

THERMAL INSULATION DESIGN FOR HYDRATE RISK MITIGATION IN SUBSEA NATURAL GAS PIPELINES: A STEADY-STATE THERMAL– HYDRAULIC ANALYSIS

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Abstract

This study develops an improved subsea gas pipeline design framework that uses effective heat transfer management to prevent gas hydrate formation. A one-dimensional steady-state thermal-hydraulic model of a 10 km, 0.30 m diameter deepwater gas pipeline (inlet 60 °C, 80 bar; seabed 4 °C; 50 kg/s) was formulated from energy and momentum balances using a thermal resistance representation of the pipe wall, insulation and external convection, and implemented in MATLAB with 200 computational nodes. Hydrate risk was assessed by comparing predicted operating temperatures with the pressure-linked hydrate equilibrium curve through a subcooling-based risk index. Results show that an uninsulated pipeline cools to the 4 °C seabed temperature within about 4 km and enters the hydrate stability region from approximately 1.2 km, with peak subcooling of 16.1 °C, exposing nearly 90 per cent of the line to hydrate risk. The proposed design, incorporating 50 mm of polypropylene insulation, reduces the overall heat transfer coefficient from 145.3 to 5.30 W/m²K, cuts inlet heat loss by 96 per cent (7,671 to 280 W/m) and delivers gas at 39.5 °C, maintaining a minimum margin of 26.6 °C above the hydrate boundary over the full pipeline length with a hydrate risk index of zero everywhere. Frictional losses reduce the pressure from 80.0 to 56.1 bar over 10 km. The study concludes that passive thermal design alone can eliminate hydrate risk on this class of tieback without chemical inhibition or active heating, and provides a quantitative basis for insulation selection in subsea pipeline design.

Keywords: Gas hydrates; heat transfer management; subsea pipeline design; flow assurance; thermal insulation; MATLAB simulation.

INTRODUCTION

The increasing global demand for natural gas has accelerated the development of offshore and deepwater hydrocarbon resources, making gas transportation systems an essential component of modern energy infrastructure. The transportation of Natural gas from field to various points of utilization and market is important because of difficulty in its storage and require a comprehensive infrastructure. Several means of transportation such as Pipeline Natural Gas (PNG), Compressed Natural Gas (CNG), Liquefied Natural Gas (LNG) and Gas to Solid (GTS) are available (Guo and Ali, 2015).

Transportation by pipeline regarded as the safest method of conveying and distributing natural gas to so many points at a large volume requires adequate design of the system for optimum delivery without failure (Lyons and Plisga, 2017). The design of a natural gas pipeline is the most important aspects of natural gas transmission and distribution through pipeline due to the dangerous nature. This design entails a plan and program that consider all factors not limited to majors (hydraulic components, mechanical components, geothermal parameters and operating/maintenance parameters) for safe and effective distribution and delivery of gas (Mike, 2010).

For successful transportation of Natural gas with flow assured in pipelines, optimum design that will consider the length and diameter of the pipeline, flow rate of gas and its composition, suction and discharge pressure of the pipe and number of compressor stations is vital. Design of Natural gas pipeline as the most suitable means of gas transportation is important because of the rise in its demand for residential, commercial, industry and power generation (EIA). In order to optimize the design of Natural gas transmission network, Babu et al. (2015) presented a model to optimize the length, diameter and number of compressors of a transmission line. Bolkan et al., (2019) developed an algorithm for optimizing gas pipeline network design with the operating condition of the system for successful delivery of gas. Adeyanju and Oyekunle (2018) applied the reduced gradient algorithm in addressing procedure of natural gas transmission network optimization. Their model was derived from the first source model developed by Aman, (2021).

Ainouche (2013) developed linear programming model considering taking line pack for the optimal planning of a gas pipeline operating system. Bhaduri and Talachi (2019) optimized the Qinghai gas pipeline by predicting the optimum pipe size, compression facilities, pipeline route, operating pressure, and storage facilities, if required. The design, constructions and operation of natural gas pipeline have been guided by developed codes and standards (ASME and API) for personnel safety and reducing the risk of pipeline failure for successful delivery (ASME B31.8; API RP 1111).

This work will optimize Natural gas pipeline with codes and standard with all components and parameters of the gas stream for optimal delivery of gas. Pipelines serve as the primary means of transporting natural gas from offshore production facilities to onshore processing plants and distribution networks. However, numerous flow assurance challenges arise in the operation of these pipelines, especially gas hydrate formation, which is one of the most critical flow assurance risks in deepwater (Liu, 2023; Qu et al., 2024). Gas hydrates are ice-like crystalline structures of water molecules joined with light hydrocarbon gases (methane) under the influence of low temperatures and high pressures. Such conditions are frequently a problem in deepwater pipelines where the pipelines are under high pressure and the temperature of the seabed is often low. The hydrates formed and deposited in the pipeline can jam the pipeline, lead to pressure loss, affect the production efficiency, and even completely block the pipeline, causing economic losses and safety hazards (Zare et al., 2021; Umuteme et al., 2024). In recent years, hydrate formation and deposition are revealed to be major hazards to pipeline reliability and integrity for the offshore gas transportation systems, especially at transient conditions, including shutdown and restart (Qu et al., 2024; Tian et al., 2026).

A significant heat loss from flowing gas to the surrounding seawater environment is one of the important factors affecting hydrate formation. During the transmission of natural gas through a pipeline, heat is always flowing into the colder atmosphere of the sea bottom through the pipeline and insulation wall. This process of heat transfer can gradually reduce the temperature of the transported fluid, which can allow the formation of hydrate crystals in the hydrate stability region (Kumar et al., 2021; Liu, 2023). Thus, the main priority of the

design of gas pipelines is to provide effective thermal management in the design in the case of deepwater and ultra-deepwater developments, where thermal gradients are more pronounced.

Thermodynamic inhibitors like methanol and monoethylene glycol (MEG) and operational measures like depressurization, pigging and active heating systems have played a major role in hydrate prevention strategies traditionally. These methods have been found to be effective, but they can be costly to operate, use a lot of chemicals and can have environmental effects (Don-Ugbaga & Saturday, 2022; Idolor & Owolabi, 2024). Moreover, increased tieback lengths and deep-sea explorations make it difficult to maintain an optimal pipeline temperature, necessitating the use of greener and more cost-effective thermal management systems.

2. MATERIALS AND METHODS

2.1 MATERIALS

Materials employed in this research study include specifications of pipelines, physical properties of fluids, environmental conditions, insulation, and hydrates formation.

2.1.1 Pipeline Specifications

- i. Pipeline length (L)
- ii. Internal diameter (D_i)
- iii. External diameter (D_o)
- iv. Wall thickness (t)
- v. Pipe material (e.g., API X65 steel or carbon steel)
- vi. Pipe roughness coefficient
- vii. Pipeline layout (subsea horizontal/undulating profile)

2.1.2 Fluid Properties

- i. Natural gas composition (methane-dominant mixture with possible CO_2 and N_2)
- ii. Gas density (ρ_g)
- iii. Specific heat capacity (C_p)
- iv. Dynamic viscosity (μ)
- v. Compressibility factor (Z)
- vi. Water content (free water and dissolved water)
- vii. Inlet pressure and temperature conditions

2.2 METHODS:

The analytical modelling and numerical simulation methods are used in the study to quantify the heat transfer behavior and hydrate risk in gas pipelines. The selection of these methods is based on their effectiveness in modelling complex thermal-hydraulic interactions, prediction of pipeline temperatures and pressures all along the pipeline, and evaluation of possible conditions for gas hydrate formation in deep water.

The analysis method of modelling is used to find governing equations for the heat transfer, fluid flow and thermodynamic equilibrium of pipeline systems. It also entails energy balance relations relating changes in temperature of a pipeline to heat losses to the surrounding environment, and pressure drop relations pertaining to the flow behaviour of the fluids. These analytical expressions provide a theoretical basis for understanding

the influence of pipeline design and environmental other factors on pipeline thermal performance. Numerical simulation method is used to solve the mathematical models developed under various operating conditions. This includes modelling the pipeline as a series of segments and determining the temperature and pressure profile along the pipeline. The effects of major parameters like pipeline material properties, flow conditions, seawater temperature and insulation thickness on heat transfer efficiency and the risk for hydrate formation are evaluated in a simulation.

The steady state can be thoroughly investigated using analytical and numerical methods, including normal production flow, shutdown and restart conditions. This integrated approach allows for improved prediction of hydrate formation regions and for evaluating improved pipeline design to leverage heat transfer and enhance pipeline flow assurance performance in subsea gas transportation systems.

2.2.1 Heat Transfer Modeling

Transfer of heat from the flowing gas to the seawater surrounding the pipe is done using a method that considers the conditions of flow inside, physical properties of the pipe itself, and the effectiveness of the insulation using thermal resistance method. In this model, the subsea pipeline system is modeled as a set of thermal resistances which control the overall heat transfer rate from the fluid to the environment. The overall heat transfer through the pipeline system is represented as:

$$Q = \frac{T_g - T_s}{R_{total}} \quad (1)$$

Where Q is the rate of heat transfer (W), T_g is the bulk gas temperature, and T_s is the surrounding seawater temperature. The total thermal resistance is given as the sum of individual resistances:

$$R_{total} = R_i + R_{wall} + R_{ins} + R_o \quad (2)$$

Where R_i is the internal convection resistance, R_{wall} is the pipe wall conduction resistance, R_{ins} is the insulation resistance, and R_o is the external convection resistance. Each resistance is defined as follows:

$$R_i = \frac{1}{h_i A_i} \quad (3)$$

$$R_{wall} = \frac{\ln\left(\frac{r_2}{r_1}\right)}{2\pi k_{wall} L} \quad (4)$$

$$R_{ins} = \frac{\ln\left(\frac{r_2}{r_1}\right)}{2\pi k_{ins} L} \quad (5)$$

$$R_o = \frac{1}{h_o A_o} \quad (6)$$

Where h_i and h_o are the internal and external convective heat transfer coefficients, k_{wall} and k_{ins} are thermal conductivities of pipe wall and insulation, r_1, r_2, r_3 are inner pipe, outer pipe, and insulation radii respectively, and L is the pipeline length. The overall heat transfer coefficient is defined as:

$$Q = UA(T_g - T_s) \quad (7)$$

Where U is the overall heat transfer coefficient and A is the heat transfer area. The temperature drop along the pipeline is estimated using steady-state energy balance based on conservation of energy for flowing gas:

$$\dot{m}C_p \frac{dT}{dx} = -UP(T - T_s) \quad (8)$$

Where $\dot{m}$ is mass flow rate, C_p is specific heat capacity, P is pipeline perimeter, and x is distance along the pipeline. Solving the energy balance equation above gives the temperature profile:

$$T(x) = T_s + (T_{ins} - T_s) \exp\left(-\frac{UPx}{\dot{m}C_p}\right) \quad (9)$$

This model enables one to predict the decrease in fluid temperature as it flows in the pipeline due to the continuous loss of heat energy to the seawater surrounding the pipeline. This profile of temperatures is then used to evaluate thermal performance and find the conditions where the fluid temperature can come close or go into the hydrate formation regime.

2.2.3 Pipeline Design

In an attempt to promote heat retention and reduce the possibility of hydrate formation in underwater gas transportation systems, various thermal designs of pipes have been analyzed. All types of thermal protection analyzed were investigated under similar technological and environmental conditions to evaluate their efficiency in terms of heat retention capability.

The analyzed designs include uncovered pipes with no thermal protection, one-layer thermal insulation systems, multi-layer thermal insulation systems, as well as pipe-in-pipe designs. The designs analyzed offer different levels of thermal protection from the uncovered pipes that offer almost no barrier for heat transmission to the highly efficient pipe-in-pipe solution. The effectiveness of the examined technologies is determined based on the heat losses that occur within the pipes and have the mathematical representation in Equation (7).

The lower values for Q indicate better thermal properties and better insulation performance. The temperature drop at the outlet is calculated by taking the difference between the inlet and outlet temperatures predicted by the thermal model. Smaller drops in temperature yield better retention of heat and a lower likelihood of the fluid entering hydrate-forming conditions at the pipeline outlet.

The potentiality of hydrate formation is assessed based on temperature profiles relative to the thermodynamic stability boundaries for hydrate formation. Those designs that can ensure that the temperatures during operations remain above the hydrate equilibrium conditions will be highly effective in hydrate prevention.

To establish the efficiency improvement, each insulated design is compared to the uninsulated design. In this case, the percentage improvement in thermal efficiency is based on the heat losses reduction and increase in the outlet temperature maintained by the system.

3. RESULTS AND DISCUSSIONS

3.1 Pipeline Specifications

The pipeline system used in the simulation is a typical deep water gas transmission pipeline. The total length of the pipeline is 10,000 m, typical subsea tie-back distance between a production wellhead and processing facility. The pipeline diameter was chosen to be 0.30 m, which is suitable for transporting gas in an efficient manner with acceptable pressure drop along the pipeline. The pipeline material used is assumed as carbon steel (API X65 grade) which is commonly used in offshore pipeline constructions because of its high strength, durability and high internal pressure and external hydrostatic load resistance.

The pipeline is discretized into 200 computational nodes, which facilitates detailed spatial analysis of the variation of temperature, pressure and heat loss along the length of the pipeline for numerical simulation. This discretization will enhance the accuracy of thermal and hydraulic prediction, and be helpful in evaluating the risk for hydrate formation in various locations along the pipeline.

Table 1: Pipeline Specifications

Parameter	Symbol	Value	Unit
Pipeline length	L	10,000	M
Internal diameter	D	0.30	M
Material	-	API X65 Carbon Steel	-
Computational nodes	N	200	-

The pipeline system used in the simulation represents a typical deepwater gas transmission pipeline designed for steady-state thermal-hydraulic analysis.

3.2 Fluid Properties

It is assumed that the fluid being carried through the pipeline is a natural gas compound containing a considerable amount of methane and perhaps small amounts of other heavier hydrocarbons along with some impurities like CO₂ and N₂. The gas used within the project has a mass flow rate of 50 kg/s, which is a typical value for the processes of offshore gas transportation. The specific heat capacity of the gas is assumed to be 2200 J/kg·K, which also corresponds to the typical values for gas mixtures at high pressure. The inlet gas temperature was assumed to be 60°C, while other properties of the gas (density, viscosity, compressibility, etc.) were taken into account implicitly by the numerical model representing real behavior of the gas flow. The assumption of working with a compressible fluid must be used due to changes of gas density caused by variations of pressure and temperature in the pipeline.

Table 2: Fluid Properties

Parameter	Symbol	Value	Unit
Mass flow rate	M	50	kg/s
Inlet temperature	T _{in}	60	°C
Specific heat capacity	C _p	2200	J/kg·K
Gas type	-	Methane-dominant natural gas	-

3.3 Environmental Conditions

One of the key features of the seabed is that it is characterized by low surrounding temperatures, which is common in deep ocean conditions. The seabed is presupposed to have the water temperature of 4°C, which is the limiting factor for hydrates to form because there is good thermal driving force to cool down the formed hydrates. The pipeline is under water and subjected to a great pressure. The water around the pipeline is able to transfer heat and makes it impossible for the heating to take place in the pipeline. The overall heat transfer coefficient is added into the model.

Table 3: Environmental Conditions

Parameter	Symbol	Value	Unit
Seabed temperature	T _{sea}	4	°C
Operating environment	-	Deepwater offshore system	-
Heat sink	-	Seawater	-

The seabed provides a constant low-temperature environment, which strongly influences pipeline cooling.

3.4 Operating Conditions

Inlet pressure in the pipeline is assumed to be 80 bar, which is common in offshore natural gas production. The factor of friction is considered as 0.015 in order to include the internal resistance due to the pipe wall roughness and turbulent nature of the fluid. The flow process is kept as steady state, meaning that the time factor is not accounted during the normal operational conditions in the simulation.

Table 4: Operating Conditions

Parameter	Symbol	Value	Unit
Inlet pressure	P ₀	80	Bar
Friction factor	f	0.015	-
Flow condition	-	Steady-state	-

These parameters define the hydraulic behavior of the pipeline during operation.

3.5 Thermal Insulation Properties

To evaluate heat loss reduction strategies, different insulation thicknesses are considered in the simulation. The insulation thickness values used are:

- i. 0 m (bare pipeline)
- ii. 0.02 m
- iii. 0.05 m
- iv. 0.10 m

The effect of insulation is calculated based on a concept of thermal resistance where the thicker the insulation material is, the lower the heat transfer coefficient will be, thus enhancing the insulation of the pipeline system.

Table 5: Thermal Insulation Data

Insulation Case	Thickness (m)	Description
Case 1	0.00	Bare pipeline
Case 2	0.02	Thin insulation
Case 3	0.05	Medium insulation
Case 4	0.10	Thick insulation

Thermal insulation is evaluated to determine its effect on heat loss reduction.

3.6 Hydrate Formation Data

Hydrate risk is determined by comparing operating temperature with equilibrium hydrate conditions.

Table 6: Hydrate Formation Data

Parameter	Expression	Description
Hydrate temperature	$T_{\text{hyd}} = 25 - 0.0012x$	Equilibrium curve
Risk condition	$T < T_{\text{hyd}}$	Hydrate formation possible
Risk index	$\Delta T = T_{\text{hyd}} - T$	Safety margin

3.7 Heat Transfer Analysis Results

Investigation of heat transmission was undertaken via a MATLAB model devised to reveal the properties of temperature in a subsea gas line in view of the operational and environmental conditions. The study presents the behaviors of temperature in different sections of the pipeline and heat loss characteristics, insulation characteristics, and how they affect hydrate formation risk.

Figure 1 indicates the temperature profile of the transported gas along the 10-km subsea pipeline for the existing (i.e., uninsulated) design and the proposed (i.e., 50 mm insulated) design. The behavior of the existing design is characterized by a rapid decline in gas temperature from 60.0 °C at the inlet to 20.1 °C at 1 km and further to 8.6 °C at 2 km, ultimately leading to a gas temperature equal to the seabed temperature of 4 °C after passing the first 4 km of the pipeline. The occurrence signifies the concept of exponential decay pattern which follows the thermodynamic law of the steady-state balance of energy. The situation with the insulated design is different as it has a much higher heat retention with a reduced heat loss from 60.0 °C to 39.5 °C along the 10 km section. The hydrate equilibrium temperature drops from 25 °C at the entrance to 13.0 °C at the exit which allows the current design to come into hydrate formation zone approximately at 1.2 km, whereas the insulated design stays with a sizeable gap over hydrate formation temperature throughout the entire pipeline from the start to completion.

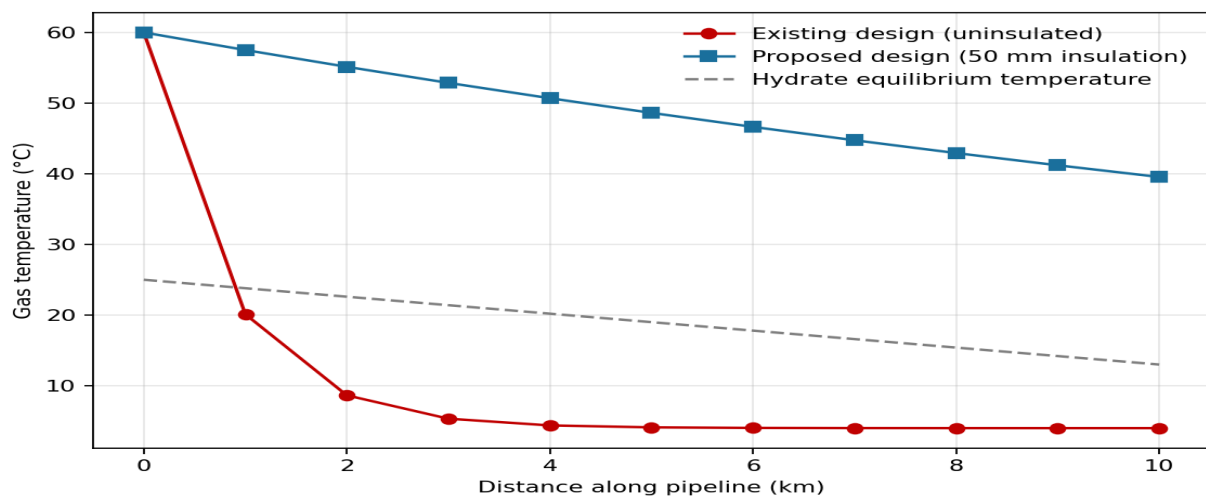


Figure 1: Temperature Profile Along Subsea Pipeline (Existing vs Proposed Design)

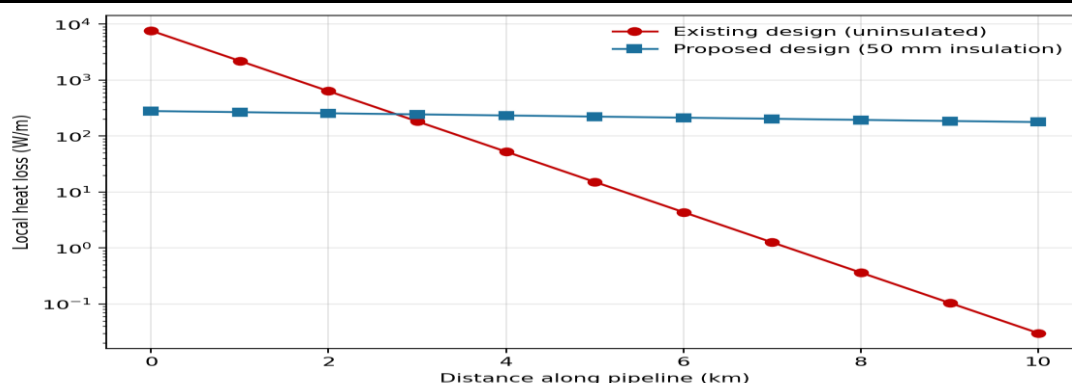


Figure 2: Local Heat Loss Variation (Existing vs Proposed Design)

Figure 2 illustrates the variation of local heat loss along the pipeline for both designs. Heat loss per unit length is greatest at the pipeline inlet, where the temperature difference between the gas (60 °C) and the seawater (4 °C) is largest: the uninsulated pipeline loses about 7,671 W/m at the inlet, decaying rapidly to below 53 W/m beyond 4 km as the gas approaches thermal equilibrium with the sea. The suggested insulated design brings down the inlet heat loss by over 96% to 280 W/m, and the loss remains lower than that at the outlet, dropping gently to 178 W/m, as the gas remains hot throughout its journey. This proves that the widespread notion that the heat loss increases over distance is wrong, since it is the local heat loss that decreases as we move backwards; the heat loss accumulated over distance. The measurement indicates that effective insulation prevents the heat loss exactly at its peak, i.e. the inlet of the pipeline where the heat loss is at its most considerable.

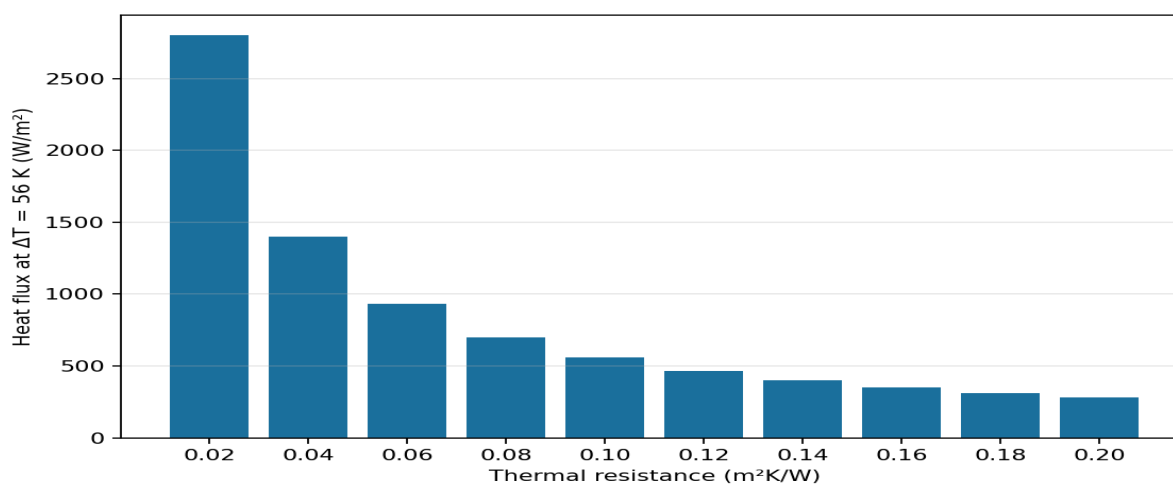


Figure 3: Effect of Thermal Resistance on Heat Transfer

The relationship between heat transfer resistance and heat flow across the wall of the pipe is depicted in Figure 3, where the temperatures differ by 56 K. As resistance increases, heat flow decreases ($q = \Delta T/R$). At resistance values of 0.02 m²K/W, the flow rate is equal to 2,800 W/m², at 0.04 m²K/W it is 1,400 W/m², at 0.06 m²K/W it is 933 W/m², and at 0.20 m²K/W it is 280 W/m². Every time resistance doubles, the rate decreases by half which leads to the conclusion that in the first phases of insulation installation the system results in an absolute decrease of heat transfer and in the latter phases the rate diminishes. Hence the relationship is reciprocal and provides means for making correct decisions in the selection of insulation thickness.

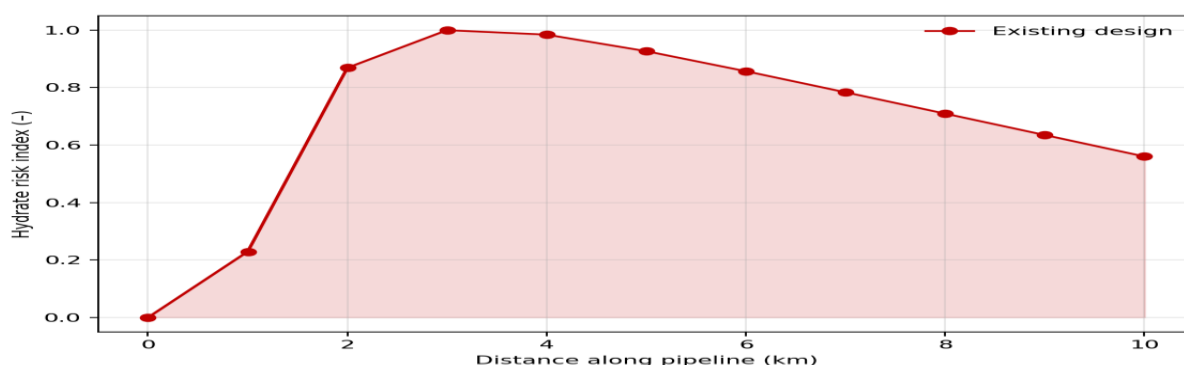


Figure 4: Hydrate Formation Risk Index (Existing Design)

Figure 4 shows the hydrate formation risk index along the pipeline for the existing (uninsulated) design. The index is defined as the positive subcooling ($T_{hyd} - T$) normalised by its maximum value, so that 0 indicates operation outside the hydrate region and 1 indicates the most severe subcooling on the line. At the inlet the gas is 35 °C warmer than the hydrate boundary and the index is 0. The index rises sharply once the gas crosses the hydrate boundary at about 1.2 km, reaching 0.87 at 2 km and a peak of 1.00 at 3 km, where the subcooling attains 16.1 °C. Beyond the peak the index declines slowly (0.56 at the outlet) only because the hydrate equilibrium temperature itself falls with the declining pressure, not because conditions become safe: the entire line from 1.2 km to the outlet remains inside the hydrate stability region, with subcooling of 9–16 °C. This identifies essentially the whole downstream length of the uninsulated pipeline as a high-risk zone requiring mitigation.

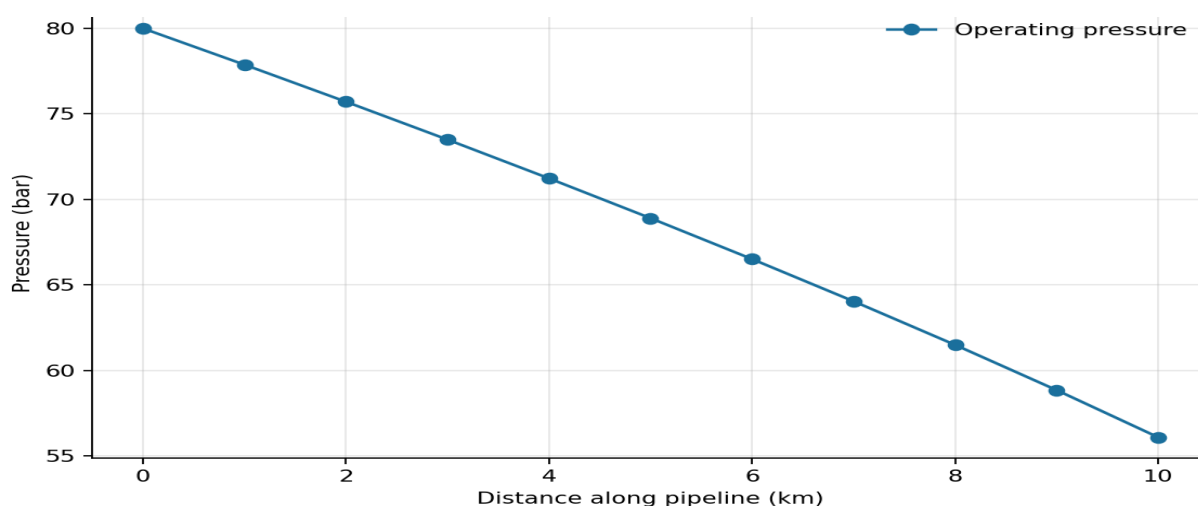


Figure 5: Pressure Profile Along Pipeline

Figure 5 illustrates the pressure profile along the 10 km pipeline. The inlet pressure of 80.0 bar declines to 56.1 bar at the outlet, a total frictional loss of 23.9 bar. The pressure gradient steepens slightly with distance (2.1 bar over the first kilometre versus 2.8 bar over the last) because, as pressure falls, the gas density decreases and the velocity rises, increasing the frictional pressure gradient in accordance with the Darcy–Weisbach relationship for compressible flow. This reduction in pressure reduces the hydrate equilibrium temperature also along the line, thereby affecting hydrate stability and making some contribution to the overall mitigating

effect, although, unfortunately, this contribution is insignificant compared to the thermal driving effect in the absence of insulation.

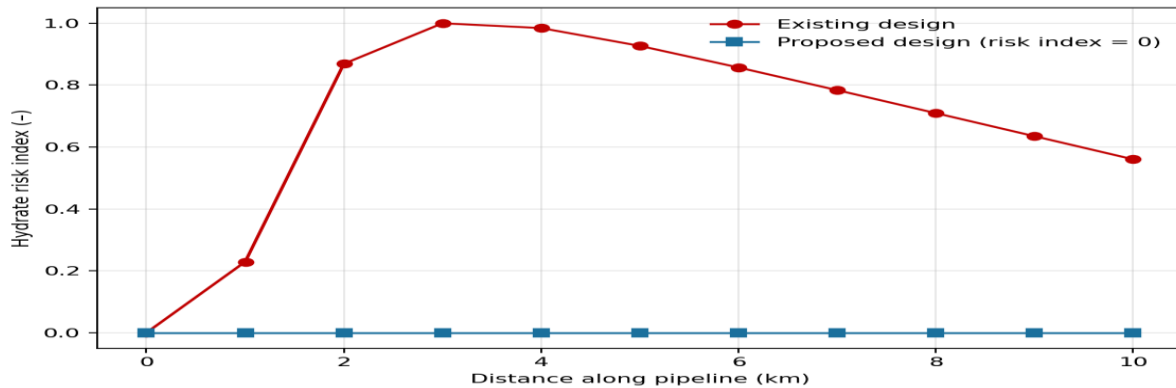


Figure 6: Hydrate Risk Index Comparison (Existing vs Proposed Design)

Figure 6 illustrates the comparison between the hydrate risk index of present design and that of the proposed one along the route of the pipeline. For the existing design that has no insulation, the hydrate stability zone was entered at a distance of about 1.2 km. Thereafter, the entire section of the pipeline stayed in the aforementioned zone where the hydrate risk index was the highest at 3 km and equaled 1.00. The proposed pipeline design with an insulation thickness of 50 mm maintained a risk index equal to zero for the entire length of the pipeline on account of the fact that gas did not cool below hydrate equilibrium temperature at any point in the pipeline, with the highest possible temperature difference from the hydrate equilibrium temperature being equal to 26.6 °C. This finding gives a numerical justification of the main result of this research work, which states that it is possible to prevent the formation of hydrate along the entire length of the pipeline by means of passive insulation.

4. Conclusion

Overall, this research show that the effective management of heat transfer is crucial in reducing the chances of hydrate formation in systems involving subsea gas pipelines. The likelihood of hydrate formation is greatly affected by temperature loss in the pipeline where the decline is brought about by heat loss to cold seawater. The current design of the pipeline, as checked in this research, fails to provide the required thermal efficiency. The decrease of temperature along the pipeline creates the environment for hydrate formation, especially in the regions of the pipeline located downstream, as the temperature of the fluid approaches the hydrate equilibrium curve.

The proposed new design, however, addresses these shortcomings by increasing thermal insulation and limiting the heat transfer between the pipeline and the surrounding medium. This s provides a better heat retention, slower cooling process, and better preservation of the required operating temperature. Research proves that keeping the temperature above the hydrate equilibrium is extremely important in order to ensure smooth delivery of gas.

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