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The effect of surfactants on upward air–water pipe flow at various inclinations

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ABSTRACT

In this work, we extend our previous efforts on the effect of surfactants on air-water flow in a vertical pipe by also considering pipe inclinations between 20° (with respect to horizontal) and vertical. For air–water flow, independent of the inclination, there is a regular annular flow at large gas flow rates, and an irregular churn or slug flow at low gas flow rates. Closely related to the transition between regular and irregular flow, although not necessarily coinciding with it, there is a minimum in the pressure gradient as a function of the gas flow rate. In gas wells, surfactants are used to shift this minimum to lower gas flow rates, which allows a stable gas production up to lower reservoir pressures. In this work, we investigate how the pipe inclination affects air–water flow without and with surfactants. Surfactants generate foam, which decreases the density and increases the thickness of the film at the pipe wall. For vertical flow, we previously established that surfactants increase the pressure gradient at high gas flow rates, decrease the pressure gradient at low gas flow rates, shift the minimum in the pressure gradient to lower gas flow rates, and shift the transition between regular and irregular flow to lower gas flow rates. The new results described in this paper show that for large gas flow rates, both the flow with and without surfactants is unaffected by the inclination. At low gas velocities, however, in inclined pipes the surfactants are much less effective at shifting the transition between irregular flow and regular flow and at shifting the minimum in the pressure gradient than in vertical pipes. The foam causes a regular film morphology at the top wall of the pipe, but is unable to make the morphology of the bottom liquid film regular. As a result, at low gas flow rates the relative decrease of the pressure gradient due to surfactants is smaller for smaller inclinations from horizontal. This larger relative decrease for vertical flow compared to inclined flow is related to an increased foam formation and therefore a smaller mass density of the film in vertical flow.

Introduction

A major problem in the production of natural gas is the *liquid loading* of gas wells. This problem occurs towards the end of the life of a well, when the reservoir pressure becomes low and the gas velocity in the well tubing is no longer sufficient to drag the liquids associated with the gas (water and gas condensate) upwards to the surface. This causes an accumulation of water at the bottom of the gas well, which can severely decrease, or even completely stop the production of gas (Lea et al., 2008).

One of the ways in which liquid loading can be postponed to lower gas flow rates, thereby extending the life of the well, is by injecting surfactants at the bottom of the gas well. Surfactants are molecules that have a polar and an apolar part, and therefore they preferentially adsorb at the gas–water interface. In this way surfactants allow the formation of a stable foam, which alters the nature of the flow in the well. As a result, the pressure gradient of the flow in the well is changed.

To show why the pressure gradient of the multiphase flow plays a key role in the phenomenon of liquid loading, we consider a gas well as a system with two components placed in series, as illustrated in Fig. 1. The first component is the flow from the reservoir to the bottom of the well tubing, also known as the bottom-hole location. The pressure at this location, known as the bottom-hole pressure, decreases with increasing gas flow rate. The Inflow Performance Relation (IPR) shows the relation between the bottom-hole pressure and the gas flow rate.

The second component of the gas well is the flow through the production tubing to the surface. This flow creates a pressure drop

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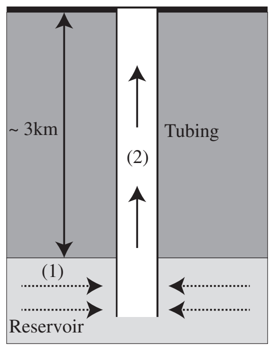

Fig. 1. Schematic of a gas well consisting of two components in series: (1) flow from the reservoir to the bottom-hole location and (2) flow from the bottom-hole location through the production tubing to the surface.

between the surface and the bottom-hole location. In single phase flow, this pressure drop would increase monotonically with increasing gas flow rate. However, because liquids are present in the well, at low gas flow rates the gas cannot drag the liquid upwards continuously, leading to a large pressure drop. As the surface pressure is usually fixed, the pressure drop in the production tubing determines the pressure at the bottom-hole location. This behaviour is illustrated by the Tubing Performance Curve (TPC), which relates the gas flow rate to the bottom-hole pressure. The TPC has a minimum: at gas flow rates above this minimum the frictional pressure drop is the dominant component of the total pressure drop, at gas flow rates below this minimum the hydrostatic component of the pressure drop is dominant.

Of course, there can only be one value of the bottom-hole pressure, such that production of gas is only possible where the IPR and the TPC cross. Furthermore, the production is only stable when this crossing occurs at gas flow rates above the minimum in the TPC. These operating points are illustrated on the left of Fig. 2, both for vertical flow and for inclined flow. The image shows that, as the reservoir pressure decreases, the IPR moves closer to the origin, until no stable operating points remain. At this point, the well becomes liquid loaded. The left graph in Fig. 2 also shows that the inclination has a significant effect on the TPC. Due to the thicker liquid film at the bottom of the pipe, it can be more difficult for the gas to drag the liquid upwards, which can lead to larger pressure gradients than for vertical flow.

The right graph in Fig. 2 illustrates the effect of surfactants on the TPC for vertical flow (van Nimwegen et al., 2014b). At large gas flow rates the foam that is created leads to an increase of the interfacial friction between the gas and the liquid, and therefore to an increase of the pressure drop. At low gas flow rates, the lower density of the film combined with the larger volume of the film allows the film to be carried upwards more easily by the gas, leading to a lower liquid holdup and a lower pressure drop. Note that the holdup of a phase is the volume occupied by this phase divided by the total volume of the pipe.

Much is known on gas–liquid flow without surfactants in inclined pipes, and we previously performed research on the effect of surfactants on air–water flow in vertical pipes (van Nimwegen et al., 2014a; 2014b). However, to our knowledge, so far no systematic research has been performed on the effect of surfactants on gas–liquid flow in inclined pipes. In this work, we perform a systematic study of the effect of surfactants on air–water pipe flow, while changing the inclination between 20° and 90° from horizontal. The results give insight into the effect of the deviation of a gas well on the effectiveness of surfactants for the deliquification of the well. In our research, we make observations of the flow morphology and measure the pressure gradient and the holdup of foam and liquid, and relate the qualitative observations to the quantitative measurements. We investigate the effect of the surfactants on the minimum in the TPC, which gives an indication of the additional production that would be obtained in an actual gas well.

In the next section, we discuss air–water flow in inclined and vertical pipes. In Section 3, we briefly cover the theory of surfactants and foam, and give an overview of earlier work on the effect of surfactants on air–water flow. Subsequently, in Section 4, a description of the experimental setup is given, and in Section 5 the results of the flow visualisation and the pressure gradient measurements are presented, both for inclined and vertical flow.

Vertical and inclined air–water flow

As discussed in the introduction, the minimum in the TPC, i.e. the pressure gradient as a function of the gas flow rate, determines liquid loading. The pressure gradient is closely related to the morphology of the flow. This can be easily observed from a balance of forces on the gas phase. We consider a regular, annular flow, as is found in normal production in gas wells, where the liquid is present in a liquid film at the pipe wall, and in droplets entrained in the gas core. Also, for the inclinations considered in our study (i.e. between 20 and 90° from horizontal), we assume that the wall is fully liquid-wetted, implying that we do not consider friction between the gas and the wall. Note that for inclinations up to 20° stratified flow can occur, and here this friction cannot be neglected (Barnea et al., 1985). The balance of forces for a section of length dx gives:

$$-\alpha_g \frac{\partial P}{\partial x} - \alpha_g \rho_g g \sin\beta - F_i = 0 \qquad (1)$$

where α_g is the gas holdup, ρ_g is the gas density, g is the gravitational acceleration, β is the inclination angle with respect to horizontal, and F_i is the interfacial friction per unit volume, which indicates the transfer of momentum between the two phases. Most of this transfer of momentum occurs at the interface between the gas and the liquid film at the wall, and only a small part is due to the entrainment

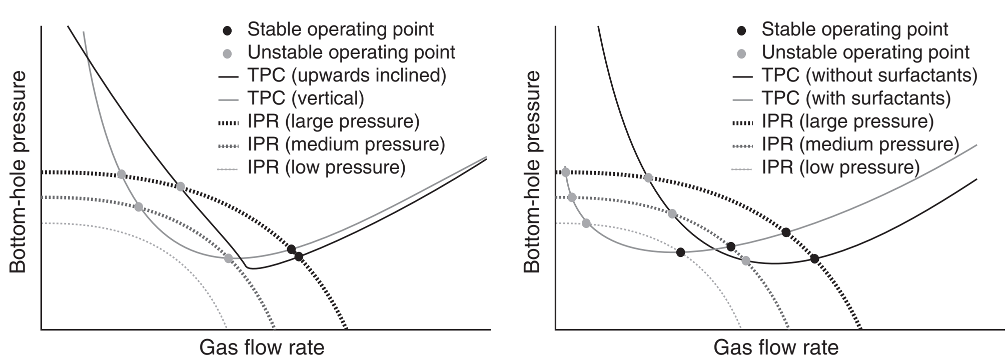

Fig. 2. Schematic of the tubing performance curves and the inflow performance relations for gas–liquid flow in vertical and inclined pipes without surfactants (left graph) and for vertical flow with and without surfactants (right graph).