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Effect of Monoethylene Glycol Injection in Hydrate Management

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Abstract

The presence of hydrates in deep water oil-gas-field operations is a fairly frequent issue. It is very important to have a hydrate management strategy for normal operation. This work evaluates the optimum mass concentration of monoethylene glycol (MEG) in hydrate management for a deep-water operation condition. A simulation-based approach was adopted and OLGA Dynamic Multiphase flow simulator and Multiflash fluid model modelling package were used. A base model was initially developed and subsequently adjusted for different mass concentrations of 10, 20, 30, 40, 44, and 45 MEG. The results for the actual production with no inhibition, shows that at 2268.53ft along the pipeline that 6.74853 x10-5 volume fraction of hydrate was formed at a pressure and temperature of 318.196psia and 3.41765°F in the pipeline. It also reveals that hydrates were formed at the inlet section of the pipeline. For 10 mass percent of Monoethylene glycol added to the fluid system, 573.651ft and 1.21864x10-7 volume fraction of hydrate was formed in the pipeline. Hydrate was thermodynamically unstable up to 573.651ft along the pipeline. After the unstable section, 1.21864x10-7 volume fraction of hydrate was formed in the pipeline. Result shows that increase in the mass percent of the MEG increases the length of instability of the hydrate formation along the pipeline and increase in the mass concentration of the MEG decreases the volume fraction of hydrate formed in the pipeline. Results further reveal that 45 percent mass concentration of MEG inhibited hydrate formation in the gas mixture.

Keywords: Monoethylene glycol, Hydrate management, MEG mass concentration, Hydrate formation

1.0 INTRODUCTION

There exist numerous flow assurance challenges concerning natural gas production and transportation. At any of these stages, natural gas may come into contact with condensed, production/formation water to form ice-like structures known as gas hydrates at certain pressures and temperatures leading to pipeline blockages, pressure build-up, and dangerous projectiles that could rupture the pipeline (Sloan Jr & Koh, 2007). Especially, in the transportation of gas through subsea pipelines from wellhead to onshore processing usually provides the typical conditions of pressure and temperature for the formation of hydrates.

Hydrate formation and its prevention remains a technical challenge for flow assurance in wet gas pipelines. Gas hydrates are crystalline solids formed from water and hydrocarbon gases molecules at low temperatures and elevated pressures. Gas hydrate formation starts with a nucleation step where microcrystalline hydrate particles form. They subsequently agglomerate and grow into large structures that may eventually obstruct the flow inside the pipeline. Hence, hydrate prevention and its management is one of the major focuses for flow assurance (Akpabio, 2013).

The work of Hammerschmidt (1934) was the start of the contemporary era of gas hydrate research. He discovered that the blockage of gas lines at a temperature greater than the ice formation temperature were due to gas hydrates as opposed to normal ice formation (Hammerschmidt, 1934). The capability to predict hydrate formation conditions was another significant development in this field. Katz (1945).and their team of researchers collated the pressure-temperature data from gas hydrate experiments that resulted in the formation of hydrates from varying gases given enough water presence (Katz, 1945).

Gas hydrates are a crystal lattice network made up of common gas components such as methane to butane, acid gases, and nitrogen encaged by molecules of water (Koh, 2002; Sloan Jr Koh, 2007). The mechanism of gas hydrate formation is built based on the theories pertaining to water crystallization. The process commences with the nucleation phase which typically happens on the water- gas interface. Succeeding this phase, the growth of hydrate begins to occur which is a complicated process (thermodynamic) deeply reliant on conditions of mass and heat transfer. As for the dissociation of gas hydrates, it is endothermic and occurs around the hydrate solid (Sloan Jr & Koh, 2007). The process can be instigated by changing the surrounding pressure and temperature of the hydrate solid lattice.

Beyond the environmental impact of gas hydrates, there have also been serious concerns from the gas and oil industries. In 1934, Hammerschmidt first recognized that natural gas hydrates rather than ice were a major potential cause of pipeline occlusion (Hammerschmidt, 1934). As the working areas of the gas and oil production are usually in the deep ocean, the conditions there are favorable for the water and gas to form hydrates, leading to blockages clogging the gas flow in pipelines. Considering the safety risks and economic loss caused by hydrate blockages, many methods have been employed to prevent their formation. Typical methods are heating the system to a temperature above the hydrate formation at the system pressure (Lili et al., 2021), drying the gas (Hubbard, 1991), and chemical control using inhibitors (Odutola et al., 2014). Chemical control of hydrates involves using chemicals to alter the hydrate formation condition of pressure and temperature or to delay hydrate nucleation, growth and agglomeration.

The control and prevention of gas hydrates may typically be achieved by chemical injection, thermal heating, depressurization, dehydration, and water removal (Son and Wallace, 2000). In terms of chemical injection, a hydrate inhibitor such as MEG as opposed to methanol is widely employed due to it being the safer, cleaner, and re-usable (through MEG regeneration) alternative (Brustad et al., 2005). Where MEG is utilized as part of the hydrate control philosophy for a field, MEG begins its journey after the wellhead mixing with the produced hydrocarbon, ultimately dropping the thermodynamic hydrate phase equilibrium to lower temperatures (Son and Wallace 2000). At the onshore arrival facilities, the production fluid is separated and pre- treated.

Okereke et al. (2020) investigated and published that MEG inhibited the hydrate mass fraction formation by mainly controlling the temperature condition. As MEG is widely used as a hydrate inhibitor, its regeneration and reclamation processes have become vital to the overall natural gas production and processing (Odeigah & Pojtanabuntoeng, 2022).

The use of MEG especially in the context of regeneration leads to the challenge of MEG degradation whether oxidative or thermal. Preliminary research suggests that MEG undergoes thermal degradation at certain temperatures generating organic acids, specifically formic and acetic acids (AlHarooni, et al., 2015). Studies of the effect of MEG injection on prevention of hydrate formation in natural gas pipeline have been the subject of many investigators. The efficiency of glycols as inhibitors of hydrate formation in natural gas, especially in offshore transportation pipelines has been studied by several researchers. Considering the usefulness of MEG injection in preventing hydrate formation in the industry, the purpose of the present work is to evaluate the effect of Monoethylene Glycol in hydrate management and its optimum concentrations for hydrate formation prevention in gas transmission pipeline using OLGA Dynamic Multiphase flow simulator and Multiflash fluid model modelling package.

2.0 MATERIALS AND METHOD

2.1 Materials

The materials (data and software) used in this study to evaluate the effect of Monoethylene Glycol in hydrate management and its optimum concentrations for hydrate formation prevention in gas transmission pipeline includes the following: OLGA Dynamic Multiphase flow simulator, Multiflash fluid model modelling package, analysis of the fluid (components and compositions), pipeline material and geometry data (length, elevation, wall roughness, internal diameter, heat capacity, density, thermal conductivity), and operating conditions of the pipeline (pressure, temperature and flow rate).

2.1.1 Gas properties for hydrate and PVT table files creation

Hydrate table file (hyd) and PVT table file (tab) are the two most essential files required to run a hydrate simulation in OLGA. These files contain pressure and temperature values for hydrate calculation and PVT parameters. Table 1 shows the gas composition which was used as a feed into Multiflash package for the generation of hydrate and PVT files respectively.

Table 1: Fluid composition and mole percent

Composition	Mole (%)	Composition	Mole (%)
Methane	88.322	n-Hexane	0.177
Ethane	6.755	n-Heptane	0.132
Propane	1.995	n-Octane	0.05
i-Butane	0.688	n-Nonane	0.012
n-Butane	0.769	n-Decane	0.005
i-Pentane	0.388	Water	0.121
n-Pentane	0.183	Nitrogen	0.237
		Carbon dioxide	0.166

2.1.2 Pipeline materials and geometry data

The gas pipeline is 28,500ft in length. In order to simulate it using OLGA software, the pipeline geometry in the model was assumed to consist of 5 pipe segments. Table 2 shows the pipeline geometry data. It has an elevation of zero to a length of 5700ft along the pipeline before its elevation increases from zero to 20ft. Figure 1 shows the flow path plot of the pipeline.

Table 2: Pipeline geometry data

Pipeline Geometry Data					
PIPE	**Length [ft]**	**Elevation [ft]**	**Wall Roughness [in]**	**Diameter [in]**	**Section**
PIPE-1	5,700	0	0.05	14	10
PIPE-2	5,700	5	0.05	14	10
PIPE-3	5,700	10	0.05	14	10
PIPE-4	5,700	15	0.05	14	10
PIPE-5	5,700	20	0.05	14	10

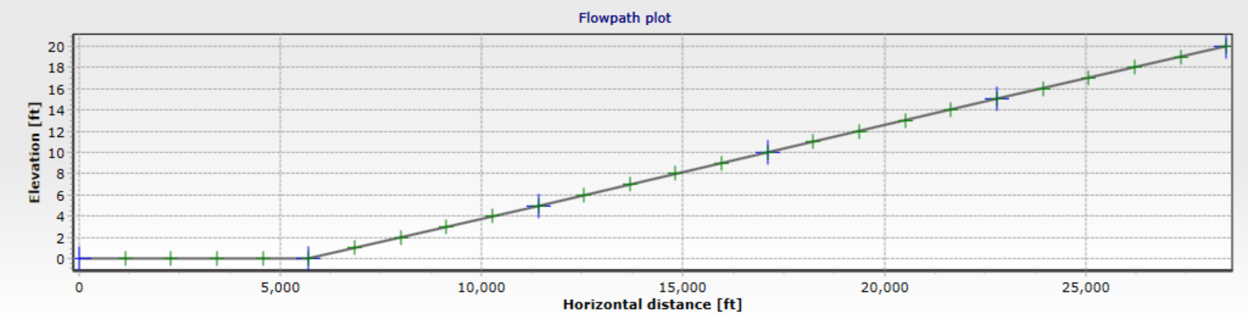


Figure 1: Flowpath of the pipeline

The carbon steel pipeline material properties used in the OLGA simulation model were 502.416 J/Kg-K heat capacity, 54W/m-K thermal conductivity, 7850 kg/m3 density and 19.05mm pipe wall thickness. It was coated with a layer of Poly Ethylene Foam having a thermal conductivity of 0.04 W/m.K, heat capacity of 2300 J/kg.K, density of 32kg/m3 and a wall thickness of 25.4mm. These data are presented in Table 3.

Table 3: Pipeline material properties

	Pipeline material properties			
	Thermal Conductivity	**Density**	**Heat Capacity**	**Wall thickness**
	[W/m.K]	**[kg/m^3]**	**[J/kg.K]**	**[mm]**
Carbon Steel	54	7850	502.416	19.05
Poly Ethylene Foam	0.04	32	2300	25.4

2.2 Simulation

2.2.1 OLGA capabilities

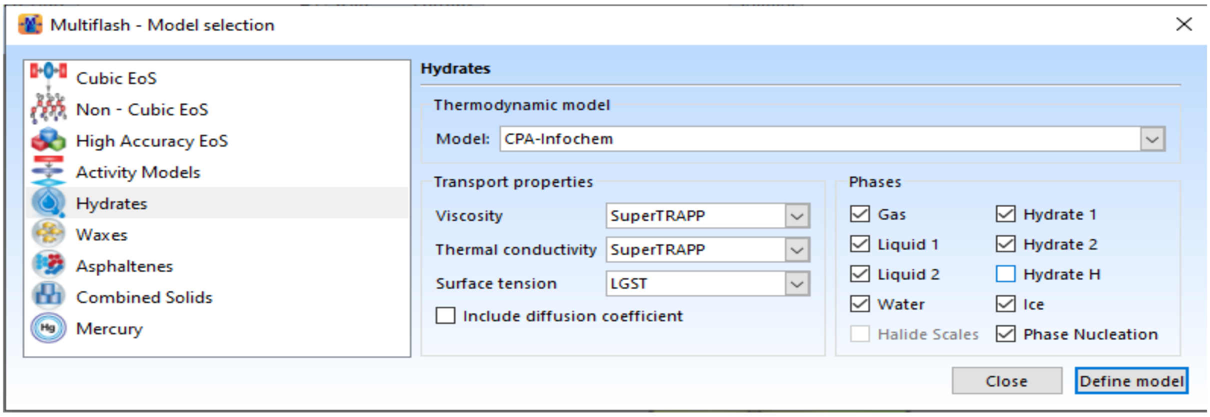
The OLGA simulation tool is a transient multiphase flow simulator. It can predict pressure drop, flow regimes and thermal behavior dynamically. Since most of the time multiphase flow is dynamic, it can be a powerful tool rather than depending on steady state calculations. The hydrate module in OLGA, the Colorado School of Mines Hydrate Kinetic model (CSMHyK) model is applied to each volume section of a pipe to estimate hydrate formation when water/gas exist together in the system. The CSMHyK model is a comprehensive transient hydrate model that predicts the behavior of hydrate formation and its transportability. This hydrate kinetics model (CSMHyK) allows for the prediction of where and approximately when hydrate plugs will form in oil and gas pipelines. The model allows for a real-time estimation of how fast hydrate may form within a flowline, thereby accounting for limitations in terms of mass and heat transfer resistances.

2.2.2 Multiflash capabilities

Multiflash enables the performance of hydrate calculation like prediction of hydrate formation at a specific temperature and pressure, hydrate formation and dissociation temperature at a given pressure, hydrate formation and dissociation pressure at a given temperature, hydrate phase boundaries for formation and dissociation, minimum water content for hydrate formation, the effect of inhibitors, including salt inhibition on hydrate formation and dissociation and dosage calculations of the amount of inhibitor required to suppress hydrate formation under specified conditions.

2.3 Method

Hydrate formation modelling performed in this work was done with OLGA v2017.2.0.107 and Multiflash v6.1. The study approach adopted in this work was to establish the possibility of hydrate formation in the pipeline first before the addition of Mono Ethylene Glycol (MEG). Multiflash was utilized as a phase behavior properties engine to generate input file into the OLGA model. OLGA reads these tables at a particular condition of pressures and temperatures within the pipeline system and uses that for multiphase calculations. This may include interpolation between values on the table of properties. The fluid composition was used as a basis for phase behavior modeling within Multiflash for the phase behavior model input to OLGA. The preconfigured model setup available was used to define the Hydrates model. The chosen equation of state (EOS) for the characterization of the PVT data was CPA-Infochem. The model selection screen is as shown in Figure 2.



Hydrates

Thermodynamic model

Model: CPA-Infochem

Transport properties

Viscosity: SuperTRAPP

Thermal conductivity: SuperTRAPP

Surface tension: LGST

☐ Include diffusion coefficient

Phases

☑ Gas ☑ Hydrate 1

☑ Liquid 1 ☑ Hydrate 2

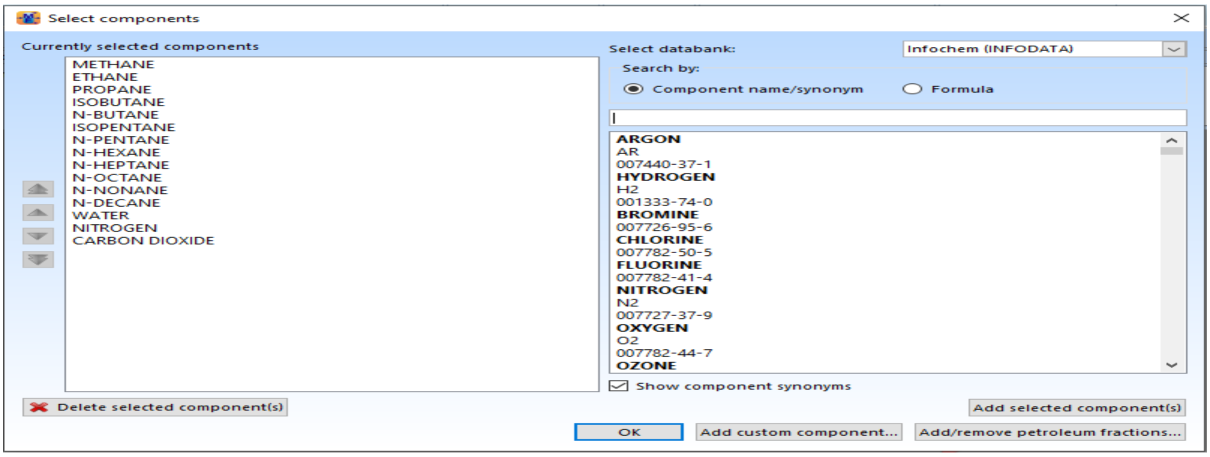
☑ Liquid 2 ☐ Hydrate H

☑ Water ☑ Ice

☐ Halide Scales ☑ Phase Nucleation

Figure 2: Model selection screen

The components that make up the fluid system were selected to make the component available on the fluid composition panel in order to enter the amount of each component. The component library screen is as shown in Figure 3.



Currently selected components

METHANE
ETHANE
PROPANE
ISOBUTANE
N-BUTANE
ISOPENTANE
N-PENTANE
N-HEXANE
N-HEPTANE
N-OCTANE
N-NONANE
N-DECANE
WATER
NITROGEN
CARBON DIOXIDE

Select databank: Infochem (INFODATA)

Search by:

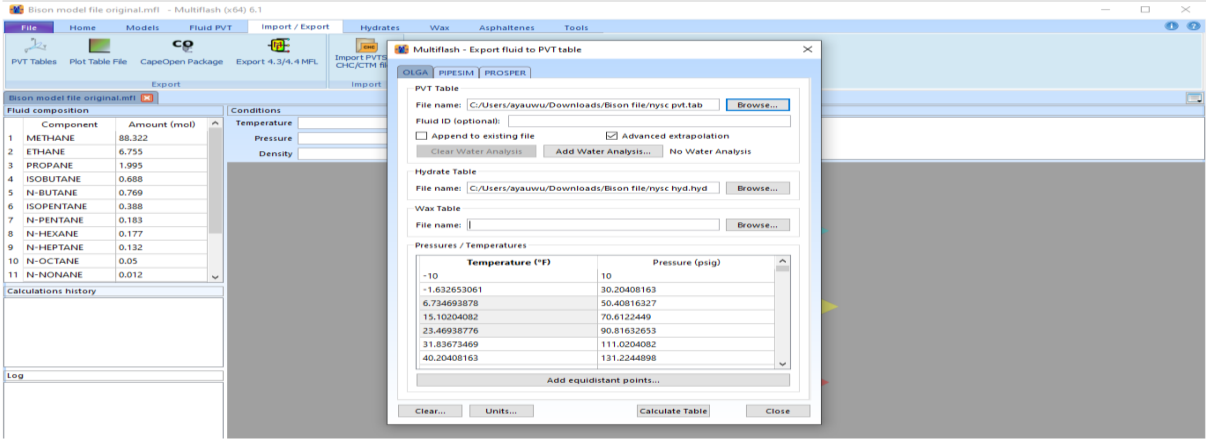
● Component name/synonym ○ Formula

ARGON
AR
007440-37-1
HYDROGEN
H2
001333-74-0
BROMINE
007726-95-6
CHLORINE
007782-50-5
FLUORINE
007782-41-4
NITROGEN
N2
007727-37-9
OXYGEN
O2
007782-44-7
OZONE

☑ Show component synonyms

Figure 3: Infochem component databank

The amount of each component was then entered into as the fluid composition panel. These components were used to create hydrate and PVT files. These tables are required in the model to predict the hydrate formation conditions of the fluid of interest. The Multiflash PVT and hydrate file generation screen is shown in Figure 4.



Fluid composition

	Component	Amount (mol)
1	METHANE	88.322
2	ETHANE	6.755
3	PROPANE	1.995
4	ISOBUTANE	0.688
5	N-BUTANE	0.769
6	ISOPENTANE	0.388
7	N-PENTANE	0.183
8	N-HEXANE	0.177
9	N-HEPTANE	0.132
10	N-OCTANE	0.05
11	N-NONANE	0.012

Conditions
Temperature
Pressure
Density

PVT Table
File name: C:/Users/ayauwu/Downloads/Bison file/nysc pvt.tab
Fluid ID (optional):
☐ Append to existing file ☑ Advanced extrapolation
No Water Analysis

Hydrate Table
File name: C:/Users/ayauwu/Downloads/Bison file/nysc hyd.hyd

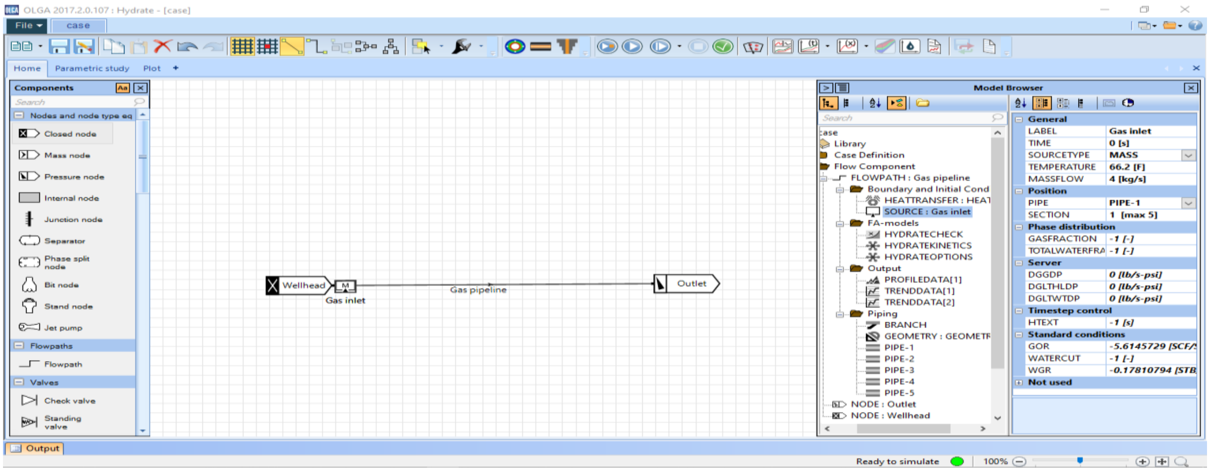
Wax Table
File name:

Pressures / Temperatures

Temperature (°F)	Pressure (psig)
-10	10
-1.632653061	30.20408163
6.734693878	50.40816327
15.10204082	70.6122449
23.46938776	90.81632653
31.83673469	111.0204082
40.20408163	131.2244898

Figure 4: Fluid file generation screen

The generated hydrate table and PVT table files were then imported into OLGA. An empty OLGA case was created and the flow path together with the nodes representing the inlet and outlet of the pipeline were selected. The gas transmission line consists of a closed node at the beginning of the pipeline with a mass source at the inlet, a flow path representing the pipeline and a pressure node at the end of the pipeline which is set at 30psig and 20°F. The pipeline materials and geometry data were used to define the pipeline. The environment surrounding the gas pipeline has an ambient temperature of 6°F. The CSMHyK model was selected in the hydrate model option with structure II hydrate selected as the hydrate phase. The default subcooling value was used as the allowable temperature difference between the hydrate formation temperature and the fluid temperature before nucleation will occur. The heat transfer from the pipeline wall to the surroundings and a mass source rate of 4kg/s were defined as the heat transfer and source keys respectively. Also, the gas pipeline was selected as the flow path where OLGA is going to check for hydrate by adding Hydrate check, which tells if hydrate will form, hydrate kinetic, which tells how fast hydrate will form and hydrate Option under the FA Models. The simulation end time was set to 1 hour. The OLGA screen together with the developed gas pipeline model is shown in Figure 5.



General	
LABEL	Gas inlet
TIME	0 [s]
SOURCETYPE	MASS
TEMPERATURE	66.2 [F]
MASSFLOW	4 [kg/s]
Position	
PIPE	PIPE-1
SECTION	1 [max 5]
Phase distribution	
GASFRACTION	-1 [-]
TOTALWATERFRA	-1 [-]
Server	
DGGDP	0 [lb/s-psi]
DGLTHLDP	0 [lb/s-psi]
DGLTWTDP	0 [lb/s-psi]
Timestep control	
HTEXT	-1 [s]
Standard conditions	
GOR	-5.6145729 [SCF/
WATERCUT	-1 [-]
WGR	-0.17810794 [STB
Not used	

Figure 5: OLGA gas pipeline model

These same procedures were repeated for the case of the addition of Monoethylene Glycol inhibitor to the fluid composition using the inhibitor calculator. After the inhibitor was added to the fluid system, the hydrate phase boundary was checked to see the effect of addition of the inhibitor to the fluid stream.

2.4 Sensitivity analysis and conditions

Sensitivity analyses were conducted to determine the optimum concentration of MEG required to supress hydrate formation in the pipeline. Mass concentration of 0%, 10%, 20% 30%, 40%, 50% and 60% each of MEG was injected into the pipeline to see their effect on hydrate formation tendencies.

3.0 RESULTS AND DISCUSSIONS

3.1 Phase Envelope

A phase envelope was developed to understand the phase changes (gas/liquid/hydrate) in the system at different conditions of temperatures and pressures. The phase envelope curve for the gas sample is as shown in figure 6. It reveals a critical point of -71.301°F and 999.637psig. Results show that hydrate II phase was present at a temperature of 38.35°F above the ice point. Liquid fractions are present in the hydrocarbon mixture at all temperature conditions below this critical temperature and pressure.

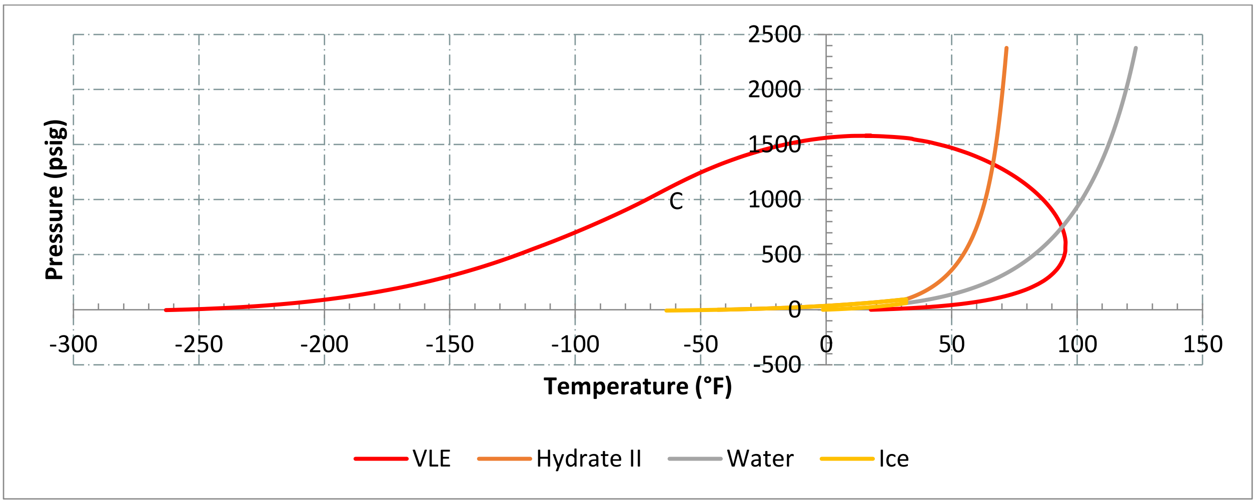


Figure 6: Phase envelope of the gas sample

3.2 Hydrate Dissociation and Nucleation curve

The hydrate nucleation curve represents when hydrates would theoretically form crystals instantly. The nucleation curve is based on the stochastic behavior of how hydrate crystals form and provides an estimate of the condition that cause hydrate crystals to go from meta-stable to stable. The hydrate dissociation temperature is the temperature below which hydrates can form. The hydrate dissociation calculation is an example of a fixed phase fraction flash. The hydrate nucleation temperature is the temperature at which the nucleation of hydrates occurs, and hydrates can form. Figure 7 shows the hydrate dissociation and nucleation curves.

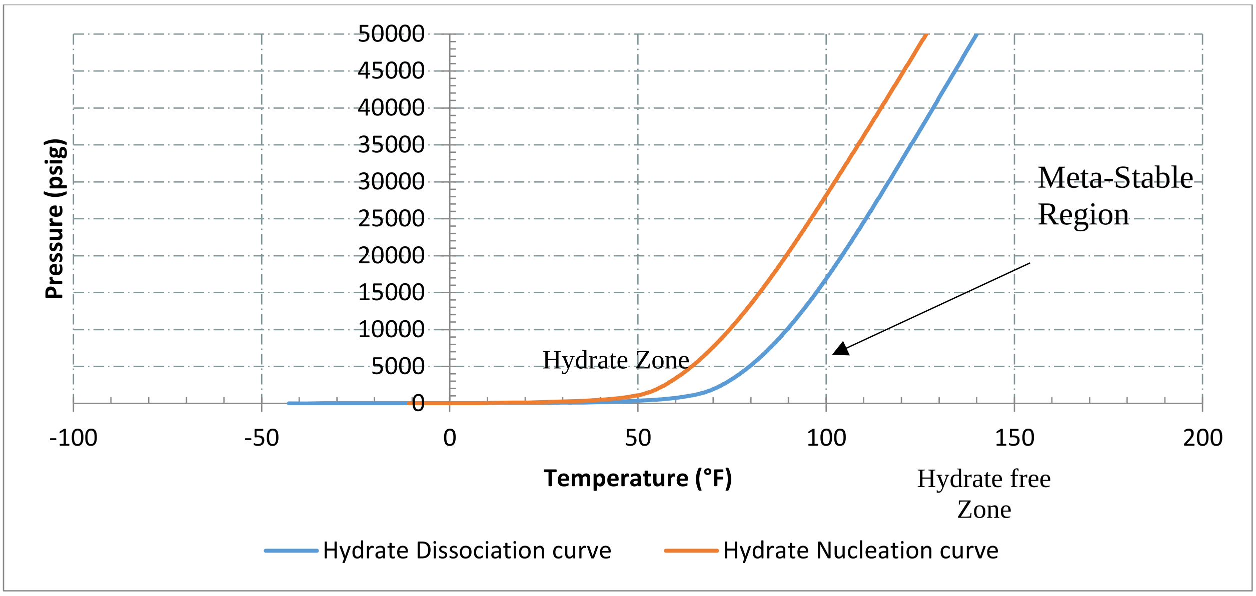


Figure 7: Hydrate Nucleation and Dissociation curves

To the left of the curves (towards lower temperature and higher pressure) is where hydrates are thermodynamically stable and to the right of the curves represent the area where hydrates do not exist as illustrated in figure 2(b). Between the dissociation and nucleation temperatures is the area of hydrate risk where hydrates may or may not form, depending on the time scale and kinetics of the formation process. The formation and dissociation temperatures vary with pressure, as shown in the figure. The dissociation temperature and pressure and the nucleation temperature and pressure are determined with a fixed phase flash calculation. From the calculation, it was observed that the hydrate has a dissociation temperature of 41.701°F at 200 psig. HYDRATE II was observed to be the most stable hydrate phase at the specified pressure. HYDRATE II was also the most stable hydrate phase at the specified temperature with a dissociation pressure of 68.622 psig at 20°F.

To calculate the hydrate nucleation temperature, a fixed phase flash calculation was used. The result shows that at 20°F, the hydrate phase starts to nucleate at a pressure of 120.330 psig, i.e. the hydrate crystals go from a meta-stable state and start to form at this condition. More so, at 200 psig, the hydrate nucleation temperature is 27.146°F. Table 4 shows a summary of the result from the calculation.

Table 4: Hydrate formation and dissociation calculation result

Fixed	**Hydrate formation value**	**Hydrate dissociation value**
Temperature (20°F)	120.330 psig	68.622 psig
Pressure (200 psig)	27.146°F	41.701°F

3.3 Effect on hydrate dissociation of adding a Mono Ethylene Glycol (MEG) inhibitor

Thermodynamic hydrate inhibitors decrease the temperature or increase the pressure at which hydrates will form from a given gas mixture. The effect of MEG inhibitor was investigated by adding it to the list of components. The inhibitor calculator was used to calculate the amount of MEG inhibitor to be added to the amount of water present in the fluid in order to reach a user-defined inhibitor concentration. Figure 8 shows the inhibition effect of adding MEG to the gas stream. The curves on the figure shows the effect of adding 0%, 10%, 20%, 30%, 40%, 50%, 60%, 70% and 80% mass concentration of MEG. The 0% concentration of MEG represents the normal fluid without any MEG. At 727 psig, hydrate may form at 60°F. If the pressure is increased further to 2000psig, hydrate may even start to form at a higher temperature (70°F). But by just adding 30% mass concentration of MEG to the fluid system, the hydrate curve has been lifted to the left and the hydrate at the same pressure (727psig) is forming at 54°F.

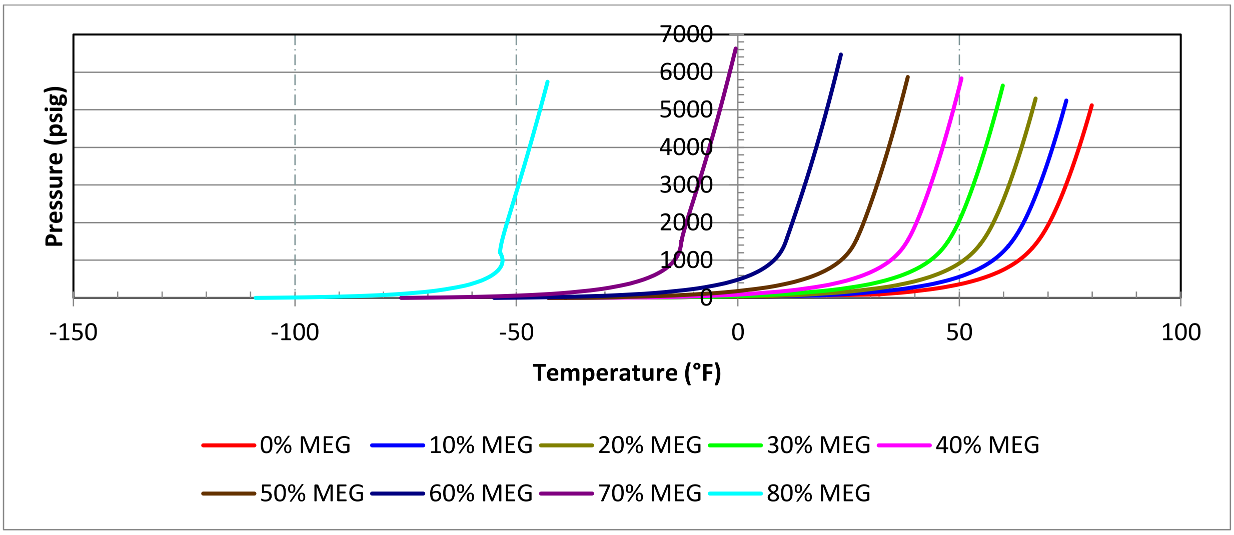
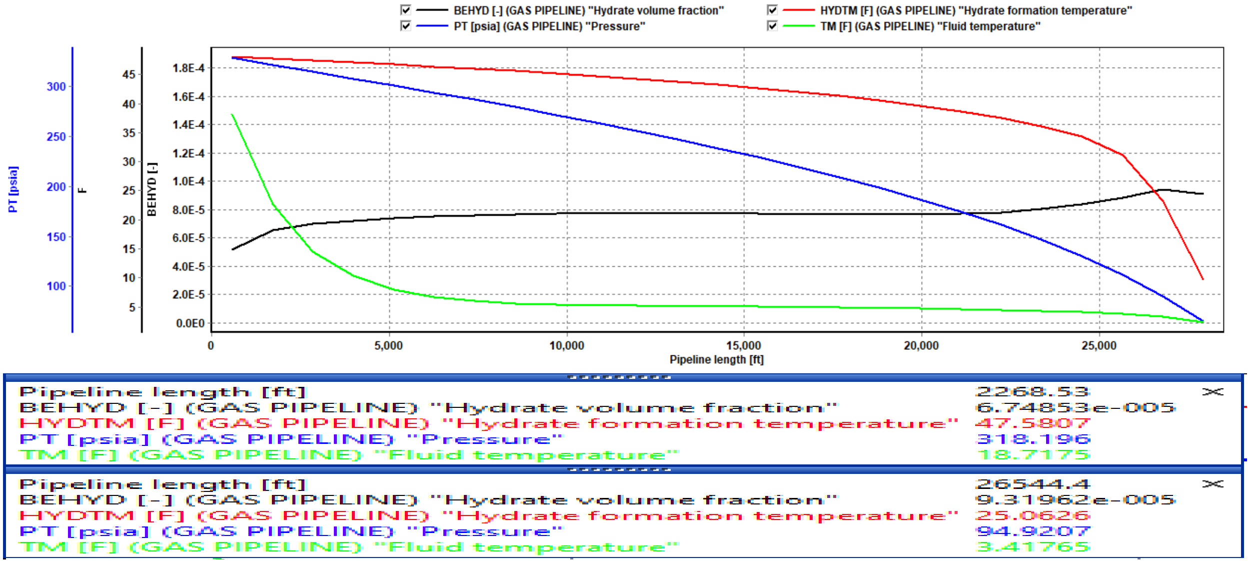


Figure 8: Effect of MEG Concentration on hydrate dissociation (hydrate curve).

3.4 Hydrate formation in the pipeline for the case of no inhibition

Figure 9 shows the section and hydrate variables. The red line is the hydrate formation temperature, the black line is the hydrate volume fraction, the blue line is the section pressure and the green line is the section temperature. The figure shows that at 2268.53ft along the pipeline that 6.74853 x10^{-5} volume fraction of hydrate has formed the pipeline for a pressure of 318.196psia and a temperature of 3.41765°F in the pipeline. Also, the figure reveals that a hydrate volume fraction of 9.31962 x10^{-5} has formed at 26544.4ft for a pressure 94.9207psia and a temperature of 3.41765°F existing in the pipeline section. It also reveals that hydrate will form right from the inlet section of the pipeline.

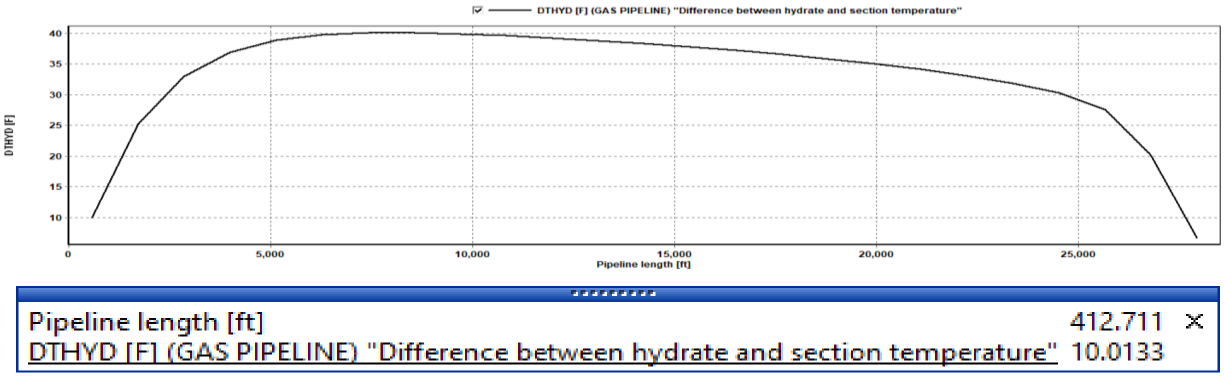


```
Pipeline length [ft]                                          2268.53
BEHYD [-] (GAS PIPELINE) "Hydrate volume fraction"            6.74853e-005
HYDTM [F] (GAS PIPELINE) "Hydrate formation temperature"      47.5807
PT [psia] (GAS PIPELINE) "Pressure"                           318.196
TM [F] (GAS PIPELINE) "Fluid temperature"                     18.7175
```

```
Pipeline length [ft]                                          26544.4
BEHYD [-] (GAS PIPELINE) "Hydrate volume fraction"            9.31962e-005
HYDTM [F] (GAS PIPELINE) "Hydrate formation temperature"      25.0626
PT [psia] (GAS PIPELINE) "Pressure"                           94.9207
TM [F] (GAS PIPELINE) "Fluid temperature"                     3.41765
```

Figure 9: Section and hydrate variables for the case of no inhibitor

This is also evident by the result showing the difference between the hydrate and section temperature (DTHYD) as shown in Figure 10. The figure shows that the variable DTHYD was positive throughout the entire pipeline length. This means that hydrates will form in the pipeline.

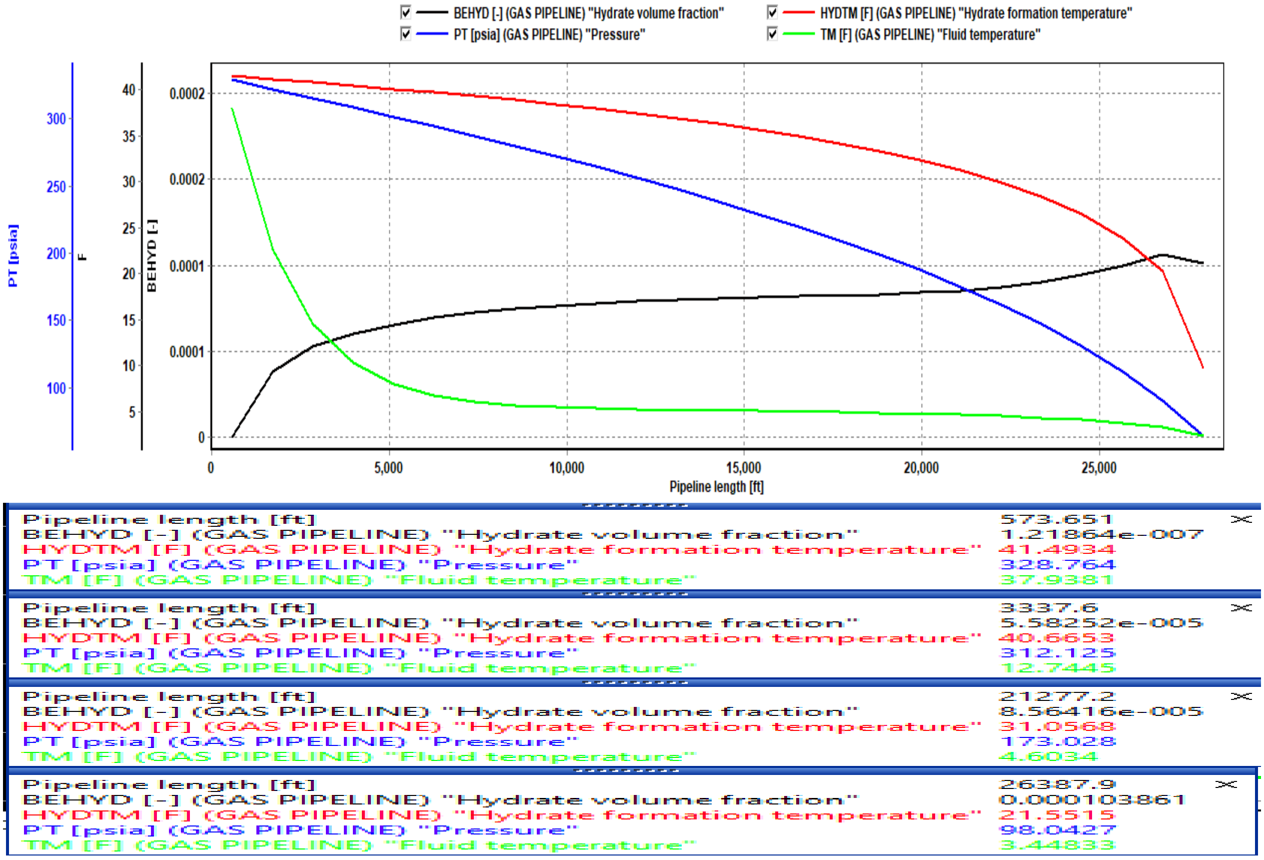


Pipeline length [ft] 412.711
DTHYD [F] (GAS PIPELINE) "Difference between hydrate and section temperature" 10.0133

Figure 10: DTHYD for the case of no inhibitor

3.4.1 Effect of 10 mass percent of MEG on hydrate formation

This is a case in which 10 mass percent of Monoethylene glycol was added to the fluid system. Figure 11 shows the section and hydrate variables along the length of the pipeline. The figure shows that hydrate was thermodynamically unstable until 573.651ft along the pipeline. At this point about 1.21864x10^{-7} volume fraction of hydrate has formed in the pipeline.



Pipeline length [ft] 573.651
BEHYD [-] (GAS PIPELINE) "Hydrate volume fraction" 1.21864e-007
HYDTM [F] (GAS PIPELINE) "Hydrate formation temperature" 41.4934
PT [psia] (GAS PIPELINE) "Pressure" 328.764
TM [F] (GAS PIPELINE) "Fluid temperature" 37.9381

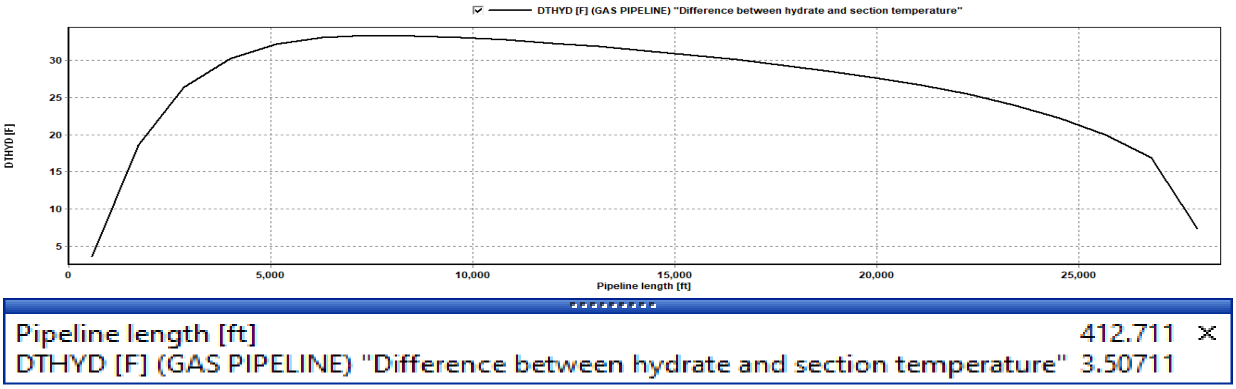
Pipeline length [ft] 3337.6
BEHYD [-] (GAS PIPELINE) "Hydrate volume fraction" 5.58252e-005
HYDTM [F] (GAS PIPELINE) "Hydrate formation temperature" 40.6653
PT [psia] (GAS PIPELINE) "Pressure" 312.125
TM [F] (GAS PIPELINE) "Fluid temperature" 12.7445

Pipeline length [ft] 21277.2
BEHYD [-] (GAS PIPELINE) "Hydrate volume fraction" 8.56416e-005
HYDTM [F] (GAS PIPELINE) "Hydrate formation temperature" 31.0568
PT [psia] (GAS PIPELINE) "Pressure" 173.028
TM [F] (GAS PIPELINE) "Fluid temperature" 4.6034

Pipeline length [ft] 26387.9
BEHYD [-] (GAS PIPELINE) "Hydrate volume fraction" 0.000103861
HYDTM [F] (GAS PIPELINE) "Hydrate formation temperature" 21.5515
PT [psia] (GAS PIPELINE) "Pressure" 98.0427
TM [F] (GAS PIPELINE) "Fluid temperature" 3.44833

Figure 11: Section and hydrate variable for the addition of 10 mass percent of MEG

Figure 12 is the profile of the variable DTHYD which is the difference between the hydrate equilibrium temperature and the section temperature for the entire pipeline. The figure shows that the variable was positive for the entire pipeline length, meaning that the hydrate equilibrium temperature was higher than the section temperature and therefore hydrate will form in the pipeline.

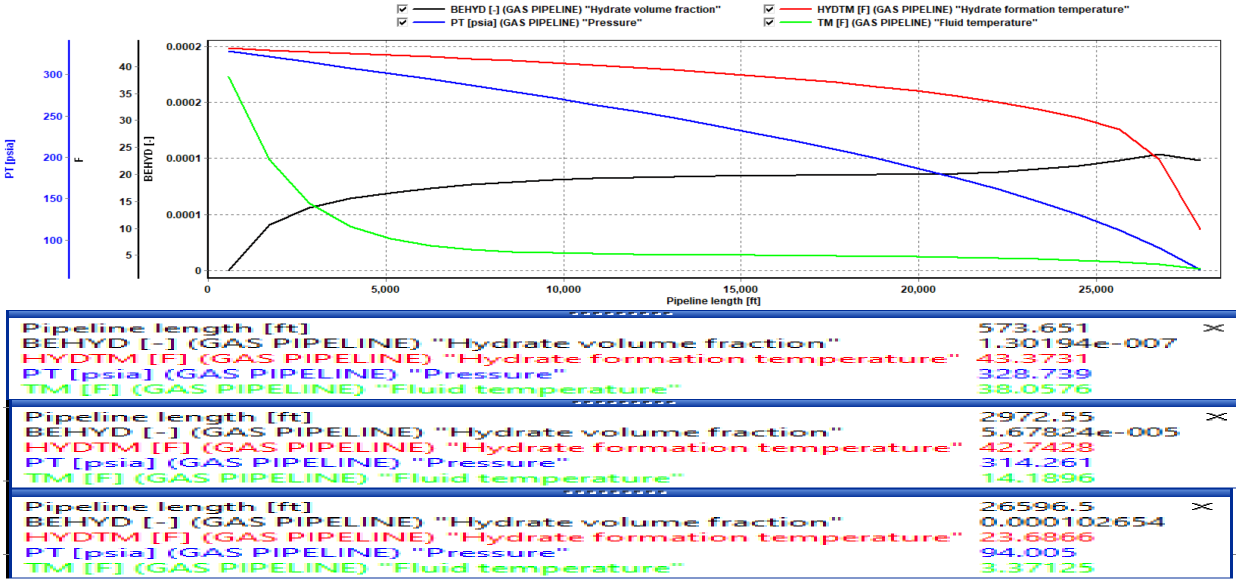


Pipeline length [ft] 412.711
DTHYD [F] (GAS PIPELINE) "Difference between hydrate and section temperature" 3.50711

Figure 12: DTHYD for the addition of 10 mass percent of MEG

3.4.2 Effect of 20 mass percent of MEG on hydrate formation

This is a case in which 20 mass percent of Monoethylene glycol was added to the fluid system. Figure 13 shows the section and hydrate variables along the length of the pipeline. The figure shows that up about 573.651ft along the pipeline that the hydrate was thermodynamically unstable. At this point about 1.30194x10^{-7} volume fraction of hydrate has formed in the pipeline.



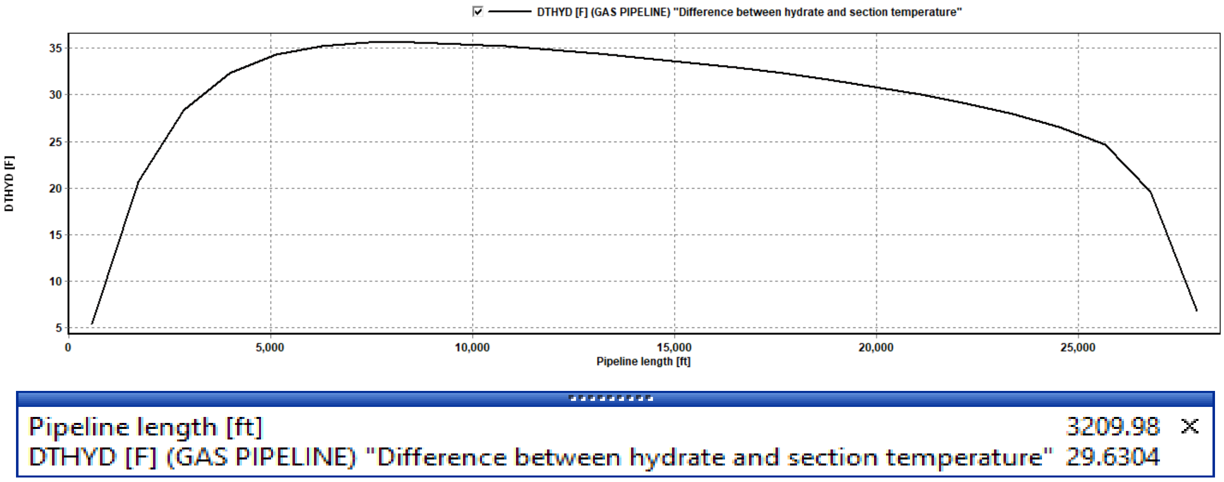
Pipeline length [ft] 573.651
BEHYD [-] (GAS PIPELINE) "Hydrate volume fraction" 1.30194e-007
HYDTM [F] (GAS PIPELINE) "Hydrate formation temperature" 43.3731
PT [psia] (GAS PIPELINE) "Pressure" 328.739
TM [F] (GAS PIPELINE) "Fluid temperature" 38.0576

Pipeline length [ft] 2972.55
BEHYD [-] (GAS PIPELINE) "Hydrate volume fraction" 5.67824e-005
HYDTM [F] (GAS PIPELINE) "Hydrate formation temperature" 42.7428
PT [psia] (GAS PIPELINE) "Pressure" 314.261
TM [F] (GAS PIPELINE) "Fluid temperature" 14.1896

Pipeline length [ft] 26596.5
BEHYD [-] (GAS PIPELINE) "Hydrate volume fraction" 0.000102654
HYDTM [F] (GAS PIPELINE) "Hydrate formation temperature" 23.6866
PT [psia] (GAS PIPELINE) "Pressure" 94.005
TM [F] (GAS PIPELINE) "Fluid temperature" 3.37125

Figure 13: Section and hydrate variable for the addition of 20 mass percent of MEG

Figure 14 shows the difference between the hydrate equilibrium temperature and the section temperature. The figure shows that this variable was positive throughout the entire pipeline length. This means that the entire pipeline length is susceptible to hydrate formation.

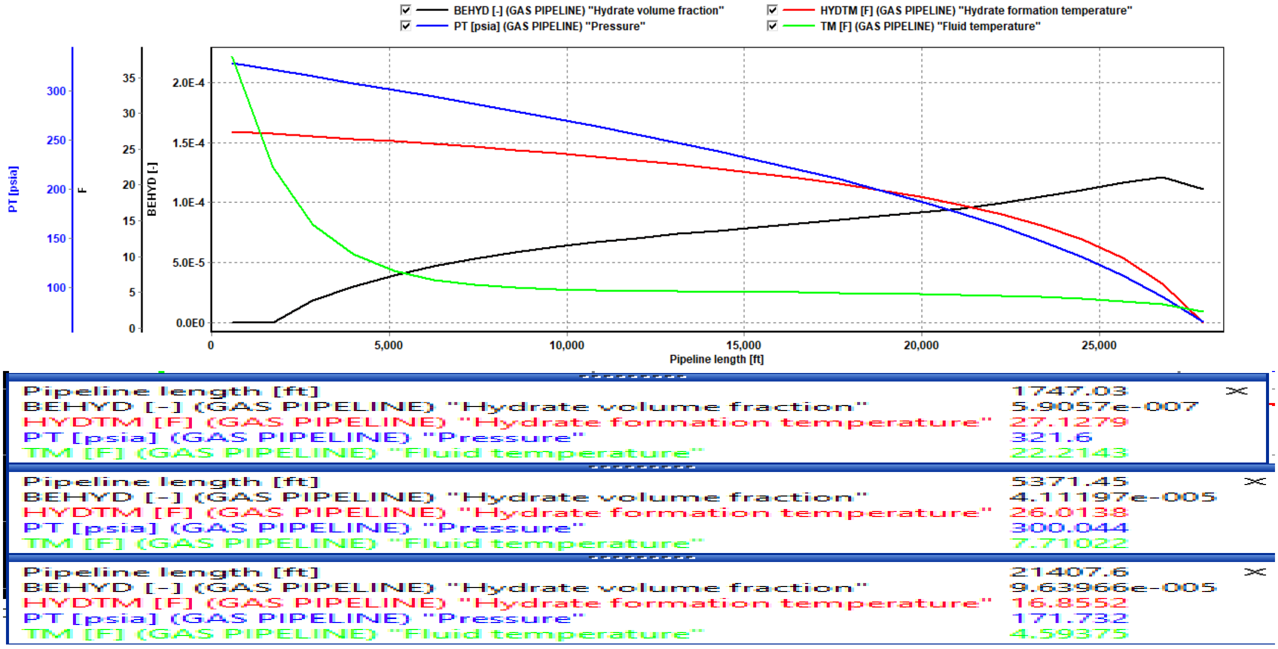


Pipeline length [ft] 3209.98
DTHYD [F] (GAS PIPELINE) "Difference between hydrate and section temperature" 29.6304

Figure 14: DTHYD for the addition of 20 mass percent of MEG

3.4.3 Effect of 30 mass percent of MEG on hydrate formation

This is a case in which 30 mass percent of MEG was added to the fluid system. Figure 15 shows the section and hydrate variable for the entire pipeline length. With the presence of 30 mass percent of MEG in the pipeline, the hydrate was thermodynamically unstable up to 1747.03ft along the pipeline length. At this point, about 5.9057x10^{-7} volume fraction of hydrate has formed in the pipeline.



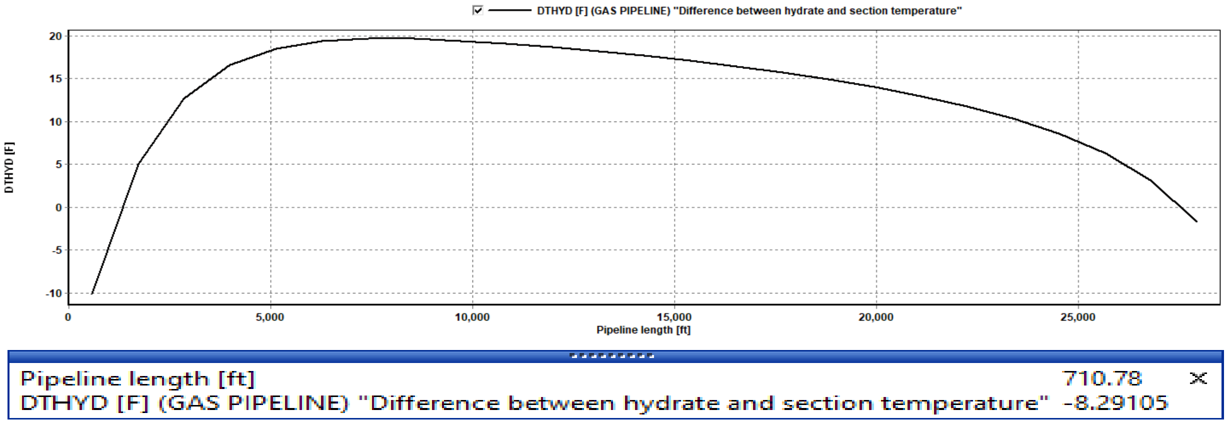
Pipeline length [ft] 1747.03
BEHYD [-] (GAS PIPELINE) "Hydrate volume fraction" 5.9057e-007
HYDTM [F] (GAS PIPELINE) "Hydrate formation temperature" 27.1279
PT [psia] (GAS PIPELINE) "Pressure" 321.6
TM [F] (GAS PIPELINE) "Fluid temperature" 22.2143

Pipeline length [ft] 5371.45
BEHYD [-] (GAS PIPELINE) "Hydrate volume fraction" 4.11197e-005
HYDTM [F] (GAS PIPELINE) "Hydrate formation temperature" 26.0138
PT [psia] (GAS PIPELINE) "Pressure" 300.044
TM [F] (GAS PIPELINE) "Fluid temperature" 7.71022

Pipeline length [ft] 21407.6
BEHYD [-] (GAS PIPELINE) "Hydrate volume fraction" 9.63966e-005
HYDTM [F] (GAS PIPELINE) "Hydrate formation temperature" 16.8552
PT [psia] (GAS PIPELINE) "Pressure" 171.732
TM [F] (GAS PIPELINE) "Fluid temperature" 4.59375

Figure 15: Section and hydrate variable for the addition of 30 mass percent of MEG

Figure 16 shows the effect of 30 mass percent concentration of MEG on the difference between the hydrate equilibrium temperature and the fluid temperature. The figure shows that at the beginning of the pipeline, the variable DTHYD was negative before it changes to positive at some point along the pipeline length. Hydrate will be thermodynamically unstable along the section of the pipeline where DTHYD was negative and stable along the section of the pipeline where DTHYD is positive.



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Pipeline length [ft]                                                          710.78
DTHYD [F] (GAS PIPELINE) "Difference between hydrate and section temperature" -8.29105
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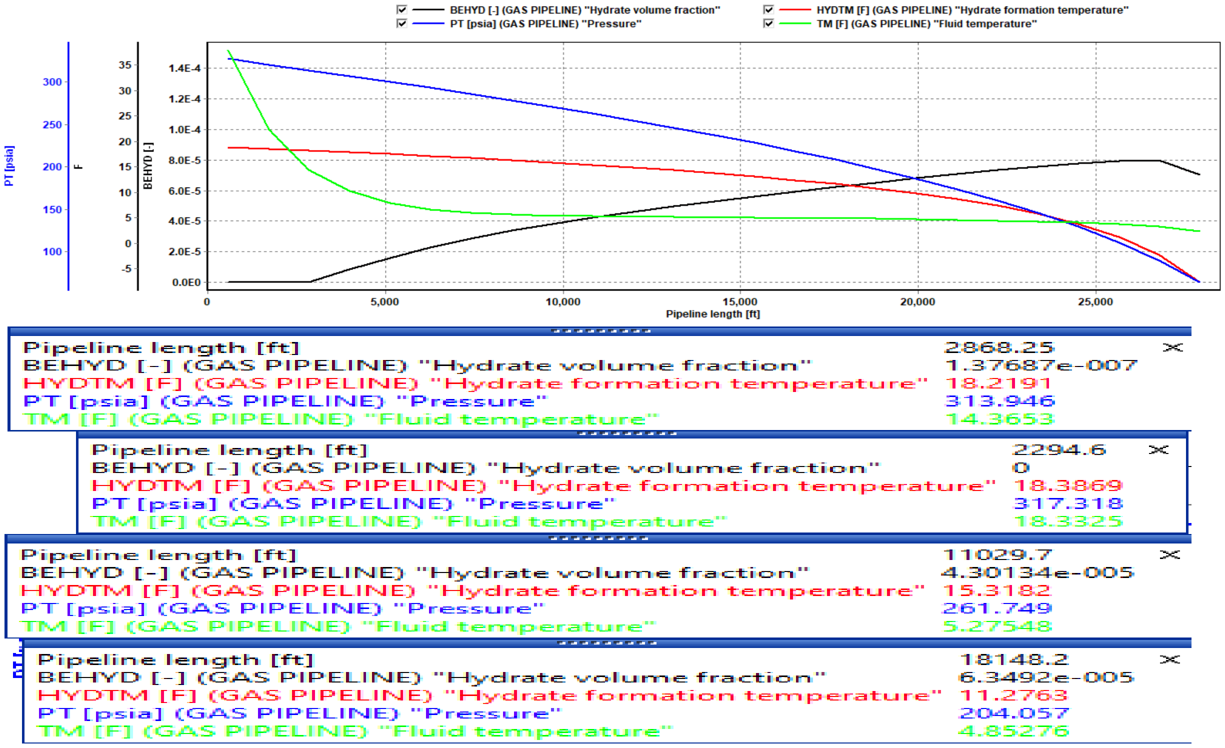
Figure 16: DTHYD for the addition of 30 mass percent of MEG

3.4.4 Effect of 40 mass percent of MEG on hydrate formation

This is a case in which 40 mass percent of MEG was added to the fluid system. Figure 17 shows the section and hydrate variable for the entire pipeline length. With the presence of 40 mass percent of MEG in the pipeline, the hydrate was thermodynamically unstable up to 2868.25ft along the pipeline length. At this point, about 1.37687x10^{-7} fraction of hydrate has formed in the pipeline. At 2294.6ft, no hydrate was present in the pipeline at a pressure of 317.318psia and 18.3325°F. Also, at 11029.7ft and a pressure and temperature conditions of 261.749psia and 5.27548°F, 4.30134 x10^{-5} volume fraction of hydrate has form in the pipeline. For a pressure and temperature conditions of 204.057psia and 4.85276°F existing at 18148.2ft along the pipeline, 6.3492x10^{-5} volume fraction of hydrate will form at this point.



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Pipeline length [ft]                                                  2868.25
BEHYD [-] (GAS PIPELINE) "Hydrate volume fraction"                    1.37687e-007
HYDTM [F] (GAS PIPELINE) "Hydrate formation temperature"              18.2191
PT [psia] (GAS PIPELINE) "Pressure"                                   313.946
TM [F] (GAS PIPELINE) "Fluid temperature"                             14.3653
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Pipeline length [ft]                                                  2294.6
BEHYD [-] (GAS PIPELINE) "Hydrate volume fraction"                    0
HYDTM [F] (GAS PIPELINE) "Hydrate formation temperature"              18.3869
PT [psia] (GAS PIPELINE) "Pressure"                                   317.318
TM [F] (GAS PIPELINE) "Fluid temperature"                             18.3325
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Pipeline length [ft]                                                  11029.7
BEHYD [-] (GAS PIPELINE) "Hydrate volume fraction"                    4.30134e-005
HYDTM [F] (GAS PIPELINE) "Hydrate formation temperature"              15.3182
PT [psia] (GAS PIPELINE) "Pressure"                                   261.749
TM [F] (GAS PIPELINE) "Fluid temperature"                             5.27548
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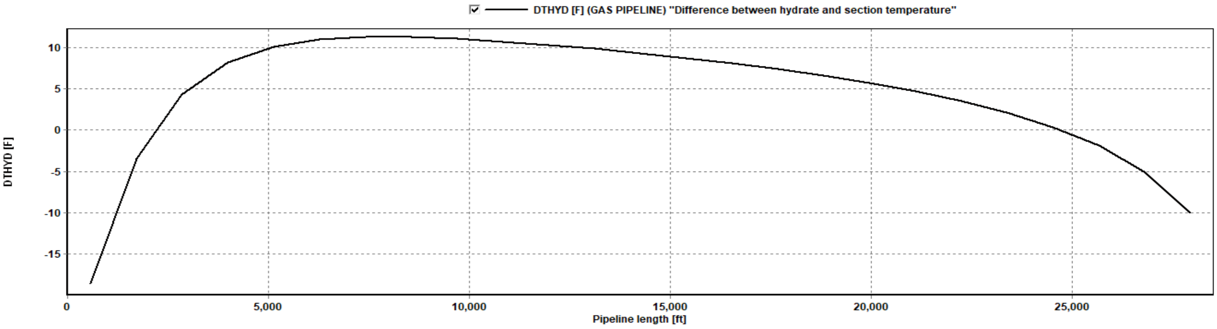
Pipeline length [ft]                                                  18148.2
BEHYD [-] (GAS PIPELINE) "Hydrate volume fraction"                    6.3492e-005
HYDTM [F] (GAS PIPELINE) "Hydrate formation temperature"              11.2763
PT [psia] (GAS PIPELINE) "Pressure"                                   204.057
TM [F] (GAS PIPELINE) "Fluid temperature"                             4.85276
```

Figure 17: Section and hydrate variable for the addition of 40 mass percent of MEG

Figure 18 shows the effect of 40 mass percent concentration of MEG on the difference between the hydrate equilibrium temperature and the fluid temperature (DTHYD). The result shows that at the beginning of the pipeline, the variable DTHYD was negative before it changes to positive at some point along the pipeline length. Also, it was far more negative when compared with that of 30 mass percent MEG. Hydrate will be thermodynamically unstable along the section of the pipeline where DTHYD was negative and stable along the section of the pipeline where DTHYD is positive.



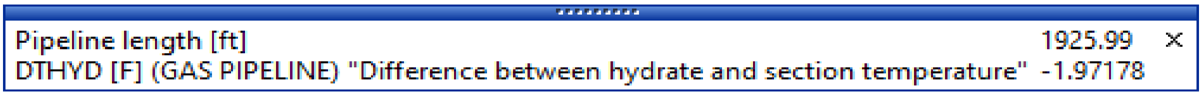
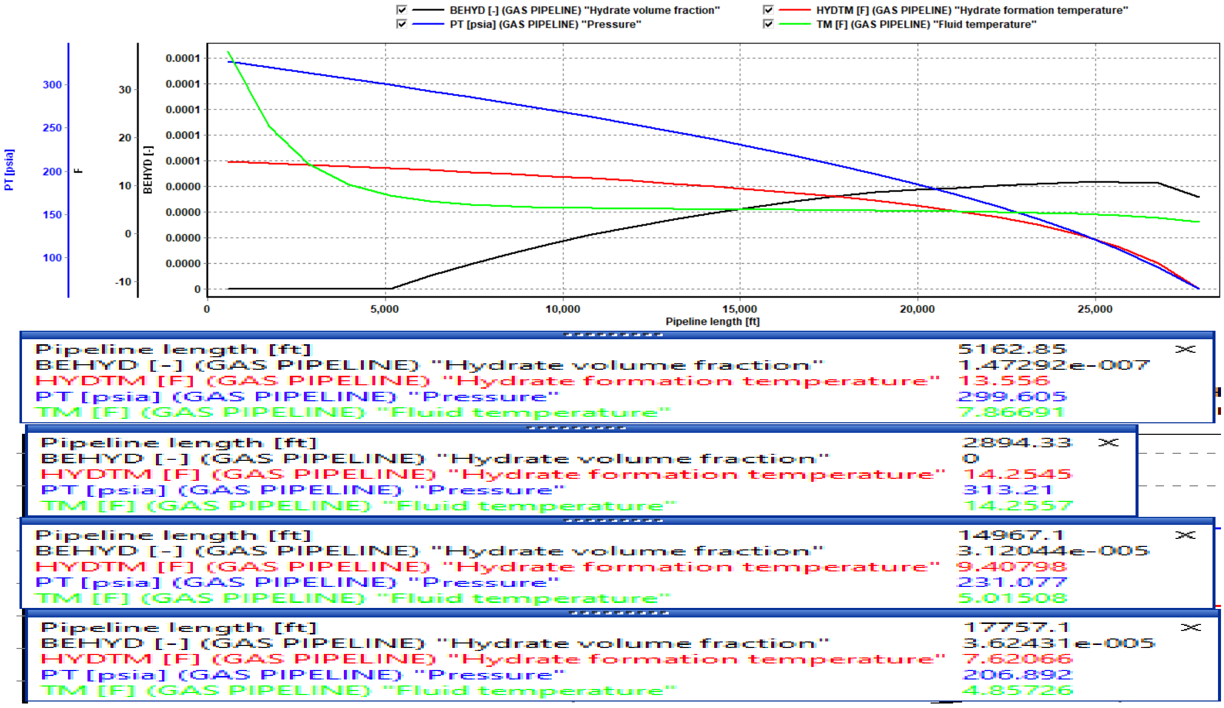

Pipeline length [ft] 1925.99
DTHYD [F] (GAS PIPELINE) "Difference between hydrate and section temperature" -1.97178

Figure 18: DTHYD for the addition of 40 mass percent of MEG

3.4.5 Effect of 44 mass percent MEG on hydrate formation

This is a case in which 44 mass percent of MEG was added to the fluid system. Figure 19 shows the section and hydrate variable for the entire pipeline length. With the presence of 44 mass percent of MEG in the pipeline, the hydrate was thermodynamically unstable up to 5162.85ft along the pipeline length. At this point, about 1.47292x10^{-7} fraction of hydrate has formed in the pipeline. At 2894.33ft, no hydrate was present in the pipeline at a pressure of 313.21psia and 14.2557°F. Also, at 14967.1ft and a pressure and temperature conditions of 231.077psia and 5.01508°F, 3.12044 x10^{-5} volume fraction of hydrate has form in the pipeline. For pressure and temperature conditions of 206.892psia and 4.85276°F existing at 17757.1ft along the pipeline, 3.62431x10^{-5} volume fraction of hydrate will form at this point.

Figure 20 shows the effect of 44 mass percent concentration of MEG on the difference between the hydrate equilibrium temperature and the fluid temperature (DTHYD). The figure shows that at the beginning of the pipeline, the variable DTHYD was negative before it changes to positive at some point along the pipeline length. Also, it was far more negative when compare with that of 30 mass percent MEG up to a value -25°F. Hydrate will be thermodynamically unstable along the section of the pipeline where DTHYD was negative and stable along the section of the pipeline where DTHYD is positive.



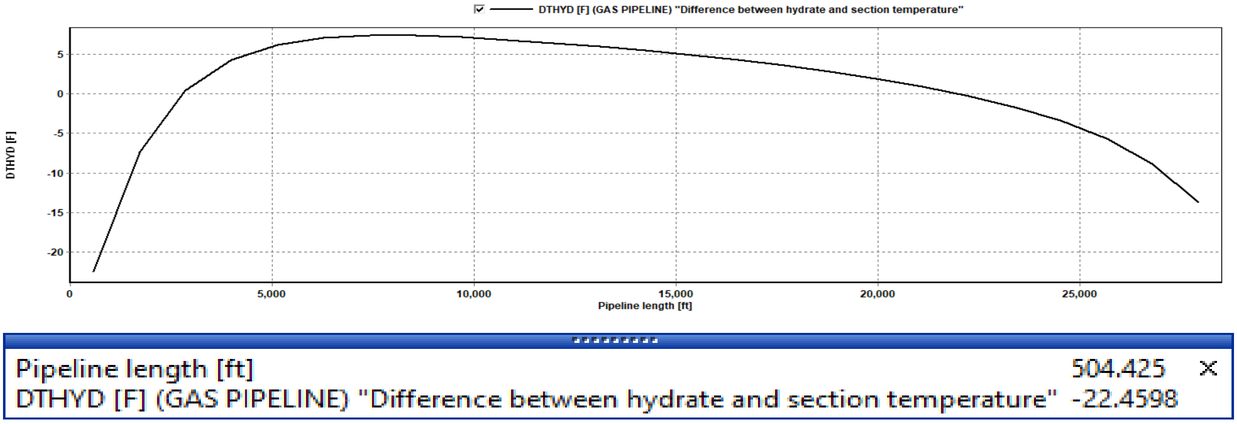
Pipeline length [ft]	5162.85
BEHYD [-] (GAS PIPELINE) "Hydrate volume fraction"	1.47292e-007
HYDTM [F] (GAS PIPELINE) "Hydrate formation temperature"	13.556
PT [psia] (GAS PIPELINE) "Pressure"	299.605
TM [F] (GAS PIPELINE) "Fluid temperature"	7.86691

Pipeline length [ft]	2894.33
BEHYD [-] (GAS PIPELINE) "Hydrate volume fraction"	0
HYDTM [F] (GAS PIPELINE) "Hydrate formation temperature"	14.2545
PT [psia] (GAS PIPELINE) "Pressure"	313.21
TM [F] (GAS PIPELINE) "Fluid temperature"	14.2557

Pipeline length [ft]	14967.1
BEHYD [-] (GAS PIPELINE) "Hydrate volume fraction"	3.12044e-005
HYDTM [F] (GAS PIPELINE) "Hydrate formation temperature"	9.40798
PT [psia] (GAS PIPELINE) "Pressure"	231.077
TM [F] (GAS PIPELINE) "Fluid temperature"	5.01508

Pipeline length [ft]	17757.1
BEHYD [-] (GAS PIPELINE) "Hydrate volume fraction"	3.62431e-005
HYDTM [F] (GAS PIPELINE) "Hydrate formation temperature"	7.62066
PT [psia] (GAS PIPELINE) "Pressure"	206.892
TM [F] (GAS PIPELINE) "Fluid temperature"	4.85726

Figure 19: Section and hydrate variable for the addition of 44 mass percent of MEG

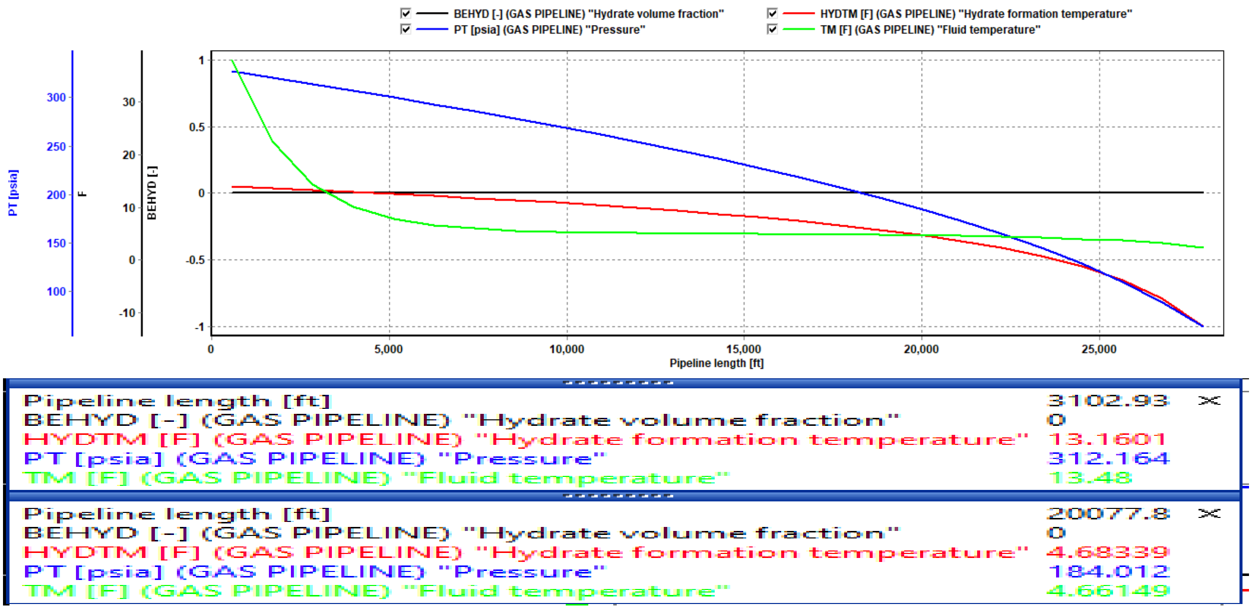


Pipeline length [ft]	504.425
DTHYD [F] (GAS PIPELINE) "Difference between hydrate and section temperature"	-22.4598

Figure 20: DTHYD for the addition of 44 mass percent of MEG

3.4.6 Effect of 45 mass percent MEG on hydrate formation

This is a case in which 45 mass percent of MEG was added to the fluid system. Figure 21 shows the section and hydrate variable for the entire pipeline length. With the presence of 45 mass percent of MEG in the pipeline, the hydrate was thermodynamically unstable throughout the pipeline length. For the entire pipeline length, the hydrate volume fraction was zero. Thus, no hydrate was formed in the pipeline. At 3102.93ft, no hydrate was present in the pipeline at a pressure of 312.164psia and 13.48°F. For pressure and temperature conditions of 184.012psia and 4.66149°F existing at 20077.8ft along the pipeline, zero volume fraction of hydrate will form at this point.

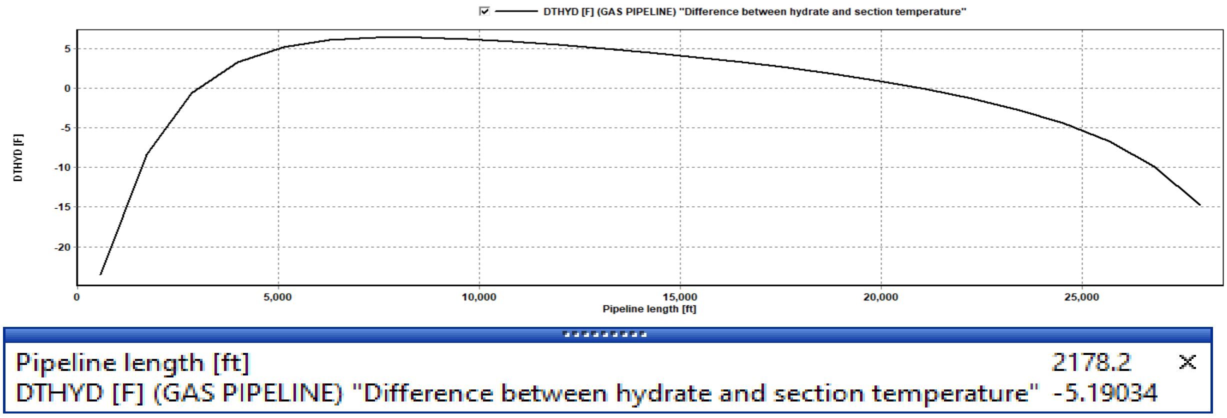


Pipeline length [ft]	3102.93
BEHYD [-] (GAS PIPELINE) "Hydrate volume fraction"	0
HYDTM [F] (GAS PIPELINE) "Hydrate formation temperature"	13.1601
PT [psia] (GAS PIPELINE) "Pressure"	312.164
TM [F] (GAS PIPELINE) "Fluid temperature"	13.48

Pipeline length [ft]	20077.8
BEHYD [-] (GAS PIPELINE) "Hydrate volume fraction"	0
HYDTM [F] (GAS PIPELINE) "Hydrate formation temperature"	4.68339
PT [psia] (GAS PIPELINE) "Pressure"	184.012
TM [F] (GAS PIPELINE) "Fluid temperature"	4.66149

Figure 21: Section and hydrate variable for the addition of 45 mass percent of MEG

Figure 22 shows the effect of 45 mass percent concentration of MEG on the difference between the hydrate equilibrium temperature and the fluid temperature (DTHYD). The figure shows that at the beginning of the pipeline, the variable DTHYD was negative before it changes to positive at some point along the pipeline length and then falling back to negative at the pipeline outlet. Note that this variable was positive along the pipeline yet no hydrate formation was observed in the pipeline.



Pipeline length [ft]	2178.2
DTHYD [F] (GAS PIPELINE) "Difference between hydrate and section temperature"	-5.19034

Figure 22: DTHYD for the addition of 45 mass percent of MEG

4.0 CONCLUSION

This work evaluates the effect of Monoethylene Glycol in hydrate management and its optimum concentrations for hydrate formation prevention in gas transmission pipeline. A simulation-based approach was adopted and OLGA Dynamic Multiphase flow simulator and Multiflash fluid model modelling package were used. The findings revealed that the increase in the mass percent of the MEG increases the length of instability of the hydrate formation along the pipeline. Additionally, it showed that the increase in the mass concentration of the MEG decreases the volume fraction of hydrate formed in the pipeline, and 45 percent mass concentration of MEG inhibited hydrate formation in the gas mixture.

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