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Prediction of Hydrate Plug Formation at Different Water Cuts in Gas Pipelines

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Abstract: *Hydrate plug formation in gas pipelines is a significant operational challenge, particularly in offshore and deepwater environments where high pressures and low temperatures favor hydrate creation. Hydrates, which are crystalline compounds formed by water encapsulating gas molecules like methane, can lead to flow blockages and costly shutdowns. This study investigates the prediction of hydrate plug formation at various water cuts, a critical factor influencing hydrate risks, using OLGA and PVTsim simulation tools. The research focuses on integrating these tools to model pipeline conditions accurately, assessing the effects of water content, pressure, temperature, and gas composition on hydrate formation. Various water cut scenarios were simulated to evaluate how different levels of water in the gas stream impact hydrate plugging tendencies. The study identifies critical thresholds for hydrate formation under both steady-state and transient flow conditions, while also exploring the effectiveness of prevention strategies such as inhibitors and thermal management. Results indicate that changes in water cut significantly affect the conditions under which hydrates form, with specific ranges where the risk of plugging increases sharply. This integrated simulation approach enhances understanding of the complex interactions involved, providing valuable insights for optimizing pipeline design and operational practices, ultimately ensuring safer and more efficient gas transport.*

.**Keywords—Hydrate plug formation; Water cuts; Gas pipeline; Simulation**

1. INTRODUCTION

The formation of hydrate plugs in gas pipelines is a critical concern for the oil and gas industry, particularly in offshore and deepwater systems where high pressures and low temperatures create optimal conditions for hydrate development. Hydrates are crystalline structures formed when water molecules encapsulate gas molecules, such as methane, leading to obstructions that can significantly disrupt natural gas flow and pose substantial operational risks [2]. As exploration efforts extend into deeper waters, the urgency to develop effective management strategies to mitigate hydrate-related issues has intensified.

Accurately determining the water content in production streams, known as water-cut, is vital for effective production monitoring. The key objective of water-cut measurement is to evaluate the quality of crude oil transported through pipelines or flow lines, as even minor measurement errors can lead to significant financial consequences [3]. These measurements are critical for maintaining the quality of extracted oil, facilitating marketing processes, overseeing custody transfers, managing corrosion, conducting material balance calculations for oil reservoirs, and minimizing bitumen loss in oil sands operations. High water content can contaminate produced oil, resulting in fouling, hydrate plug formation, and corrosion. Furthermore, water separation demands considerable energy, making precise water content assessment essential for optimizing crude oil production economics [1].

Gas hydrates were initially produced in laboratory conditions by Joseph Priestly in 1778, when he bubbled SO_2 through water at 0°C under atmospheric pressure and low room temperatures. Approximately 30 years later, in 1811, Sir Humphrey Davy identified similar aqueous chlorine crystals, referring to them as gas hydrates. While Davy is often credited with their discovery, Priestly was the first to create them in a laboratory. Industrial interest in gas hydrates remained minimal until the 1930s [7].

Kamal et al. [8] noted that Humphrey Davy first recognized hydrates in 1810, although his theoretical work attracted limited attention at that time. This scenario persisted until 1930 when hydrate formation in gas pipelines became a significant industrial challenge. Hammerschmidt [16] published pioneering research on hydrates, highlighting their formation in flowlines as a major issue for the oil and gas sector. This necessitates either preventing hydrates in flowlines or ensuring their safe transport. Extensive research has focused on predicting hydrate formation to mitigate associated costs.

Usman et al. [9] proposed a model-based approach to manage hydrate impacts, utilizing PVTSim software based on the Peng-Robinson equation of state to create a temperature-pressure operational envelope. This model effectively defined the operational boundaries of production systems to prevent hydrate blockages during unplanned shutdowns. Their scenario analyses established operational limits for subsea facilities to avoid hydrate formation. Salam et al. [10] employed the HYSYS simulation tool to predict hydrate formation conditions in three different gas streams, comparing results with empirical data, which showed strong correlation.

Yanli et al. [11] compared four pipe system temperature prediction methods with field data and evaluated five hydrate formation prediction techniques against experimental results. They introduced a method using OLGA and PVT Sim to predict hydrate formation in wellbores, leveraging data from the South China Sea. Their study revealed that increasing inhibitor concentrations and insulation thickness reduced hydrate formation areas, while higher insulation thermal conductivity and longer shutdowns expanded these areas. Additionally, they found that the throttling effect significantly raised wellbore temperature and pressure, increasing hydrate formation risk.

Zerpa et al. [12] developed a gas hydrate model for oil-dominated systems to assess plugging risks in offshore wells, specifically in Brazil's Compos Basin. Their evaluation covered three well lifecycle phases: low gas-oil ratio (GOR) with minimal water cut, higher GOR, and even higher GOR with increased water cut. They used pressure drop, hydrate volume fraction, and slurry viscosity as risk indicators. The model demonstrated that ethanol injection reduced plugging risks under steady and transient conditions, helping identify optimal ethanol concentrations. A novel method to monitor hydrate safety margins was also introduced [13].

This new approach optimizes hydrate inhibitor injection by evaluating the actual safety margin, reducing unnecessary costs, and minimizing environmental impacts. It involves measuring acoustic velocity and electrical conductivity in downstream aqueous samples, with a neural network determining salt and inhibitor concentrations. These values feed into a thermodynamic model to identify the hydrate phase boundary. The method proved effective across various inhibition systems, including methanol-salt, monoethylene glycol-salt, and kinetic hydrate inhibitor-salt combinations, delivering accurate safety margin monitoring.

Hydrate growth is primarily influenced by two parameters: the time constant and the growth exponent. Determining kinetic parameters for different crude oils can enhance hydrate growth models, aiding in pipeline plugging risk assessments. The oil-water emulsion state significantly affects these parameters, as changes in hydrate formation rates correlate with emulsion inversion, which is influenced by water cut—a key factor in hydrate growth rates [14].

Joshi et al. [17] conducted comprehensive hydrate formation experiments using a 95 m long, 9.7 cm diameter flow loop to study plugging mechanisms in high water cut systems. They identified three distinct regions post-hydrate formation, with the transition concentration (φtransition) serving as an indicator for potential plugging events.

Hydrates pose significant challenges in deep-water subsea systems, forming when gas and water coexist under specific thermodynamic conditions. These crystalline compounds consist of hydrocarbon gas molecules (guest molecules) encapsulated within a lattice of hydrogen-bonded water molecules. The high-pressure and low-temperature environments characteristic of extended subsea tiebacks strongly favor hydrate formation, potentially leading to flowline blockages [2].

Much research has focused on experimental data to develop predictive and management models for hydrates. Traditional mitigation strategies, such as methanol or glycol injection, are costly and environmentally unsustainable. The industry has relied on passive insulation to maintain flowline temperatures above hydrate formation thresholds. However, unexpected well shutdowns can disrupt operations, requiring significant time and strategies to prevent hydrate formation during restarts [4].

The aim of this work is to predict hydrate plug formation in gas pipelines at different water cuts using OLGA and PVTsim design. This analysis does not address mitigation strategies, shutdown procedures, or restart scenarios.

2. MATERIALS AND METHODS

2.1 Materials

The materials used in this study are literature data from the work of [2], OLGA and PVTsim software for model development and simulation. These data include 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. Table 1 to 5 presents these data in details.

Table 1: Fluid Composition Analysis [20], [6], [18], [19]

Component Name	Mole %
Nitrogen	0.04
Carbon Dioxide	0.94
Methane	50.22
Ethane	3.94
Propane	2.59
I-Butane	1.02

N-Butane	1.35
I-Pentane	0.95
N-Pentane	0.77
C6	1.5
C7	2.82
C8	3.93
C9	2.98
C10	2.47
C11	2.07
C12+	22.41
C12+ Density	0.874g/cc
C12+ Molecular weight	284.22kg/kmol

Table 2: Pipeline Geometry [6]

X-Coordinate (m)	Y-Coordinate (m)	Diameter (in)	Roughness (in)
0	-989	7	0.0006
1300	-985	7	0.0006
4100	-995	7	0.0006
4900	-1000	7	0.0006
6400	-985	7	0.0006
6800	-980	7	0.0006
7200	-975	7	0.0006
7900	-970	7	0.0006
8700	-965	7	0.0006
9600	-960	7	0.0006
10200	-955	7	0.0006
11200	-950	7	0.0006
12900	-945	7	0.0006

Table 3: Riser Geometry [6]

X-Coordinate (m)	Y-Coordinate (m)	Diameter (in)	Roughness (in)
12900	-945	7	0.0006
12970	-600	7	0.0006
13002	-100	7	0.0006
13005	0	7	0.0006
13006	40	7	0.0006

Table 4: Properties of the Pipeline Materials [5]

Material	Density (kg/m^3)	Specific heat (J/kg K)	Thermal conductivity (W/m K)	Wall thickness (mm)
Steel	7850	500	50	8
Insulation	1000	1500	0.135	13.28

Table 5: Heat Transfer Data

Property	Value
Pipeline overall heat transfer coefficient	8W/m^2-C
Riser overall heat transfer coefficient	8W/m^2-C
Riser and pipeline ambient temperature	4°C

Table 6: Operating Parameters

Property	Value
Inlet mass flow rate	15kg/s
Inlet temperature	60°C
Outlet temperature	22°C
Outlet pressure	27psig

2.2 Methods

The OLGA hydrate module and PVTsim, a phase behaviour and fluid property program were used in this study. Table 1 shows the gas composition which was fed into PVTsim for the generation of hydrate and PVT files. An OLGA case was created and the flowpath together with the nodes representing the inlet and outlet of the system were added. The system consisted of a mass node at the beginning of the tieback, a flowpath representing the tieback/riser and a pressure node at the outlet. The tieback/riser materials and geometry data presented in Table 2, 3 and 4 were used to define the system. Data in Table 5 were used in defining operating conditions and heat transfer between the system and its surroundings. The model was run for 30hrs for a water cut of 40, 50, 60 and 70 percent.

2.3 Simulation Workflow: The flowchart of the simulation workflow is given in figure 1

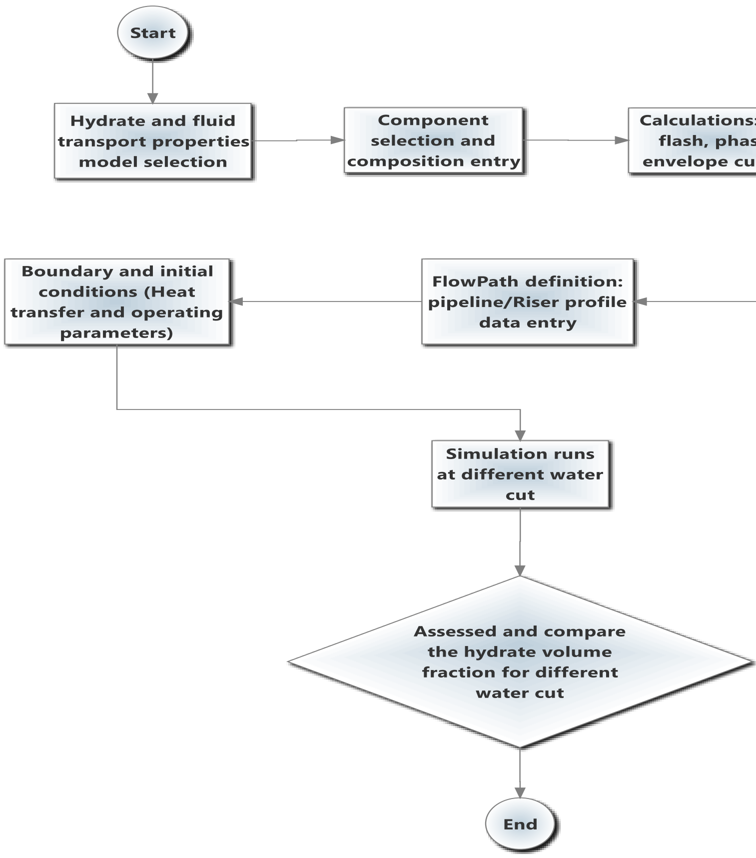

FIGURE 1: SIMULATION WORKFLOW

3. RESULTS AND DISCUSSION

3.1 FLUID PHASE ENVELOPE

Figure 2 shows the fluid phase envelope. The Vapour Liquid Equilibrium (VLE) represents the boundary separating the liquid and vapour phases, where both phases exist together in equilibrium within the two-phase boundary. The critical temperature and pressure at the critical point are 69.537 °C and 522.736 bar, respectively.

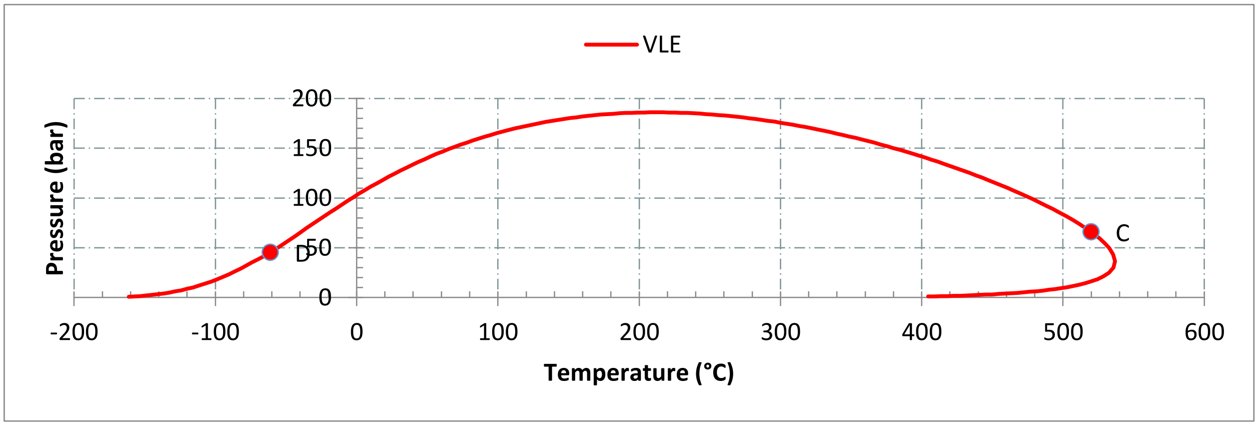

Figure 2: Fluid Pressure against Temperature

3.2 Hydrate Phase Boundary

Figure 3 illustrates the hydrate phase boundary for the fluid system. The findings indicate that field activities to the right of the hydrate equilibrium boundary imply conditions without hydrates, whereas field activities to the left indicate a risk of hydrate formation. Hydrates are thermodynamically stable as they move toward the left side of the curve and are thermodynamically unstable as they progress toward the right side of the curve.

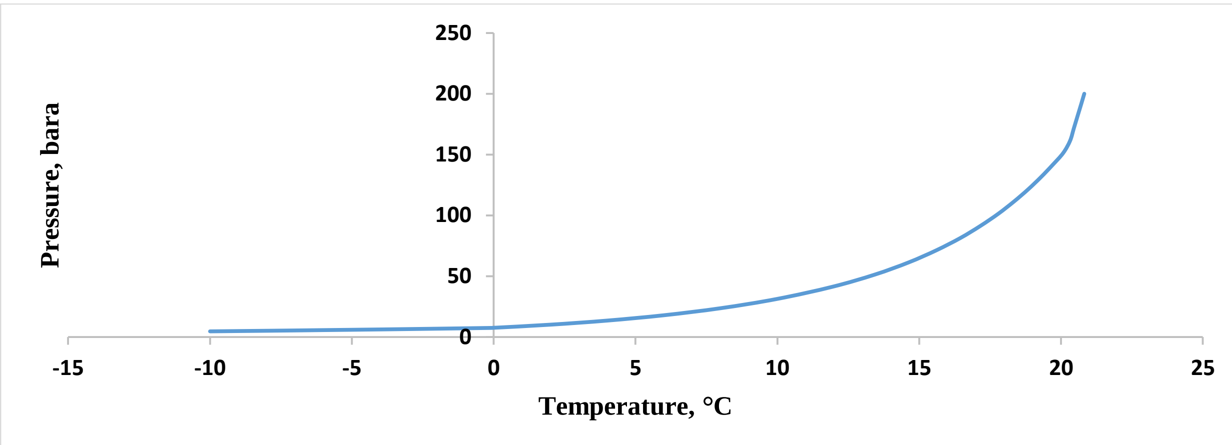

Figure 3: Hydrate Formation Pressure against Temperature

3.2.1 Effect of 50% Water Cut

Figure 4 illustrates the section and hydrate variables for the impact of a 50% water cut. The results indicate an initial hydrate volume fraction of 0.0000000424476 at 12533.3m that increases to 0.0000110463 at 13524.8m under a pressure of 180.89psia and a temperature of 25.89°F.

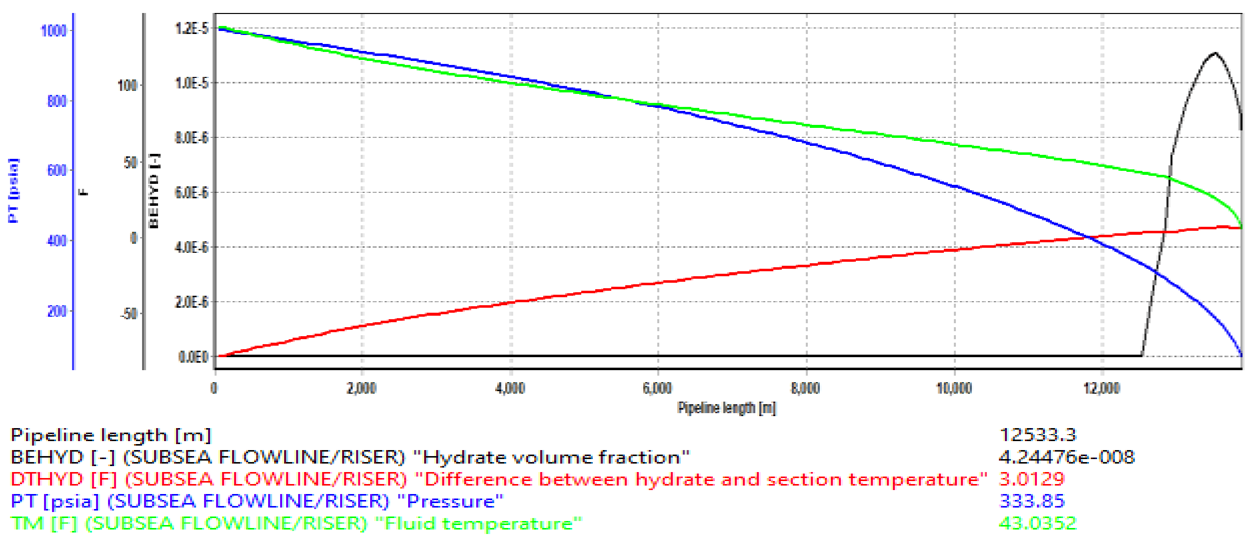

Figure 4: Fluid and Hydrate Variables for 50% Water Cut

3.2.2 Effect of 60% Water Cut

Figure 5 illustrates the fluid and hydrate parameters for the impact of a 60% water cut. The findings reveal an initial hydrate volume fraction of 0.000000400508 at 12965.5 m, which increases to a peak value of 0.00000791405 at

13626.4 m, corresponding to a pressure of 158.015 psi and a temperature of 22.739 °F.

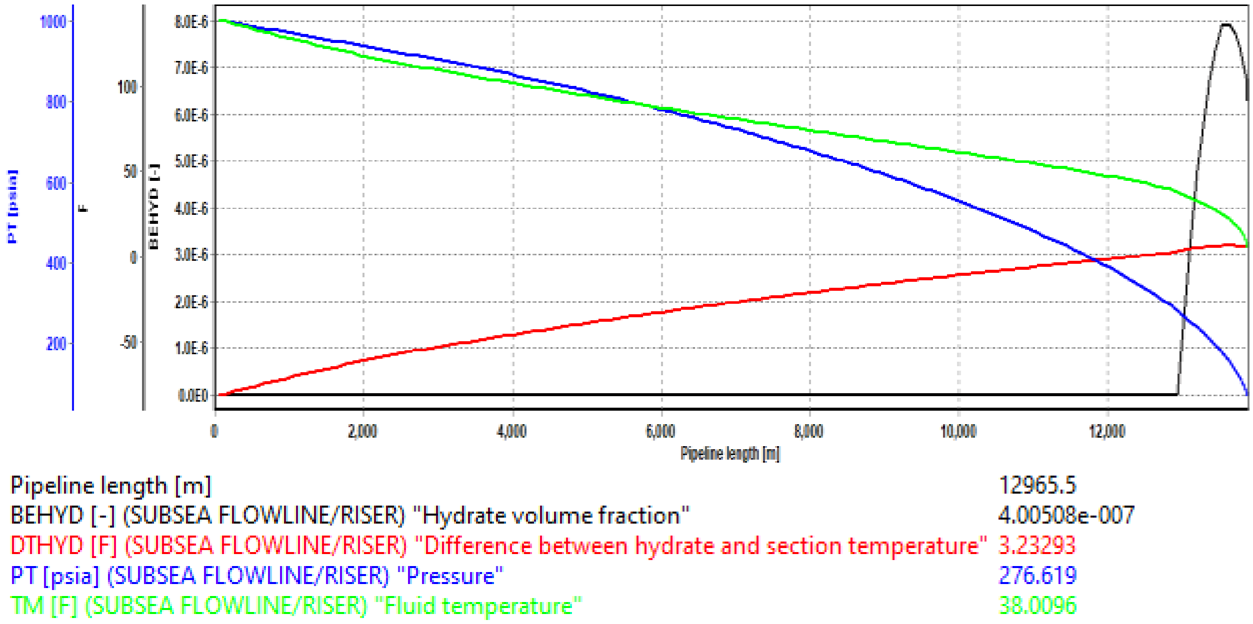

Figure 5: Fluid and Hydrate Variables for 60% Water Cut

3.2.3 Effect of 70% Water Cut

Figure 6 illustrates the fluid and hydrate parameters resulting from a 70% water cut. The hydrate volume fraction starts at 0.000000147345 at 13219.7 m and rises to 0.00000474673 at 13728.1 m, with a pressure of 130.891 psia and a temperature of 18.884 °F.

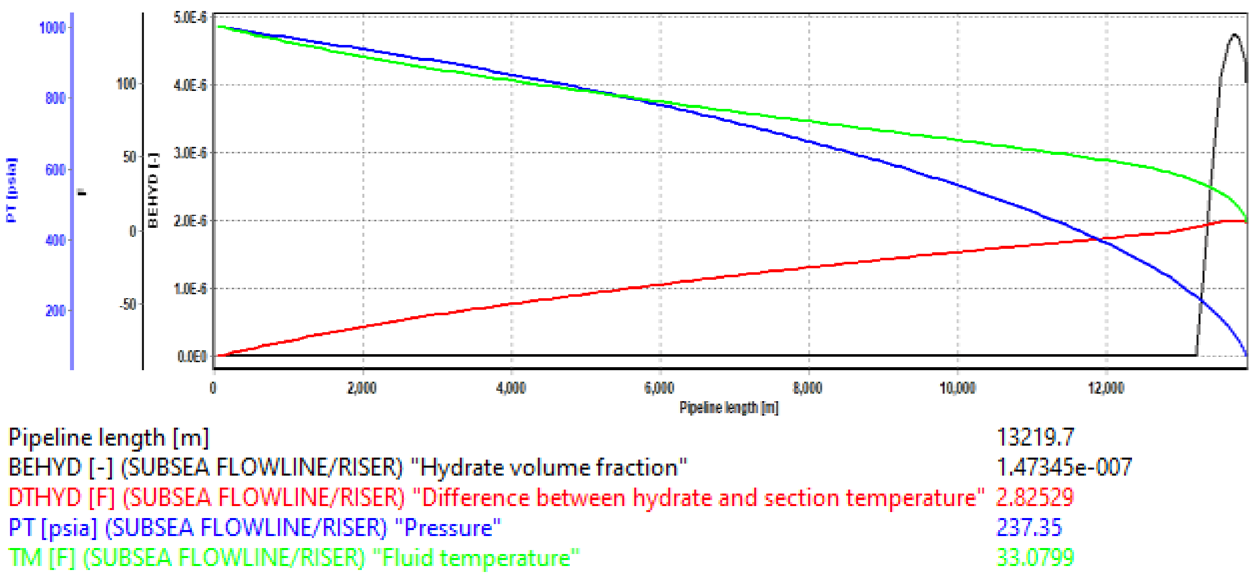

Figure 6: Fluid and Hydrate Variables for 70% Water Cut

3.2.4 Effect of 80% Water Cut

Figure 7 illustrates the fluid and hydrate parameters concerning an 80% water cut. The findings indicate that under all temperature and pressure conditions, there was no formation of hydrates within the system, as demonstrated by a volume fraction of zero for hydrates and the negative difference between hydrate and section temperature across the system.

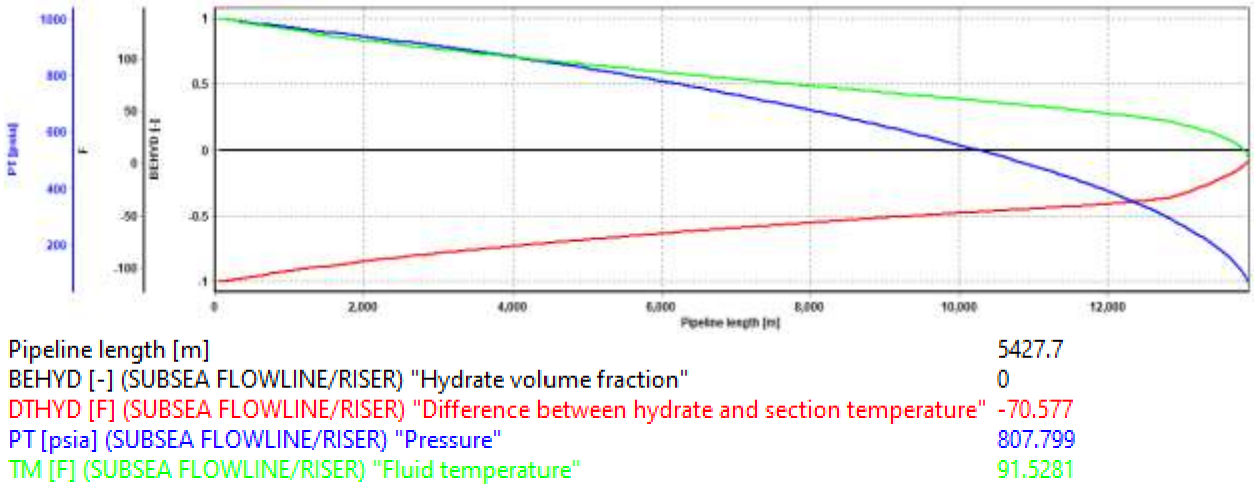

Figure 7: Fluid and Hydrate Variables for 80% Water Cut

4 CONCLUSION

This study on the prediction of hydrate plug formation in gas pipelines at different water cuts has provided valuable insights into the operational challenges posed by hydrates in the oil and gas industry. The primary objectives were achieved through the use of OLGA and PVTsim simulation tools, which facilitated the modeling of hydrate formation conditions based on varying water content in the gas streams.

The research involved determining the specific conditions under which hydrates form, simulating various water cut scenarios, and evaluating the performance of the prediction tools. By integrating dynamic multiphase flow modeling with advanced thermodynamic phase behavior predictions, the study captured the critical interactions between water content, pressure, temperature, and gas composition.

The findings indicate that changes in water cut significantly affect the likelihood of hydrate plugging, with specific ranges where the risk escalates sharply. The results emphasize the importance of accurate predictions for optimizing pipeline design and operational practices, ultimately enhancing flow assurance strategies and ensuring uninterrupted gas transport.

Through this integrated approach, the study contributes to the development of effective hydrate prevention strategies, underscoring the necessity of continuous monitoring and adaptation in real-world operational environments. Enhanced understanding of hydrate dynamics will aid in mitigating associated risks, thus ensuring safer and more efficient operations in gas pipelines.

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