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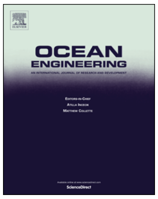

Numerical modelling of two-phase oil–water flow patterns in a subsea pipeline

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ABSTRACT

The concurrent flow of oil and water in pipelines is a common occurrence in offshore oil production systems. The internal structure of the oil–water flow, known as the flow pattern, and the distribution of water have a great influence on the design of the pipeline. However, due to the complex nature of oil–water flows, predicting flow patterns under different operating conditions is a challenging task. The present study is an attempt toward using a computational fluid dynamics model for predicting the flow patterns under different working conditions. To this end, an Eulerian–Eulerian model along with appropriate closure laws was employed to model two-phase oil–water flows through a horizontal pipe. The standard *k*–epsilon model was adopted to account for the turbulence effects. Furthermore, a brief description of the main interfacial forces namely the drag, lift, and turbulent dispersion forces has been presented. The numerical model was used to predict the flow patterns under different operating conditions ranging from low to high velocities and water cuts, respectively. A comparison among the obtained numerical results and published experimental data showed reasonable agreement.

1. Introduction

The flow of two immiscible liquids is encountered in a diverse range of processes, such as those of the petroleum industry. The simultaneous flow of oil and water in pipelines is a common occurrence in offshore oil production systems. In the early stages of a well's lifetime the amount of water is negligible. However, as the well ages the water production increases. Furthermore, water injection for enhanced oil recovery is commonly used to maintain the reservoir pressure. In contrast to the early days of the offhore oil industry, when the amount of produced water was negligible, these days many wells are mature and are producing large amounts of water. From an economical point of view, operation of a well might be reasonable even for water cuts as high as 90% (Elseth, 2001; Kumara et al., 2009). The internal structure of the oil–water flow, known as the flow pattern, and the distribution of water have a great influence on the design of the pipeline. The distribution of oil and water in the pipeline significantly affects the corrosion rate, the pressure drop, wax deposition, etc. An effective design can be made only if the flow pattern and the phase distributions under different conditions are known. (Xu, 2007).

Liquid–liquid flows in a horizontal pipeline can be classified into two major groups and several sub-groups, based on the interface structure. At relatively low velocities two immiscible liquids are separated by a clearly defined interface. This flow regime is referred to as a stratified flow pattern. However, at relatively high velocities there is no clear interface and one fluid is in the form of drops in the continuum of the other. This flow pattern is usually called a dispersed flow. At intermediate velocities a combination of the dispersed and stratified flow patterns is observed, where both phases retain their continuity at the top and bottom of the pipe, with a dispersed region present in the middle of the pipe cross section. Apart from these, formation of slug flow and annular flow was reported by several investigators. Experimental studies showed that by increasing the oil viscosity the extent of core annular flow increases. The transition boundaries among these flow patterns depend on many factors. A great deal of effort has gone into studying flow patterns under different conditions. Various experimental studies have been carried out to get reliable flow pattern maps through which we can identify the flow regime inside the pipe. However, because of the diversity of the oil properties, the available flow pattern maps lack a general agreement. Previous experimental studies show that the observed flow

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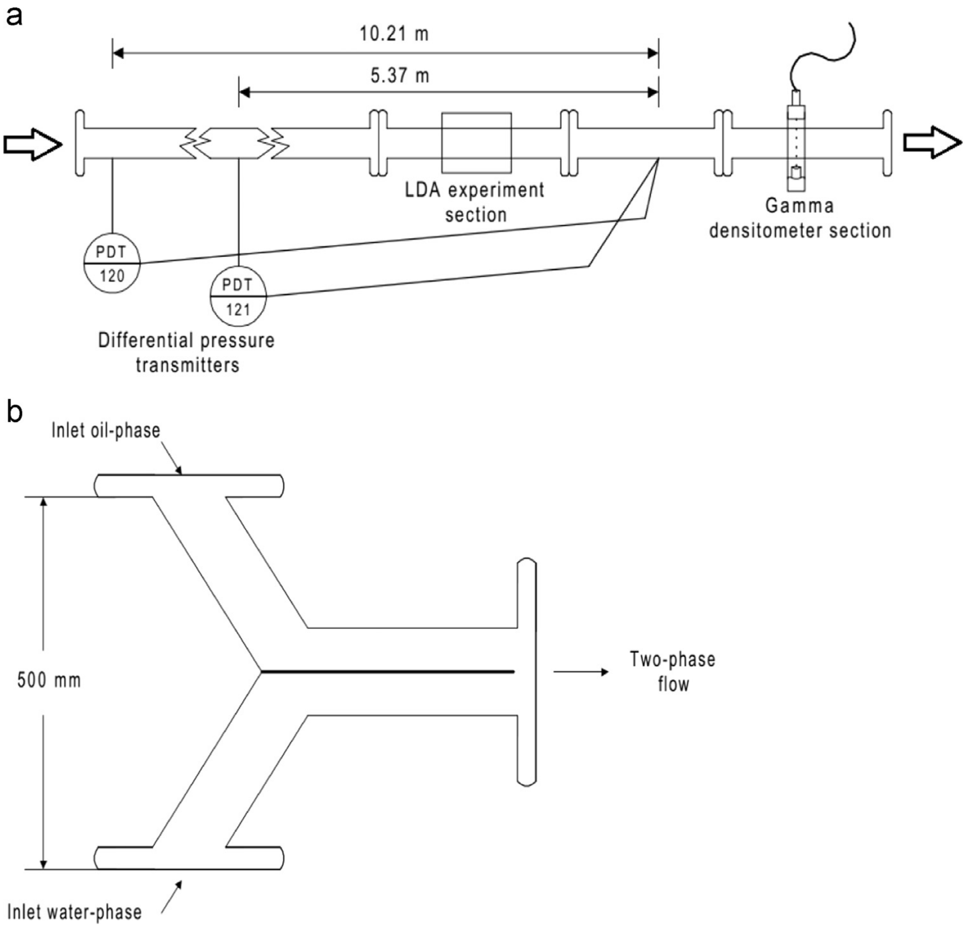

Fig. 1. A schematic of the test pipe (a) and the mixing unit (b).

patterns and the phase distribution critically depend on the fluid properties, mixture velocity, inlet water cut,and the geometry (diameter and inclination angle) as well as wetting property of pipe (Arirachakaran et al., 1989, Angeli and Hewitt, 2000a; Lovick and Angeli, 2004a; Xu, 2007; Kumara et al., 2009, Strazza et al., 2011, Yusuf et al., 2012, Hanafizadeh et al., 2015).

As mentioned earlier, the prediction of the flow pattern and phase distribution is essential for the proper design of the wells and the pipeline. Prior knowledge of the type of flow pattern is needed to choose an appropriate method for predicting the pressure drop (Xu, 2007). In addition, predicting phase distribution is essential for wax deposition management in subsea pipelines, because wax deposition is a flow pattern-dependent phenomenon (Matzain et al., 2002; Sarica and Panacharoensawad, 2012). Furthermore, predicting the distribution of water inside the pipe is of the utmost importance when modelling sweet corrosion. Corrosion problems are associated with the continuous water phase being in contact with the wall at the bottom of the pipe. Hence, it is crucial to predict whether a free water layer exists at the bottom of the pipe (water wetting) or the oil is a continuous phase (oil wetting) containing water drops. The incorrect prediction of water distribution leads to significant mistakes in predicting the corrosion rate. Furthermore, it may lead to use of the wrong type of inhibitor, a larger amount of inhibitor, or the use of corrosion resistant material, thereby, increasing the operational and capital costs (Nyborge, 2005; Nesic, 2007; Cai et al., 2012).

The computational fluid dynamics (CFD) technique is a powerful tool for simulating flow-field characteristics in a multiphase pipeline. Using CFD we can gain a deeper insight into the underlying physics and thus foster an understanding of the different phenomena. In addition, CFD can provide phase distribution and velocity profiles with high resolution, which can significantly reduce uncertainty at the design stage. However, extensive evaluation with experimental results is essential before using the model predictions for scale-up and optimisation of facilities.

Thus far, few numerical studies have been reported on predicting the hold-up distribution in oil–water flow. Parvini et al. (2010) used the Eulerian–Eulerian approach to model dispersed oil in water flow in vertical pipes. Their results suggested that the interfacial lift force is more important than the turbulent dispersion and virtual mass forces. Hamad et al. (2013) also investigated dispersed oil–water flow in vertical pipes and there was a good agreement with the experimental data. Recently, Burlutsky and Turangan (2015) used the Eulerian–Lagrangian approach to model dispersed oil–water flow in vertical pipes. Their numerical results

Table 1
Description of the properties of the fluids and the geometry used in the experiment (Elseth, 2001)

Experimental condition	
Pipe diameter	0.0563 m
Pipe roughness	0.00001 m
Pipe length	15 m
Oil density	790 kg/m^3
Oil viscosity	0.00164 Pa s
Water density	1000 kg/m^3
Water viscosity	0.00102 Pa s
Interfacial tension	0.043 N/m