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Toward a predictive model for estimating dew point pressure in gas condensate systems

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ABSTRACT

Dew-point pressure is one of the most important quantities for characterizing and successful prediction of the future performance of gas condensate reservoirs. The objective of this study is to present a reliable, computer-based predictive model for prediction of dew-point pressure in gas condensate reservoirs. An intelligent approach based on least square support vector machine (LSSVM) modeling was developed for this purpose. To this end, the model was developed and tested using a total set of 562 experimental data points from different retrograde gas condensate fluids covering a wide range of variables. Coupled simulated annealing (CSA) was employed for optimization of hyper-parameters of the model. The results showed that the developed model significantly outperforms all the existing methods and provide predictions in acceptable agreement with experimental data. In addition, it is shown that the proposed model is capable of simulating the actual physical trend of the dew-point pressure versus temperature for a constant composition fluid on the phase envelope.

1. Introduction

Gas condensates are highly valued hydrocarbon resource and their importance has grown continuously since the 1930s. Gas condensate reservoirs differ from conventional gas reservoirs in their thermodynamic and flow behaviors [1–3]. The phase behavior of a gas condensate reservoir is strongly dependent on the P–T envelope and thermodynamic conditions of the hydrocarbon mixture. The phase diagram of a condensate gas is somewhat smaller than that for oils, and critical point is further down the left side of the envelope. These changes are a result of condensate gases containing fewer of the heavy hydrocarbons than do the oils [4,5]. The phase diagram of a gas condensate has a critical temperature less than the reservoir temperature and a cricondentherm greater than the reservoir temperature (See Fig. 1).

Gas condensate systems commonly appear as a single gas phase in the reservoir at the time of discovery. The gas will drop out liquid by retrograde condensation in the reservoir, when the pressure falls below the dew-point, from (1) to (2) in Fig. 1 [6]. If the pressure continues to decrease, a second dew-point pressure will be reached and the liquid can be re-vaporized. This lower dew-point is usually below the reservoir abandonment and would be of no interest in reservoir performance. Gas condensate reservoirs generally produce gas to liquid ratios ranging from 3200 to 150,000 SCF/STB [5,7,8]. The produced gas to liquid ratio initially remains constant when the reservoir pressure falls below the dew-point pressure and increases thereafter [7]. The original heptanes-plus fraction of the reservoir gas is generally less than 12.5 mol% in gas condensate fluids and condensate specific gravity ranges between 0.74 and 0.82 [5,7]. Exceptional cases with condensation as high as 15.5 mol% of heptanes-plus [9] and condensate specific gravity values as high as 0.88 have also been reported [10].

Fevang and Whitson [11], Afidick et al. [12] and Barnum et al. [13] have reported field data which show that under some conditions a significant loss of well productivity can occur in gas wells due to near wellbore condensate accumulation. This drop out causes an apparent skin resistance at the wellbore that impairs the production capacity of well [14–18]. As pointed out by Boom et al. [19] even for lean fluids with low condensate dropout, high condensate saturations may build up as many pore volumes of gas pass through the near wellbore region. As the condensate saturation increases, the gas relative permeability decreases, and thus the productivity of the well decreases. Therefore, accurate determination of the dew-point pressure is important.

Traditionally, the dew-point pressure of a gas condensate fluid is experimentally determined in a laboratory in a process called constant mass expansion (CME) test using a visual window-type PVT cell. The laboratory measurement of the dew-point pressure provides the most accurate and reliable determination. However, the

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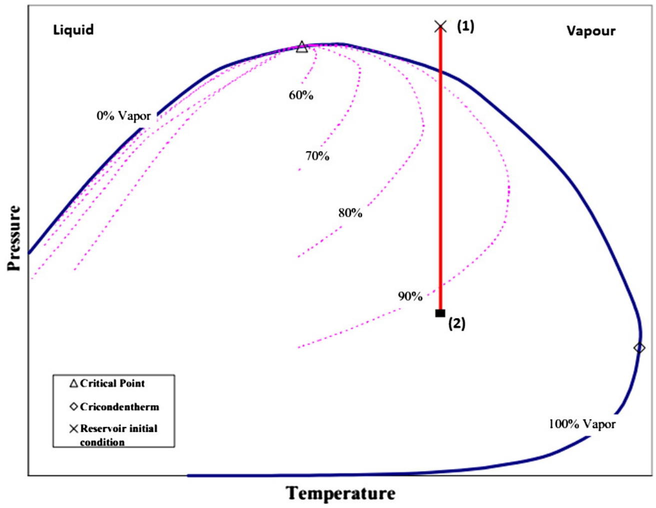

Fig. 1. A typical gas condensate phase envelope [6].

experimental determination of dew-point pressure at reservoir temperature for gas condensate reservoir is relatively expensive and time consuming [20–22].

During recent decades, various researchers attempted to develop a general correlation for prediction of gas condensate fluids. In 1942, Kurata and Katz [23] established a correlation to predict critical properties of volatile hydrocarbon mixtures. Twenty nine dew-point pressures were used but no attempt was made to correlate them with fluid composition. Eilerts and Smith [24] developed four correlations relating dew-point pressure to temperature, composition, boiling point and gas-oil ratio. Olds et al. [25] used the compositions of oil and gas samples obtained from primary separator of a well in the Paloma field, to develop a new correlation for prediction of dew-point pressure in graphical and tabular form. They also investigated the omission of intermediate molecular weight on dew-point pressure. They showed that intermediate molecular weight components have a considerable effect on dew-point pressure. Olds et al. [26] experimentally investigated the volumetric behavior for different mixtures of gas condensate samples from a San Joaquin Valley field. They developed a rough correlation relating the retrograde dew-point pressure to the gas-oil ratio, temperature and stock tank API oil gravity. The results of this correlation were presented in tabulated and graphical forms. Reamer and Sage [27] attempted to extend existing correlation to higher gas-oil ratio by studying combinations of five different pairs of fluids from a field in Louisiana. They also studied the effect of temperature and gas-oil ratio on dew-point pressures. Moreover, they concluded that due to complexity of the influence of composition on dew-point pressure, a general correlation for this purpose is not possible. Organick and Golding [28] presented a correlation for the prediction of saturation pressure in condensate gas and volatile-oil mixtures. The correlation was given in the form of working charts, which are not well suited to electronic computation. Nemeth and Kennedy [29] proposed a mathematical relationship between the dew-point pressure of a hydrocarbon reservoir fluid and its composition, temperature and characteristics of the heptanes-plus fraction, such as molecular weight and specific gravity. In their study, 579 dew-point pressures from 480 different condensate systems were used in a multiple-variable regression analysis to develop the correlation. Later, Crogh [30] performed several evaluations to improve the Nemeth and Kennedy correlations to fit better the dew-point pressure. One should note here that, reservoir temperature was not considered in the developed correlation. Humoud and Al-Marhoun [31] published a new empirical correlation to predict the dew-point pressures of gas condensate fluids from readily available field data. This correlation relates the dew-point pressures of a gas condensate fluid directly to its reservoir temperature, pseudo reduced pressure and temperature, primary separator gas-oil ratio, the primary separator pressure and temperature, and relative densities of separator gas and heptanes-plus fraction. The correlation was developed using several gas condensate fluid samples representing different gas reservoirs in the Middle East. In 1996, Carison and Cawston [32] investigated the influence of H_2S on dew point pressure. According to their researches, as H_2S content increases, the volume of liquid drop out decreases. Using 146 PVT analyses information of western Venezuela (Anaco) fields, Marruffo et al. [33], developed correlations to determine the dew-point pressure and C_{7+} content of gas condensate reservoirs. Elsharkawy [16] published another empirical model to predict dew-point pressure for gas condensate reservoirs as a function of routinely measured gas analysis and reservoir temperature. It correlates dew-point pressure with reservoir temperature, reservoir composition of hydrocarbon and non-hydrocarbon, with molecular weight of C_{7+} and with specific gravity of C_{7+}. In 2003, Gonzalez et al. [34] developed an artificial neural network model to estimate the dew-point pressure. The hydrocarbon and non-hydrocarbon gas condensate compositions (C_1–C_{7+}, N_2, CO_2, H_2S), reservoir temperature, molecular weight and specific gravity of C_{7+} are used as an input to feed the neural network. The neural network architecture consists of three layers; one input layer with 13 neurons, one hidden layer with 6 neurons and one output layer with one neuron. The back propagation technique and the conjugate gradient decent training algorithm are used to minimize the mean-square error. Akbari et al. [35] developed another artificial neural network model to estimate the dew-point pressure. The hydrocarbon and non-hydrocarbon gas condensate compositions (C_1–C_{7+}, N_2, CO_2, H_2S), reservoir temperature, molecular weight of C_{7+} are used as an input to feed the neural network. The neural network architecture consists of three layers; one input layer with 14 neurons, one hidden layer with 8 neurons and one output layer with one neuron. The back propagation technique and the Levenberg–Marquardt training algorithm are used to minimize the mean-square error. Shokir [36] developed a genetic programming (GP) based model using experimental data of 245 gas condensate systems covering a wide range of gas properties and reservoir temperature in gas condensate systems. However, the effect of specific gravity of heptanes-plus was not considered in the developed model. In 2009, Nowroozi et al. [17] developed a neural fuzzy system (NFS) for prediction of dew-point pressure. The model was developed using 110 measurements of dew-point pressure. Reservoir temperature, C_{7+} molecular weight, non-hydrocarbon (H_2S, CO_2, N_2) and hydrocarbon (C_1–C_{7+}) compositions as inputs and dew-point pressure as output were selected to build a neuro fuzzy system. Back propagation and hybrid optimization methods were used to optimize generated fuzzy inference system. Results of comparison indicated that the proposed dew point prediction model is more accurate than published empirical correlations.

Using equation of state is another approach to calculate the dew-point pressure. Although numerous number of equations of state [37–39] have been published in the literature to model reservoir fluid phase behavior in general but, it deteriorates for phase behavior modeling of complex hydrocarbons such as volatile oils and gas condensates especially in the retrograde region [40].

The complexity, fuzziness and uncertainty existing in addition to the non-linear behavior of most reservoir parameters require a powerful tool to overcome these challenges [17]. To this end, this study is aimed at the following objectives:

1. Propose novel, reliable, yet accurate mathematical model to estimate dew-point pressure in retrograde gas condensate reservoirs.
2. Testing the performance of the model and compare the results with the performance of the most accurate correlations for dew-point pressure prediction [16,29,36]).