Hydrate Management – Effect of Water Cuts on the Cool Down Times of an Unplanned Shutdown

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Abstract:
Hydrates are one of the biggest challenges in the oil and gas industry because they can plug flowlines and destroy equipment. Once formed, it can take a very long time for it to dissociate and removal could cost millions of dollars. Therefore, it is paramount for us to find a solution to manage hydrates. Preventive and remedial solutions already exist. The new frontier is finding ways to optimize these solutions from cost and schedule perspectives. This work looks at the schedule perspective in terms of the cool down time of the fluid during an unplanned shutdown scenario. A case study approach has been used with data from an actual field. This case study employed both PVTSim and OLGA software to model and analyze the cooldown time for different water cuts representing the mid-life and late life of the field respectively. The PVT Sim software was used to characterize the fluid while the OLGA software was used to model and analyze the representative field. The results from this study showed that for the 50% water cut representing the mid-life of the field, although not prone to hydrate formation, it took around 4 to 5 hours for the fluid to cool down to its ambient temperature of 16°C from a shut-in temperature and pressure of 75°C and 3100psia respectively. The 95% water cut representing the late life of the field showed an increase in the cool down time to about 19 to 24 hours at the same shut-in temperature and pressure.

Keywords: Hydrate, cooldown time, early-life, late-life, unplanned shutdown.

I. INTRODUCTION

Hydrates are a thorn in the flesh for the oil and gas industry because they can plug flowlines and destroy equipment. Once formed, it can take a very long time for it to dissociate and removal could cost millions of dollars. Hydrates are crystalline solids composed of light hydrocarbons and water molecules formed under high pressure and low temperature. A condition that exist in a deepwater seabed. Thus, the search for hydrocarbons keep taking us to deeper waters, it is paramount for us to find a solution to manage hydrates. Preventive and remedial solutions already exist. The new frontier is finding ways to optimize these solutions from cost and schedule perspective. Hydrates can also be referred to as Clathrate Hydrates. The hydrocarbon gas molecules such as methane, propane, ethane and carbon dioxide are trapped by the water molecules (1). A lot of research has been done on the physics and science of hydrate formation in flowlines since the 19th Century. Most of this research have focused on using experimental data in building models which can be used to predict and manage hydrates. This has led to the invention of ways we can use to manage hydrates. Conventional methods involving the injection of methanol/glycol are very expensive and not entirely environmentally friendly. Passive insulation to overcome the cool down over the entire flowline length has been the standard industry practice of holding the temperature of the flowline inside the hydrate formation temperature. (2). Unplanned well shut down can occur during the life of an oil and gas field. When it occurs, operators usually need an ample time to restart the well and employ methods to avoid the formation of hydrates. The cool down time is therefore a very important parameter to calculate. Cool down time is the time it takes the fluid to cool down to its hydrate formation temperature. Already a lot of work has been done analyzing the cool down times of various insulators with different thicknesses. It is the aim of this study to contribute in analyzing the cool down time for a flexible flowline. Different water cuts representing the mid-life and late life of the field will be simulated and its effect on the cool down time investigated.

II. LITERATURE REVIEW

Hydrates are one of the most challenging problems in deepwater subsea systems. They are formed when there is a presence of gas and water under the right conditions in the flowline. They are formed in a lattice structure containing hydrocarbon gas molecules trapped by hydrogen bonded water molecules. This gas molecules are sometimes referred to as guest molecules. Higher pressures and lower temperatures operations often promote the formation of these hydrates. Therefore, they are prone to form in production facilities with longer subsea tiebacks. (3). Once they are formed, they tend to plug the flowlines (see Figure 1).

Figure.1. Pipeline plugged by hydrates
Source: http://hydrates.mines.edu/CHR/FlowAssurance.html
Kamal et al. (2016) claim that hydrates were first discovered by Humphrey Davy in 1810 but Davy’s work was purely academic, and no much attention was given to it. It remained like this until 1930 when large scale hydrate formation in gas pipelines became a serious challenge. By 1934, Hamm erschmidt made the first publication on hydrates. (4), (5). Hydrate formation in flowlines is a big challenge for the oil and gas industry and in order to assure flow, the flowline must be free of hydrates or contain hydrates that are of transportable nature. Various researchers have worked on prediction of hydrate formation to avoid the huge cost associated with them. Usman et al (2012) presented a model-based hydrate management strategy to control the effects of hydrates. The model temperature-pressure operating envelope was generated with PVT Simulation software called PVTSim using the Peng Robinson equation of state. The model was able to determine the operational limits of the production system to prevent the formation of hydrates plugs in an unplanned shut in. Their analyses on different scenarios was concentrated towards setting the operational limit of the subsea production facilities to prevent hydrate formation during unplanned shut in. (6).

HYSYS simulation package was used by Salam et al (2013) for predicting hydrate formation condition for 3 different gas streams. The predicted conditions were compared with published empirical methods and it was found out that there was a close match between the predicted result from HYSYS and the published empirical data. (7) Yanli et al (2016) compared four prediction methods of temperature in pipe with field data and compared five prediction methods of hydrate formation with experimental data. Also, a method based on OLGA and PVT Sim for predicting hydrate formation in wellbore was proposed. The well data was from the South China Sea. The results from the study showed that the hydrate formation area decreased with the increase of inhibitor concentrations and the thickness of the insulation materials. It also increased with the increase of the thermal conductivity of the insulation materials and the shutdown time. Result also showed that throttling effect causes a steep rise in temperature and pressure in the wellbore which can increase the hydrate formation area. (8) Zerpa et al (2012) presented a gas hydrate model for an oil dominated system to estimate the hydrate plugging risk for an offshore well with properties like those in the Caratinga field located in the Compos Basin, Brazil. Their estimation was done for three different periods of the well life – case 1 is low production GOR and low water cut, case 2 is increased GOR, and finally case 3 is higher GOR and higher water cut. The calculation of three performance indicators were used to estimate the hydrate plugging risk. These indicators are the pressure drop along the flowline, hydrate volume fraction in pipe and hydrate slurry relative viscosity. Their model was used to study the performance of ethanol injection both in steady state and transient state. Their result showed that ethanol injection decreased the hydrate plugging risk both in steady state and transient operations. Finally, they claimed that their model was useful in determining the optimal ethanol concentration that minimized the hydrate plugging risk. (9) A novel technique for monitoring hydrate safety margin was presented by Jinhai et al (2011). This technique was developed to optimize the injection of hydrate inhibitors by monitoring the actual hydrate safety margin. They claim that with this technique, it is possible to reduce unwarranted costs and protect the environment from potential chemical impacts. The technique employed measuring the acoustic velocity and electrical conductivity of the aqueous samples downstream. After which a trained artificial neural network determined both the salt concentration and inhibitor concentration. These concentrations are then used by an integrated in-house thermodynamic model to determine the hydrate phase boundary (hydrate safety margin). Results from this study indicated that the technique can be used for different inhibition systems including methanol-salt systems, mono ethylene glycol salt systems, and kinetic hydrate inhibitor-salt systems with an acceptable measurement accuracy for monitoring hydrate safety margin. (10).

III. OVERALL FORMAT SPECIFICATIONS

This case study analysis would be conducted using two commercially available hydrate formation simulation software – PVTSim and OLGA. The purpose was to understand the effect of different cuts on the cooldown times of an unplanned shutdown. Data was sourced from a field in the Nigerian Gulf of Guinea. Following the literature review and software study, the following data from an actual field flowline was required to proceed with this study: Fluid compositions, Flowline Elevation Profile including, Internal Diameter and thickness of the flowline, Wellhead Outlet Pressure and Temperature, Separator Maximum Pressure at the Riser Outlet, Water Mass Fraction, Ambient Seabed Temperature, Properties of the flowline material (Density, Specific Heat, Thermal Conductivity, Roughness and Heat Transfer Coefficient), Fluid mass flow rate from the wellhead and Field Location.

A. Modelling with PVTSim

The aim of carrying out modelling with PVTSim was to characterize the fluid composition and generate the hydrate curve of the field. It was also done to generate a fluid file (.tab) to be inputted into OLGA to run the transient analysis. To carry out this modelling, it was necessary the obtain the fluid composition data of the field. The table below shows the fluid composition of the field.

<table>
<thead>
<tr>
<th>Component</th>
<th>Mol %</th>
</tr>
</thead>
<tbody>
<tr>
<td>N2</td>
<td>0.04</td>
</tr>
<tr>
<td>CO2</td>
<td>0.94</td>
</tr>
<tr>
<td>C1</td>
<td>50.22</td>
</tr>
<tr>
<td>C2</td>
<td>3.94</td>
</tr>
<tr>
<td>C3</td>
<td>3.29</td>
</tr>
<tr>
<td>C4</td>
<td>1.02</td>
</tr>
<tr>
<td>C5</td>
<td>1.25</td>
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<tr>
<td>C6</td>
<td>0.77</td>
</tr>
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<td>C7</td>
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<td>C8</td>
<td>0.32</td>
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<td>C9</td>
<td>1.7</td>
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<tr>
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<td>1.97</td>
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<tr>
<td>C12+</td>
<td>2.27</td>
</tr>
<tr>
<td>MW</td>
<td>264.22</td>
</tr>
<tr>
<td>Density</td>
<td>0.74</td>
</tr>
<tr>
<td>kg/m³</td>
<td></td>
</tr>
</tbody>
</table>

Table 1. Fluid composition data

This data was then inputted into PVTSim (see Figure.1) to generate the phase envelope (see Figure.2), hydrate equilibrium curve (see Figure 4) and table file to be inputted into OLGA.

Figure 1. Fluid composition entered in PVTSim

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For Figure 1, C10, C11, and C12+ are not captured although they were inputted into the program. The field data did not include the mol wt. values and individual liquid densities. Thus, the default standard generated values were used.

Figure 2 shows the phase envelope of the fluid in the field. From the figure, we can see that the fluid maintains its 3-phase flow under normal operating conditions. Also, the bubble point at 200 bara is about 125 °C. This is when the first gas comes out of solution. The critical point is the point where the bubble point curve meets with the Dew point curve. It is the point where all the properties are equal both for the gas and liquid. For this fluid, the critical point occurs at 282.12 °C and 119.72 bara. The dew point is the temperature at which the first drop of gas begins to condense to a liquid. Defining the phase envelope of the fluid is important to define the range of operating conditions that can maintain a 3-phase flow (oil, water, and gas).

For hydrates to form, water must be present. In this study, water cuts of 50% and 95% were investigated. These water cuts were chosen to represent the mid field life and late field life of the field. For the 50% water cut, a 2.08 mol% of NaCl salt was assumed. It was also assumed that there was no inhibitor present except for the salt content. It is also good to note that salt can also act as an inhibitor and can affect the formation of hydrates. PVTSim has the capability to incorporate different fluid characteristics into one fluid file to be used in OLGA. Figure 3 and Figure 4 show the 50% water cut and 95% water cut fluid inputted into the PVTSim.

Figure 3. 50% water cut fluid

Figure 4. 95% water cut fluid

The SRK Peneloux equation was adopted for this analysis. It is to be noted that the SRK Peneloux EOS was chosen because it greatly improves the vapour pressure conditions. The predicted liquid density using this equation also improved because of the work of Peneloux et al (1982) (11). At the end of modelling with the PVTSim, a fluid file to be exported to OLGA as input was generated.

B. Modelling with OLGA

Modelling the system in OLGA started by defining the case in the case definition tab. From Table 2, OK-11 is seen as the longest tieback distance with a length of 3149m. Thus, this flowline will be more prone to hydrate formation and as such our analysis focused on this flowline. The PVT table file generated from PVTSim was then inputted into the files section of the model browser. The next step was inputting the structure in which our chosen fluid will flow. The structural properties were inputted in the library tab of OLGA.

Table 2. Tieback distance and water depth of the field
Table 3 shows the material properties of both the riser and the flowline respectively. These properties were inserted into the OLGA simulator software. The following basis was used when performing the simulations unless specified otherwise:

1. A Minimum FPSO arrival pressure of 150 psi
2. The FPSO arrival pressure is constant during steady state
3. Ambient Seabed temperature of 16°C
4. Ambient Air temperature of 25°C
5. No pipeline burial
6. Flexible Pipe Wall roughness as ID/250 mm
7. Gas export pressure 3000 psi at topsides
8. Gas Lift pressure 3000 psi at topsides
9. Gas temperature of 50°C at Topsides

For the modelling of the piping modelling, a network of 3 pipes was modelled to represent the subsea flowline, the riser and the riser extension connecting the HP Separator. The flowline was assumed to rest on a flat seabed. The riser had a length of 450m. The water depth of the OK-11 flowline was used as a reference for the modelling of the geometries. Pipe 1, Pipe 2 and Pipe 3 all have a roughness of 250mm with a diameter of 152.4mm. Flowline was divided into 150 sections. For the riser, the pipe 2 was also divided into 15 sections while the pipe 3 remained at only 1 section. The more the pipe sections, the more computing time and the more accurate the result. These values were selected to give a reasonable computing time together with a reasonable accuracy.

For the wellhead valve, a hydro valve model was selected. The wellhead valve was place at the inlet of the first section of pipe 1. Data for the valve model was not available at the time of writing the report of this study, thus, a maximum valve diameter of 0.254m was assumed for this analysis. This valve diameter is same value as that of the flowline.

IV. RESULTS AND DISCUSSIONS

C. Cooldown Time for the 50% Water Cut

The cooldown time from Figure 7 shows that it takes around 4 to 5 hours for the hydrocarbon in the flowline to cool down to its surrounding ambient temperature. Data from the FEED studies showed that the fluid will take around 3 hours to cool to its surrounding ambient temperature. This analysis agrees with the FEED study data carried out with only about an hour or so difference. This can be due to the different version of OLGA used for this study and that used during the FEED study for the field. Also, it can also be from the assumption that the flowline lies in a flat seabed. During FEED, the actual topography must have been taken into consideration. The black, red and blue cooldown time graph represents the Fluid temperature at sections 1, 75 and 150 respectively.

D. Cooldown Time for the 95% water Cut

The cooldown time for the flowline with 95% water cut shows that it takes around 19 to 24 hours for the hydrocarbon in the flowline to cool down to its surrounding ambient temperature. This can be assumed to be as a result of the increase in the water cut. The rate of water cut may be a function of the cool down time. At the same time, the presence of water in the hydrocarbon increases the risk of hydrate in the flowline. Thus, optimizing the amount of water in the system to increase the cool down time and decrease the risk of hydrate can be avenue for further research.

V. CONCLUSION

Although, there is no risk of hydrates forming from this study in the flowline, the cool down times of the fluid to its ambient temperature at the shut-in pressure of 3100 psia have been investigated. From the results gotten, it was found out that the cooldown time of the fluid may be a function of the water cut.
as increasing the water cut from 50 to 95% showed an increase of the cool down time of the fluid to its ambient temperature from 5 hours to about 24 hours. From the field data, it was seen that CO$_2$ was present in the fluid composition. This gas increases the risk of corrosion in the flowlines. Thus, this may be the reason the Operators opted for a flexible flowline. The absence of methane (CH$_4$) in the fluid composition may be another reason why there is no apparent risk of hydrate forming in the flowline as methane is an active hydrate former when combined with water at the correct pressure and temperature. Finally, this study successfully modelled the use of flexible pipes in hydrate control in terms of heat transfer using OLGA. PVT table values were imported from the PVTSim software. A comparative study for a series of water cuts representing the mid-life and late life of the field were also successfully modelled.

VI. DECLARATION OF INTEREST

The authors report no conflicts of interest. The authors alone are responsible for the content and writing of this article.

VII. ACKNOWLEDGEMENT

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VIII. REFERENCES


