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Model for Predicting Hydrate Onset Formation Temperature Downstream of the Wellhead

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Abstract

The formation and deposition of hydrates downstream the wellhead restrict flow and constitute a major flow assurance problem that affects the safe gas production and transportation. Many works have been done to predict the downstream hydrate formation temperature howbeit, considers only the pressure and the specific gravity of the gas. In this study, in addition to pressure and the specific gravity of the gas, the acid gas compositions was integrated to develop a non-linear empirical model for predicting the onset of hydrate formation temperature through the combination of logarithmic and polynomial functions. The results show good agreement with existing models particularly those that incorporates specific gravity and pressure as the independent variables which are either logarithmic or polynomial models. In fact, at some pressures, it performed better than the existing model with which it was compared. When compared with the observed data, the model has a coefficient of correlation (R^2) of 0.95 and a percentage average absolute deviation (%AAD) of 2.19% as against the other models which have 15.402%, 15.426% and 74.4166% AAD respectively. The developed model has both logarithmic function and polynomial function integrated, hence the lowest %AAD and good prediction capability compared to other models.

Keywords: *Hydrate; Temperature; Pressure; Specific gravity; Logarithmic function.*

1. Introduction

Gas hydrates are ice-like solids, where molecular cages of water surround light hydrocarbon species (e.g. methane) at high pressure and low temperature [1]. In high-pressure gas pipelines, hydrate can become thermodynamically stable with adequate cooling, resulting in pipeline blockage under extreme conditions [2]. A produced hydrocarbon stream from a wellhead encounters formation of solid gas hydrate deposits, which plug flowlines, as was first revealed by Hammerschmidt [3] in natural gas transmission lines. Gas hydrates are considered one of the most challenging problems in deep subsea facilities. High pressures and low temperatures of operation in these facilities promote rapid formation of gas hydrates [4]. In downstream wellhead operating at high pressure, hydrate can become thermodynamically stable with sufficient cooling, which result in downstream wellhead choke blockage under extreme conditions [2]. Managing the risk of hydrate blockage in gas pipelines is a major flow assurance concern for new and existing subsea developments; particularly with increased exploration in deep water, long residence times and cool seafloor temperatures which increases the rate of hydrate growth and, thus, blockage risk. Thermodynamic hydrate inhibition, in which anti-freeze chemicals are injected to break the hydrogen-bonded cage network, is commonly employed to reduce hydrate stability, however the high expense of this technology in deep-water conditions may easily surpass production revenue [5]. The flow assurance community is increasingly gravitating toward a risk management approach that focuses on preventing hydrate blockage while allowing some hydrate to remain stable in the line. To succeed in this approach, engineers must first understand the mechanism by which hydrates block gas pipelines [6]. For

the past twenty years, the community has focused on understanding the mechanism by which hydrate blockages form in oil-dominant flowlines, which have been tested at both the laboratory [7] and on pilot scales [8].

Liquid natural gas hydrate is a crystalline compound formed by the combination of water and natural gas (e.g., methane, ethane, and propane) under low-temperature and high-pressure conditions [6,9-10]. In the petroleum industry, gas hydrates are widely seen in oil and gas exploitation and transportation processes [11-15]. During the process of subsea natural gas transportation, horizontal annular flow usually occur in the transportation pipeline, where hydrate formation, deposition, and even blockage occurs easily under conditions of low temperature and high pressure [16-18]. Once hydrate blockage occurs in the subsea transportation pipeline, natural gas transportation operations would be stopped accordingly, which will cause serious economic losses due to down time [19].

Hurlburt and Newell [20] developed a model for predicting the liquid film distribution in a horizontal annular flow whereas Cioncolini and Thome [21] developed a model in which the disturbance wave is the primary mechanism for transporting the liquid film in an annular flow and obtained a new prediction method for the liquid film's asymmetry degree. A simple method for calculating the void fraction, liquid carrying capacity, pressure drop, and liquid film distribution was developed by Mauro *et al.* [22]. Jassim *et al.* [23] proposed a method to study hydrate deposition in a gas-dominated system and studied the migration and adhesion mechanisms of hydrate particles on the pipe wall. Hydrate formation and transportation under annular flow conditions was investigated; and it was observed that droplets entrained in a gas phase plays an important role in hydrate formation and deposition [24]. Di Lorenzo *et al.* [26] and Liu *et al.* [16] established a hydrate deposition prediction model that considered the shedding effect of the hydrate layer in horizontal gas-dominated flows. While Wang *et al.* [27] and Zhang *et al.* [28] developed a coupling model to predict the rate of hydrate deposition in horizontal gas-dominated flows, which can be used to estimate the risk of hydrate plugging.

Several traditional hydrate mitigation techniques have been modified over time, including chemical inhibition, thermal insulation, and depressurization. Many of them, however, are either incompetent or require a large number of chemical solvents, resulting in high operational costs and a negative environmental impact on operating gas and oil facilities. However, understanding the the factors that influence and exacerbate hydrate deposition could help mitigate potential deposition and applying proactive measures that could help in preventing deposition. Hence, several models have been developed to investigate and predict the hydrate formation temperature downstream of the pipeline.

Obviously, temperature is one of the most critical parameters that influence hydrate deposition. Hence, many existing models try to predict the downstream temperature of hydrate deposition. Some of these models are just a function of pressure, while some are a function both pressure and specific gravity of the gas. Hydrate temperature prediction models that is just a function of pressure are those proposed by Hammerschmidt [3]:

$$T = 8.9p^{0.285} \quad (1)$$

and that of Naseer and Brandsatter [29] given as:

$$T = 270.86 + 8.5274\ln(P) \quad (2)$$

Another category of model used in predicting the onset of hydrate deposition temperature is that which considers both pressure and specific gravity of the gas as controlling factors. A notable models in this category is that proposed by Towler and Mokhatab [30] given as:

$$T = 13.47\ln(P) + 34.27\ln(\gamma_g) - 1.675(\ln(P)\ln(\gamma_g)) - 20.35 \quad (3)$$

where: T is the temperature (°F); p is pressure (psia) and $\gamma_g$is the specific gravity

No known empirical model exist that incorporates the effects of the acid composition as a factor that could influence the hydrate deposition temperature when sour gases are produced. Hence, in this paper, an empirical model that incorporates pressure, specific gravity and composition of acid gases is developed to predict the onset hydrate formation downstream of the wellhead of a pipeline.

2. Method

The reliability of any model is strongly depended on the quality of data used in developing it. A simplified work flow used in developing the model in this work is shown in Figure 1. Since hydrate formation depends on several parameters, the accuracy of empirical model capable of predicting hydrate formation would depend on a lot of data points.

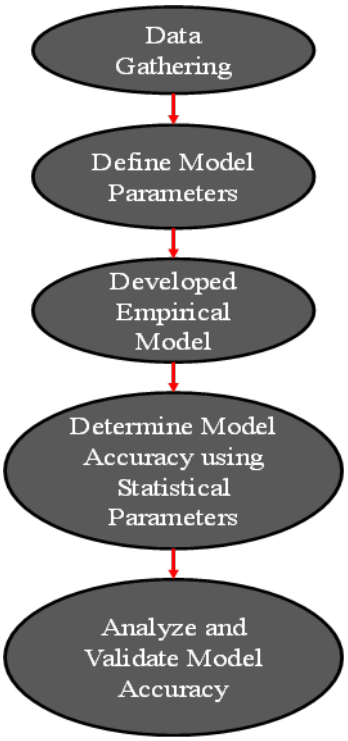

Figure 1. Flow Chart showing the sequence of developing the hydrate prediction model.

There were 2096 data points used for the empirical model development with diverse information on temperature, pressure, specific gas gravity and acid gas compositions; howbeit obtained from literature . The empirical model was developed based on non-linear models which contains different functions. Logarithm, exponential functions, trigonometric functions, and combination of polynomial functions that are most common in nonlinear models was investigated. These functions were tested in the model to find the combination of the functions that fit the model and gives it a better accuracy. The use of nonlinear function in the development of the empirical model was to ensure that the model performs better and exhibits reliability in predicting and estimating the formation of hydrates in natural gas pipelines than existing models with the inclusion of the acid gas composition as one of the independent variables. Hence, in this study, the function that best describes the hydrate formation temperature can be represented as:

$$T = f(p, \gamma_g, y_{ag}) \quad (4)$$

where: p is pressure (psia), $\gamma_g$is the specific gravity of the natural gas and y_{ag} is the summation of mole fractions of the acid gases. The summation of the acid gases mole fractions is given as:

$$y_{ag} = \sum (y_{CO2} + y_{H2S} + y_{N2}) \quad (5)$$

Hence, the empirical model developed in this work becomes:

$$T = aP^b + c\left(\frac{x_t}{p^d}\right) + e\ln\left(\frac{p^f}{x_t^g}\right) + h \quad (6)$$

where x_t is the sum of the specific gas gravity (γ_g) and the total gas composition of the acid gas (y_{ag}).

$$x_t = \gamma_g + y_{ag} \quad (7)$$

where; T is the gas hydrate formation temperature (°F); y_{ag} is the total composition of the acid gases (mole fraction); p is the hydrate formation pressure (psia); and γ_g is the natural gas specific gravity (dimensionless). The values of the coefficients a, b, c, d, e, f, g and h are constants given in Table 1. A uniform thickness of the hydrate deposits is assumed in this model development.

Table 1. Values of coefficients in the nonlinear empirical model.

Coefficient	Value	Coefficient	Value
a	0.2568	e	3.0069
b	0.4549	f	3.2433
c	-11.6477	g	10.7981
d	-0.1283	h	14.024

Finally, two measures of deviation were used to validate the model developed in this paper with the existing models. These measures are the average deviation and the percentage average absolute deviation (AAD). The model was developed based on 95% confidence level, indicating that whatever empirical nonlinear model developed, it will represent the true behaviour of the data points and the variables selected.

3. Results and discussions

Figure 2 shows that the observed hydrate formation temperature exhibits a logarithmic function with the observed hydrate formation pressure. Figure 2 has three trend line, an indication of the impact of the acid gases temperature as a function of composition. The logarithmic behaviour is in tandem with previous studies [31].

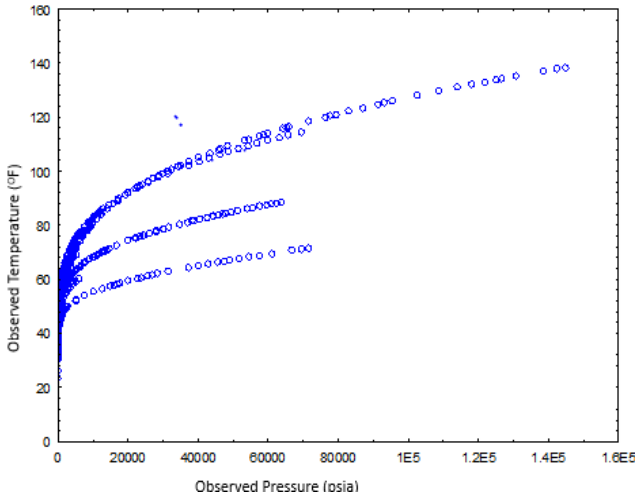

Figure 2. Behaviour of observed hydrate formation temperature and pressure.

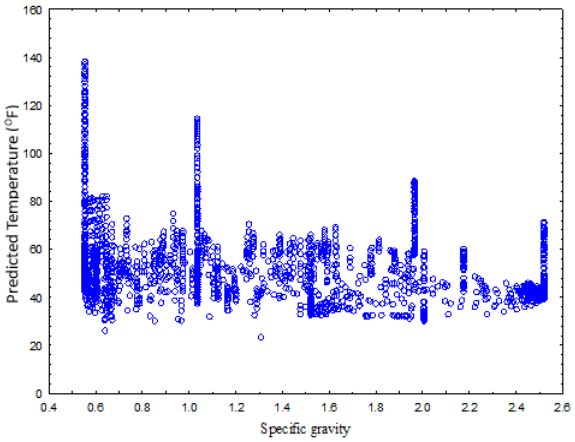

Figure 3. Plot showing the effects of specific gravity on hydrate formation temperature.

To explore the behavior of the hydrate temperature, the impact of the total specific gravity was investigated as shown in Figure 3; a nonlinear nonlinear behaviour was exhibited between the predicted hydrate formation temperature and the total specific gas gravity (with composition of acid gases). The increase in specific gravity does not affected the prediction of temperature significantly. As the specific gravity increases the temperature predicted remain within the average. The difference between the observed data points and the predicted data points is the residuals of each data points. These residuals were further used to examine the accuracy of prediction of the developed model. To achieve this, a frequency plot was plotted to show the region of dense concentration of the residue (error). More than 95% of the highest frequency of the distribution of the errors is expected to concentrate around zero. Figure 4 shows the residual frequency plot of the hydrate formation temperature model developed from this study and it shows that the most of the higher frequencies are concentrated around zero; in the interval of +10 to -10, indicating a better prediction of the hydrate formation temperature given the hydrate formation pressure, natural gas specific gravity and the composition of the acid gas components respectively.

3.1 Validation of the model

Figure 5 is a cross plot showing the predicted against observed hydrate formation temperature. The plot follows a typical nonlinear model with an R^2 value of 0.95, indicating that the model closely predicted to the observed data.

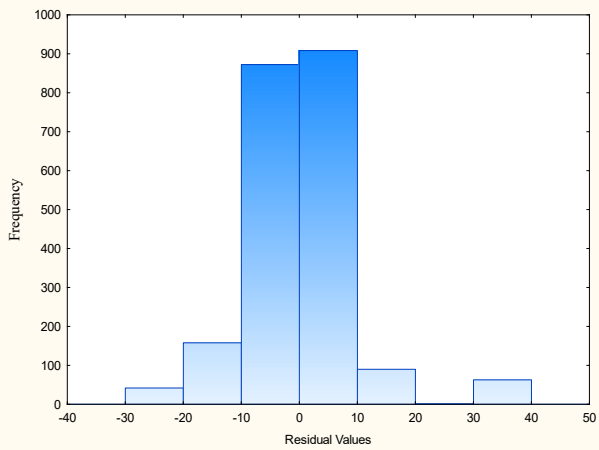

Figure 4. Frequency-residual plot of the hydrate formation temperature prediction.

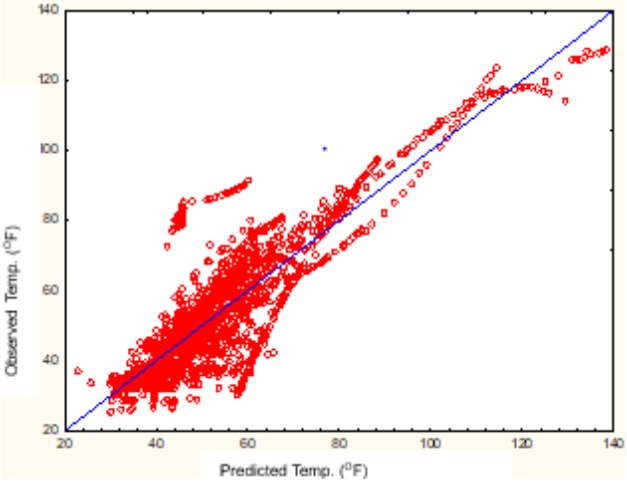

Figure 5. Cross-plot for observed and predicted hydrate formation temperature.

The model developed in this work, Equation 6, was compared with the models developed by Hammerschmidt [3],Towler and Mokhatab [30] and Naseer and Brandsatter [29] as shown in Figure 6. As can be seen in Figure 6, the Hammerschmidt [3],Towler and Mokhatab [29] and the model developed in this study closely matched the observed data compared to that of Naseer and Brandsatter [29], which gave a huge variance from the observed data. The closeness of the predicted temperature using the model in this work to the experimental can be clearly seen in Figure 7 compared to those of Hammerschmidt [3],Towler and Mokhatab [30].

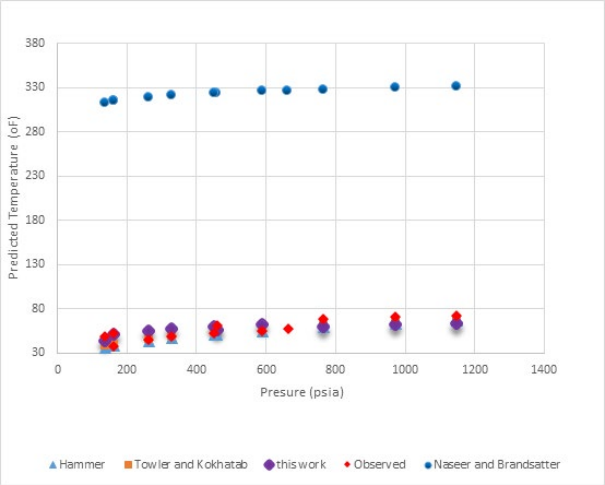

Figure 6. Comparison of models performance on predicting hydrate formation temperature for Hammerschmidt [3], Towler and Mokhatab [30], Naseer and Brandsatter [29] and this work.

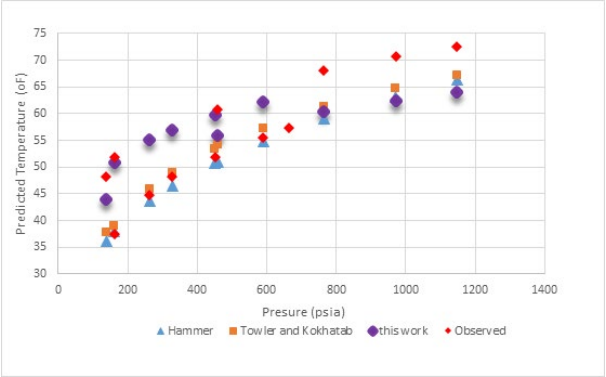

Figure 7. Plot of predicted temperature and observed pressure for the different models Hammerschmidt [3], Towler and Mokhatab [30], and this study.

Moreover, the closeness of the predicted temperatures from Hammerschmidt [3] and Towler & Mokhatab [29] model which are logarithmic and that from this work model is an indication that logarithmic functions are more appropriate and good in predicting the hydrate formation temperature in pipeline downstream of wellhead. To show the extent of agreement and performance of the model developed, a statistical error analysis was done as shown in Table 2.

Table 2. Percentage absolute average deviation for the different models.

	Hammerschmidt [3]	Towler & Mokhatab [30]	Naseer & Brandsatter, [29]	This work
%AAD	15.402	15.426	74.4166	2.1968

From Table 2, it can be seen that the percentage average deviation; which is a measure of the deviation of each data point from the mean; is smallest for the model developed in this work with a value of 2.1968%, followed by Hammerschmidt [3], (15.402%); and then Tower and Mokhatab [30], (15.426%) respectively. The Naseer and Brandsatter [29] gave the largest deviation with a value of 74.4166%, which was also depicted in Figure 6.

4. Conclusion

Accurate prediction of hydrate formation temperature downstream the well head is critical to the reduction of development costs, down time, the improvement on safe and efficient operations performance in the oil and gas industry. Several authors have developed variant models for predicting the hydrate formation temperature. However, none could be adjudged to have predicted the downstream temperature perfectly accurate. The variant models are based on different independent parameters but common is to them all is the pressure. Some have pressure alone as the independent variable, while others are developed using pressure and specific gravity. This study developed a new model for predicting the hydrate formation temperature downstream the wellhead by incorporating the impact of acid gas composition in addition to pressure, and specific gravity.

The new model closely predicted the observed hydrate formation temperatures and also better prediction when compared with existing models. The R^2 value was 95% and the average absolute deviated was 2.1968%. Data used and even performed better from the results obtained, it could be inferred that the new model developed is best accurately predicted the hydrate formation temperature. From the investigation it could seen that by incorporating the acid gas composition into the model, the hydrate formation prediction. In testing this model, the determined R-square from the cross plot was 0.95 which is close to 1 indicting a better prediction. From this model, mathematical function was tested to determine the functions that best predict hydrate formation temperature. Therefore, the that contain both logarithmic and polynomial function has better ability to predict hydrate formation temperature.
Taking into consideration more than two parameter (that is pressure and temperature) are dominantly used will also provide higher tendency for predicting hydrate formation temperature.

Recommendations

Base on the finding made on this research work the following recommendation have been made: Developing empirical model that will predict onset hydrate formation temperature more nonlinear function should be combined rather using one or two function. Since natural gas contain many components, more component should be put into consideration as a function in the model. The data used for the model should be gathered from similar field sharing similar characteristics.

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