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EFFECT OF CO_2 AND H_2S MOL FRACTION ON THE INHIBITOR INJECTION RATE IN NATURAL GAS MULTIPHASE FLOW PIPELINES

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Abstract

Multiphase flow in petroleum transfer lines with different flow patterns considering the variation of pressure and temperature has been studied. The corrosion in carbon steel pipes is modeled and the optimum injection rate of inhibitor to control the corrosion rate is studied for different pipeline conditions. The flow pattern is recognized using the models presented in the references for different conditions of gas flow considering thermal and hydraulic situations. The optimization is carried out by genetics algorithms. The effect of gas CO_2 and H_2S mol fraction on the inhibitor injection rate is studied.

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1. Introduction

Multiphase flows occur in many industrial transfer pipelines such as natural gas or petrochemical flows. Corrosion in these transfer lines plays a significant role in the technical and economical considerations. Variation of temperature, pressure and mol fraction of components in these flows leads to different flow patterns. Modeling the flow characters is necessary to analyze the situation. Corrosion on the internal wall of a pipeline can occur when the pipe wall is exposed to water and contaminants in the flow such as O_2, H_2S, CO_2 or chlorides. The nature and extent of the corrosion damage that may occur are related to the concentration and particular combinations of these various corrosive constituents and also the operating conditions in the pipeline. For example, gas velocity and temperature in the pipeline play a significant role in determining if and where corrosion damage may occur in natural gas pipes. The problem facing industry related to material performance is corrosion and erosion-corrosion of pipelines and decreasing the result cost. Many studies have been done to find out the optimum rate of injection inhibitors in multiphase flows in oil and gas industries. Most of them has been studied this by doing experiments [1]. This simulation is based on a trial and error procedure. At first, some inhibitors are selected considering the situations of pipeline flow and then using these in a series of runs, the proper one would be selected. Then, by using the inhibitors in simulated pipelines at different injection rates and analyzing the results of erosion and corrosion rates, the optimum injection rate would be achieved. Apparently, this procedure is very time consuming and expensive.

In the present paper, a code is generated to calculate the flow parameters in gas-oil-water three phase pipeline flows and then optimize the injection rate of inhibitor by genetic algorithm. Genetic algorithm, as a tool to optimization, has been started by Fraser [2], who published papers on simulation of artificial selection of organisms with multiple controlling a measurable trait. These methods were presented more precisely by Fraser and Burnell [3] and Crosby [4]. There can be found the improvements of this method reported by Fogel [5], General Electric introduced first genetic algorithm product, a mainframe-based toolkit designed for industrial processes.

2. Hydraulic Modeling of Pipelines

Simulation of multiphase flow in pipelines is provided in order to determine the profiles of pressure, temperature, flow regime and liquid accumulation through the transfer pipeline [3]. Different experimental methods with some advantages and defaults have been used for this purpose by Mansoori [6]. In this study, the Beggs and Brill [7] model is used, due to its accuracy in line simulation and considering all different flow conditions. The study of horizontal, vertical, inclined to the top, inclined to the bottom pipes are covered by this model.

In this simulation method, the flow regime is determined according to the classification, using experimental correlations at the first step. Then the liquid accumulated in the horizontal test is calculated and a correction factor is investigated for the pipe slope. Finally, the temperature and pressure drop throughout the line is calculated by the principal parameters already found. Once the hydraulic modeling and the related parameters have been found, corrosion profile can be determined. Different experimental and analytical methods have been presented so far. The advantages and disadvantages of each of them are studied in the references (Beggs and Brill [7], Norsok Standard [8], de Waard and Williams [9], de Waard and Lotz [10] and de Waard et al. [11]). In this study, all existing models are simulated and used, however, in this paper, two of them; Norsok Standard [8] and de Waard and Williams model [9] have been used. In these models, all effective parameters are taken into consideration. In addition, all studies references have indicated these models accuracy in predicting the corrosion rate.

Corrosion rate calculation by Norsok Standard [8] formulation is as follows:

$$CR_t = K_t \cdot f_{\mathrm{CO_2}}^{0.62} \cdot (s/19)^{0.146+0.0324\log(f_{\mathrm{CO_2}})} \cdot f_{(\mathrm{pH})_t}. \qquad (1)$$

In this equation, the parameters are defined as:

K_t = Constant for the temperature T

f_{CO_2} = the fugacity of CO_2 (bar)

s = Wall shear stress (Pa)

$f_{(pH)_t}$ = the pH factor at temperature T

CR_t = corrosion rate (mm/year)

de Waard and Williams [9] model formulation can be seen as below:

$$CR = 1/[(1/V_r) + (1/V_m)]$$

$$V_m = 2.45 P_{CO_2} U_l^{0.8} / d^{0.2}$$

$$P_{CO_2} = \text{total pressure} \times CO_2 \text{ mole fraction}$$

$$Log(V_r) = 6.23 - 1119/(T + 273) + 0.0013T$$
$$+ 0.41 Log(P_{CO_2}) - 0.34\text{pH}, \quad (2)$$

where V_m is the maximum corrosion rate due to mass transfer (mm/year) and V_r shows the corrosion rate due to reaction. U_1 represents the apparent velocity of liquid (m/sec) and d demonstrates the hydraulic diameter (*m*), while T is the temperature.

In order to prevent the corrosion in the pipelines, corrosion inhibitors are widely used. As inhibitor's exact composition and function are exclusive and are not published by the manufacturing companies, it is only the percentage of inhibition which is appeared in the modeling processes for prediction of corrosion. In this case, for any injecting value of these substances, a correction factor, which is indicated by the manufacturer or provided by the experiment, is used in the model. All the correction factors should be multiplied by the corrosion value.

3. Optimization of the Inhibitor Injection Rate

In this study, the injection rate of inhibitor is optimized by genetic algorithm method by considering and respecting all the restrictions. On the other hand, there are various parameters which affect the consumption of the corrosion inhibitors. In order to reduce the injection amount to its minimum value by maintaining the proper operating conditions and transporting rate, some of these parameters can be altered while some others are unchangeable.

Flow rate is one of those parameters that are not supposed to change, because transferring the maximum amount of the fluid is usually one of the aims of pipeline designing. Hence during the present optimization and calculations, the gas flow rate is considered as a constant.

Thus, temperature and pressure of the fluid flowing in the pipeline are the remaining parameters which can be altered. Obviously, the changes are restricted in a certain boundary condition which is indicated by the user and the optimization is made in this very domain.

The temperature and pressure affect the corrosion rate and consequently the injection rate in two ways. The first effect is the direct effect which is observed in corrosion models of Norsok Standard [8], de Waard and Williams [9], de Waard and Lotz [10] and de Waard et al. [11]. The second effect of the mentioned parameters on corrosion is indirect, because the variation of each of the parameters would change the flow regime in the pipeline, which in turn, can reduce or increase the turbulence of the flow and affect the corrosion rate as the result. Fraser [2] experimental data are the basis of the present optimization. These data are given to the system at the beginning. By changing the operational conditions followed by change in the flow regime and other parameters; the optimum quantity of inhibitors injection is found. The obtained results consist of the optimized inhibitor injection amount, the percentage of inhibiting power, the optimized pressure of the pipeline fluid and finally the optimized temperature of the pipe in the conditions of the flow predefined by the user.

4. Model Validation

The model results are validated by comparing with PIPEPHASE software for the temperature and liquid holdup and the results are nearly the same.

5. Results

A three phase flow of oil, gas and water in a pipeline is considered. The length of the pipe is assumed to be 350000 feet and the profile of the pipeline is such that the elevation varies between –300 to –50 feet. Table 1 shows the efficiency factors for different flow patterns. Flow conditions and modeling factors are illustrated in Table 2.

Table 1. Empirical corrosion inhibitor efficiency

Inhibitor concentration (ppm)	Efficiency (%)
0	0
11	2
21	4
36	8
43	12
50	18
58	27
70	37
8	45
96	60
120	78
160	94
200	100

Table 2. Genetic algorithm data

Genetic algorithm data: Number of population = 8 Maximum iteration = 20 Mutation rate = 2
Constraint limitation: Pressure = 1500 to 2500 psia Temperature = 80 to 120 F Max. gas velocity = 40 ft/sec Min. liquid velocity = 0.05 ft/sec Max. corrosion rate = 4 mm/year Corrosion consideration = Max. local corrosion
Corrosion model = M-506 (Norsok)

The variation of inhibitor injection rate versus the flow CO_2 mol fraction is illustrated in Figure 1.

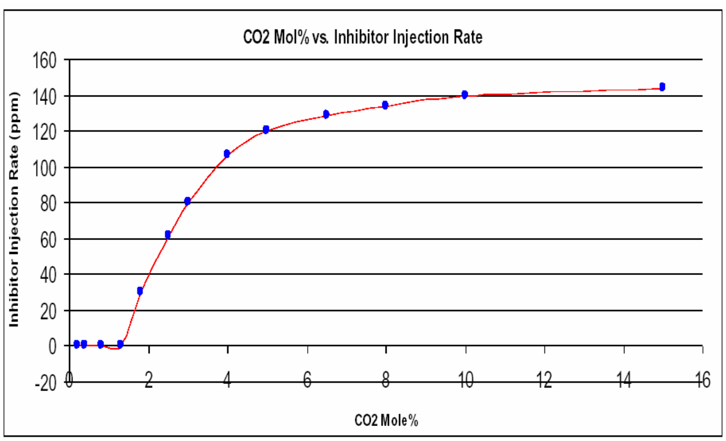

Figure 1. The CO_2 mol fraction versus the inhibitor injection rate.

It can be seen that increasing mol fraction leads to more corrosion rate and consequently more injection rate. The gradient of the curve is more at lower mol fractions and would be nearly smooth at higher mol fractions. The corrosion rate variation in the pipeline can be seen in Figure 2.

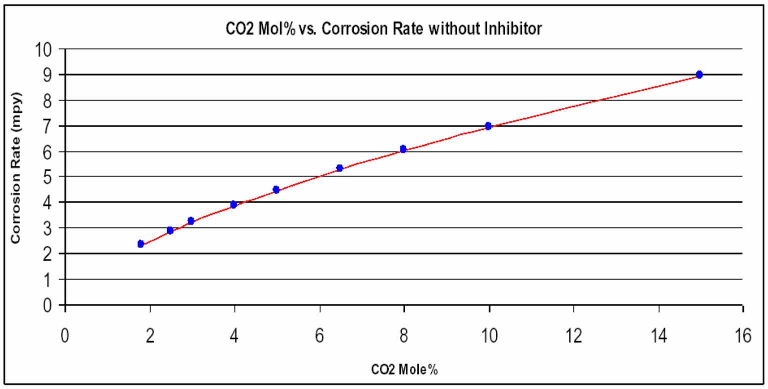

Figure 2. The effect of CO_2 mol fraction on corrosion rate.

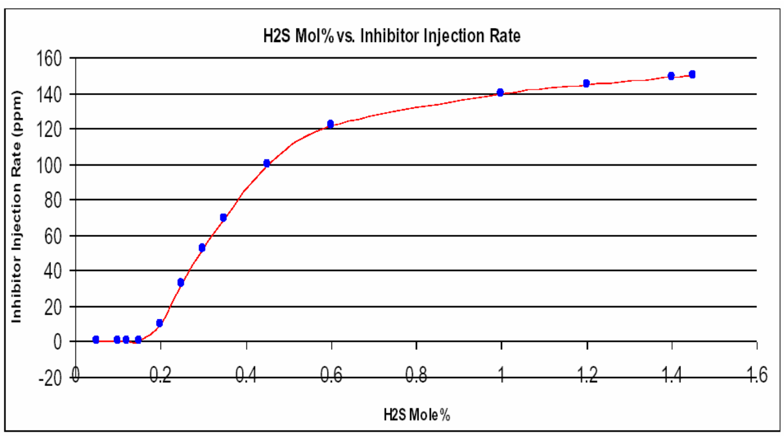

Figure 3. The H_2S mol fraction versus the inhibitor injection rate.

Figure 2 shows that how the corrosion rate will increase with CO_2 mol fraction in absence of inhibitor injection. In spite of Figure 1 curve, the gradient of the variations are nearly the same at all studied mol fractions.

Figure 3 shows the more injection rate for different H_2S mol fraction. The behavior of the variations is nearly the same as the ones for CO_2 mol fraction variations. In Figure 4, the results are presented the effect of the water cut of flow on injection rate. It can be seen that, with higher values of water cut in the pipeline flow, more considerable corrosion rate is observed. For values of water cut more than 4, the variations would be nearly smooth and low slope curve can be seen.

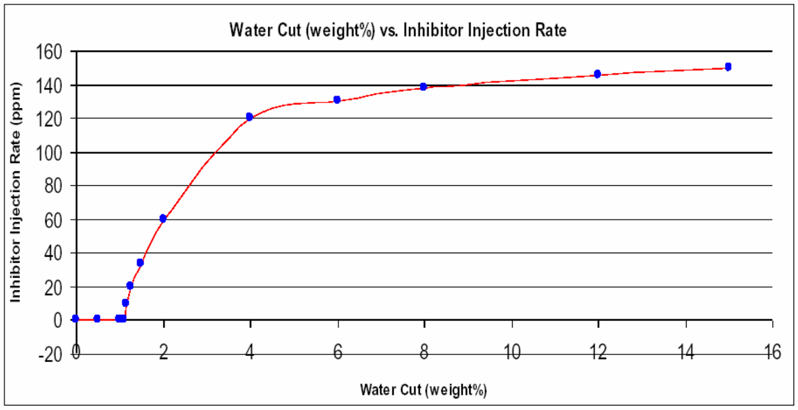

Figure 4. The water cut value versus the inhibitor injection rate.

Figure 5 illustrates the effect of pH value on the inhibitor rate. More pH values represent more corrosion rates. The slope of the cure is much more in the range of pH 5-6.5.

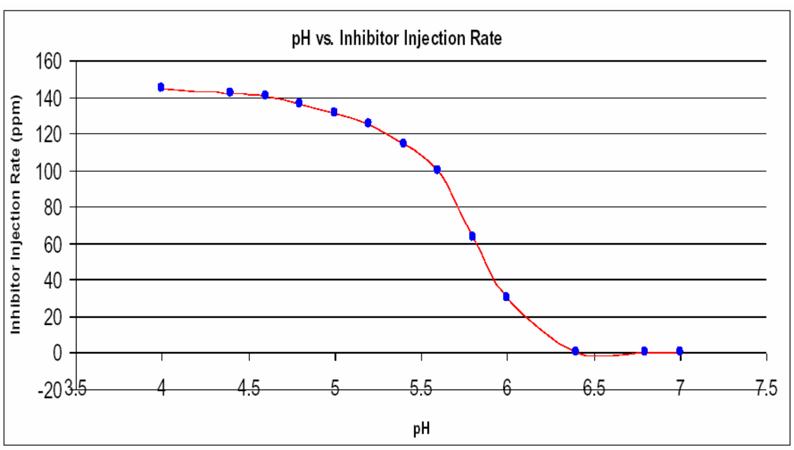

Figure 5. The pH value variation effect on the inhibitor injection rate.

These figures show that the most dangerous situation for the pipelines is when the flow consists of high pH value and low water cut.

6. Conclusion

The multiphase flow in transferring petroleum flows has been modeled and for each situation of the flow, the corrosion rate and injection rate of inhibitor in flow have been calculated numerically. Three phase flow of oil, gas and water in a pipeline has been considered. The optimum injection rate of inhibitor to control the corrosion phenomena was examined and the variation of it has been studied with the variation of CO_2, H_2S mol fractions. Also, the effect of pH value and water cut on the corrosion rate in pipeline has been studied.

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