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Hydrate mitigation for subsea production multiphase pipeline by flow assurance approach

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Abstract. Nowadays, gas and oil production through subsea pipeline are moving to deeper developments. It affects pressure and temperature conditions decrease within hydrate stability region. The composition of fluid, including mixed produced water, liquid, and gas also affects the formation of hydrate inside pipeline. It is potentially leads to serious operational and safety problems. The aim of this study is to predict the hydrate free zone in multiphase fluid, chemical inhibitor, and insulation designed for subsea production pipeline by flow assurance approach. This study was conduct using steady state multiphase simulation to build a model for predicting the hydrate free zone and build the sensitivity of chemical inhibitor and thermal insulation for optimizing the hydrate free zone. Data used for this study are gas rate, fluid composition includes 10% bbl/bbl water, pipeline data, and chemical hydrate inhibitors include Methanol, Monoethylene Glycol (MEG), Triethylene Glycol (TEG). This study yield sensitivity of gas flow rate, the composition of hydrate inhibitor, the effect of insulation thickness to shifting hydrate free zone. This study can be concluded that variation of gas rate could be more effective depends on fluid composition and injection of methanol inhibitor is the most effective methods to mitigate the hydrate formation.

1. Introduction

Gas hydrates is one of the serious economic and safety problems in petroleum industry during exploration, production, processing, until transportation of natural gas. Pipelines, processing facilities, and transportation system can be blocked by hydrate thus he blockage cause reduce and stop the fluid flow. It means hydrate blockage can cause loss production and operation shutdown.

Precise knowledge of phase behaviour in hydrocarbon and hydrate system, or water-hydrocarbon system, especially in the occurrence of salt and organic inhibitor is very important to design and operation of oil and gas pipelines production and processing facilities [1]. Gas hydrates are crystalline compound that can form at moderate pressures more than 10 bar and temperatures less than 20^{o}C in the occurrence of water and small molecules such as methane (C1), ethane (C2), propane (C3), carbon dioxide (CO2), and hydrogen sulfide (H2S) [2]. These conditions cause the risk of pipelines blockages as production move to colder, higher pressure in subsea environment.

Flow assurance is one that has grown immensely in popularity over recent times, due to in large part to progress of the oil and gas industry into frontier environment [3]. So that, flow assurance is the analysis of the whole of production system from upstream to downstream to ensure that fluids will continue to flow over the life of the field [4]. In the other words, deep water or subsea production depend heavily on flow assurance to ensure that the large capital investment [5]. Therefore, due to difficulty of oil and gas transport and process in deep water or subsea, this research is important to predict the hydrate formation in subsea pipeline production.

2. Methods and materials

This research is conducted using steady state simulator that used for modelling fluid flow inside wellbore, flow line, and piping system. The simulator provides an advance network for analysing complex production and injection networks, enabling the designer to engineer the best well, pipeline, and facilities design for complete system [6].

Methods used in this research are modelling and simulation using steady state simulator. Equation of state (EoS) used in this model is *Soave-Redlich-Kwong (SRK)*. The data source is using hypothesis yet plausible with parameters that already determined previously, such as boundary condition of field, hydrocarbon component, pipeline data, and riser data. The parameters used for simulation can be seen in table 1, table 2, table 3, and table 4 respectively. The simplified pipeline geometry in subsea production can be seen in fig 1. The length of subsea production flowline is 8 miles from satellite platform and height of riser to processing platform is 2000 ft.

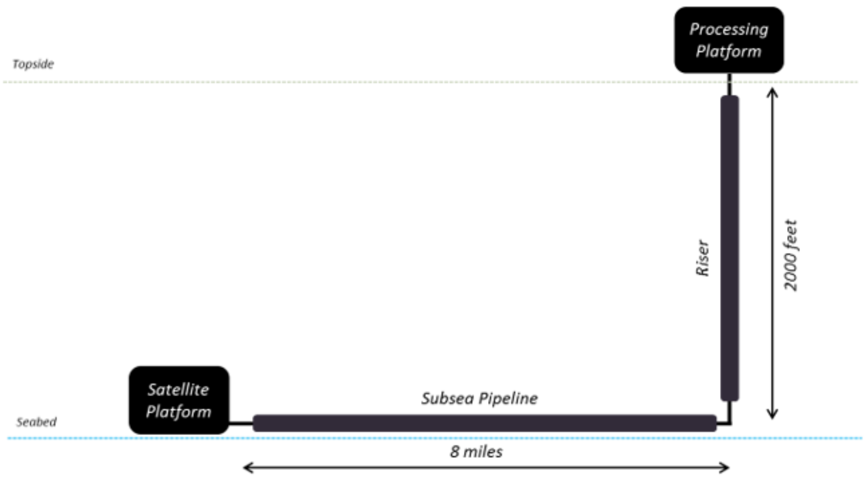

Figure 1. Simplified subsea production pipeline geometry.

The data first is determined by literature and hypothesis data yet plausible for real case in subsea field of natural gas production. All various data will be compiled and inputted as a data source use to make a simulation then hydrates curve will occur. This curve will be used as a base to see whenever in which limit of boundaries that hydrates formed.

Table 1. Boundary condition data for modelling.

Boundary Condition Parameters	Initial Condition
Fluid inlet pressure at satellite platform	1500 psia
Fluid inlet temperature at satellite platform	176°F
Gas Flow rate	30 MMSCFD
Minimum arrival pressure at processing platform	1000 psia
Minimum arrival temperature at processing platform	75°F

Table 2. Hydrocarbon components.

Components	Moles
C_1	79.91
C_2	5.31
C_3	3.27
i-C_4	0.64
n-C_4	1.13
i-C_5	0.32
n-C_5	0.24
C^{7+}	8.00
N_2	0.48
CO_2	0.71

Table 3. Pipeline data.

Pipeline Geometry	Input
Height of undulations	10/1000
Horizontal distance	8 miles
Elevation difference	0 inch
Inner diameter	10 inches
Wall thickness	0.5 inch
Ambient temperature	38°F
Overall heat transfer coefficient	0.2 Btu/hr/ft²/°F
Pipe thermal conductivity	35 Btu/hr/ft²/°F
Insulation thermal conductivity	0.15 Btu/hr/ft²/°F
Insulation thickness	0.25 inch

3. Results and discussion

Initial condition can be seen in Figure 1. The prediction of phase envelope of hydrocarbon in this research is using *Soave-Redlich-Kwong (SRK)* Equation of State. As we can see in fig 2, hydrate line is located in about 50°F -70°F. It means that if the operating condition across to hydrate line less than about 50°F (left side of hydrate line), it will probably form hydrate. Yet, if the operating condition is located more than about 70°F, it will probably hydrate free.

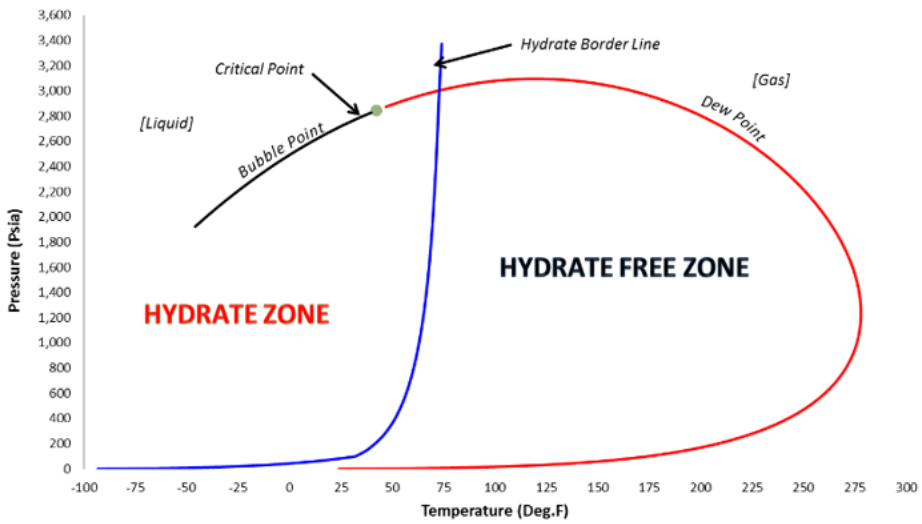

Figure 2. Initial condition phase behavior and hydrate line.

3.1. Effect of gas rate to hydrate formation

As we can see from fig 3, the curve that gas variation: 30 MMSCFD; 60 MMSCFD; and 100 MMSCFD, doesn't have any effect of avoiding operation condition for entering hydrate region. Another consideration is to change the diameter of pipeline in order to change the operating condition curve, as pressure drop along pipeline could give an effect for avoiding hydrates.

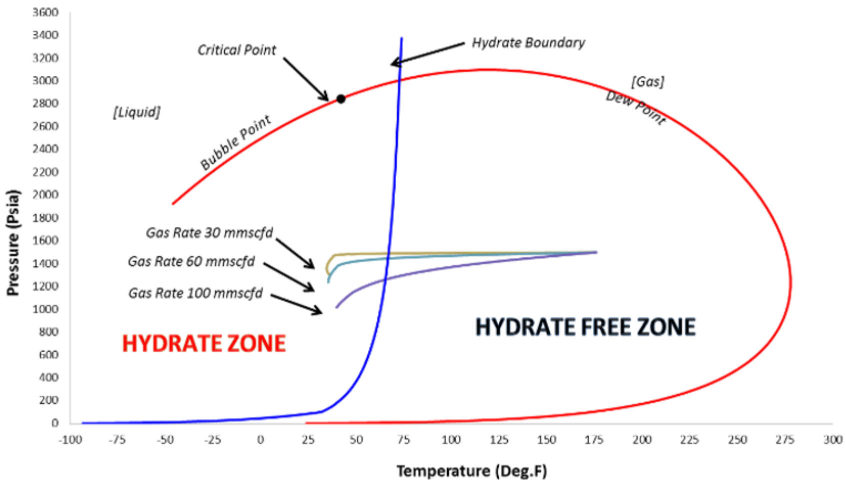

Figure 3. Sensitivity of gas rate to predict hydrate formation.

3.2. Effect of insulation thickness to hydrate formation

Insulation for piping could make difference in operating condition, although this option should be implemented at the first stage of designing and could make Capital Expenditure (CAPEX) become high yet will not make any additional cost during production [7]. This option can be only applied to the environment which has a stable condition. Insulation works with maintaining fluid temperature above hydrate zone as fig 4.

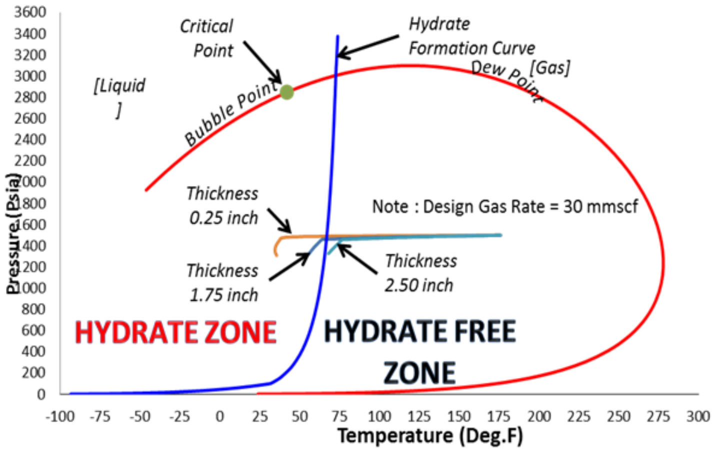

Figure 4. Sensitivity of insulation thickness to predict hydrate formation.

3.3. Effect of chemical inhibitor to hydrate formation

Chemical hydrate inhibitors used in this research are Methanol, Mono Ethylene Glycol (MEG), and Tri Ethylene Glycol (TEG) with various concentrations. Methanol has significant effect on hydrate. The use of 5% Methanol can eliminate hydrate within the curve that can be seen in Fig 5. Yet the use of 5% will be over because 3% of Methanol is enough to shift hydrate curve line away from operating condition.

The use of MEG has a better effect to eliminate hydrate, with the use of MEG composition 3-10% which is shown a significant result of shifting hydrate curve/hydrate line in fig 6. As we can see from the curve that MEG 1.1-14% have more distance of shifting hydrate curve away from the operating condition, yet this percentage will not be considered to use due to the percentage 3-10% already enough to shift or move hydrate curve line away from operating condition.

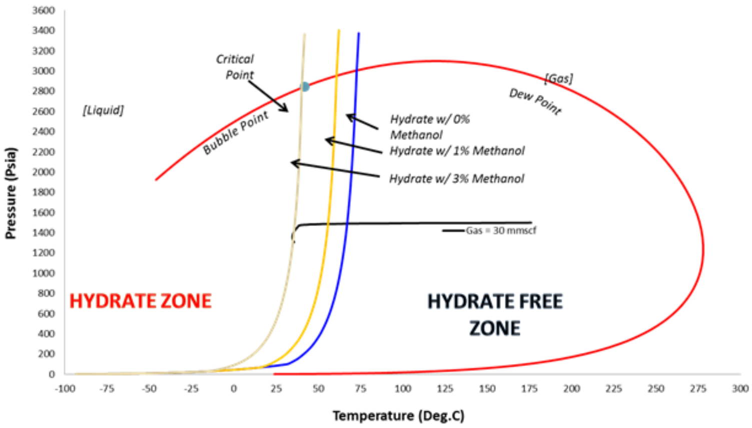

Figure 5. Effect of methanol inhibitor concentration to predict hydrate formation.

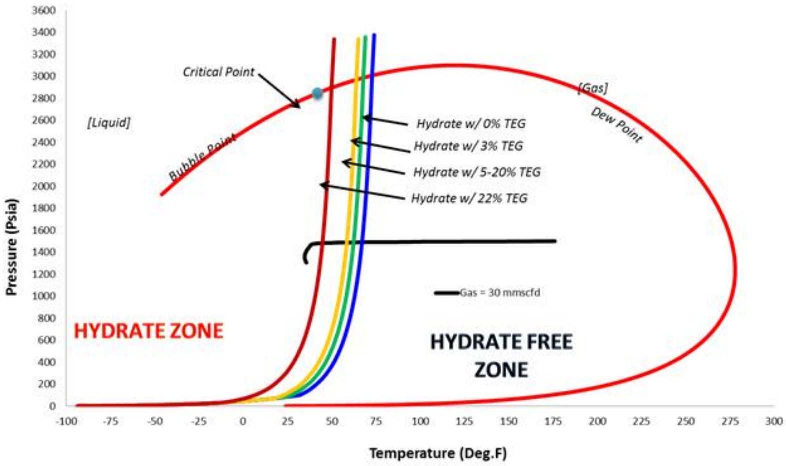

Figure 6. Effect of Mono Ethylene Glycol (MEG) inhibitor concentration to predict hydrate formation.

TEG has less significant effect on hydrate if compare to Methanol and MEG. The use of 22% TEG is the maximum percentage can be applied to the steady state simulator and give the best shifting of hydrate curve among others concentration: 3% TEG; 5-10% TEG; and 22% TEG as shown in fig 7. An experiment has already done with 22.1% TEG yet the curve output result has shown no hydrate being formed. This issue due to as the limitation function of the steady state simulator.

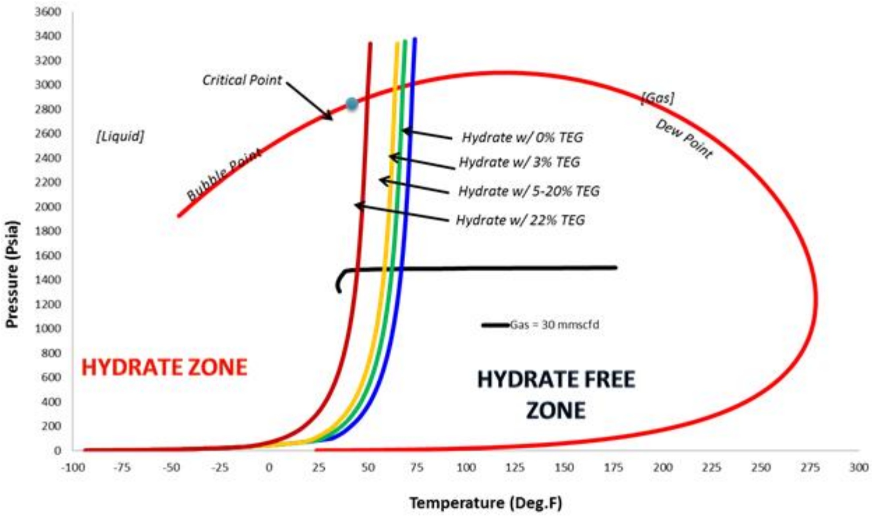

Figure 7. Effect of Tri Ethylene Glycol (TEG) inhibitor concentration to predict hydrate formation.

4. Conclusion and recommendation

Variation of gas rate could be more effective depends on natural gas composition [8], yet for this hypothetical data, the gas rate will not effective. For chemical inhibitors used in this research, the most effective methods and lower cost is Methanol, yet the hazard to environment make this chemical not ease to use and become second opinion for hydrate mitigation.

Mono Ethylene Glycol (MEG) is the second best of hydrate mitigation based on the experiment, though MEG have a higher price and need more percentage to prevent hydrate but this option has a better solution to reduce cost and that is by reclamation process. The reclamation of MEG can reduce cost and have friendlier environmentally [9].

Thermal insulation has high capital expenditure in advance, however it doesn’t affect to operation expenditure at the early operating [10]. Yet the environmental and well condition change during production can be caused additional operating expenditure.

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