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Analytical-numerical Investigation of Factors Influencing Overall Heat Transfer Coefficient of Multiphase Petroleum Fluids in Horizontal Subsea Pipelines

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Abstract

This paper aims to identify the factors which influence overall heat transfer coefficient, *U*, in subsea petroleum pipelines. For this purpose, first, factors that influence fluid temperature in pipelines, i.e. properties of pipe, insulation and fluid, are divided into two groups. *Group 1* (*2*) factors affect temperature *solely* (*possibly*) through influencing *U*. Examples are pipe thickness for group 1 and ambient temperature for group 2. Group 1 factors definitely impact on *U*. The dependence of *U* on group *2* factors is unclear. To resolve this ambiguity in subsea pipelines, a combined analysis of theoretically derived relationships and OLGA software results is proposed for horizontal subsea pipelines carrying multiphase petroleum fluids in steady state. Outcomes show that, in group 2, *U* only depends on input fluid temperature and pipe diameter. These two alongside group 1 form an inclusive list of factors influencing *U*. Such a list is essential to develop an accurate mathematical model to estimate overall heat transfer coefficient to be used in thermal analysis of the pipeline.

Keywords: Overall heat transfer coefficient, subsea petroleum pipelines, multiphase fluids, OLGA

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1. INTRODUCTION

Deep-water drilling will potentially lead to accessing more of world's untapped oil and gas resources. The increase in global energy demand has led to deeper offshore sites being explored and drilled. Thus extreme challenges associated with longer pipelines, lower ambient temperatures and higher pressures need to be addressed. One of the main technical issues encountered for offshore development is flow assurance (1). Heat transfer from the petroleum fluids in pipelines to the surrounding cold water can cause fluid temperature to drop and consequently develop gas hydrates and/or wax deposits, which may block pipelines (2-4). This can lead to system shutdowns or even site abandonment (5, 6). Therefore, for flow assurance, low temperatures, which may cause wax deposition and hydrate formation, should be avoided (7, 8). As a result, temperature estimation at pipeline design stage is essential.

The temperature along the axial path of a pipeline can be estimated as a function of ambient and input fluid temperature, equivalent heat capacitance, pipe diameter and length, mass flow rate and the overall heat transfer coefficient (U), based on the energy conservation for a defined control volume of internal flow in pipelines. Therefore, for temperature estimation, U needs to be accurately estimated. U represents the convection from the petroleum fluid to the inner pipeline wall, conduction across pipeline wall and insulation, and convection from the outer pipeline surface to the surroundings (9).

Conventionally, U is determined by making analogy between heat transfer and electrical current, where U is the sum of the reciprocal of the convective heat resistances of internal and external fluids as well as the conductive heat resistance of the pipeline (9-13). However, this method cannot determine U accurately in a wide range of applications. Na et. al showed that for crude oil pipelines, U's accuracy obtained by the conventional method is low (14). Due to inaccuracy of the conventional method, many investigators prefer to determine U experimentally by using the overall heat loss, temperature difference and contact surface area (15, 16). With this approach, empirical correlations have been established between a number of factors and U for heat pipes and buried pipelines (16, 17).

In order to develop mathematical models to accurately estimate U, specifically for pipelines, it is crucial to realize which factors affect this coefficient. Gooya et al. used OLGA software and showed the effect of flow rate and input fluid temperature on U is negligible and significant respectively for subsea pipes shorter than 8000m (18). Ovando-Castelar et al. carried out sensitivity analysis and indicated that insulation thermal conductivity and thickness considerably affect overall heat transfer coefficient in steam pipelines (19). However, an inclusive approach to determine the factors which influence U in pipelines is still missing.

In pipelines, it is known that many properties affect fluid temperature only through influencing U (let's name them group *1*); thus, they definitely impact on U (9, 10).

These factors include insulation and pipe thickness and material, oil, gas and water mass proportions, gas and oil type (represented by specific gravity), and pipe roughness. However, a number of other factors may affect temperature without influencing *U* (let's call them group *2*); therefore, their influence on *U* is uncertain. These include input fluid and ambient temperature, pipe diameter and length, mass flow rate and equivalent heat capacitance of internal fluid.

This paper aims to clarify the influence of factors of group 2 on the overall heat transfer coefficient in horizontal pipes carrying multiphase petroleum fluids in steady state. This investigation identifies a complete list of factors that influence *U* in such a pipeline, and the presented approach can be employed for other pipelines.

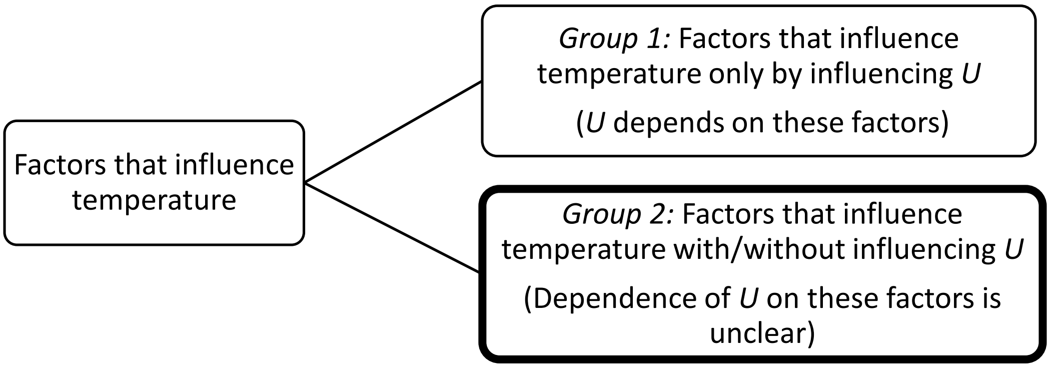

Figure 1. Different categories of factors affecting temperature in a subsea pipeline

2. METHODOLOGY

In this research, a combination of numerical and analytical methods is used to assess the dependence of *U* on factors in group 2 (presented in Eq. 1). For numerical analysis, OLGA software is used. This is an industry standard multiphase flow simulator which has shown to be accurate in determining the temperature profile (20) particularly for petroleum fluids (21). Analytically, temperature distribution within a pipe is calculated by (10):

$$T(x) = T_0 + (T_{in} - T_0)\exp\left(-\frac{U\pi Dx}{\dot{m}c_{eq}}\right), \tag{1}$$

where *T* is temperature, *D* and *x* are pipe diameter and length, and $\dot{m}$ and c_{eq} are mass flow rate and equivalent heat capacitance of internal fluid, respectively. Subscripts *in* and 0 represent input fluid and ambient. Six factors presented in Eq. 1 (T_{in}, T_0, $\dot{m}$, c_{eq}, *D* and *x*) can affect temperature even without having an influence on *U* (group 2).

In order to examine the dependency of *U* on group 2 factors, *U* is initially assumed to be independent of all six factors in Eq. 1, then the validity of this assumption is assessed for each factor. To do so, as detailed in section 2.1, a set of typical values of the aforementioned six factors are fed to OLGA software to determine temperatures of two typical multiphase fluids composed of natural gas, oil and water; the result is called 'original' temperatures. Then each of six factors is doubled one at a time, and OLGA is again employed to obtain their associated temperatures for both fluids, namely 'expected' temperatures.

As reported in section 2.2, an analytical relationship is derived between the original temperature and the temperature when each of the aforementioned six factors is doubled assuming that U is independent of the factor. The temperature values calculated through the derived relationships are called 'predicted'.

As detailed in section 3, comparison of expected (simulated by OLGA) and predicted temperatures (assuming the factor does not influence U), show to what extent U is independent of that factor.

2.1 Numerical Analysis to Obtain Original and Expected Temperatures

Finding original and expected temperatures are detailed in this subsection. OLGA was used to obtain temperature of multiphase fluids in horizontal pipelines. Figure 2 shows the basic layout used in OLGA. The pressure at the outlet was 20 bar. The surrounding fluid around the pipeline was chosen as sea water.

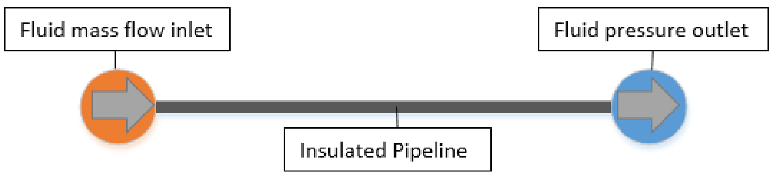

Figure 2. Layout of pipeline setup in simulation runs

Two petroleum fluids, a two-phase, consisting of gas and oil (fluid 1), and a three-phase consisting of oil, gas and water (fluid 2), were used. For each, fluid properties were generated by PVT Sim software, as a Pressure, Volume and Temperature (PVT) table (22). Tables 1 and 2 show the properties and compositions of the chosen fluids respectively at standard temperature and pressure.

Table 1. Composition and properties of two-phase fluid (fluid 1) approximated at standard temperature and pressure

Gas Mass Fraction	Gas density	Oil density
0.25	1.01 kg/m^3	875.6 kg/m^3

Table 2. Composition and properties of three-phase fluid (fluid 2) approximated at standard temperature and pressure

Gas Mass Fraction	Oil Mass Fraction	Gas density	Oil density	Water density
0.46	0.53	0.9 kg/m^3	910.3 kg/m^3	999.1 kg/m^3

Original values of six factors of group 2, except for c_{eq}, are shown in Table 3. These values and their doubled values are within the normal range for subsea systems (23-28). Equivalent specific heat capacity is calculated as following:

c_{eq} = (gas volumetric fraction).$c_{p/gas}$ +(oil volumetric fraction).$c_{p/oil}$ +(water volumetric fraction). $c_{p/water}$ (2)

Table 3. Original values of five of group 2 factors used to find original temperature together with their ranges in subsea applications

	Length of pipeline	Inner diameter of pipeline	Mass flow rate of petroleum fluid	Ambient temperature	Input fluid temperature
Original Factor	2000 m	0.5 m	5 kg/s	4°C	40 °C
Range	0.5-2000 km	0.1-1.4 m	0.07-15 kg/s	4-20 °C	4-90 °C

Shown in Tables 4 and 5 are the original pipeline wall and insulation layers properties.

Table 4. Uniform properties for pipeline wall used in all numerical analyses

Surface Roughness	Thermal conductivity	Specific heat capacity	Density
5x 10^{-5} m	50 W/m.K	500 J/kg.K	7850 kg/m^3

Table 5. Uniform properties for pipeline insulation layers used in all numerical analyses

Thermal conductivity	Specific heat capacity	Density
0.35 W/m.K	1550 J/kg.K	946/m^3

For each fluid, one simulation run was performed with original values of factors, shown in Table 3, which results in the original temperature, then each of the six factors was doubled in a separate run (seven runs for each fluid) which result in the expected temperature ($T_{Expected}$) associated with every factor. In total, 14 runs were performed.

2.2 . Predicted Temperatures Calculation

In this subsection, analytical formulae to calculate predicted temperatures, based on original temperatures, are derived. Assuming $a = -\frac{U\pi Dx}{\dot{m}c_{eq}}$, Eq. 1 becomes

$$T_{Original}(x) = T_0 + (T_{in} - T_0)e^{a} \tag{3}$$

Eq. 3 is used to calculate the value of *a* (using numerically obtained $T_{Original}$ and known values of T_{in} and T_0), and to analyze predicted temperatures.

In the following paragraphs, group 2 factors, presented in Eq. 1 are doubled, one at a time, formula are derived to obtain their corresponding predicted temperatures, the assumption is *U* remains unchanged with doubling factors.

In order to calculate predicted temperature when diameter, *D*, is doubled, Eqs. 1 and 3 are rewritten as below:

$$T_{Predicted-2D}(x) = T_0 + (T_{in} - T_0)\exp\left(\frac{U\pi(2D)x}{\dot{m}c_{eq}}\right) = T_0 + (T_{in} - T_0)e^{2a} \ . \tag{4}$$

As a result,

$$\frac{T_{Predicted-2D}(x) - T_0}{T_{Original}(x) - T_0} = e^{2a-a} = e^{a},$$

or

$$T_{Predicted-2D}(x) = e^{a}\left(T_{Original}(x) - T_0\right) + T_0, \tag{5}$$

Similarly, due to the identical role of diameter and length, *x*, in Eq. 1,

$$T_{Predicted}(2x) = e^{a}\left(T_{Original}(x) - T_0\right) + T_0, \tag{6}$$

For doubled value of $\dot{m}$, the predicted temperature is calculated as following:

$$T_{Predicted-2\dot{m}}(x) = T_0 + (T_{in} - T_0)\exp\left(\frac{U\pi Dx}{2\dot{m}c_{eq}}\right) = T_0 + (T_{in} - T_0)e^{\frac{a}{2}}, \tag{7}$$

Thus, $$\frac{T_{Predicted-2\dot{m}}(x) - T_0}{T_{Original}(x) - T_0} = e^{\frac{a}{2}-a} = e^{-\frac{a}{2}}. \tag{8}$$

From Eqs. 3 and 8, $\frac{T_{Predicted-2\dot{m}}(x) - T_0}{T_{Original}(x) - T_0} = e^{\frac{a}{2}-a} = e^{-\frac{a}{2}}$, Therefore,

$$T_{Predicted-2\dot{m}}(x) = e^{-0.5a}\left(T_{Original}(x) - T_0\right) + T_0, \tag{9}$$

Similarly, for heat capacitance,

$$T_{Predicted-2c_{eq}}(x) = e^{-0.5a}\left(T_{Original}(x) - T_0\right) + T_0, \tag{10}$$

For doubled input flow temperature, from Eq. 3,

$$T_{Predicted-2T_{in}}(x) = T_0 + (2T_{in} - T_0)e^a = T_0 + (T_{in} - T_0)e^a + T_{in}e^a, \tag{11}$$

Re-considering Eq. 3, $$T_{Predicted-2T_{in}}(x) = T_{Original}(x) + T_{in}e^a, \tag{12}$$

For doubled ambient temperature,

$$T_{Predicted-2T_0}(x) = 2T_0 + (T_{in} - 2T_0)e^a = T_0 + (T_{in} - T_0)e^a + T_0 - T_0e^a, \tag{13}$$

Considering Eq. 3, $$T_{Predicted-2T_0}(x) = T_{Original}(x) + T_0(1 - e^a). \tag{14}$$

3. RESULTS AND DISCUSSION

Equations 5, 6, 9, 10, 12 and 14 provide the predicted temperature values when one of the six investigated factors is doubled with the assumption that the doubled factor has no influence on *U*. To be used in these equations, T_{in} and T_0 are given in Table 3, and the values of $T_{Original}$ and its corresponding *a* are 19.9 °C, -0.8144 and 12.9 °C, -1.3975, for fluids 1 and 2, respectively obtained from OLGA and Eq. 3. Table 6 compares the predicted ($T_{Predicted}$) and numerically obtained ($T_{Expected}$) temperatures for doubled factors.

Figure 3 depicts the percentage of absolute discrepancy between Expected and Predicted values defined by:

$$Discrepancy\% = \frac{T_{Predicted} - T_{Expected}}{T_{Predicted}} \times 100\,. \tag{15}$$

Table 6. Expected and predicted temperatures when a factor is doubled in a horizontal pipe or fluid

Factor	Fluid	$T_{Predicted}$(°C)	$T_{Expected}$(°C)
Length	1	11.06	10.94
	2	6.20	6.13
Diameter	1	11.06	11.89
	2	6.20	6.77
Mass Flow Rate	1	27.96	28.00
	2	21.90	22.03
Heat Capacitance	1	27.96	27.97

	2	21.90	21.62
Ambient Temperature	1	22.17	22.23
	2	15.91	15.95
Input Fluid Temperature	1	37.66	41.27
	2	22.79	25.55

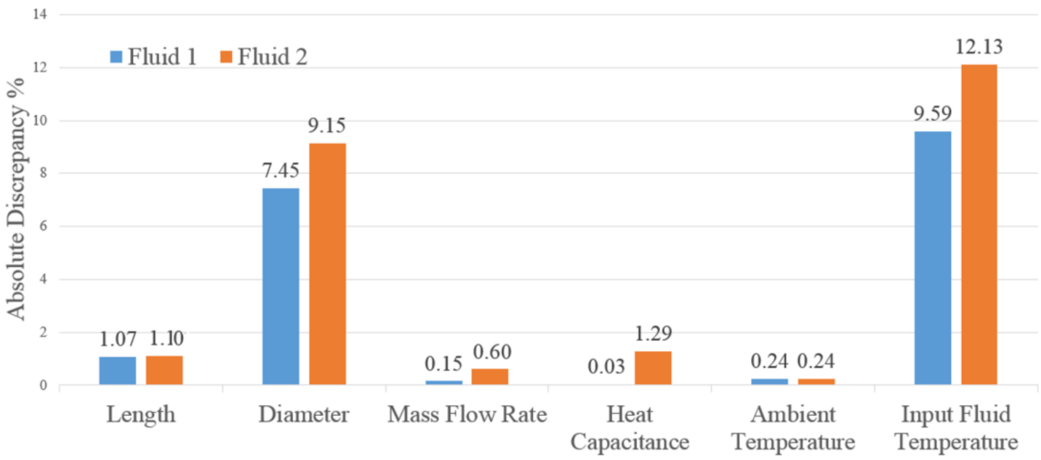

Figure 3. Absolute discrepancy of predicted and expected temperature for investigated factors

There is a significant discrepancy (i.e. higher than 1.5%) in predicted and expected temperature when pipe diameter or input fluid temperature is doubled. The sole assumption used in the calculation of the predicted temperature is the independence of *U* from the investigated factors. Therefore, discrepancies presented in Fig. 3 mean that this assumption is invalid for pipe diameter and input fluid temperature. That is, *U* depends on these two factors in normal subsea operating conditions. These together with group 1 form a complete list of factors that need to be considered to determine *U* for horizontal subsea pipelines carrying petroleum fluids in steady state, e.g. through mathematical modelling. The list includes insulation thickness and material, pipe thickness, material, roughness and diameter, oil, gas and water mass proportions, gas and oil type (represented by specific gravity) and input fluid temperature.

4. CONCLUSION

This paper investigated the influence of six factors, ambient and input fluid temperature, pipe diameter and length, equivalent heat capacitance, and mass flow rate on overall heat transfer coefficient (*U*) of horizontal subsea petroleum pipelines. As these factor could impact on temperature with or without affecting *U*, their influence on *U* was unclear. In this paper this ambiguity was removed, and a list of all factors influencing *U* was identified. To do so, a systematic four-stage method was presented for multiphase petroleum fluids at typical conditions and in steady state: (i) Fluid temperature (named "original" temperature) was obtained using OLGA software. (ii) OLGA software was employed to obtain temperature when each of aforementioned six factors is doubled, named "expected" temperatures. (ii) Analytical relationships were derived to calculate the fluid temperature based on the original temperature when each of six factors is doubled, assuming *U* is independent of the factor. Calculated temperatures at this stage were named "predicted" temperatures. (iv) Expected and predicted temperatures were compared. A significant discrepancy (here assumed >1.5%) means that the assumption behind analytical calculation of predicted temperatures is incorrect; that is, *U* depends on the factor. Based on this analysis, amongst the aforementioned six factors, *U* was found to depend on pipe diameter and input fluid temperature for horizontal subsea pipelines carrying petroleum fluids in steady state but not on ambient temperature, equivalent heat capacitance, pipe length, and mass flow rate. Considering other factors in which their impact on *U* is evident, an inclusive list of factors which influence *U* was formed. This list is crucial in developing mathematical models to estimate *U*.

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