeration) on hydrate slurry transportability should also be considered in future studies. Here, the slurry sizes were between 1-10 micrometres.

Furthermore, other simulation software (especially an unsteady state simulator) should be used to run this kind of task in order to compare the results obtained from this work, both from the PIPESIM® and the hand calculations with the hydrate prediction models. To effectively do this, other hydrate prediction models should also be evaluated and results compared to those of the simulators.

Finally, it is very crucial to categorise the conditions in terms of economics, water depth range and actual pipeline distance that would make hydrate slurry transport to be preferable over chemical inhibitor and heat application methods.

This study provides.

i. Evidence of the possibility of hydrate particle slurry transportation with zero addition of any hydrate inhibiting-chemical to encourage further studies on this technology of which eventual success will be a substantial economic benefit to our country's (both the developed and emerging) offshore oil and gas installations and new projects.
ii. Reference document providing idea on the design input parameters (flowrate, pipeline diameters and lengths) and other operating conditions needed in the design and optimisation of offshore oil and gas transportation pipelines to guarantee products flow assurance.
iii. The directive in identifying amongst the existing models, the efficient model for accurate prediction of HFT and provides comparison basis for subsequent studies using other hydrate prediction models (correlations) and simulation software.

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