

Numerical Simulation of the Minimum Insulation Thickness to Thermally Design a Subsea Pipeline Carrying an Oil and Gas Flow



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ABSTRACT

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This paper considered an existing subsea pipeline transporting an oil and gas flow, and proposed to find the best thermal insulating material and the required thickness of insulation necessary to meet an output temperature of 40°C and a pressure of 2.4MPa so as to avoid flow assurance issues. MATLAB and PIPESIM software were employed to run the simulations of the temperature and pressure profiles along the considered pipeline. Data used for the simulations were obtained from open literature. Results obtained from our simulations in MATLAB are validated using PIPESIM software, measured values and prediction model from literature. The temperature model was then used to thermally design an insulation thickness for the 50 km long pipeline using three insulating materials which are: black aerogel, polyurethane and calcium silicate. Results from the analysis showed that the black Aerogel material with a critical thickness of 10.16 cm is most effective to satisfy the criterion design. The effect of the selected insulating material was also investigated on the phase envelop. Results shows that for proper insulation thickness the flowing fluid temperature can be maintained at a temperature above which no flow assurance issues can be observed.

1. INTRODUCTION

In deepwater oil production project, where wells are located far from platforms, offshore fluids generally consisting of oil gas and water are often transported over long distances in subsea pipelines [1]. During the transportation, the multiphase fluids is cooled on its way to the surface production due to heat transfer, through the pipelines walls, with the surrounding seawater [1]. If the production flow-line is not properly and sufficiently insulated against heat losses to the external surrounding, temperature of the flowing fluids inside the subsea pipeline will drop and this may lead to some flow assurance issues such as the precipitation of asphaltenes and/or paraffin wax and the formation of hydrates [2]. For example, it is shown by Ahmed [3] that at temperature around 288, 15°k, wax will start to form inside the pipeline and at temperature below 313, 15°k, combine with high-pressure gas hydrates will occur. As results of these issues, pipe effective flow area may reduce and if serious, blockage may occur [4]. In subsea area, the interaction between the cold surrounding water and the warm flowing fluids inside pipeline is a major cause of temperature drop, which is responsible of some flow assurance issues such as wax deposition, and risk of hydrates formation. Therefore, temperature drops must be prevented in oil and gas production in order to minimize flow assurance issues. This can be achieved by choosing a proper insulation material with an appropriate thickness for the pipeline.

Insulation of pipeline is becoming more and more increasingly important in any subsea project because of the increase in energy saving that it can provides. Optimum insulation thickness need then to be calculated for an appropriate selection of the insulating material with respect to

a proper thickness. In recent years, many researches have been carried out on this topic in the open literature showing the interest of scientific for the pipeline thermal design. For examples: Nurfarah and William [5] carried out a study on the optimum thermal insulation design for subsea pipeline. One of theirs objectives was to establish a workflow procedure in selecting thermal insulation materials, thickness and number of layers required for protective coating. The pipeline length considered was comprised between 500 and 1500m and the design criterion was that the output temperature should be above 20°C. They used Visual Basic Application with Excel for the simulations purpose. Kiran [6], explored and compared the various types of insulation and find the optimum thickness of insulation required to maintain the temperature of the fluid inside the pipeline, above the hydrate/wax formation temperature of about 40°C to ensure smooth flow. Excel spreadsheet calculation was used to compare the effect of various insulation material with different thicknesses on the temperature profile of the fluid in deep-water environment. Ibrahim Masaud Ahmed [3], focuses he study on the thermal insulation pipelines used for subsea crude oil transportation. He used MATLAB and Ansys fluent CFD to validate the MATLAB model. Briggs et al. [7] carried out a study using PIPESIM software to investigate the effects of flowline sizes, flow rates, insulation material, type and configuration on flow assurance of waxy crude over 10.2 km between the wellhead and the first stage separator on the platform. Considering the implications of these factors for flow assurance. They used Polyurethane Foam, and pipe-in-pipe insulation type. Mobolaji et al. [8] investigated the best material that is suitable for the thermal insulation of subsea flowlines using the ANSYS software package, and then provided the best

composite arrangement of insulation materials for better heat optimization. They used different insulating materials such as Aerogel, Paraffin Wax, Mineral Wool and Grooved Mineral to fill the gap between the inner pipe and the outer pipe. Marfo et al. [9] used PIPESIM software to design a suitable pipeline for transporting condensate gas for the Jubilee and TEN Fields. The design comprises of two risers and two flowlines. Hydrate formation temperature was determined to be 72.5 °F at a pressure of 3 000 psig. The insulation thickness for flowlines 1 and 2 were determined to be 1.5 in. and 2 in. respectively. Marfo et al. [9] employed PIPESIM software to design a subsea pipeline for transportation of natural gas from Gazelle Field in Côte d'Ivoire to a processing platform located 30 km and to predict the conditions under which hydrate will form so as to be avoided. The found that an insulation thickness of 0.75 in. with specific pipe size of 10 in. could satisfy the arrival pressure condition of 800 psia. However, most of these studies thermally design insulation material for pipelines using computational method and commercial software. Moreover, some of them are based on single-phase flow. As far as two-phase gas and liquid flow is concerned, none of these studies calculated the optimum insulation thickness based on a coupled temperature-pressure model. Pressure and temperature are dependent variables that affect all the flow parameters.

Oluwaseun [10] carried out a study that focuses on choosing and sizing of an insulation material to meet an output temperature of an oil and gas wells. The criterion design output temperature was set at 20°C. the pipeline used was 1km long. The fluids properties was modeled using compositional model. Aspen Hysys software was used and Urethane Foam was used as the insulating material. Similarly to the work done by Zulkefli and Pao [5], this paper focuses on choosing and sizing of an insulation material to meet an output temperature of an oil and gas transporting pipelines in a subsea area from a wellhead to a surface processing plant. The particular points of this work that differ from [4] are:

- the pipeline is 50km long with undulation;
- the fluids properties are calculated using black oil model,
- the design output temperature used is 40°C
- three insulating materials: Calcium Silicate (CS), Black Aerogel (BA) and Polyurethane Foam (PUF) are used for the optimum insulation thickness
- MATLAB and PIPESIM software are used to perform numerical simulations

The aim of this study is to analyze the performance of different insulating materials along with the different insulation thickness. Then choice of the thermal insulation design should have the ability to maintain the flowline temperature above the critical point of hydrate formation temperature in order to prevent hydrate and wax crystals, which is usually 20°C. However, in this study the criterion temperature design was set to 40°C. More specifically, the study objectives are to:

- model the fluids properties with black oil model;
- model the temperature and pressure profiles of an oil and gas flow in an undulated subsea pipeline;
- build a computer program code in MATLAB for numerical simulations; model the temperature with PIPESIM software;

- use the temperature model for the thermal design of the subsea pipeline by performing numerical simulations analysis of different insulating materials with different thicknesses.

This research project is therefore devoted to the investigation of thermal insulation properties and fluid properties on the temperature profile in the pipeline system during steady state condition. The thermal insulation design should have a capability of maintaining the temperature above 40°C. This project is therefore restricted to: undulated subsea pipeline of 427m of altitude and 50km long; passive thermal insulation. This work contributes to a better understanding of the calculation of temperature and pressure distributions during gas and liquid flow in subsea pipeline using black oil model approach for fluids properties characterization, which lead to the optimal choice of the thermal insulation design.

This study is organized as follow: Section 2 presents the methodology and the propose algorithm for steady state flow analysis. Section 3 presents ours case study and field data. The results of our numerical analysis are presented and discussed. Section 4 conclude the work and presents recommendations and future work.

2. METHODOLOGY

2.1 Geometrical parameters of pipeline and insulation materials

The subsea pipeline geometry considered in this study is the same as that presented by Duan et al. [4] for the example 1 case. Figure 1 below represent a vertical section of the considered offshore pipeline. The figure was represented with MATLAB software based on data from the schematic in ref. [4].

Table 1. Geometrical parameters of pipeline and insulation [4]

Internal diameter of pipeline (m)	Outer diameter of pipeline (m)	Thickness of pipeline (m)	Length of pipeline (m)
0.3112	0.3239	0.0127	50,000

The geometrical parameters of the pipeline and insulation materials as well as the thermophysical properties of insulation materials are given in Table 1 and Table 2.

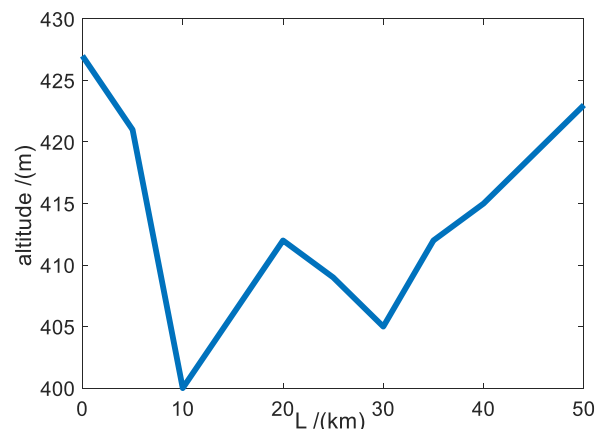


Figure 1. Vertical sectional profile of the pipeline [4]

Table 2. Thermophysical properties of the insulation materials [11, 12]

Insulation materials	Thermal conductivity (W/m K)	Specific heat (Kj/Kg K)	Density (Kg/m ³)
Calcium Silicate	0.069	0.96	260
Polyurethane	0.04	1400	45
Black Aerogel	0.012	950	140

2.2 Fluids properties

The black oil model assumed that there are at most three distinct phase: Oil, gas and water. Water and oil are assumed to be immiscible and they do not exchange mass or change phase. Gas is assumed to be soluble in oil but not in water. In this work, the fluids properties were calculated using the black oil approached as follow. All black oil variables are given in S.I units unless precise.

2.2.1 Bubble point pressure P_b

The bubble point pressure can be determined by [13]:

$$P_b = 1.255 \left[\left(\frac{GOR}{0.0059\gamma_g 10^{2.14/\gamma_o} 10^{-0.00198T}} \right)^{0.83} - 1.76 \right] \quad (1)$$

with T is in °k, P_b in Bar.

2.2.2 Gas oil solution R_s

Standing in 1951 [14], proposed a correlation for the calculation of the gas-oil solution.

$$R_s = 0.00590\gamma_g 10^{2.14/\gamma_o} 10^{-0.00198T} (0.797 \cdot 10^{-5} P + 1.4)^{1.205} \quad (2)$$

For pressures greater than bubble point pressure, $R_s=GOR$, with T in °k and P in Pa, R_s in Sm^3/Sm^3 .

2.2.3 Oil formation volume factor B_o

B_o is defined as the ratio between the oil volume at flow conditions and the oil volume at standard conditions.

$$B_o = \frac{V_o(P, T)}{V_{o_sc}} = \frac{Q_o(P, T)}{Q_{o_sc}} = \frac{V_{so}}{V_{so_sc}} \quad (3)$$

Oil formation volume factors at or less than bubble point pressures can be estimated by using the correlation obtained by Standing [14].

$$B_o = 0.9759 + 0.952 \cdot 10^{-3} \left(R_s \left(\frac{\gamma_g}{\gamma_{osc}} \right)^{0.5} + 0.401T - 103 \right)^{1.2} \quad (4)$$

For pressures greater than bubble point pressure, oil formation volume factor is calculated by [14]:

$$B_o = B_{ob} \exp[-C_o(P - 10^5 P_b)] \quad (5)$$

The coefficient of oil isothermal compressibility is calculated by Vazquez and Beggs [15] using the correlation below:

$$C_o = 10^{-9} \frac{2.81R_s + 3.10T + \frac{171}{\gamma_o} - 118\gamma_g - 1102}{P} \quad (6)$$

With, T in °k, P in Bar, B_o in m^3/m^3 and C_o in Bar^{-1} .

2.2.4 Oil viscosity μ_o

The oil viscosity is determined for three thermodynamic pressure levels

- For $P=P_{atm}$, the dead oil viscosity is calculated using the equation by Beal [16] as presented by [17]:

$$\mu_{od} = C_4 \left(0.32 + \frac{1.8 \times 10^7}{API^{4.53}} \right) \left(\frac{360}{C_3 + 200} \right)^{10^{(0.433 + \frac{8.33}{API})}} \quad (7)$$

- For $P_{atm} < P \leq P_b$, the live oil viscosity is calculated using Beggs and Robinson [17] formulation

$$\mu_o = 10.715C_4(C_1 R_s + 100)^{-0.515} \left(\frac{\mu_{od}}{C_4} \right)^{(5.44(C_1 R_s + 150)^{-0.338})} \quad (8)$$

- For $P > P_b$, the relation from Vasquez and Beggs [18] is used

$$\mu_o = \mu_{ob} \left(\frac{P}{P_b} \right)^m \quad (9)$$

where,

$$m = 2.6(C_2 P)^{1.187} \times e^{-11.513 - 8.9810^{-5} C_2 P} \quad (10)$$

μ_{ob} is the viscosity at the bubble-point pressure obtained using and setting $R_s=GOR$.

μ_o is given in Pa.s.

2.2.5 Oil specific gravity and oil density γ_o, ρ_o

In petroleum industry, the oil specific gravity and oil density are given by:

$$\gamma_o = \frac{141.5}{API + 131.5} \quad (11)$$

$$\rho_{o_sc} = \gamma_o \rho_{w_sc} \quad (12)$$

$$\rho_o = \frac{\rho_{o_sc} + \rho_{g_sc} R_s}{B_o} \quad (13)$$

where,

ρ_{o_sc} , ρ_{w_sc} and ρ_{g_sc} are standard densities of oil, water and gas respectively. γ_o is the specific density of oil. ρ_o is the local density of oil at flow conditions.

2.2.6 Gas compressibility factor Z

Correlation presented by Andreolli et al. [11] approximating the abacus data in Standing and Katz [19] is given by:

$$Z = 1 - \frac{3.52}{10^{0.9813T_{pr}}} + \frac{0.274P_{pr}^2}{10^{0.8157T_{pr}}} \quad (14)$$

$$T_{pr} = \frac{T}{T_{pc}} \quad (15)$$

$$P_{pr} = \frac{P}{P_{pc}} \quad (16)$$

where, the pseudocritical properties were calculated using the Standing [15] correlation

$$T_{pc} = \frac{1}{C_5} (168 + 325\gamma_g - 12.5\gamma_g^2) \quad (17)$$

$$P_{pc} = \frac{1}{C_2} (677 + 15.0\gamma_g - 37.5\gamma_g^2) \quad (18)$$

2.2.7 Gas formation volume factor B_g

B_g is defined by the ratio of the free gas volume in flow condition to the volume at standard condition of the same mass of gas.

$$B_g = \frac{V_g(P,T)}{V_{g,sc}} = \frac{\rho_{g,sc}}{\rho_g} \quad (19)$$

$$B_g = \frac{P_{sc} ZT}{T_{sc} P} \quad (20)$$

where, P_{sc} and T_{sc} are pressure and temperature at standard condition. T and P are temperature and pressure at flow conditions respectively.

2.2.8 Gas density ρ_g

$$\rho_g = 0.009225 \frac{\gamma_g P}{ZT} \quad (21)$$

where, T is in °k, P in Pa.

2.2.9 Gas viscosity μ_g

For the gas viscosity calculation, we used the Lee et al. [18].

$$\mu_g = C_4 F_1 \exp(F_2 (C_4 \rho_g)^{F_3}) \quad (22)$$

$$F_1 = \frac{(9.379 + 16.07M_g)(C_5 T)^{1.5}}{209.2 + 19260M_g + C_5 T} \quad (23)$$

$$F_2 = 3.448 + \frac{986.4}{C_5 T} + 10.09M_g \quad (24)$$

$$F_3 = 2.447 - 0.2224F_2 \quad (25)$$

where, T is in °k

2.2.10 Water formation volume factor B_w

B_w is defined as the ratio between the water volume at flow conditions and the water volume at standard conditions.

$$B_w = \frac{V_w(P, T)}{V_{w,sc}} = \frac{Q_w(P, T)}{Q_{w,sc}} \quad (26)$$

It can be calculated using the McCain correlation [20].

$$B_w = (1 + \Delta V_{wT})(1 + \Delta V_{wP}) \quad (27)$$

where, ΔV_{wT} and ΔV_{wP} are respectively the volume corrections for temperature and pressure, obtained by:

$$\Delta V_{wT} = -1.00010(10^{-2}) + 1.33391(10^{-4})C_3 + 5.50654(10^{-7})C_3^2 \quad (28)$$

$$\begin{aligned} \Delta V_{wP} = & -1.95301(10^{-9})C_2 C_3 P \\ & - 1.72834(10^{-13})C_2^2 C_3 P^2 \\ & - 3.58922(10^{-7})C_2 P \\ & - 2.25341(10^{-10})C_2^2 P^2 \end{aligned} \quad (29)$$

T is given in °k and P in Pa.

2.2.11 Water density

The water density at local flow condition is calculated as:

$$\rho_w = \frac{\rho_{w,sc}}{B_w} \quad (30)$$

where, $\rho_{w,sc}$ and $\gamma_{w,sc}$ are respectively water density at standard conditions and specific gravity of water at standard condition.

2.2.12 Water viscosity

The water viscosity was estimated by using the correlation of Collins [21], neglecting salinity effect as presented by [11].

$$\mu_{w,sc} = 109.574C_4 C_3^{-1.12166} \quad (31)$$

$$\mu_w = \mu_{w,sc} (0.999 + 4.029510^{-5}k_6 + 3.1062 \times 10^{-9}k_6^2) \quad (32)$$

$$k_6 = (C_2 P + 14.7) \quad (33)$$

2.2.13 Volumetric flow rate

Volumetric flow rate of petroleum fluids (gas, oil and water) at flow conditions are defined as follow:

$$Q_g = (Q_{g,sc} - R_s Q_{o,sc}) B_g = Q_{o,sc} (GOR - R_s) B_g \quad (34)$$

$$Q_o = Q_{o,sc} B_o \quad (35)$$

$$Q_w = Q_{w,sc} B_w \quad (36)$$

$$Q_l = Q_{o,sc} B_o + Q_{w,sc} B_w = Q_{o,sc} (B_o + WOR \cdot B_w) \quad (37)$$

where, $Q_{g,sc}$, $Q_{w,sc}$ and $Q_{o,sc}$ are the flow rates of gas, water and oil at standard conditions. Q_g , Q_w , Q_o and Q_l are the flow rates of gas, water, oil and liquid at flow conditions. GOR and WOR are gas oil ratio and water oil ratio at surface.

2.3 Pressure gradient formulation

The pressure gradient is calculated using Dukler and Taitel correlation [22] in which, void fraction is determined based on drift-flux model using correlations from [23]. Eq. (1) below describes the pressure profile along a flow-line.

$$\left(\frac{dP}{dL}\right) = \frac{f_{tp} \rho_m v_m^2}{2D} + \rho_m g \sin(\theta) \quad (38)$$

where: P is the pressure given in P_i ; L is the length of the pipeline in m; ρ_m is the mixture local density in $k_g \cdot m^{-3}$; v_m is the mixture velocity in $m \cdot s^{-1}$; D is the pipeline outer diameter in m; g is the gravitational acceleration given in $m \cdot s^{-2}$ and θ is the inclination of the pipeline expressed in degrees. In Eq. (38), two necessary variables are to be determined: the friction factor of two-phase flow f_{tp} and the mixture density ρ_m .

$$\rho_m = \rho_L \left(\frac{\lambda^2}{1-\alpha}\right) + \rho_g \left(\frac{(1-\lambda)^2}{\alpha}\right) \quad (39)$$

$$\frac{1}{\sqrt{f_{tp}}} = -2 \log \left[\frac{2\varepsilon/d}{3.7} - \frac{5.02}{Re} \log \left(\frac{2\varepsilon/d}{3.7} + \frac{13}{Re} \right) \right] \quad (40)$$

$$\lambda = \frac{Q_{o,sc}B_o + Q_{w,sc}B_w}{Q_{o,sc}B_o + Q_{w,sc}B_w + (Q_{g,sc} - Q_{o,sc}R_s)B_g} \quad (41)$$

$$\alpha = \frac{V_{sg}}{C_d V_m + V_d} \quad (42)$$

$$C_d = \frac{V_{sg}}{V_m} \left[1 + \left(\frac{V_{sl}}{V_{sg}} \right) \left(\frac{\rho_g}{\rho_L} \right)^{0.1} \right] \quad (43)$$

$$V_d = 2.9 \left[\frac{g \cdot D \cdot \sigma (1 + \cos \theta) (\rho_L - \rho_g)}{\rho_L^2} \right]^{0.25} + 1.22 \sin \theta \frac{P_{atm}}{P} \quad (44)$$

From (Eq. (38)) to (Eq. (44)):

ρ_g , is the local density of the gas, $\text{kg} \cdot \text{m}^{-3}$; ρ_L is the local liquid density, $\text{kg} \cdot \text{m}^{-3}$; α is the void fraction of the gas phase given by drift flux correlation of Woldesemayat. For more details, see [23]. V_{sg} is the superficial velocity of the gas phase, $\text{m} \cdot \text{s}^{-1}$; V_m is the mixture velocity, $\text{m} \cdot \text{s}^{-1}$; C_d is the profile parameter and V_d is the drift velocity. σ is the surface tension calculated given in $\text{N} \cdot \text{m}^{-1}$. P_{atm} , is the atmospheric pressure, in Pa . λ is the liquid input fraction. $Q_{o,sc}$ and $Q_{w,sc}$ are oil and water flowrate respectively at standard condition given in $\text{m}^3 \cdot \text{s}^{-1}$. Black oil parameters which are: B_w , $\text{m}^3 \cdot \text{s}^{-3}$; B_g , $\text{m}^3 \cdot \text{m}^{-3}$; B_o , $\text{m}^3 \cdot \text{m}^{-3}$; R_s , $\text{Sm}^3 \cdot \text{Sm}^{-3}$, ε , is the pipe roughness, d the pipe diameter and Re is the Reynolds number of the mixture given by (Eq. (45)) below:

$$Re = \frac{\rho_m V_m d}{\mu_m} \quad (45)$$

2.4 Temperature profile model using MATLAB

Difference material of thermal insulation will result to various temperature profile inside the subsea pipeline. Thus, we present here the temperature calculations model for an oil and gas flow inside subsea pipeline. The temperature are pressure dependent. From the general equation describing the temperature profile along pipeline considering that the kinetic energy is negligible as in ref. [24], we have:

$$\frac{\partial(T_m)}{\partial t} - \eta_m \frac{\partial P}{\partial t} = -v_m \frac{\partial(T_m)}{\partial L} - \frac{U_o \pi D (T_m - T_e)}{A_p \rho_m C_{p_m}} + v_m \eta_m \frac{\partial P}{\partial L} - v_m \frac{g \sin(\theta)}{C_{p_m}} \quad (46)$$

where, T_m is the average temperature of the fluid given in $^\circ\text{K}$, A_p is the pipe cross-sectional area m^2 , t is the time given in s , C_{p_m} is the mixture specific heat capacity in $\text{J} \cdot \text{k} \cdot \text{kg}^{-1}$, η_m is the mixture Joule Thomson coefficient, $\text{k} \cdot \text{Pa}^{-1}$, U_o is the overall heat transfer coefficient in $\text{w} \cdot \text{k} \cdot \text{m}^{-2}$, T_e is the environment temperature in $^\circ\text{K}$.

In steady state conditions, (Eq. (47)) becomes:

$$\frac{dT_m}{dL} = - \frac{U_o \pi D (T_m - T_e)}{C_{p_m} w_m} + \eta_m \frac{dP}{dL} - \frac{g \sin(\theta)}{C_{p_m}} \quad (47)$$

where:

$$w_m = \rho_m V_m A_p \quad (48)$$

$$C_{p_m} = C_{p_g} \alpha \frac{\rho_g}{\rho_m} + C_{p_L} (1 - \alpha) \frac{\rho_L}{\rho_m} \quad (49)$$

$$C_{p_L} = \left(\frac{Q_o}{Q_o + Q_w} \right) C_{p_o} + \left(\frac{Q_w}{Q_o + Q_w} \right) C_{p_w} \quad (50)$$

From (Eq. (47)) to (Eq. (50)):

w_m is the mixture mass flow rate in $\text{kg} \cdot \text{s}$, C_{p_m} , is the average specific heat capacity calculated as in ref. [25], C_{p_g} and C_{p_L} are the specific heat capacity of the gas and liquid respectively. C_{p_m} , C_{p_g} and C_{p_L} are expressed in $\text{J} \cdot \text{k} \cdot \text{kg}^{-1}$. Q_o and Q_w are respectively the local flowrates of the oil and water. η_m , is the average Joule-Thomson, coefficient calculated using (Eq. (51)) through (Eq. (54)) as shown below,

$$\eta_m = - \left(\frac{w_g C_{p_g} \eta_g + w_L C_{p_L} \eta_L}{w_m C_{p_m}} \right) \quad (51)$$

$$\eta_g = \left(\frac{1}{\rho_g C_{p_g}} \right) \left[\frac{T_m}{Z} \left(\frac{dZ}{dT} \right)_p \right] \quad (52)$$

$$\eta_L = \frac{1}{\rho_L C_{p_L}} (T_m \beta - 1) \quad (53)$$

$$\beta = \frac{WOR}{1 + WOR} \frac{\partial B_w}{\partial T} + \frac{1}{1 + WOR} \frac{\partial B_o}{\partial T} \quad (54)$$

Where is the thermal expansion coefficient and Z is the gas compressible factor.

The overall heat transfer coefficient U_o is calculated as

$$\frac{1}{U_o} = \left(\frac{r_{ins}}{r_i h_{in}} + r_{ins} \frac{\ln \left(\frac{r_o}{r_i} \right)}{k_{pipe}} + r_{ins} \frac{\ln \left(\frac{r_{ins}}{r_o} \right)}{k_{ins}} + \frac{r_{ins}}{h_o} \right) \quad (55)$$

k_{pipe} and k_{ins} represent the thermal conductivity of the metallic pipe and the insulation layer respectively, they are expressed in, $\text{w} \cdot \text{k}^{-1} \cdot \text{m}^{-1}$. r_{ins} , r_o and r_i are respectively the insulation material radius, the outer and the inner radius given in m . The surrounding heat transfer coefficient h_o expressed in $\text{w} \cdot \text{k}^{-1} \cdot \text{m}^{-2}$, is calculated using (Eq. (56)) below:

$$h_o = \frac{K_o Nu_o}{D} \quad (56)$$

where, $Nu_o = 0.027 \cdot Re_o^{0.8} Pr_o^{0.3}$, represent the Nusselt number; $Re_o = \frac{\rho_o V_o D}{\mu_o}$, is the outer Reynolds number of the seawater; ρ_o is the density of the seawater, $\text{kg} \cdot \text{m}^{-3}$; V_o , is the seawater velocity, m/s ; μ_o is the viscosity of the seawater, in $\text{Pa} \cdot \text{s}$; $Pr_o = \frac{\mu_o C_{p_o}}{K_o}$, is the Prandtl number of the outer seawater; C_{p_o} is the specific heat capacity of the seawater, $\text{J} \cdot \text{k} \cdot \text{kg}^{-1}$; K_o is the thermal conductivity of the seawater, $\text{w} \cdot \text{k}^{-1} \cdot \text{m}^{-1}$.

The internal heat transfer coefficient expressed in $\text{w} \cdot \text{k}^{-1} \cdot \text{m}^{-2}$, is calculated according to Pourafshary et al. [25] as follow:

$$h_{in} = \frac{K_{tp} Nu_{tp}}{D} \quad (57)$$

where, K_{tp} expressed in $\text{w.k}^{-1}.\text{m}^{-1}$, is the mixture thermal conductivity of the two-phase flow given as

$$K_{tp} = \alpha k_g + (1 - \alpha)k_L \quad (58)$$

With k_g and k_L representing each the thermal conductivity of the gas and liquid respectively, expressed both in $\text{w.k}^{-1}.\text{m}^{-1}$.

Nu_{tp} , the Nusselt number of the two-phase flow determined as follow:

If flow is laminar ($Re_T \leq 2000$), for long pipe, we have:

$$Nu_{tp} = 1.86 \left[Re_T Pr_m \left(\frac{D}{L} \right) \right]^{\frac{1}{3}} \quad (59)$$

If flow is turbulent flow ($Re_T \geq 6000$), for long pipe, we have:

$$Nu_{tp} = 0.023 Re_T^{0.8} Pr_m^{0.33} \left(1 + \left(\frac{D}{L} \right)^{0.7} \right) \quad (60)$$

For transition flow regime ($2000 \leq Re_T \leq 6000$)

$$Nu_{tp} = Nu_{laminar} \left[\frac{Re_T}{6000} \right]^a \quad (61)$$

with, parameter a given by:

$$a = \frac{\ln \left(\frac{Nu_{turbulent}}{Nu_{laminar}} \right)}{\ln \left(\frac{Re_{max}}{Re_{min}} \right)} \quad (62)$$

The total Reynolds number Re_T is calculated as follow:

$$Re_T = \frac{\rho_L V_{sL} D}{\mu_L} + \frac{\rho_g V_{sg} D}{\mu_g} \quad (63)$$

The Prandtl number of the mixture is given by:

$$Pr_m = \frac{\mu_m C_{p_m}}{K_{tp}} \quad (64)$$

2.5 Numerical simulations

The finite difference method was used to discretize the temperature model given by Eq. (47). All the equations in this study are solved simultaneously using MATLAB software. Numerically, we divide the pipeline into sections, and each section was divided into cells and consider average value of temperature and pressure in the cells. The numerical solution obtained using finite difference method is therefore given by:

$$\frac{T_m(i+1) - T_m(i)}{\Delta x} = \left(\frac{T_e - T_m}{A} + \eta_m \frac{dP}{dL} - \frac{g \sin(\theta)}{C_{p_m}} \right)_i \quad (65)$$

In which, the parameter A is:

$$A_i = \left(\frac{C_{p_m} w_m}{U_o \pi D} \right)_i \quad (66)$$

The temperature model presented above is first validated by

using it to produce the same work done by [4]. The difference done here by this research is the methodology approach for the determination of the pressure gradient, the calculation of the Z-factor, the calculation of the liquid holdup and the determination of the of the joule Thomson coefficient of gas, liquid and thus, for the mixture. In Table 3 below, we present all the necessary inputs fluids data to run simulations.

Table 3. Operating parameters [4]

Oil flow rate	0.00955 m ³ /s
Gas flow rate	9.05 Nm ³
Density of natural gas	0.710 Kg/m ³
Density of crude oil (20°C)	886.9 Kg/m ³
Surrounding temperature	277.15 K
Inlet temperature	323.15 K
Outlet temperature	278.75 K
Inlet pressure	5 MPa
Outlet pressure	2.4 MPa
Over all heat transfer coefficient	2 (W/m ² K)

2.6 Temperature model using PIPESIM

This study also uses the PIPESIM software to build and validate the temperature model presented above. The operating parameters are enter in the software. The fluid type is set as black oil. The simulations are

2.6.1 Pipeline model

The network schematic model was used to build the pipeline model in PIPESIM. Figure 2 below shows a sketch of the simulation modeling of the pipeline in PIPESIM.

2.6.2 Multiphase correlation

The multiphase model selected in PIPESIM was the revised correlation of Beggs and Brill [17] described by the following equation

$$\frac{dP}{dL} = \frac{f_{tp} \rho_n V_m^2}{2d} + \rho_m g \sin \theta \quad (67)$$

$$1 - E_k$$

In which E_k is a dimensionless acceleration term that take into consideration the pressure gradient due to kinetic energy effects and is given by:

$$E_k = \frac{V_m V_{sg} \rho_m}{P} \quad (68)$$

The Beggs and Brill multiphase correlation deals with both the friction pressure loss and the hydrostatic pressure difference. First the appropriate flow regime for the particular combination of gas and liquid rates (Segregated, Intermittent or Distributed) is determined. The liquid holdup, and hence, the in-situ density of the gas-liquid mixture is then calculated according to the appropriate flow regime, to obtain the hydrostatic pressure difference. A two-phase friction factor is calculated based on the "input" gas-liquid ratio and the Moody friction factor table using Colebrook equation. From this, the friction pressure loss is calculated using "input" gas-liquid mixture properties. That is why this model was selected.

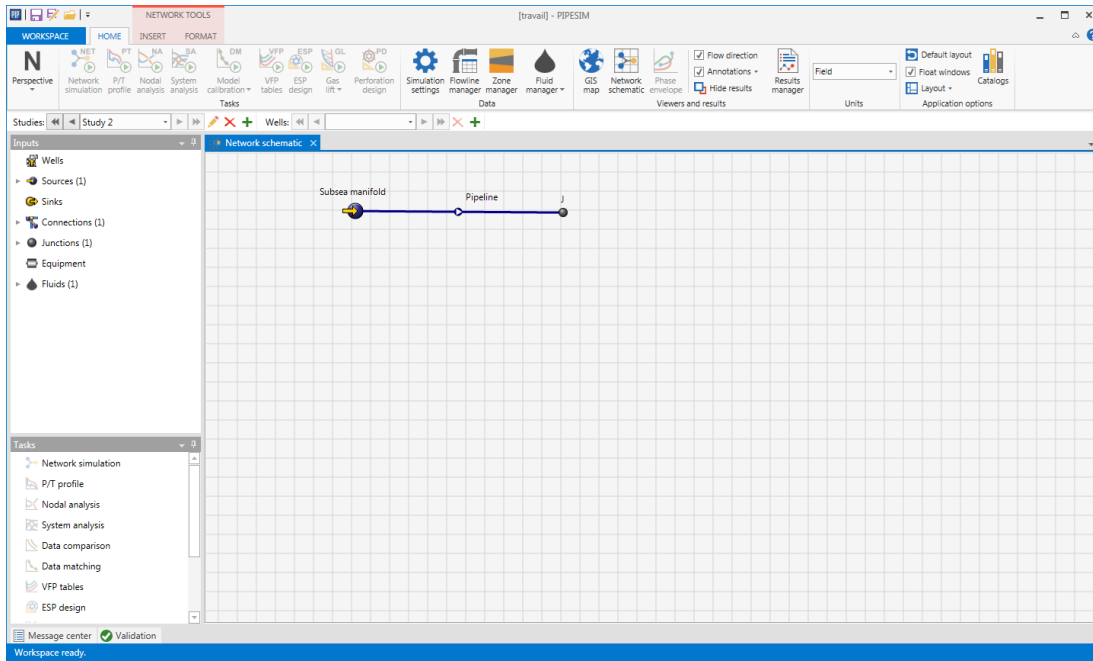


Figure 2. Sketch of the simulation modeling of subsea pipeline in PIPESIM

2.6.3 Energy equation

PIPESIM uses the first law of thermodynamics to perform a rigorous heat transfer balance on each pipe segment. The first law of thermodynamics is the mathematical formulation of the principle of conservation of energy applied to a process occurring in a closed system (a system of constant mass m). It equates the total energy change of the system to the sum of the heat added to the system and the work done by the system. For steady-state flow, it connects the change in properties between the streams flowing into and out of an arbitrary control volume (pipe segment) with the heat and work quantities across the boundaries of the control volume (pipe segment). For a multiphase fluid in steady-state flow, the energy equation is given by:

$$\Delta \left[\left(H + \frac{1}{2} V_m^2 + gz \right) dm \right] = \sum \delta Q - \delta W \quad (69)$$

where the specific enthalpy:

$$H = U + PV \quad (70)$$

is a state property of the system since the internal energy U the pressure P and the volume V are state properties of the system. It is clear from the left-hand side of Eq. (69), the change in total energy is the sum of the change in enthalpy energy,

$$\Delta[Hdm] = \Delta[(U + PV)dm] \quad (71)$$

the change in gravitational potential energy:

$$\Delta(E_p) = \Delta[(gz)dm] \quad (72)$$

and the change in total kinetic energy (based on the mixture velocity)

$$\Delta(E_k) = \Delta \left[\left(\frac{1}{2} V_m^2 \right) dm \right] \quad (73)$$

which is assumed to be negligible.

On the right-hand side of Eq. (69), $\sum \delta Q$ includes all the heat transferred to the control volume (pipe segment) and δW represents the shaft work, that is work transmitted across the boundaries of the control volume (pipe segment) by a rotating or reciprocating shaft

2.6.4 Setup calculation

In PIPESIM, after the pipeline model is built and the fluid model is considered, the setup data for simulations can then be edited as it be seen in the Figure 3 below.

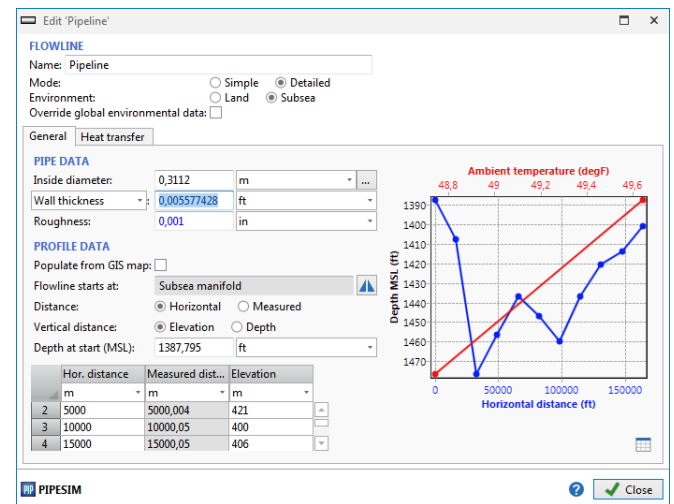


Figure 3. Sketch of data edit in PIPESIM

2.6.5 Run simulations

You can perform nodal analysis, reservoir simulation, and use other analytical tools (such as pressure/temperature (P/T) profiles, VFP tables, and network simulation) to calculate the distribution of flowrates, temperatures, and pressures throughout the system and plan new field developments. Figure 4 below presents a sketch of temperature simulation run using PIPESIM.

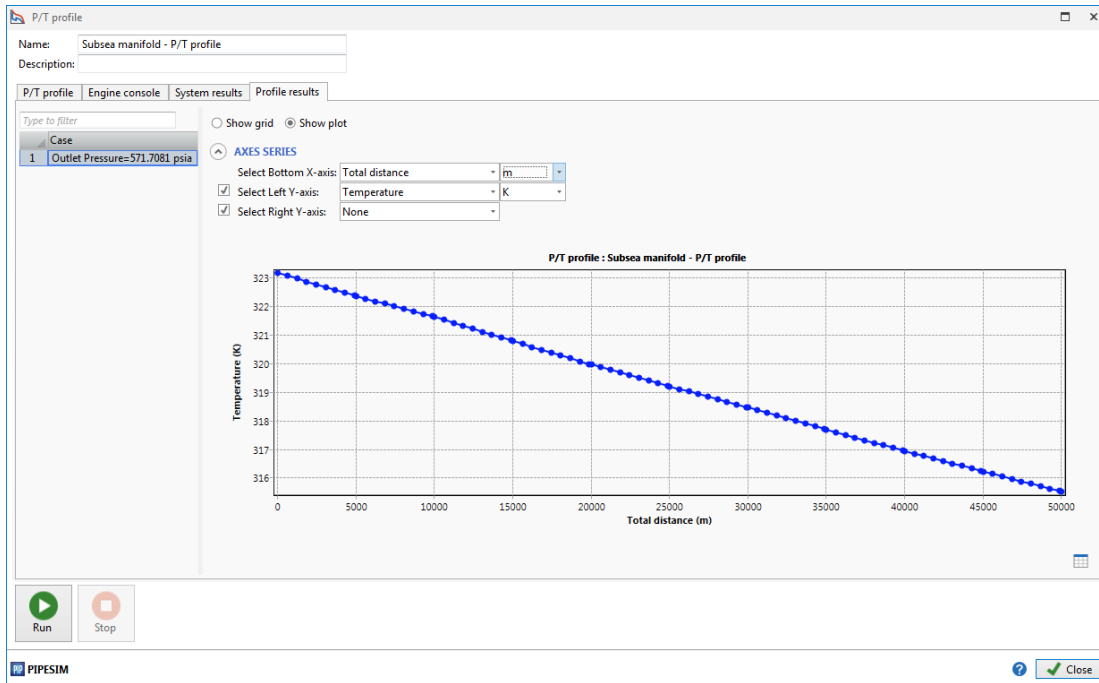


Figure 4. Sketch of temperature simulation with PIPESIM

3. RESULTS AND DISCUSSIONS

The given calculations are performed to select the insulation material and appropriate insulation layer thickness. The design criterion is to ensure that the temperature at any point on the flow line does not drop to below 40°C, as required by flow assurance. Insulating materials considered for this design are Calcium Silicate (CS), Black Aerogel (BA) and Polyurethane Foam (PUF). Firstly, MATLAB software was used to implement numerical simulations and PIPESIM software was used for numerical validation purpose of the temperature profile. Further simulations are run to thermally design the subsea pipeline. Finally, the effect of the selected insulation material on the heat flux and the phase envelop of the fluids was carried out

3.1 Pressure profile inside the subsea pipeline

As pressure and temperature are simultaneously dependent, we first present the result of the pressure profile along the considered subsea pipeline. In order to verify the pressure model describes above in Eq. (38), numerical simulation was performed with MATLAB software using data presented in Table 3 above. The validation of the predicted model is done using PIPESIM software and measure value data obtained from [4].

3.1.1 Validation with the PIPESIM model

In order to validate the model used for predicting the pressure profile, the output of the predicted model was compared to the output of the PIPESIM model. From Figure 5 above, we observed the Pressure drop is not linear because of the presence of more than phase. Predicted pressure decreases along the subsea pipeline from 5×10^6 Pa to 2.4327×10^6 Pa. The pressure obtained with the PIPESIM software have an end-point value of 3×10^6 Pa. The predicted used Dukler and Taitel model in which liquid holdup is calculated using drift-flux correlation while the PIPESIM model used the Beggs and

Brill correlation. These different approaches could explain the difference observed when comparing the outputs of the models. However, the pressure drop from PIPESIM is closed to the one obtained by our predicted program with a relative error of about $(3-2.4327)/3=19\%$. This shows that the predicted model presented in this study can be used for two-phase pressure drop calculation in an undulated subsea pipeline of about 50km. A greater pressure drop will cause a smaller displacement of the fluid, thus additional energy will be required to displace the fluid.

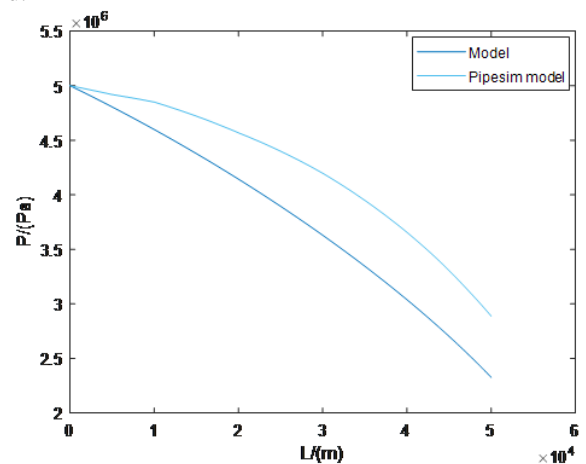


Figure 5. Pressure profile inside subsea pipeline obtained using proposed model with MATLAB software and validated with PIPESIM model

Table 4. Pressure comparison and validation [4]

Methods	Inlet pressure/(MPa)	Endpoint pressure/(MPa)	Pressure drop/(MPa)	REPD
Model	5	2.4327	2.5673	1.26%
Measured Value	5	2.4	2.6	

3.1.2 Validation with measured data

We compared in Table 4, the end-point value of the predicted model of pressure profile and the measured value from experiment in [4]. We then calculated the relative pressure difference (REPD). From Table 4, we noticed that the predicted pressure and the measured end-value are in good agreement with a relative error of 1.26% which shows that the proposed model capture well the two-phase flow pressure profile inside the subsea pipeline.

3.2 Temperature profile inside subsea pipeline

Temperature is one of the most important parameter in all thermal insulation design in subsea pipeline. Before investigating on the proper insulation material and the required insulation thickness, the temperature profile of the fluid flowing inside the pipeline must be well described. In order to make sure that the proposed temperature model is good for further simulations run, validation was carried out using PIPESIM model, measured value from experiment in [4] and literature calculation model from [4]. The predicted temperature from Eq. (65) was implement in MATLAB.

3.2.1 Validation with the PIPESIM model

Using the data presented in Table 3 above in conjunction with the above temperature model described by Eq. (65), the predicted temperature profile has been calculated using MATLAB software. The model was first validated numerically with the PIPESIM software as shown in Figure 6 below. It can be observed that the mixture of oil and gas enters the subsea pipeline with a temperature of 323.15°k and decreases along the subsea pipeline until it reaches the temperature of approximately 277.9934°k. This result was obtained for an overall heat transfer coefficient $U = 2 \text{ W}/(\text{m}^2 \text{ K})$ as presented by Duan et al. [4]. From the plot, it can be observed that the predicted model and the PIPESIM model show a good agreement. It can also be observed that the flowing temperature decreases rapidly to 313.15°K for a travelled distance of about 0.5 km, which represent the maximum distance the fluid moved before starting undergoing flow assurance issues such as paraffin wax formation and deposition. By considering the pipeline length of 50 km, the close match results shows that the model can predict the temperature distribution of an oil and gas flow through an undulated subsea pipeline.

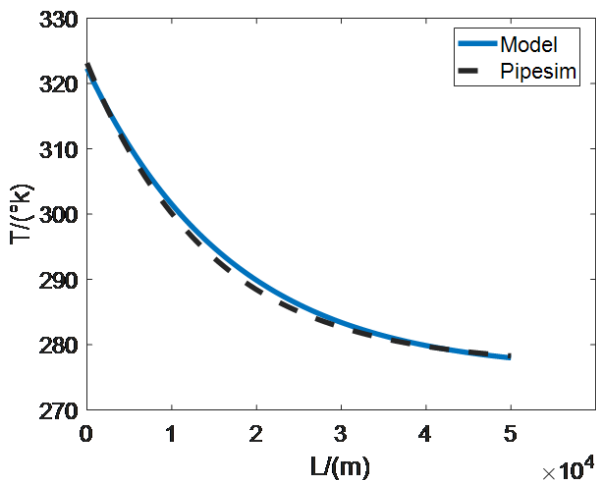


Figure 6. Temperature profile comparison between our model and PIPESIM model

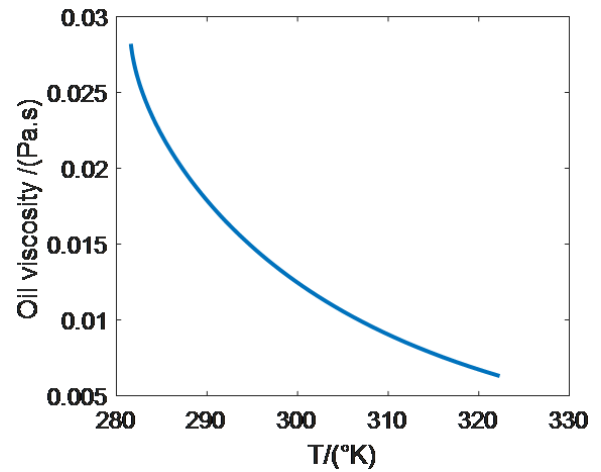


Figure 7. Oil viscosity variation with temperature

As the fluid temperature decreases along the pipeline due to the heat losses between the cold surrounding and the hot fluid, oil viscosity will increase as it is shown in Figure 7 above. Such situation may promote formation of solids such as wax in the pipeline resulting in pipeline obstruction thus to an increase in pressure drop of the fluid. Another problem, is the decrease of the oil production along the subsea production pipeline as can be seen in the Figure 8.

Figures 6, 7 and 8 show that the temperature is an important parameter for the analysis of fluid flow in subsea pipeline. A drop in temperature will cause a reduction in production due to a restriction of the flow area by solids deposition such as wax and hydrates resulting from a thermal unbalance between the surrounding cold water and the hot fluid flowing through the pipeline. This situation may required a more suitable insulation design for remediation.

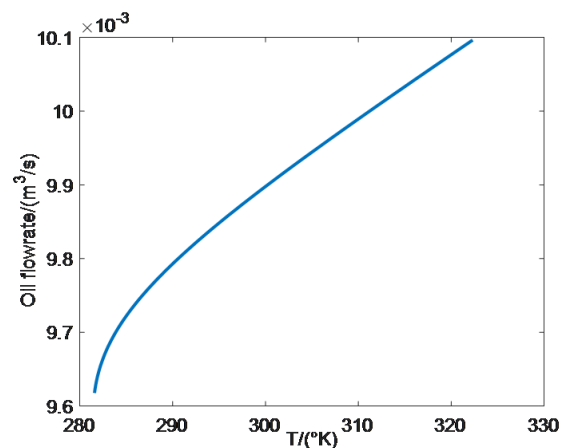


Figure 8. Oil flowrate variation with temperature

3.2.2 Validation with measured field data from literature model

The model was also validated using measured value from field data. The results was presented and compared in Table 5 below. From this table, it is show that the predicted temperature from our model is in good agreement with that of the measured value and the predicted model from [4]. The results show a relative error of 1.68% with the measured value, 1.04% with the PIPESIM model and 3.37% with the model presented by Duan et al. [4]. This result shows that the model can predict accurately the temperature profile inside the considered subsea pipeline for an overall heat transfer coefficient $U = 2 \text{ W}/(\text{m}^2 \text{ K})$.

Table 5. Validation of the temperature calculations with others models

Methods	Inlet temperature/(K)	Endpoint temperature/(K)	Temperature drop	RETD
Predicted model	323.15	277.99	45.1566	1.68%
MV	323.15	278.75	44.4	1.04%
PIPESIM prediction	323.15	278.28	44.86	
UPTP	323.15	277.25	45.9	3.37%

Form the results presented in Figure 6 and Table 5 above, it clear that the temperature model presented in this study can be further used for the thermal insulation design because of its good accuracy with other models. The main goal of the thermal design analysis was to select an appropriate insulation layer thickness and material. The design criterion is to ensure that the temperature at any point on the flow line does not drop to below 40°C, as required by flow assurance. Insulation materials considered for this design are Calcium Silicate, Polyurethane Foam and Black Aerogel.

3.3 Numerical simulations for the determination of the minimum insulation thickness of Calcium Silicate

Figure 9 below shows the effect of various Calcium Silicate thickness on the fluid temperature along the subsea pipeline.

The thickness is comprised between 2.54 to 66.04 cm. It can be seen that, for insulation thickness less than 66.04 cm, the fluid temperature would drop below the 313.15°K, leading to high risk of flow assurance issues inside the subsea pipeline. The minimum insulation thickness to be used in this case is 66.04 cm.

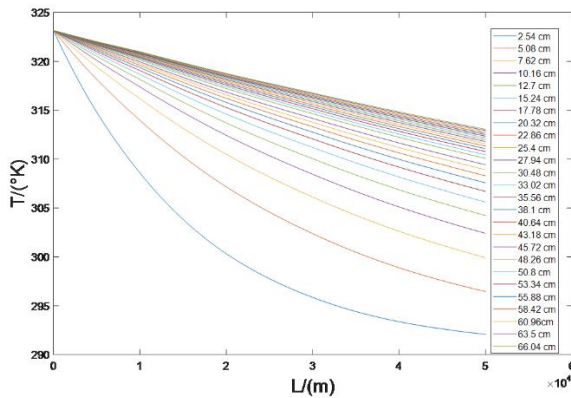


Figure 9. Temperature profiles of the flowing fluids inside subsea pipeline with different insulation thickness of Calcium Silicate

3.4 Numerical simulations for the determination of the minimum insulation thickness of Polyurethane Foam

Figure 10 below, shows the temperature profile for different Polyurethane Foam thickness taken between 2.54 cm and 25.4cm. It can be observed that the minimum insulation thickness that would achieved an output temperature of at least 313.15°K is 25.4cm.

3.5 Numerical simulations for the determination of the minimum insulation thickness of Black Aerogel

In Figure 11 below, we plotted the temperature profile for different insulation thickness of Black Aerogel. The thickness range from 1.27 cm and 10.16 cm. The minimum insulation thickness necessary to satisfy the design criterion is 10.16 cm

as can be seen.

When comparing the temperature profiles plotted in figure 9 to Figure 11 for the various insulating materials with different thickness, we observed that either a 25.4 cm of Polyurethane or a 10.16cm of Black Aerogel material should be used as insulating material type for the subsea pipeline. However, only cost analyses can justify one of the options, which is beyond the scope of this work. In this study, because Black Aerogel has the smallest thermal conductivity and provide the smallest insulation thickness, it was chosen as the best insulating material with a thickness of 10.16cm for the design purpose.

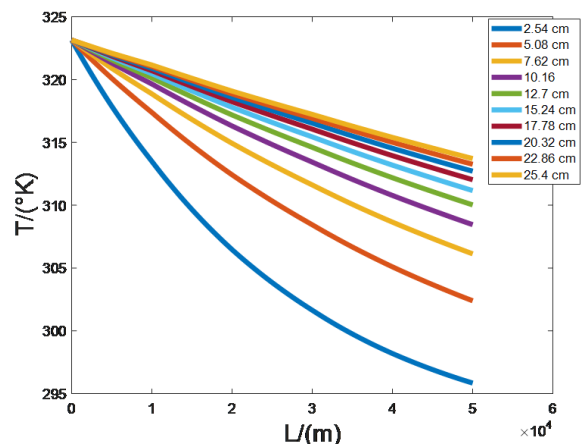


Figure 10. Temperature profiles of the flowing fluids inside subsea pipeline with different insulation thickness of Polyurethane Foam

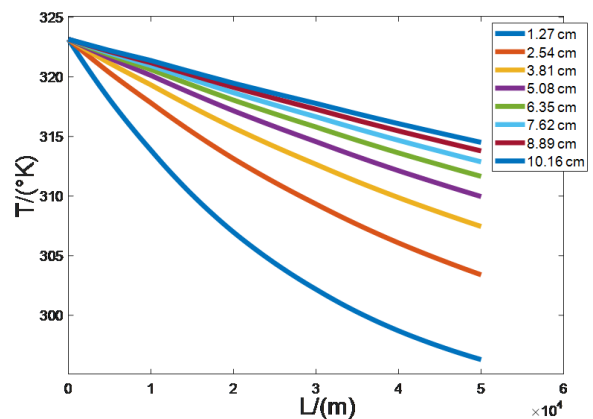


Figure 11. Temperature profiles of the flowing fluids inside subsea pipeline with different insulation thickness of Black Aerogel

The temperature profiles have also help us to investigate the risk of flow assurance issues by examined the phase envelop.

3.6 Effect of Black Aerogel on the phase diagram

Due to the low temperature and high pressure of deep water,

the pipe thermal insulation has important effects on the fluid temperature in pipeline. Effect of Black Aerogel on the formation area of some flow assurance issues under different insulating material thickness.

In Figure 12, F.A is for Flow Assurance. The effect of different insulating material thickness was investigated on the phase diagram. It can be seen that the flow assurance risk formation area decreases with the increase of the thickness of insulating material. Thus, this approach can also be used to optimize the thermal insulation design of subsea pipeline.

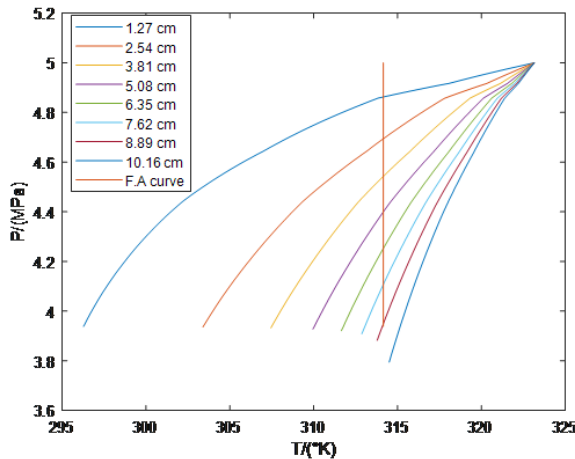


Figure 12. Pressure variation vs temperature

4. CONCLUSION

In this work, we proposed a model to thermally design a subsea pipeline for heat conservation purpose in subsea pipeline and therefore to avoid the formation of some flow assurance issues such as paraffin wax and hydrates. As temperature and pressure greatly influence the flow assurance issues caused by thermal unbalance, a temperature and pressure model were proposed and validated using field data and others models. The good agreement obtained shows that the predicted models are suitable for temperature and pressure prediction in subsea pipeline. Further simulations were run to find out the optimal insulation thickness among three different insulating materials with various thicknesses in order to achieve the subsea pipeline design. From the obtained results, it is concluded that a minimum of 10.16 cm Black Aerogel thermal insulation thickness is required to ensure that the discharge temperature at the discharge end of the subsea pipeline does not fall below 313.15 degree Kelvin. It was also observed that, the selected insulation material has direct impacts on the flow assurance issues formation area in the subsea pipeline. Because of this, flow assurance risk formation region can be shifted or avoided. The proposed model can therefore be used to thermally design a subsea pipeline during steady state operation. For future work, logistic regression can be used to predict hydrate formation probability in a subsea production and transportation pipeline for a given composition and operating conditions. Machine learning approach can also be used to risk assessment of hydrate and wax formation. Multi-variate Logistic Regression Model to Analyze hydrate formation risk can also be carried out. Thermal insulation design can be studied on transporting pipeline that crosses offshore and onshore pipeline. Transient analysis can also be considered to capture wax, hydrates deposition tendencies

during shut down, and restart scenarios for subsea pipeline transporting liquid and gas flow. A comparative study using PIPESIM, Aspen Hysys and MATLAB can be done in order to choose the best software that properly offer a good estimation of optimal insulation thickness. Investigation should be carried out for optimal economic insulation thickness design in subsea pipeline.

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NOMENCLATURE

A	cross section area, m^2
B_o	oil formation volume factor, $m^3 \cdot m^{-3}$
B_w	water formation volume factor, $m^3 \cdot m^{-3}$
B_g	gas formation volume factor, $m^3 \cdot m^{-3}$

C_d	profile parameter
C_p	specific heat at constant pressure, $J \cdot kg^{-1} \cdot K^{-1}$
D	inner diameter of pipe, m
f	friction factor
g	acceleration of gravity, $m \cdot s^{-2}$
h_{in}	inner convective heat transfer coefficient, $w \cdot K^{-1} \cdot m^{-2}$
h_o	outer convection heat transfer coefficient, $w \cdot K^{-1} \cdot m^{-2}$
k	thermal conductivity of pipe, $w \cdot K^{-1} \cdot m^{-1}$
L	pipe length, m
P	pressure, Pa
q	heat flux rate
Q_w	local flow rate of water at flow conditions, $m^3 \cdot s^{-1}$
Q_o	local flow rate of oil at flow conditions, $m^3 \cdot s^{-1}$
Q_g	local flow rate of gas at flow conditions, $m^3 \cdot s^{-1}$
Q_{w_sc}	flow rate of water at standard conditions, $m^3 \cdot s^{-1}$
Q_{o_sc}	flow rate of oil at standard conditions, $m^3 \cdot s^{-1}$
Q_{g_sc}	flow rate of gas at standard conditions, $m^3 \cdot s^{-1}$
Re	Reynolds number
R_s	solution gas-oil ratio, $Sm^3 \cdot Sm^{-3}$
r	radius of pipe, m
T	temperature, K
U	overall heat transfer coefficient, $w \cdot K \cdot m^{-2}$
V_d	drift velocity, $m \cdot s^{-1}$
V_{sw}	superficial velocity of water, $m \cdot s^{-1}$
V_{so}	superficial velocity of oil, $m \cdot s^{-1}$
V_{sg}	superficial velocity of gas, $m \cdot s^{-1}$
V_g	velocity of the gas phase, $m \cdot s^{-1}$
V_l	velocity of the liquid phase, $m \cdot s^{-1}$
V_m	mixture velocity, $m \cdot s^{-1}$
w	mass flow rate, $kg \cdot s^{-1}$
Z	gas compressibility factor

Greek symbols

ρ	density, $kg \cdot m^{-3}$
μ	viscosity, $kg \cdot m^{-1} \cdot s^{-1}$
α	void fraction
η	joule Thomson coefficient, $K \cdot Pa^{-1}$
θ	inclination angle of pipe, <i>rad</i>
σ	surface tension, $N \cdot m^{-1}$

Subscripts

<i>atm</i>	atmospheric
<i>o</i>	oil, outer
<i>g</i>	gas
<i>w</i>	water
<i>l</i>	liquid
<i>m</i>	mixture
<i>sc</i>	standard conditions
<i>tp</i>	two phase
<i>p</i>	pipe
<i>i</i>	inner
<i>ins</i>	insulation
<i>e</i>	ambient