Hydrate Control in Subsea Natural Gas Production

ABSTRACT

One of the most significant technological challenges that this industry faces today is securing the production flow in deep water exploration. Intense conditions of high pressure and low temperatures will favor the formation of the hydrates which could restrict or block the pathway to the extent that there can be a humungous financial loss.

This research was devoted to hydrate control in subsea natural gas production using results from water concentration estimation for reservoir, wellhead and onshore receiving terminal conditions. For illustration, a natural gas stream from the Niger Delta was selected where the transportation medium is a pipeline. Further implementation as part of the hydrate formation assessment input was done on the temperature and pressure profile along this pipeline.

A hydrate inhibition strategy based on monoethylene glycol (MEG) is under consideration. It is revealed that in the case if a temperature falls below 20°C and pressure will increase above 100 bar, then it would be met with a flow configuration in a region where hydrates are formed. Estimation of water concentration thus suffices to give useful information as possible prevention methods to hydrate formation while the gas flow is going on in the pipeline. The actual thermodynamic conditions required for the hydrate formation can also be deduced from the temperature and pressure data.

Keywords: hydrate inhibition strategy, pressure profile, marine environments, hydrocarbons

INTRODUCTION

1.1 BACKGROUND

The exploration for oil and gas has shifted from onshore to offshore areas, with many countries granting permits for offshore and deep offshore exploration. The first offshore oil production occurred in the late 1940s, and by 1973, 18.9% of the world's oil supply was from offshore sources. Projections suggest that while onshore reserves are expected to double, offshore reserves may quadruple (ETA Offshore Seminars, 1976).

In Nigeria, there is a growing interest in offshore production due to the increasing demand for crude oil, even though oil production started over 50 years ago. Notable offshore fields in Nigeria include Bonga, Akpo, Erha Field, Agbami, Abana, Amenam-kpono oil and gas field, Exxon East Area NGL II, Usan field, and Yoho oil field.

Offshore production, particularly in deep water, presents unique challenges due to extreme water depths and harsh marine environments, including high pressures and low temperatures. Production risers, connecting wells to Floating Production Storage and Offloading vessels (FPSOs), face operational challenges such as hydrate formation, scale formation, asphaltenes, corrosion, and slugging. To optimize production, flow assurance studies are crucial to minimize these challenges and determine optimal operating practices.

Flow assurance, a term coined by Petrobras in the early 1990s, focuses on ensuring the successful flow of hydrocarbons from reservoir to sale point. It considers fluid interactions in the reservoir, wellbore, surface facilities, and pipelines, offering techniques to ensure uninterrupted, optimum productivity in oil and gas streams. Flow assurance encompasses production surveillance, operational well remediation, pipeline remediation, PVT and rheology analysis, thermo-hydraulic analysis, mechanical integrity, and strategies to prevent and mitigate issues like gas hydrates, asphaltenes, wax, scale, and naphthalenes. Incorporating flow assurance considerations during completion design can significantly reduce hydrate and paraffin wax deposits.

Understanding reservoir fluid properties and their potential effects on the production system is crucial for effective flow assurance studies. Challenges in flow assurance include organic scales (paraffin, asphaltenes), hydrates, emulsions, foaming, mineral scales, sand deposition, erosion, slugging, corrosion, and multiphase flow instabilities.

Hydrocarbon solids, such as paraffin wax and hydrates, can deposit at various points in the production system, leading to plugging, increased pressure gradient, and decreased productivity. Monitoring production variables like temperature, pressure, and flow rates is vital to flowing systems.

The rise of natural gas in the energy matrix globally has driven increased offshore exploration and production. Natural gas consumption has grown significantly, driven by economic, environmental, and technological factors. Offshore pipelines, though contributing to project costs, offer guaranteed delivery with lower maintenance costs. Ensuring hydrate formation risks are minimized is crucial for the safe and efficient operation of offshore pipeline systems.

In the past decade, the industry has shifted to exploring and producing deepwater deposits, posing new challenges for hydrate prevention in subsea environments where pressure and temperature are conducive to hydrate formation.

Hydrate formation in offshore pipelines is a significant issue caused by temperature drops and thermodynamic changes during hydrocarbon production. The formation of hydrates, solid deposits with hydrocarbons like methane, can lead to pipeline clogging, pressure losses, reduced flow rates, and safety risks. Effectively and economically preventing hydrate formation in subsea gas transmission pipelines is essential for ensuring normal operation and avoiding costly repair work.

1.2 STATEMENT OF THE PROBLEM

The rapid and unexpected formation of hydrate plugs in marine environments is primarily attributed to low temperatures and relatively high pressures. To address this issue, Kinetic Hydrate Inhibitors and Anti Agglomerates have been employed to control the kinetics of hydrate formation and agglomeration. However, these solutions are costly and do not possess the capability to melt hydrate plugs.

In contrast, Polar Thermodynamic Inhibitors stand out for their high effectiveness in both melting existing hydrate plugs and preventing hydrate formation in pipelines. Despite their efficacy, they come with the drawback of requiring large volumes, and their regeneration is seldom pursued due to the associated high costs.

The uncontrolled formation of hydrates poses a significant threat to production targets and can even result in the shutdown of facilities. Consequently, the choice of hydrate inhibitors becomes a critical aspect of operational strategy, considering the need to balance effectiveness, cost, and the potential impact on production continuity.

1.3 AIMS AND OBJECTIVES

The principal aim of this research is to delve into the flow assurance aspects of natural gas produced from a subsea environment. Specifically, the focus is on preventing hydrate formation within the pipeline system during transportation. This is achieved through a thorough analysis of the temperature and pressure profiles under steady-state production conditions along the pipeline. The investigation seeks to comprehend the dynamics of these key factors to ensure the uninterrupted and efficient flow of natural gas, addressing potential challenges associated with hydrate formation during the transportation process.

1.4 SCOPE OF STUDY

This study focuses on the analysis of a pipeline transportation system designed for conveying natural gas streams from subsea to shore, terminating at a receiving terminal on land. The natural gas stream composition chosen for examination is sourced from the Niger Delta, providing a real-world example for the study.

A critical aspect of the research involves the prevention of hydrate formation within the pipeline system. The chosen hydrate inhibitor for this purpose is mono-ethylene glycol (MEG). The analysis encompasses a detailed examination of the inhibitor rate required to effectively prevent hydrate formation under the given conditions. By thoroughly investigating the interactions between the natural gas stream composition, environmental factors, and the chosen hydrate inhibitor, the goal is to develop insights into optimizing the use of MEG for ensuring the integrity and efficiency of the pipeline transportation system.

1.5 SIGNIFICANCE OF STUDY

This research holds significant importance in mitigating the risk of hydrate formation within pipelines. The primary focus is on analyzing the temperature and pressure profiles under steady-state production conditions along the pipelines. By doing so, the aim is to gain a comprehensive understanding of the environmental factors that contribute to hydrate formation and to identify potential risk areas.

Moreover, the study endeavors to analyze various inhibitors that could be employed to prevent hydrates from obstructing the pipeline. This includes an examination of their effectiveness, optimal dosage, and overall suitability for the given conditions. The ultimate goal is to develop strategies and recommendations that can effectively reduce the likelihood of hydrate formation, ensuring the smooth and continuous operation of the pipeline transportation system. The outcomes of this research have the potential to enhance the reliability and safety of natural gas transportation from subsea to shore.

2.0 METHODOLOGY

Methodology of this work is based on a specific steady-state defined production case. The production data analyzed is provided in table 1 below.

Table 1: Natural Gas Reservoir, Production and Pipeline Parameters

Reservoir Pressure	P_R	290	bar
Wellhead Pressure	P_{wh}	200	bar
Reservoir Temperature	TR	90	oC
Wellhead Temperature	T_{wh}	80	oC
Seawater temperature	T_{sea}	10	oC
Wellhead (template) Depth	D_{wh}	150	m
Total Natural Gas Rate	q	$3.50\text{x}10^{-07}$	Sm3/day
Pipeline Internal Diameter ID	d_{in}	600	mm
Pipeline Length	L	120	km
Pipeline Overall Heat Transfer Coefficient	U	10	W/m2.k
Pipeline Roughness	Ɛ	35.10	microns

3.1 Hydrates Prevention Using MEG

Hydrate mitigation commonly relies on the continuous injection of a thermodynamic hydrate inhibitor, typically monoethylene glycol (MEG), with minimal or no insulation of the subsea system. Presently, MEG stands as the state-of-the-art method for hydrate control (Estefen et al, 2005). MEG not only prevents hydrate formation but also demonstrates additional benefits, such as reducing corrosion rates in the carbon steel pipelines commonly used. It serves well as a carrier for corrosion inhibitors and pH-stabilizers. Moreover, MEG is recognized for being regeneratable and environmentally friendly, owing to its chemical properties and application within a closed-loop system with relatively small losses (Estefen et al, 2005).

The primary advantages of a MEG solution encompass:

Reliable Solution: MEG is acknowledged for its reliability in preventing hydrate formation, ensuring the smooth operation of subsea systems.

Closed Loop: The utilization of a closed-loop system is a distinctive feature, contributing to the sustainability and efficiency of the hydrate control strategy.

Corrosion Protective: MEG not only inhibits hydrate formation but also reduces the corrosion rate in carbon steel pipelines, providing corrosion protection for the infrastructure.

No Gas Plant or Refinery Contamination: The injection of MEG does not lead to contamination of gas plants or refineries, maintaining the integrity of these facilities.

Environmentally Friendly, Non-Toxic, Non-Flammable: MEG is considered environmentally friendly, non-toxic, and non-flammable, aligning with safety and environmental standards.

Qualified Technology: The use of MEG is well-established and qualifies as a proven technology for hydrate control in subsea environments.

In a closed-loop system, the Rich MEG arriving at the production unit needs to be regenerated to Lean MEG quality, typically containing 90-95 weight % MEG, before being re-injected at the subsea producers. This regeneration process ensures the continued effectiveness of MEG in preventing hydrate formation. A visual representation of the full reclamation of the MEG process is illustrated in Figure 1.

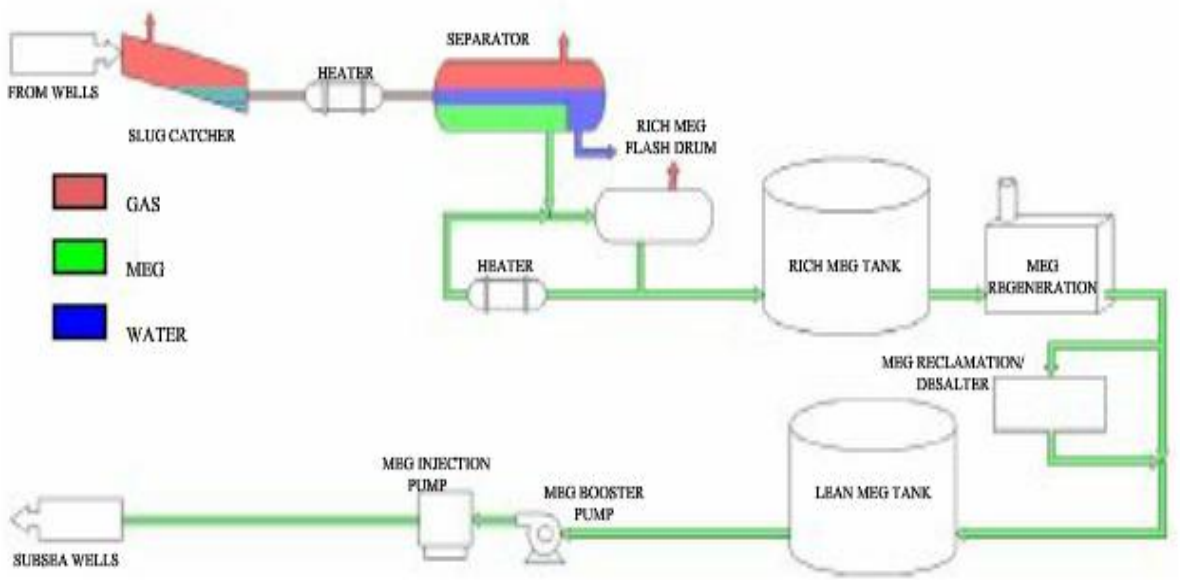

Figure 1: Full reclamation of mono ethylene glycol [MEG] process (Estefen*et al*, 2005)

3.2 Hydrates Prevention Using Methanol

Methanol has been employed as a hydrate inhibitor for an extended period, proving more effective than alternatives like glycol and gas dehydration in preventing hydrate formation. Despite its efficacy, methanol presents challenges due to significant losses during the process, making regeneration for reuse difficult (Bullin and Bullin, 2004).

In practical applications, methanol is often utilized as a last resort, especially when other inhibitors such as monoethylene glycol (MEG) are unable to sufficiently address hydrate issues

(Statoil, May 2002). One of its notable advantages is its very low freezing point in comparison to glycols, enhancing its suitability for hydrate inhibition.

However, the volatility of methanol contributes to its high expense, primarily due to substantial loss rates during the inhibition process. Unlike some inhibitors like MEG, methanol faces challenges in being easily regenerated for reuse.

From an environmental standpoint, methanol is classified as a green additive by the Climate and Pollution Agency. Nonetheless, its HSE (Health, Safety, and Environment) classification as black, indicating a high level of caution, suggests a potential decline in its usage in the future (Statoil, 2009).

In conclusion, while methanol stands out for its effectiveness in preventing hydrate formation, its drawbacks, including high costs and challenges in regeneration, have prompted considerations for alternative inhibitors with a more sustainable and cost-effective profile. The classification of methanol as a green additive emphasizes environmental considerations, but its HSE classification and limited reusability suggest a need for evolving strategies in hydrate inhibition.

3.0 RESULTS AND DISCUSSION

The main objective of this research was to investigate the flow assurance of a natural gas produced offshore and piped onshore. The analysis carried out was based on the fact that the formation of hydrates is favored by low temperatures, high pressure and the presence of water. A typical natural gas composition from Nigeria was used for this study.

The natural gas composition obtained is shown in Table 2, with some compositions that were not available being slightly modified for the purpose of this analysis only. However, this section presents the results for the various analyses considered in this work.

Table 2: Natural Gas Stream Composition from Nigeria (Maina, 2005)

Component	**Symbol**	**Mol %**	**Mol fraction, zi**
Methane	C1	91.25	0.9125
Ethane	C2	3.61	0.0361
Propane	C3	1.37	0.0137
i-Butane	i-C4	0.31	0.0031
n-Butane	n-C4	0.44	0.0044
i-Pentane	i-C5	0.16	0.0016
n-Pentane	n-C5	0.17	0.0017
Hexane	C6	0.27	0.0027
Heptane+	C7+	2.42	0.0242
Carbon dioxide	CO2	0	0
Hydrogen Sulphide	H2S	0	0
Nitrogen	N2	0	0
Total		**100**	**1**

Table 3: Natural Gas Stream Composition from Nigeria modified

Component	**Symbol**	**Mol %**	**Mol fraction, zi**
Methane	C1	90.01	0.9001
Ethane	C2	5.35	0.0535
Propane	C3	2.46	0.0246
i-Butane	i-C4	0.31	0.0031
n-Butane	n-C4	0.38	0.0038
i-Pentane	i-C5	0.21	0.0021
n-Pentane	n-C5	0.2	0.002
Hexane	C6	0.05	0.0005
Heptane+	C7+	0.57	0.0057
Nitrogen	N2	0.04	0.0004
Carbon dioxide	CO2	0.14	0.0014
Hydrogen Sulphide	H2S	0.28	0.0028
Total		**100**	**1**

2.1 Water Content of Natural Gas at Different Conditions

In this study, empirical correlations and diagrams were employed as part of the methodology. Specifically, the estimation of water content in natural gas streams, which also contain sour/acid gases, was undertaken. This estimation considered the contribution of sour/acid gases through the incorporation of a correction factor.

Notably, the correction factor for sour gas demonstrated a consistent increase with decreasing temperature and pressure, reflecting the gradient from reservoir conditions to the receiving terminal. The outcomes of this analysis indicated that the gas, under these varying conditions, exhibited a reduced water content in the gas phase.

The summarized findings of the water content estimation, incorporating the correction factor for sour gas under different temperature and pressure conditions, are presented in Table 4 below. This table serves as a concise representation of the study's results in relation to the water content variations in the gas phase across the specified conditions.

Table 4: Water Content of Gas at different conditions

Conditions	Pressure (bar)	Temperature (^oC)	Sour Gas Correction Factor	Water Content (mg/Sm3)
Reservoir	290.00	90.00	0.9785	3495
Wellhead	200.00	80.00	0.9855	3063
Terminal	113.34	17.59	0.9932	374

The condensation of water vapor from the gas phase reveals significant variations between the wellhead and the receiving terminal on land. At the wellhead, the condensed water is measured at 432.67 mg/Sm3, while at the receiving terminal, it significantly increases to 2689.04 mg/Sm3. Notably, the difference between the water content in the reservoir and the condensed water at the receiving terminal represents the quantity of water that must either be removed or prevented from forming hydrates.

The total condensed water value at the receiving terminal, amounting to approximately 806 mg/Sm3, is noteworthy. This figure signifies a substantial amount of water that has the potential to induce hydrate formation under conducive conditions. Given the elevated water content, it becomes imperative to implement effective measures to control and manage the water content within the gas, ensuring the secure and trouble-free operation of the gas pipeline. This underscores the significance of controlling water levels as a critical aspect of maintaining the integrity and reliability of the gas transportation system.

2.2 Temperature Profile

The specified gas quantity of 35x10^6 Sm3/day, in conjunction with a steady-state thermal analysis under constant mass rate, heat capacity, overall heat transfer coefficient, and internal diameter of the pipeline (600 mm), leads to a notable observation. The arrival temperature of the system is approximately 18°C. This finding suggests that, in the thermal analysis, as the gas flows along the pipeline, the temperature tends to converge toward the constant sea (ambient) temperature, which is around 10°C. This trend is visually represented in Figure 2, illustrating the temperature profile along the pipeline and emphasizing the convergence towards the prevailing sea temperature. This steady-state thermal analysis provides insights into the behavior of the gas temperature distribution throughout the pipeline under the specified conditions.

Table 5: Temperature Profile Data

Segment Number	**Pipeline Segment**	**Pipeline Temperature**
S/N	**dL**	**Ti**
	m	**^{o}C**
1	0	80.000
2	100	79.871
3	200	79.741
4	300	79.612
5	400	79.484
6	500	79.355
7	600	79.227
8	700	79.099
9	800	78.971
10	900	78.843
11	1000	78.716
12	1100	78.589
13	1200	78.462
14	1300	78.335
15	1400	78.209
16	1500	78.083
17	1600	77.957
18	1700	77.831
19	1800	77.706
20	1900	77.581
21	2000	77.456
43	4200	74.763
1190	118900	17.747
1191	119000	17.733
1192	119100	17.718
1193	119200	17.704
1194	119300	17.690
1195	119400	17.676
1196	119500	17.661
1197	119600	17.647
1198	119700	17.633
1199	119800	17.619
1200	119900	17.605
1201	120000	17.591

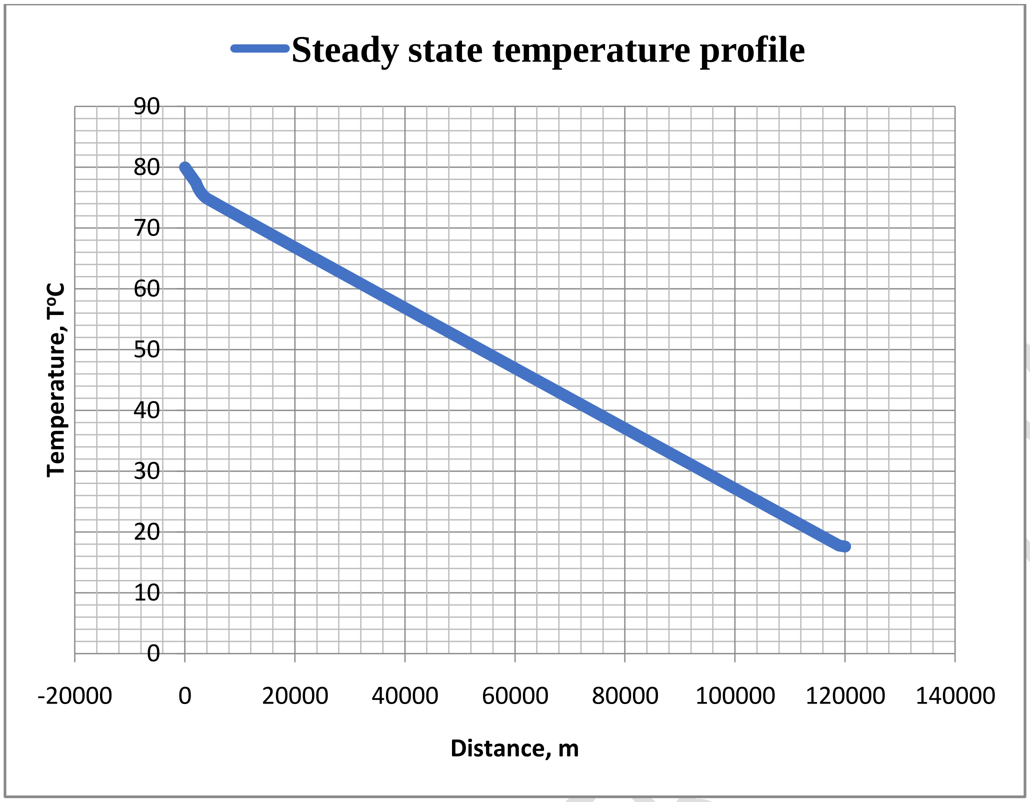

Figure 2: Steady-State Temperature Profile

The analysis indicates that the liquid in the pipeline is operating within a temperature range conducive to hydrate formation, especially when compared to the necessary conditions (below 21°C) for such formation. The presence of a cooling ocean current exacerbates this situation, leading to a decline in gas temperature within the pipeline, favoring hydrate formation.

In the course of steady-state operation, the temperature of the liquid being pumped undergoes a decrease as it moves through the pipeline due to heat transfer through the pipe walls. This established temperature profile during steady-state conditions serves as a fundamental basis for determining optimal flow rates and insulation requirements, crucial for maintaining the system above the minimum critical temperature during pumping operations.

The thermal assessment of a standard subsea conveyance system, predicting the temperature profile along the conveyance pipeline, holds significant importance in subsea system design (Vianna et al., 2009). Simultaneously, the analysis of heat transfer in pipeline systems becomes pivotal for predicting and preventing hydrate formation. A detailed understanding of the temperature distribution within the plant, coupled with knowledge of critical temperature thresholds for solid deposit formations, necessitates comprehensive evaluation to ensure continuous production at the desired level for profitability.

2.3 Pressure Profile

In this investigation, the steady-state pressure drop in a gas pipeline was analyzed using the correlation outlined in Gudmundsson's publication "Pressure drop in Gas Pipeline, TPG 4140" (2010). The initial wellhead pressure, serving as the pipeline's inlet pressure, was established at 200 bar. Simultaneously, the estimated pressure at the arrival terminal was approximately 113 bar. This led to a total pressure drop (ΔPT) of approximately 87 bar for a flow rate of 35x10^6 Sm3/day and a pipeline diameter of 600 mm. Notably, variations in gas compressibility, influenced by pressure, temperature, and gas composition, induced changes in gas velocity.

Despite these variations, the obtained results suggest that the flow remains within the hydrate-forming region. This conclusion is drawn based on theoretical conditions that indicate hydrate formation is favored at high pressures, typically 100 bar and above, in a gas pipeline. The steady-state pressure profile along the pipeline is visually represented in Figure 3, providing a comprehensive illustration of the pressure changes throughout the pipeline.

Table 6: Pressure Profile Data

Segment Serial Number	Pipeline Segment	Pipeline Temp	Compressibility factor	Density	Velocity	Constants			Viscosity	Reynolds Number	Haaland's friction factor	Outlet pressure	Total Pressure drop
	dL	Ti	Z	ρ_g	U	X	Y	K	μ	Re	f_H	P_2	dP_T
#	m	^oC		kg/m3	m/s				mPa.s			bar	bar
1	0	80.000	0.8835	143.473	7.8485	5.188	1.293	128.905	0.0196	34399147	0.0108	200.00	0.00
2	100	79.871	0.8833	143.559	7.8438	5.188	1.293	128.859	0.0196	34395012	0.0108	199.92	0.08
3	200	79.741	0.8831	143.591	7.8420	5.189	1.293	128.813	0.0196	34397808	0.0108	199.84	0.16
4	300	79.612	0.8829	143.624	7.8402	5.189	1.293	128.767	0.0196	34400597	0.0108	199.76	0.24
5	400	79.484	0.8826	143.657	7.8384	5.190	1.293	128.721	0.0196	34403379	0.0108	199.68	0.32
6	500	79.355	0.8824	143.690	7.8367	5.190	1.293	128.676	0.0196	34406153	0.0108	199.60	0.40
7	600	79.227	0.8822	143.722	7.8349	5.191	1.293	128.630	0.0196	34408921	0.0108	199.52	0.48
8	700	79.099	0.8819	143.755	7.8331	5.191	1.292	128.585	0.0196	34411681	0.0108	199.44	0.56
9	800	78.971	0.8817	143.787	7.8313	5.192	1.292	128.539	0.0196	34414434	0.0108	199.36	0.64
10	900	78.843	0.8815	143.820	7.8296	5.193	1.292	128.494	0.0196	34417180	0.0108	199.28	0.72
11	1000	78.716	0.8812	143.852	7.8278	5.193	1.292	128.449	0.0196	34419919	0.0108	199.20	0.80
12	1100	78.589	0.8810	143.885	7.8261	5.194	1.292	128.404	0.0196	34422650	0.0108	199.13	0.87
13	1200	78.462	0.8808	143.917	7.8243	5.194	1.292	128.359	0.0196	34425375	0.0108	199.05	0.95
14	1300	78.335	0.8806	143.949	7.8225	5.195	1.292	128.314	0.0196	34428094	0.0108	198.97	1.03
15	1400	78.209	0.8803	143.981	7.8208	5.195	1.292	128.269	0.0196	34430805	0.0108	198.89	1.11
1193	119200	17.704	0.7597	115.775	9.7262	5.520	1.219	106.249	0.0158	42701098	0.0108	114.19	85.81
1194	119300	17.690	0.7598	115.662	9.7357	5.520	1.219	106.244	0.0158	42722431	0.0108	114.08	85.92
1195	119400	17.676	0.7599	115.549	9.7452	5.520	1.219	106.239	0.0158	42743828	0.0108	113.98	86.02
1196	119500	17.661	0.7600	115.435	9.7548	5.520	1.219	106.233	0.0158	42765288	0.0108	113.87	86.13
1197	119600	17.647	0.7600	115.321	9.7644	5.520	1.219	106.228	0.0158	42786813	0.0108	113.77	86.23
1198	119700	17.633	0.7601	115.207	9.7741	5.520	1.219	106.223	0.0158	42808401	0.0108	113.66	86.34
1199	119800	17.619	0.7602	115.093	9.7838	5.520	1.219	106.217	0.0158	42830054	0.0108	113.55	86.45
1200	119900	17.605	0.7603	114.978	9.7936	5.521	1.219	106.212	0.0158	42851772	0.0108	113.45	86.55
1201	120000	17.591	0.7604	114.862	9.8034	5.521	1.219	106.207	0.0158	42873556	0.0108	113.34	86.66

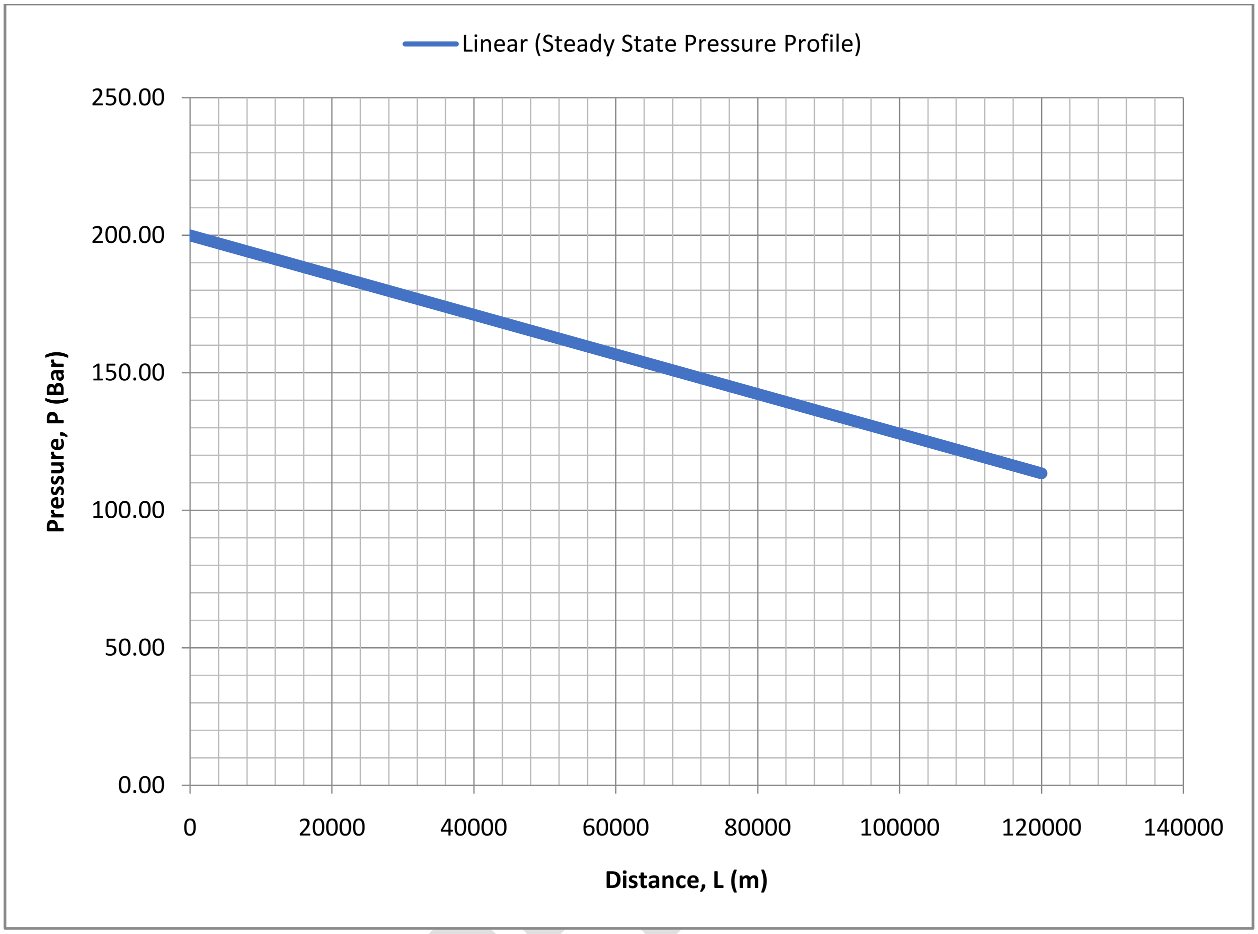

Figure 3: Steady State Pressure Profile

2.4 Hydrate Inhibition Using Mono Ethylene Glycol (MEG)

To mitigate hydrate formation in gas pipeline systems, the application of thermodynamic inhibitors is crucial, as they alter the composition of the fluid. In this specific study, monoethylene glycol (MEG) was chosen as the inhibitor, and the Hammerschmidt's correlation was utilized to ascertain the required concentration of the inhibitor to prevent hydrate formation.

The analysis results indicated that the calculated concentration of monoethylene glycol (MEG) needed was 27.32%. This corresponds to an upstream (wellhead) rate of 9.24 kg/s (798.350 tonnes/day). Furthermore, the anticipated amount of vapor condensed out of the gas phase at the terminal, requiring inhibition to prevent hydrate formation, was determined to be 806.23 mg/Sm3. It is important to note that the increased production of water will necessitate a higher quantity of monoethylene glycol (MEG) to maintain the correct concentration and prevent hydrate formation effectively. These findings provide valuable insights into the inhibitor requirements for managing hydrate-related challenges in gas pipeline systems.

CONCLUSION AND RECOMMENDATION

3.1 Conclusion

The threat posed by hydrate formation in subsea natural gas production is a significant concern, particularly in the transmission of the fluid from offshore/subsea environments to the shore through pipelines. The natural gas stream produced from the reservoir inherently carries water saturation, underscoring the need to understand the crucial parameters and factors conducive to hydrate formation for effective control and management.

A pivotal aspect in ensuring the operational success of pipeline transmission systems involves estimating the water content in the natural gas stream at different points, including the reservoir, wellhead, and receiving terminal conditions. In this study, the estimated amount of water vapor condensed was found to be 803.23 mg/Sm3.

The thermal analysis disclosed that the initial wellhead temperature was 80°C, with the arrival temperature recorded at 17.59°C, resulting in a total temperature drop of 62.41°C. Consequently, the gas flow was determined to be within the hydrate-forming region, as the terminal arrival temperature fell below 20°C. The pressure profile analysis further indicated a total pressure drop of 86.66 bar, with the arrival pressure at 113.34 bar. Given the initial wellhead pressure of 200 bars, the arrival pressure exceeded the 100-bar threshold, a condition favoring hydrate formation.

In light of the identified hydrate-forming conditions, monoethylene glycol (MEG) was chosen as the hydrate inhibitor to prevent plug formation. The total quantity of MEG required to inhibit hydrate formation was estimated to be 798.35 tonnes/day. Consequently, it is essential to initially assess the potential for hydrate formation in a pipeline system and subsequently formulate a prevention strategy for safe and reliable operations. These findings underscore the importance of proactive measures to address hydrate-related challenges in subsea gas transmission systems.

3.2 Recommendation

Indeed, a comprehensive exploration and analysis of alternative methods for hydrate control are strongly recommended, with particular emphasis on operations-based control strategies. One such strategy involves managing the relative volume-flow rates of wells in comingled flow, which can play a crucial role in mitigating hydrate formation.

Operations-based controls, such as adjusting volume-flow rates, can be instrumental in preventing the conditions conducive to hydrate formation. Additionally, the use of insulators in the pipeline system represents another avenue worth exploring for its potential in minimizing heat exchange and maintaining temperatures above the critical threshold for hydrate formation.

Encouraging a critical study of these alternative methods is essential for gaining insights into their effectiveness, feasibility, and practicality in real-world applications. This approach aligns with the broader goal of developing a comprehensive toolkit of hydrate control strategies that can be tailored to specific operational scenarios and conditions.

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NOMENCLATURE

MEG = Mono-Ethylene-Glycol
CAPEX = Capital Expenditure
OPEX = Operational Expenditure
P1 = Upstream or Inlet Pressure (bara)
P2 = Downstream or outlet Pressure (bara)
A = Cross sectional Area of pipeline (m2)
f = Friction factor
z = Gas compressibility factor
R = Gas constant (J/kmol.K)
T1 = Upstream or Inlet temperature (oC)
T2 = Downstream or outlet temperature (oC)
din = Pipeline internal diameter (m)
Tf = Gas flowing temperature (oC)
QMEG = MEG flow rate (tonne/day)
L = Pipeline Length (m)
µg = Gas viscosity (cp)
Tr = Reduced temperature
Pr = Reduced pressure
ρg = Gas density (kg/m3)
Tc = Critical temperature (K)
Pc = Critical pressure (MPa)
CO2 = Carbon dioxide
Mw = Molecular weight (kg/kmol)
m = Mass rate (kg/s)
Cp = Heat capacity (J/kg.K)
H2S = Hydrogen Sulfide
TLMTD = Logarithmic mean temperature difference (K)
U = Overall heat transfer coefficient (W/m2.K)
xg = Gas mass fraction (kg/kmol)
THIs = Thermodynamic hydrate inhibitors
KHIs = Kinematics hydrate inhibitors
$Z'H2S$ = equivalent mol fraction of hydrogen sulfide,
$ZH2S$= hydrogen mol fraction
$ZCO2$= carbon dioxide mol fraction
Fsour = Sour gas correction factor
To = Absolute temperature (oC)
Po = Absolute pressure (bara)
yw_sour = Sour gas water content (mg/Sm3)
yw_sweet = Sweet gas water content (mg/Sm3)