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**Sadri, M., Mahdiyar, H. & Mohsenipour, A.**

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# A Compositional Thermal Multiphase Wellbore Model for Use in Non-Isothermal Gas Lifting

**Mahdi Sadri\***, Fluid and Complex Systems Research Centre, Coventry University, Coventry, UK

**Hojjat Mahdiyari**, Department of Petroleum Engineering, Shiraz University, Shiraz, Iran

**Ali Mohsenipour**, Department of Chemical Engineering, University of Waterloo, Waterloo, Canada

## Abstract

In this paper, a new compositional mechanistic wellbore model, including gas lifting parameters, is presented. In the governing equations of this model, new terms for mass transfer between phases and the enthalpy of phase change, which are important in non-isothermal gas lift systems, have been considered. These terms have been ignored in some recent research studies and subsequent results show that by ignoring them, serious errors may arise. In the current research study, using a mechanistic drift-flux approach, the pressure distribution in a wellbore was modeled. To verify the new simulator, the results were compared with those of commercial simulators. They were also verified against the phase behavior analysis of the fluid flowing in the wellbore. In addition, in order to show the novel aspects of the new simulator, the results of the presented simulator were compared with the results of a recently proposed model found in the literature. It was concluded that neglecting phase change effects may cause significant errors in calculating pressure and temperature values along wellbores. This error could be significant, up to 24% depending on conditions, when flowing fluid pressure is close to its saturation point or in the case of simulating gas lift operation.

**Keywords:** compositional simulator, wellbore simulator, multiphase flow, non-isothermal gas lifting, drift-flux model

## Introduction

Considerable effort has been devoted to modelling multi-phase flow in wellbores. For this purpose, many empirical correlations have been presented by different authors [1-4]. Since these correlations have been developed based on field and laboratory data, their accuracy, like any empirical correlation, is highly dependent on the range of their source data bank. On the other hand, mechanistic models are developed based on simple physical concepts such as mass, momentum and energy balance. In this case, the flow regimes play a profound role in the calculations. Mechanistic models were introduced for the first time by Taitel, *et al.* in two separate studies [5, 6]. In these studies, the authors described the mechanisms which control transitions between different flow regimes. Since then, several mechanistic models have been presented. Among them, one can mention the research works of Hasan and Kabir [7], Ansari, Sylvester, Sarica, Shoham and Brill [8], Xiao, Shoham and Brill [9] and Zhang, Wang, Sarica and Brill [10]. Although mechanistic models are able to calculate pressure drop more accurately, their complexity makes them more expensive in terms of CPU time demand. To overcome this problem some researchers have considered other options such as drift-flux models. The basic concept of a drift-flux model is to consider the mixture as a whole, rather than two phases separately. This simplicity of drift-flux models makes them very useful in many engineering applications.

Shi, *et al.* in two papers [11, 12] developed a drift flux model using the experimental data of Oddie, Shi, Durlifsky, Aziz, Pfeffer and Holmes [13]. In their model, some parameters were determined experimentally. Khasanov, Krasnov, Khabibullin, Pashali and Guk [14] employed a mechanistic approach to calculate the void fraction and developed a drift-flux model based on it.

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\* sadrim@uni.coventry.ac.uk

They used flow regime transitions determined by Taitel, Bornea and Dukler [6] to obtain a simple formula for the void fraction in each flow regime. In comparison to other mechanistic models, their model has acceptable accuracy and with much lower CPU time. Their model could be used to calculate pressure drop for several wells simultaneously due to the simplicity of their mechanistic model provided by the drift-flux approach they employed. Pressure drop calculation for several wells is essential in some cases such as production optimization.

The other important governing equation of wellbore models is the energy equation which is used to estimate the temperature profile. Ramey Jr [15] developed a theoretical model to estimate temperature as a function of depth in a wellbore. His model was developed based on a single phase flow assumption. Satter Jr [16] developed a model for calculating the temperature profile in multiphase flow. Hasan and Kabir [17] considered the Joule-Thompson effect in their proposed model to estimate fluid flow temperature in wellbores. In contrast to the above mentioned models which were developed by employing a black oil approximation, Pourafshary, Varavei, Sepehrnoori and Podio [18] proposed a model based on a compositional approach, assumed to be under steady state conditions. Livescu, Aziz and Durlafsky [19] generalized their compositional models by adding time derivative terms to the governing equations.

In order to develop a wellbore model, a material balance equation must also be employed as well as pressure and energy equations. Different wellbore simulators have been presented in the literature. Bendiksen, Maines, Moe and Nuland [20] developed a dynamic two fluid model based on a black oil approximation. They presented three material balance equations for gas and liquid phases, and liquid droplets. They considered mass transfer between the phases by adding a term to their mass conservation equations. Similar to the conservation of mass, the conservation of momentum was also expressed in three equations in their work. However, unlike the mass and momentum balance equations, they employed a single energy equation for the whole mixture. Nothing has been mentioned about considering the enthalpy of phase change in their energy equation. The model that Bendiksen, Maines, Moe and Nuland [20] have presented in their publication is a black oil model. It means a simulator based on this model cannot undertake compositional calculations to obtain fluid properties. Fluid properties must be provided to the simulator in the form of tables of numbers as the authors have mentioned in the article. The OLGA commercial simulator [21] was later developed based on this publication and as it is claimed that its compositional tracking section provides the option to undertake compositional simulations. However, since there are restrictions in accessing the formulation of the model behind the software (similar to any other commercial software), the details of the model are not completely known. It is not clear how the model has been upgraded to a fully compositional simulator and if the enthalpy of phase change has been considered in the energy balance. Therefore, there is still a gap in the literature in regard to a detailed formulation of a fully compositional simulator that considers mass transfer between phases and the enthalpy of phase change.

Pourafshary, Varavei, Sepehrnoori and Podio [18] and Livescu, Aziz and Durlafsky [19] presented two compositional wellbore simulators in their publications. In both of these works, the wellbore model is coupled to a reservoir model to make a wellbore/reservoir coupled simulator. Pourafshary, Varavei, Sepehrnoori and Podio [18] expressed their material balance in two separate equations for the gas and liquid phases. In their material balance equations, no term represents the mass transfer between the phases. In the energy equation in the mentioned model, no term for the enthalpy of phase change is also mentioned. Ignoring mass transfer between phases and the enthalpy of phase change is an acceptable assumption when a great fraction of the well is occupied by gas and the mass transfer from the liquid phase to the gas phase is negligible compared to the high gas content in the well. The reason is that the density of the mixture plays an important role in both the material and energy balance equations and in such a case the density

does not change significantly due to the mass transfer. However, if the gas fraction is low, mass transfer can considerably reduce the liquid holdup and the density of the mixture. In that case, the mass transfer between phases can have a significant effect on the calculated pressure and temperature profiles and cannot be ignored. Livescu, Aziz and Durlofsky [19] extended their previous black oil model [22] to a compositional one. In their model, a drift-flux approach was used for phase velocities in the well. They did not, however, consider the enthalpy of phase change in the energy equation of their model.

In addition to the wellbore models that have been developed to generally simulate a well, some researchers have published models for specific types of wells or simulating specific phenomena and processes in the oil and gas industry. For instance, the models presented by Zhang, Xiong and Guo [23] and Chen, Gao, Yang, Luo, Feng and Li [24] are specifically for drilling wells, Tan, Li, Zhou, Jiang, Wang and Zhang [25] have published a wellbore/reservoir model, and Shi, Liu, Ding, Lv and Gong [26] have focused on hydrate formation in their model formulation. Although some of the general wellbore models are capable of modelling these phenomena, the purpose of these models is to provide more accurate calculations. Among the aforementioned processes is gas lifting which is widely undertaken in the oil and gas industry. Many publications on the techniques and technologies of gas lifting are accessible in the literature [27-29]. However, fewer publications are found on the modeling of this process. To the knowledge of the authors, no compositional wellbore model has been published that specifically focuses on gas lifting. One advantage of a compositional model is that it can show the effect of the composition of the injected gas on gas lifting process.

In this paper, a new compositional wellbore simulator with the ability of simulating gas lift is presented. In this wellbore model, the effects of mass transfer between phases and the enthalpy of vaporization are considered. To achieve this, new terms have been added to the material balance and energy balance equations. This simulator is also capable of simulating gas lift. The simulator therefore now makes it possible to study the effects of injecting different types of gas in a gas lift operation. This study begins by expressing the governing equations of the model. To justify and present its considerable value, the main differences between the model and similar studies, are clarified. Along with presenting the solution procedure, results of the simulator are compared with numerical results of three well-known simulators, including two commercial ones to validate the simulator. Finally, the effects of neglecting mass transfer between the phases and the enthalpy of vaporization on simulation results are also investigated, and the results being verified against phase behavior analyses of wellbore flowing fluid.

## **Governing Equations**

In order to calculate pressure and temperature profiles in a wellbore, many equations need to be solved simultaneously. Among these equations, the material balance, momentum balance, and energy balance equations are the most important. These governing equations are employed to model a conventional multiphase flow well system. Figure 1 shows a schematic of the well which is modeled in this work. In the proposed model, the well is divided into smaller segments in the direction of its axis ( $z$ ). The datum depth is considered to be the deepest point of the well. Reservoir fluids enter the lowest well segments through perforations. Injected gas could be defined to enter any segment of the well in the case of an existing gas lifting operation.

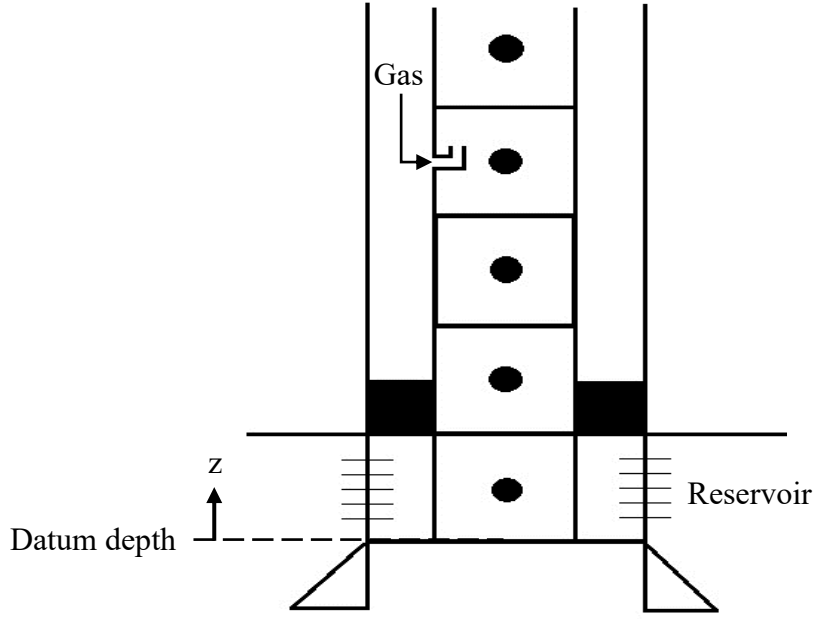


Fig. 1-The grid blocks in the well system

All governing equations are discretized using a backward finite difference method and all of them have been solved for each well segment. In these equations, the terms which represent entering material or energy from the reservoir are considered to apply just to the segments which are perforated. Also, the terms for material and energy that enter the well due to any gas lifting operation are just considered for the segment in which gas is injected.

### Material Balance Equations

The total material balance equations for liquid and gas phases are, respectively,

$$-A \frac{\partial}{\partial z} (v_{sl} \sum_{i=1}^{n_c} \rho_{il} x_i) + \sum_{i=1}^{n_c} m'_{il} + \sum_{i=1}^{n_c} m''_{il} - \sum_{i=1}^{n_c} \psi_i = 0 \quad (1)$$

$$-A \frac{\partial}{\partial z} (v_{sg} \sum_{i=1}^{n_c} \rho_{ig} y_i) + \sum_{i=1}^{n_c} m'_{ig} + \sum_{i=1}^{n_c} m''_{ig} + \sum_{i=1}^{n_c} \psi_i = 0 \quad (2)$$

Considering a single segment of the wellbore, in these equations, the first left-hand side term represents the difference between the input mass flow rate from the previous segment and the output mass flow rate to the next segment. The second and the third terms represent input mass flow rate from reservoir and input mass flow rate due to gas lifting, respectively. The last term represents the mass transfer rate between the two phases, which is neglected in most previous compositional wellbore models presented in the literature. This is one of the main differences between this study and some previous ones.

As shown in Equations 1 and 2, the last left-hand-side term of the two equations have equivalent values but opposite signs (one term is positive and the other is negative). Consequently, if these two equations are summed, the term which represents the mass transfer rate between phases will disappear in the resulting equation:

$$-A \frac{\partial}{\partial z} (v_{sl} \sum_{i=1}^{n_c} \rho_{il} x_i) + \sum_{i=1}^{n_c} m'_{il} + \sum_{i=1}^{n_c} m''_{il} - A \frac{\partial}{\partial z} (v_{sg} \sum_{i=1}^{n_c} \rho_{ig} y_i) + \sum_{i=1}^{n_c} m'_{ig} + \sum_{i=1}^{n_c} m''_{ig} = 0 \quad (3)$$

Since the aim of solving the material balance equation is to calculate the phase velocities (i.e.  $v_{sl}$  and  $v_{sg}$ ), we assume these two terms to be unknowns. As a result, there is one equation and two unknowns. Therefore a component material balance is added to equalize the number of unknowns and equations:

$$-A \frac{\partial}{\partial z} (x_j v_{sl} \sum_{i=1}^{n_c} \rho_{il} x_i) - A \frac{\partial}{\partial z} (y_j v_{sg} \sum_{i=1}^{n_c} \rho_{ig} y_i) + m'_{il} + m'_{jg} + m''_{jl} + m''_{jg} = 0 \quad (4)$$

where  $x_j$  and  $y_j$  are mole fractions of arbitrary component  $j$  in liquid and vapor phases, respectively.

Equations 1 and 2 have been written for individual phases (liquid or gas) in the two phase flow. They are solved at the same time to represent the whole gas-liquid system. However, since each material balance equation is just for one phase, the mass transfer between the phases is included in it. As a result, a term for the mass transfer between the phases is needed in these two equations. On the other hand, Equation 3 is for the whole system of gas and liquid. Since the mass transfer between phases happens within this liquid-gas system and no mass crosses its borders, no term for the mass transfer between phases is required in this equation. As a result, the mass transfer between phases is hidden in this equation as well, although there is no term for it. Solving Equations 1 and 2 or interchangeably Equation 3, therefore, leads to the same results.

### Pressure Drop Equation

The pressure equation for a well bore has three main terms:

$$\frac{\partial P}{\partial z} = \left(\frac{\partial P}{\partial z}\right)_E + \left(\frac{\partial P}{\partial z}\right)_F + \left(\frac{\partial P}{\partial z}\right)_A \quad (5)$$

These terms are the pressure drop due to elevation,  $(\partial P/\partial z)_E$ , pressure drop due to friction,  $(\partial P/\partial z)_F$ , and pressure drop due to acceleration,  $(\partial P/\partial z)_A$ . Due to the high weight of fluid in the wellbore column, in many cases, the most significant part of pressure drop is due to elevation. It means the parameter which highly affects calculated pressure drop is the fluid mixture density. This important parameter is related to liquid and gas density by liquid holdup. In different pressure equations proposed in the literature, different methods have been presented to calculate liquid holdup. The most accurate methods are those which are used in mechanistic models [8]. In the present work, we used the mechanistic model of Khasanov, Krasnov, Khabibullin, Pashali and Guk [14]. This model has a simple drift-flux formulation in addition to its acceptable accuracy. This simplicity highly reduces the computation time, which is an important factor for a gas lift simulator. In some cases, gas lift simulators should be able to simulate several wells simultaneously in a reasonable CPU time. Moreover, performing compositional calculations demands more CPU time than black oil calculations. The model has a slightly lower accuracy in annular flow. However, the fact that an annular flow regime does not occur in the gas lifting process, makes this fast model a good choice for a compositional gas lifting simulator. For those simulators where high CPU time is not an issue (such as black oil simulators or the ones that have been designed to simulate just a few wells), more complicated mechanistic models might prove to be better options. It can be a good title for future research projects to determine the conditions (such as fluid type, flow regime, or number of simulated wells) in which the simulations need to be undertaken by complex compositional models that might involve a higher computational cost. The alternative to the latter option is employing simpler simulators where they have an

acceptable accuracy to reduce the computational cost. Fluid composition and C1 content can be some of the factors to be considered in making the decision.

In this mechanistic model, mixture density is calculated using the void fraction parameter,  $f_g$ , which is defined as the volume of a well segment occupied by gas, divided by the total segment volume. It is also referred to as gas hold up in the literature.

$$\rho_m = \rho_l(1 - f_g) + \rho_g f_g \quad (6)$$

$f_g$  is equal to the inverse of liquid hold up ( $1/H_L$ ). Based on the concept of drift-flux modelling [30] it is presented as

$$f_g = \frac{v_{sg}}{C_0(v_{sg} + v_{sl}) + v_d} \quad (7)$$

where  $C_0$  is called flow profile distribution parameter and shows how non-uniform the gas distribution in the well cross section is, and  $v_d$  denotes drift velocity that accounts for the relative velocity between the phases.  $f_g$  is dependent on the flow regime. The full details of calculating  $f_g$  for different flow regimes has been presented in Khasanov, Krasnov, Khabibullin, Pashali and Guk [14].

### Energy Equation

The energy balance equation for the new model is written as following:

$$Q_{loss} - \left\{ \sum_{j=1}^{n_p} \sum_{i=1}^{n_c} A \frac{d}{dz} \left[ \rho_{ij} v_{ij} \left( C_{Pij} T + \frac{v_{ij}^2}{2} + gz \sin \theta \right) \right] \right\} + \sum_{i=1}^{n_c} \frac{A \rho_i v_i}{\Delta z} \left( C_{Pi} T_{inj} + \frac{v_i^2 - v_{ig}^2}{2} + gz \sin \theta \right) + \sum_{i=1}^{n_c} A \frac{d(\rho_i v_i)}{dz} (h_i^{lv})_{out} = 0 \quad (8)$$

where the first term represents heat loss to surrounding formation. The second term represents changes in energy due to changes in temperature, velocity, and elevation of components in each phase. The third term represents energy which enters the well system by injected gas during gas lifting and the fourth term represents energy due to phase change. Contrary to some previous work, the enthalpy of phase change is considered in the proposed energy balance. In Equation 8,  $C_{Pij} T$  is enthalpy change for component  $i$  in phase  $j$  due to variation in temperature and  $h_i^{lv}$  is the change in enthalpy of component  $i$  as a result of phase change.  $C_{Pij}$  is a function of temperature and pressure which is estimated using Lee-Kesler method [31] and  $h_i^{lv}$  is calculated using the Clausius/Clapeyron equation [32].

### Fluid Properties Calculation

In this work, fluid properties are calculated by performing vapor-liquid equilibrium calculations based on Peng-Robinson equation of state [33, 34]. The modified Riazi-Daubert [35] and Edmister [36] correlations are employed to calculate the critical properties and the acentric factor of the pseudo component, respectively. The binary interaction parameters are estimated using the correlation presented by Chueh and Prausnitz [37]. The fluid viscosities are calculated based on the method of Lohrenz, Bray and Clark [38] and the interfacial tension between phases is predicted by employing the correlations presented by Weinaug and Katz [39].



## Solution procedure

In order to calculate pressure and temperature profiles in a well, values of too many unknowns need to be calculated. Some of these unknowns include composition, density, viscosity, velocity of phases, interfacial tension, flow regimes, liquid hold up, heat capacity of components in each phase and enthalpy of vaporization. To calculate these unknowns, an equal number of equations needs to be solved. In the present simulator, an iterative solution procedure is used. The procedure for calculating pressure and temperature profiles is shown in Figure 2.

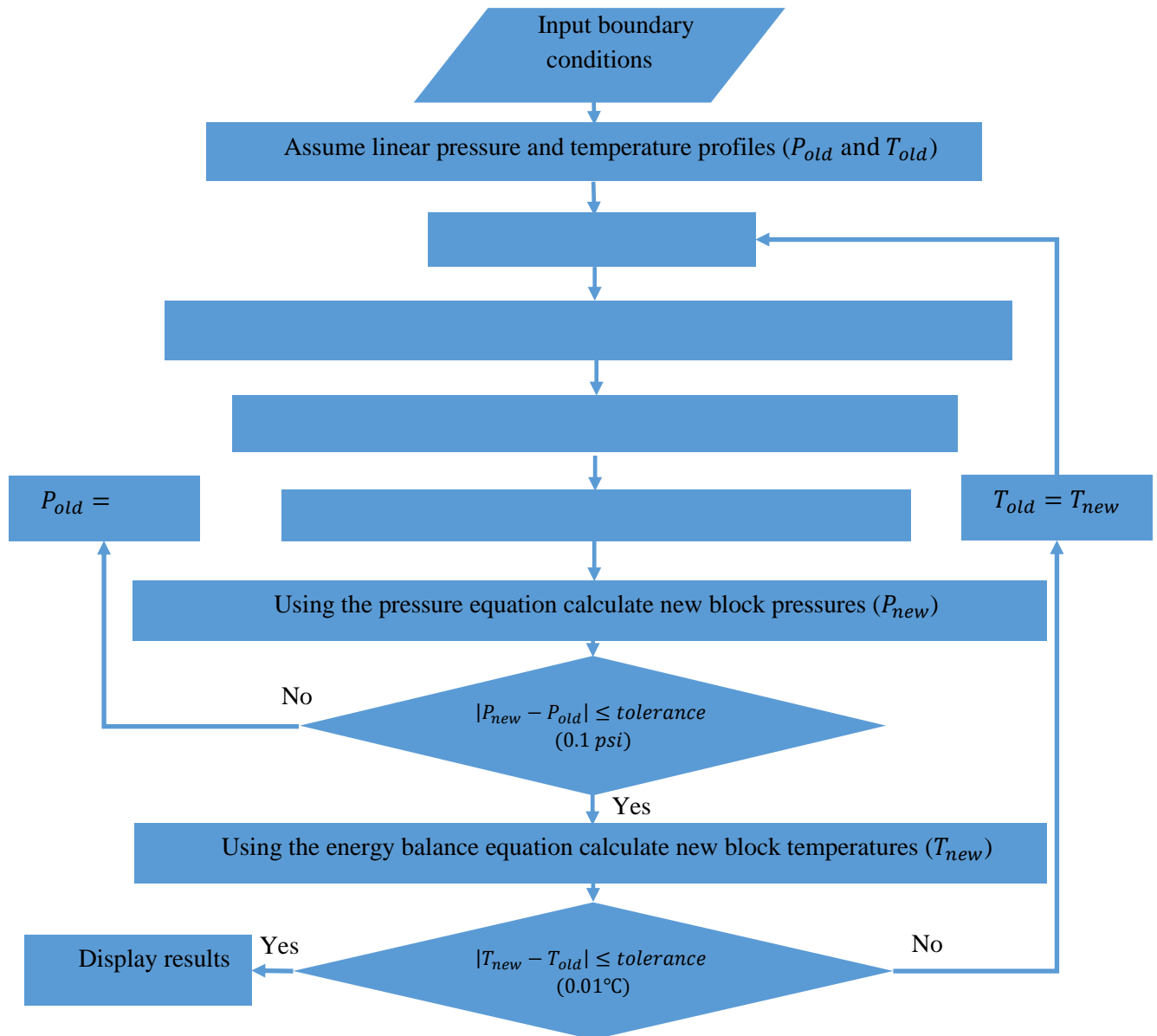


Fig. 2-The solution procedure

## **Boundary Conditions and Unknown Parameters**

The values of bottom-hole parameters are considered to be boundary conditions of the system. These parameters are pressure, temperature, mass flow rate, and reservoir fluid composition. In addition to these, injected gas pressure, temperature, mass flow rate, and composition should also be known in the case of simulating gas lift.

Many parameters need to be calculated during the solution procedure. These parameters are calculated in the step-by-step procedure of Figure 2. One or more than one parameters are considered to be unknowns in each step. Therefore, an initial value is considered for each of the other parameters so that the number of equations and unknowns are equal in every step. When the unknowns are calculated in a step, their values are used as the guessed values for the next steps in an iterative procedure. As a result, new values are calculated for parameters in each iteration. These values converge to the final results after several iterations. This is how the entire unknown parameters are calculated in this procedure. The unknown parameters of each step are illustrated in Figure 2.

## **Results and Discussion**

### **Comparison with Well-Known Simulators**

In order to investigate how much the new model affects the calculated pressure values, the results of the new simulator are compared with the results of three simulators, including two well-known commercial ones (i.e. Eclipse VFPi and OLGA), and the simulator which was proposed by Pourafshary, Varavei, Sepehrnoori and Podio [18]. The pressure profiles of the two commercial simulators are calculated based on black oil models. However the new simulator and the simulator based on the publication of Pourafshary, Varavei, Sepehrnoori and Podio [18] are fully compositional. The results of the four simulators are shown in Figure 3. The calculated pressure drops based on Pourafshary, Varavei, Sepehrnoori and Podio [18] and VFPi simulators show that there is a 1.2% absolute deviation (Equation 9) of the surface pressure values calculated by these two simulators. Their results are relatively similar for their same material balance equations. Likewise, the calculated surface pressure results of the new simulator and OLGA have a strong approximation to each other (2.1% absolute deviation). They also result in the calculation of a lower pressure drop in the wellbore in comparison to the other two simulators. This is a result of considering the phase change term in the material balance equations of these two simulators. The simulated scenario is a natural production from a wellbore (no gas lift). The composition of the oil which is used as the entering fluid in the well is shown in Table 1, while the values for well parameters and boundary conditions can be seen in Table 2. In order to use same input data for all simulators in this comparison, input fluid properties in VFPi were calculated based on the composition in Table 1 using the Peng-Robinson equation of state [33, 34].

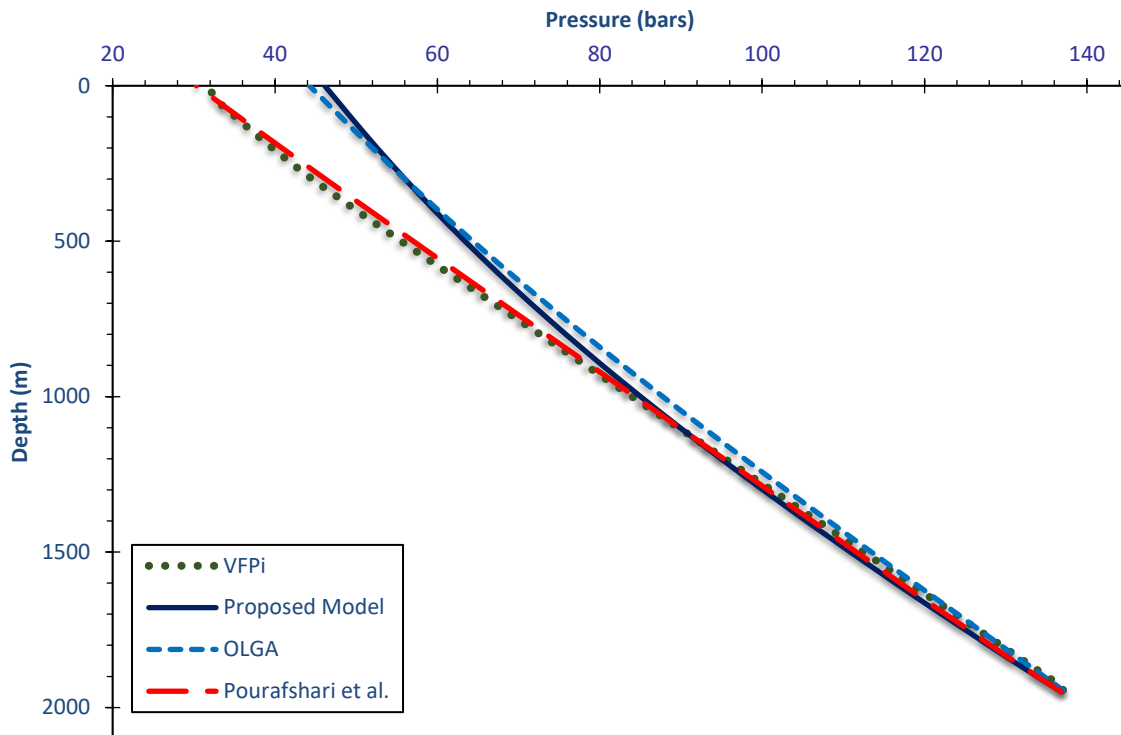


Fig. 3-The comparison between the calculated pressure profiles of the new simulator and three well-known simulators for a natural production scenario

component	Mole percent
C1	36.47
C2	9.67
C3	6.95
iC4	1.44
nC4	3.93
iC5	1.44
nC5	1.41
C6	4.33
C7+	33.29
N2	0.16
CO2	0.91

Table 1-The black oil (heavy fluid) composition [40]

Well Depth (m)	2000
Inner diameter of tubing (m)	0.12
Tubing roughness (m)	1.5E-5
Geothermal gradient (K/m)	0.029
Bottom hole pressure (bar)	137.41
Bottom hole temperature (K)	363
Flow rate between well and reservoir ( $m^3/s$ )	6.3E-5

Table 2-The values for well parameters and boundary conditions

### Effects of Neglecting Phase Change on Simulation Results

More recently proposed well models in the literature have neglected the effects of phase change in the material and energy balance equations [18, 41]. The difference between the proposed model in this study in comparison to previous compositional models is that effects, such as mass transfer between phases and enthalpy of phase change, have been considered. In the following, the effects of neglecting phase change on simulation results are investigated in two different scenarios. These two scenarios are for natural oil production and oil production assisted by gas lift in a single well. The scenarios were simulated by employing two different models. The first model (Model A) is the proposed model in this study and the second model (Model B), like most models presented in the literature, is a model which neglects the effects of phase change in the material and energy balance equations. The results of these two models are subsequently compared and analyzed based on the phase behavior of the flowing fluids in the well.

### Natural Oil Production Results

In order to investigate the effects of neglecting phase change on the simulation results for natural oil production in a well, two different cases were simulated by employing two defined models. In the first case, the simulated well is producing black oil and in the second one, the produced fluid is volatile oil. Then the calculated pressure and temperature profiles based on each model were compared. The black oil (heavy fluid) in Table 1 is considered the produced fluid in the first simulated case. Also, the composition of the volatile oil (light fluid) in the second case is shown in Table 3. For both cases, the well parameters and boundary conditions are the same as for Table 2, except that no gas lift is in operation in the well. The calculated pressure and temperature profiles for the black oil case are shown in Figures 4 and 5.

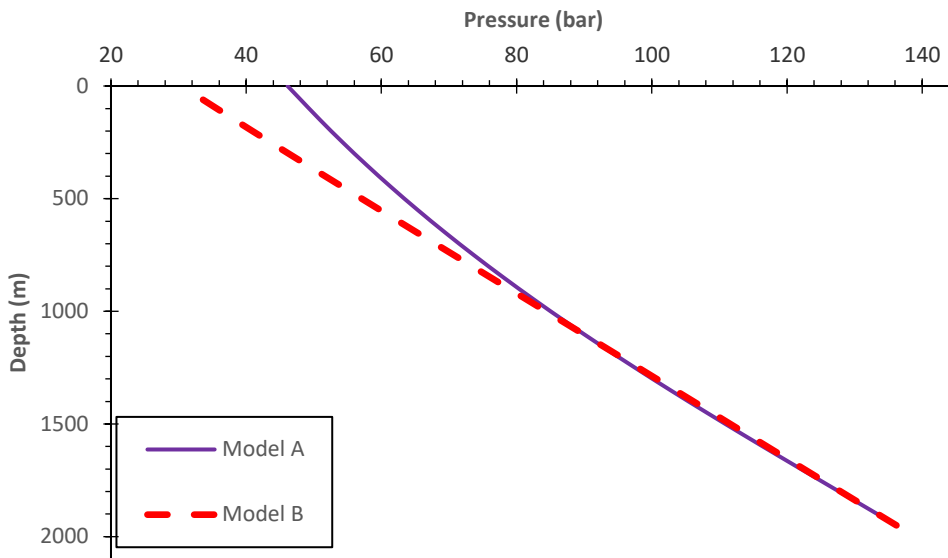


Fig. 4-The calculated pressure profiles based on Model A (incorporating phase change effects) and Model B (excluding phase change effects) for the heavy fluid case

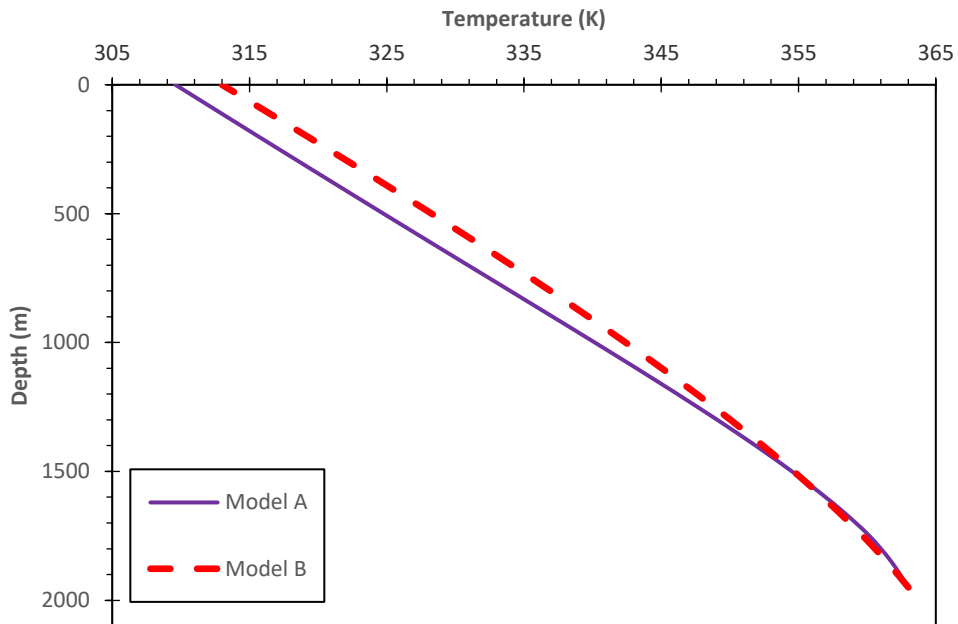


Fig. 5-The calculated temperature profiles based on Model A (incorporating phase change effects) and Model B (excluding phase change effects) for the heavy fluid case

component	Mole percent
C1	66.59
C2	5.31
C3	4.22
iC4	0.85
nC4	1.76
iC5	0.67
nC5	1.12
C6	1.22
C7+	16.64
N2	0.12
CO2	1.5

Table 3-The volatile oil (light fluid) composition [40]

As expected, the calculated values based on Model A for both pressure drop and surface temperature are less than those calculated based on Model B. The term for mass transfer between gas and liquid is considered in the material balance equation of Model A. Consequently, the amount of vaporized liquid in any well section is calculated in Model A. Therefore, the calculated value for liquid hold-up in any section of the wellbore based on this model is less than that of Model B. As a result, the calculated density of the two-phase mixture is reduced in Model A which leads to a lower calculated pressure drop in each section of the well. The absolute percentage deviations (Equation 9) for calculated surface values in Figures 4 and 5 are 17.44 and 6.36, respectively. Therefore, using Model B results in a significant deviation in calculating the pressure values for black oil production wells. Also, the deviation in the temperature results may be important in some cases where accurate calculations are required, such as wells with hydrate formation problems.

$$Dev = \left| \frac{value_{model\ B} - value_{model\ A}}{value_{model\ A} - value_{bottom\ hole}} \right| \times 100 \quad (9)$$

Ideally the denominator in Equation 9 should be the actual pressure drop in the well. However, since the actual value is not known, the pressure drop that has been calculated based on model A (which is assumed to be the more accurate model in this work) is replaced by it. The denominator (pressure drop in the well) is used in the equation to normalise the calculated deviation value.

The pressure and temperature profiles for the second case (volatile oil) are shown in Figures 6 and 7.

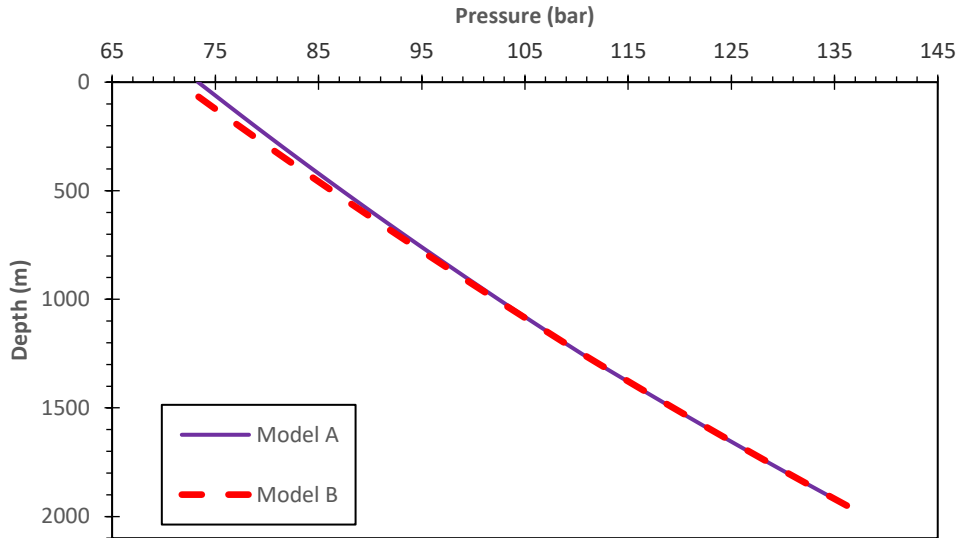


Fig. 6-The calculated pressure profiles based on Model A (incorporating phase change effects) and Model B (excluding phase change effects) for the light fluid case

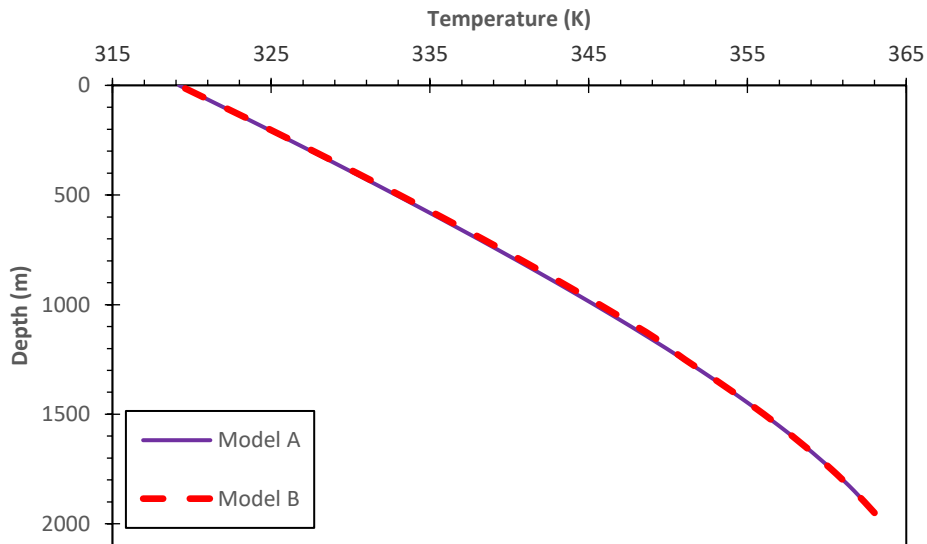


Fig. 7-The calculated temperature profiles based on Model A (incorporating phase change effects) and Model B (excluding phase change effects) for the light fluid case

As in the first case, that of simulating volatile oil production, the calculated pressure drop and temperature values based on Model A are less than those of Model B. However, in this case, the absolute percentage deviations are 3.04 and 0.02 for calculated surface pressure and temperature values, respectively. This implies that Model B has sufficient accuracy in calculating both pressure and temperature profiles for this case.

Based on Figures 4 and 6, there is a higher deviation between the results of the two models for the black oil (heavy fluid) case compared to the volatile oil (light fluid) case. The gas to oil ratio (GOR) is higher for volatile oil compared to black oil. Therefore, there is more gas in the well system when the flowing fluid is volatile oil. Figure 8 shows the calculated values for gas

hold-up along the wellbore for these two fluids. Since there is a little free gas in the deeper parts of the well, for the black oil case, a small amount of vaporization can change the gas hold-up remarkably in this case. However, for the volatile oil case, vaporization does not cause such a significant change in gas hold-up due to the high amount of existing free gas in the well. More changes in gas hold-up values for black oil result in more changes in calculated pressure drop along the wellbore. As a result, neglecting the term of mass transfer between the phases in the material balance equation, does not affect the calculated pressure profile in the volatile oil case as much as the black oil case. Other simulations based on different oil compositions (e.g. heavier oil with less C1 content) also showed the same results.

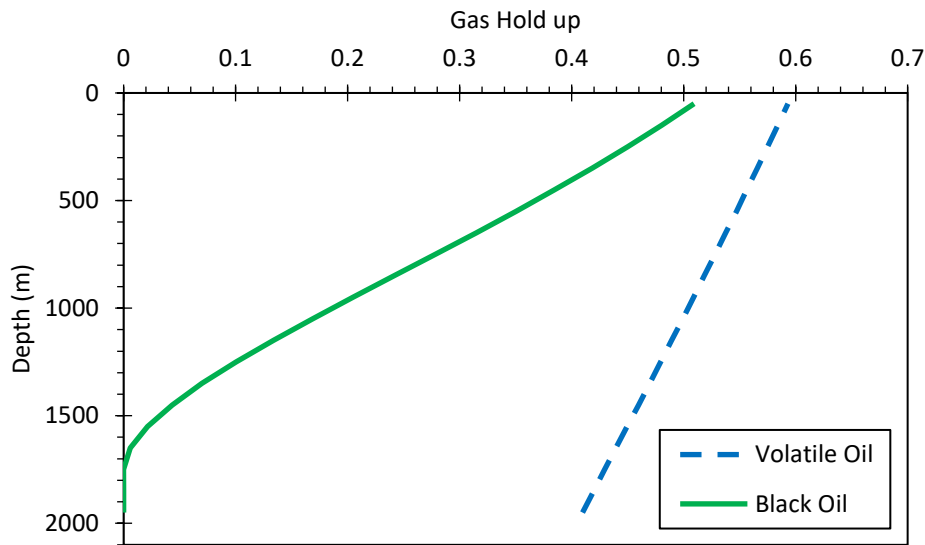


Fig. 8-The calculated gas hold up for the volatile oil and black oil fluids

Based on the same reasoning, it can be concluded that even for volatile oil, if bottom-hole pressure is high enough to be close to the flowing fluid saturation pressure, deviation between the results of the two models may be high. In Figures 9 and 10, the results of simulating volatile oil for a higher bottom-hole pressure are illustrated. The bottom-hole pressure for this case is greater than the volatile oil saturation pressure (394.4 bar at  $T=363$  K) and gas hold-up equals zero in bottom-hole depth. Therefore, when pressure falls below the saturation point, vaporization changes gas hold-up significantly and affects pressure considerably. Consequently neglecting the phase change term in the governing equations is not reasonable for this case. In Figures 9 and 10, the percentage deviations for calculated surface pressure and temperature are 24.20 and 13.97, respectively.



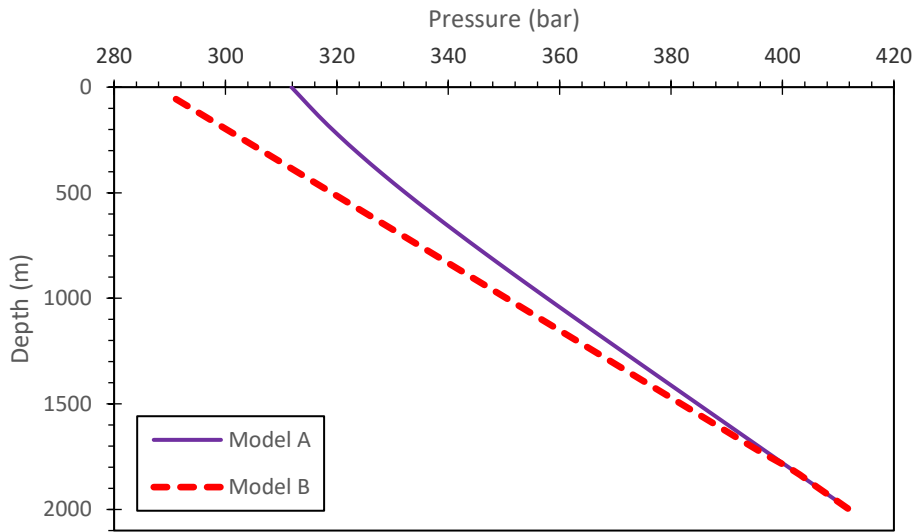


Fig. 9-The calculated pressure profiles based on Model A (incorporating phase change effects) and Model B (excluding phase change effects) for the light fluid case (bottom-hole pressure more than saturation point)

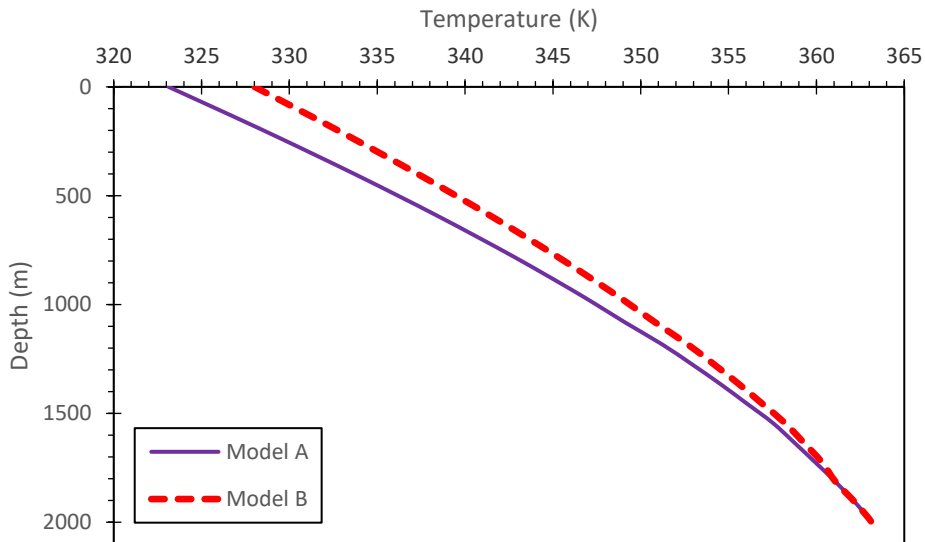


Fig. 10- The calculated temperature profiles based on Model A (incorporating phase change effects) and Model B (excluding phase change effects) for the light fluid case (bottom-hole pressure more than saturation point)

Based on the results of these simulations, it can be concluded that neglecting the mass transfer between phases and the enthalpy of vaporization creates remarkable deviations in calculated pressure and temperature results when the gas hold-up value is small (i.e. close to saturation pressure).

## Gas Lifting Results

Two different cases of gas lift have been simulated using Models A and B, namely the injection of two different types of gas (carbon dioxide and nitrogen) into the well for lifting. The resulting calculated pressure profiles from the simulations have been compared. In the oil and gas industry, the injected gas in gas lifting is normally the separator gas. However, injection of such a gas does not significantly change the phase behavior of the fluid in the well and in many cases it can be simulated using black oil simulators. On the other hand, when the injected gas has a high carbon dioxide or nitrogen content, it can considerably change the phase behavior of the flowing fluid in the well. Therefore, in such cases, using a black oil well simulator can cause a substantial error in the calculated results and to avoid it a compositional simulator is required. It is one reason for choosing these two types of gas for injection in this work. The other reason, which is probably more important, is that simulating nitrogen and carbon dioxide provides the opportunity to validate the simulator against the phase behavior analysis of the fluid in the well due to the completely different nature and phase behavior of the two types of gas.

The two cases of gas lifting were simulated for each model based on the reservoir fluid composition in Table 1 and the values for well parameters in Table 2. The standard injection flow rate for each case equals  $2832 \text{ m}^3/\text{day}$  (0.1 MMSCF/day) and the injection depth is 1150 m. The pressure profiles for injection of each of the two gases in the case of using Model A are shown in Figure 11. The simulation results based on Model A show less pressure drop for the case of nitrogen injection compared to that of carbon dioxide injection. However, for Model B, the pressure profiles show completely different results. As it is shown in Figure 12, employing Model B leads to a lower pressure drop calculation along the wellbore for carbon dioxide injection.

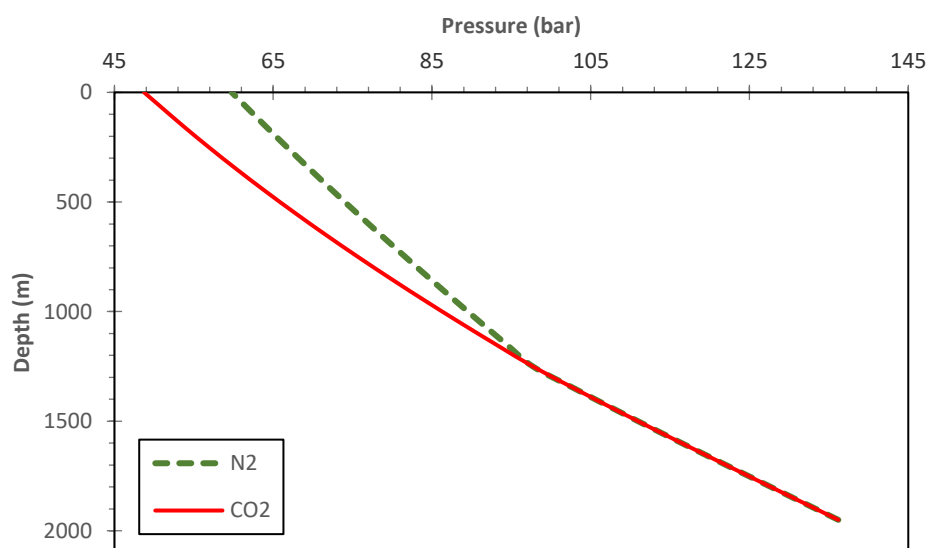


Fig. 11-The calculated pressure profiles based on Model A (incorporating phase change effects) for the nitrogen and carbon dioxide injections

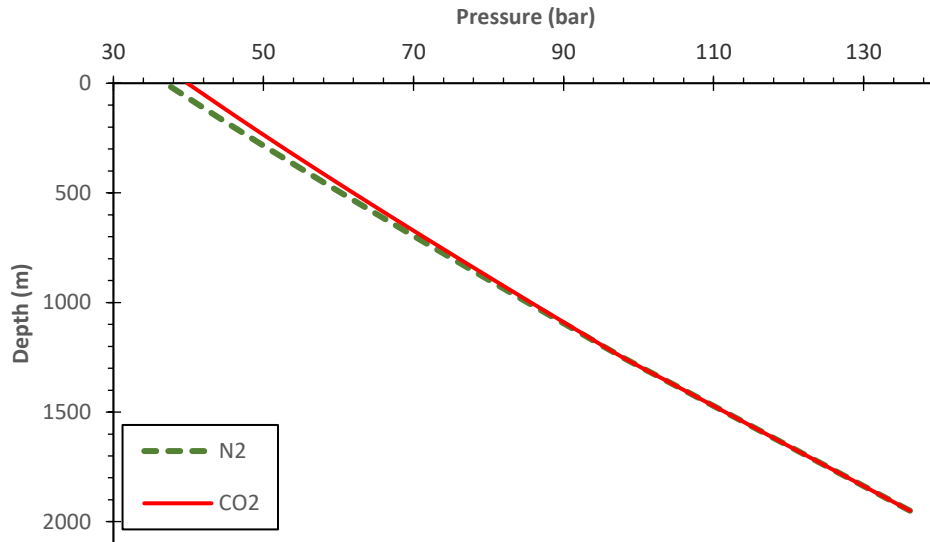


Fig. 12-The calculated pressure profiles based on Model B (neglecting phase change effects) for the nitrogen and carbon dioxide injections

To find out which model results in more accurate predictions, a verification method based on phase behavior analysis of the flowing fluids in the wellbore was employed. The composition of inflow (i.e. reservoir fluid) in all simulated cases is that of Table 1. Since the well system is considered to be in steady state, the composition of fluid flowing along the wellbore remains the same as the inflow, when there is no gas lift. The phase envelope of the reservoir fluid is shown in Figure 13. However, when a gas is injected into the wellbore for gas lifting, it is mixed with reservoir fluid and therefore the composition of the flowing fluid is changed at the injection point. The gas lifting operation is also considered to be in steady state. As a result, the composition of wellbore flowing fluid below the injection point is the same as the composition of the reservoir fluid itself, and the composition of wellbore flowing fluid above the injection point is the same as the composition of the mixture in the injection point. For the same input data used in the simulations (i.e. the same mass flow rates of reservoir fluid and injected gas), the phase envelope of the fluid in the injection point is independent of the model being used. Consequently, for both models, the phase envelopes for the mixture of reservoir fluid and injected gases (i.e. flowing fluid above the injection point) are those in Figures 14 and 15 in the cases of carbon dioxide and nitrogen injection, respectively.

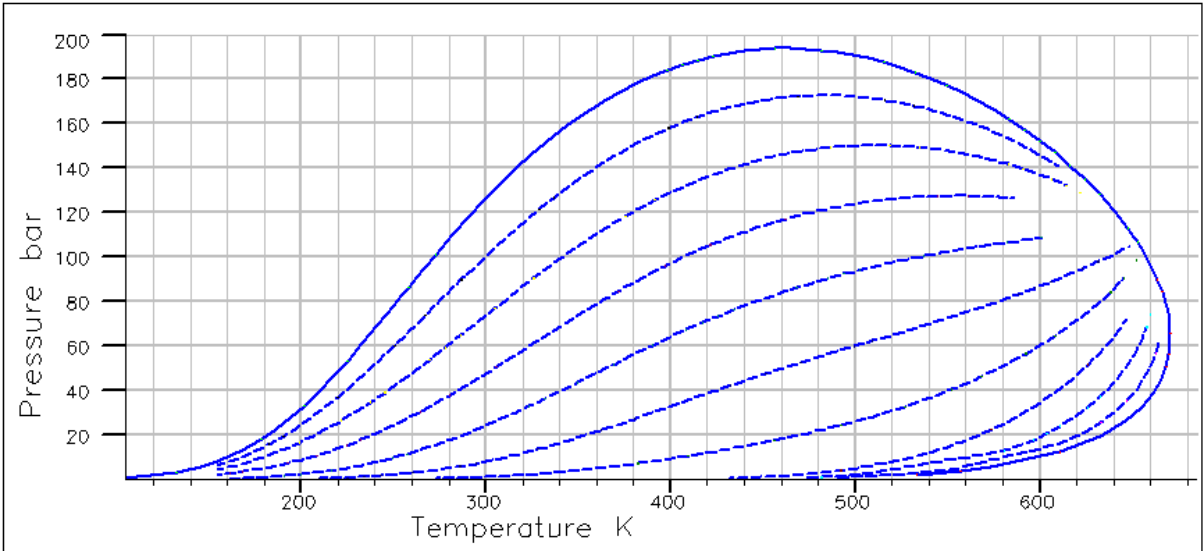


Fig. 13-The phase envelope for the reservoir fluid (the fluid below the injection point)

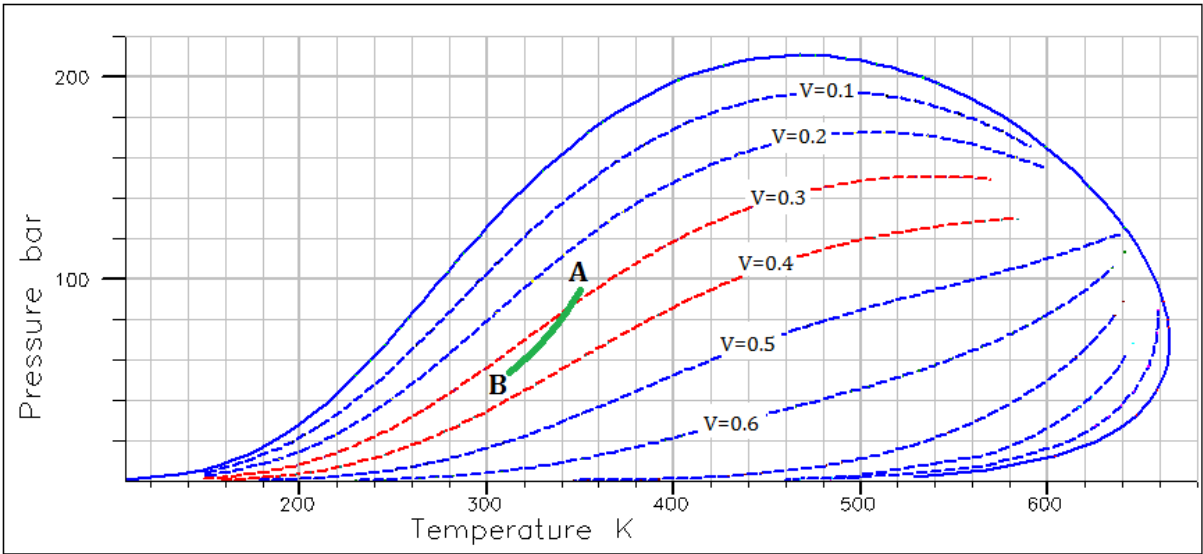


Fig. 14-The phase envelope for the mixture of reservoir fluid and injected carbon dioxide (the fluid above the injection point)

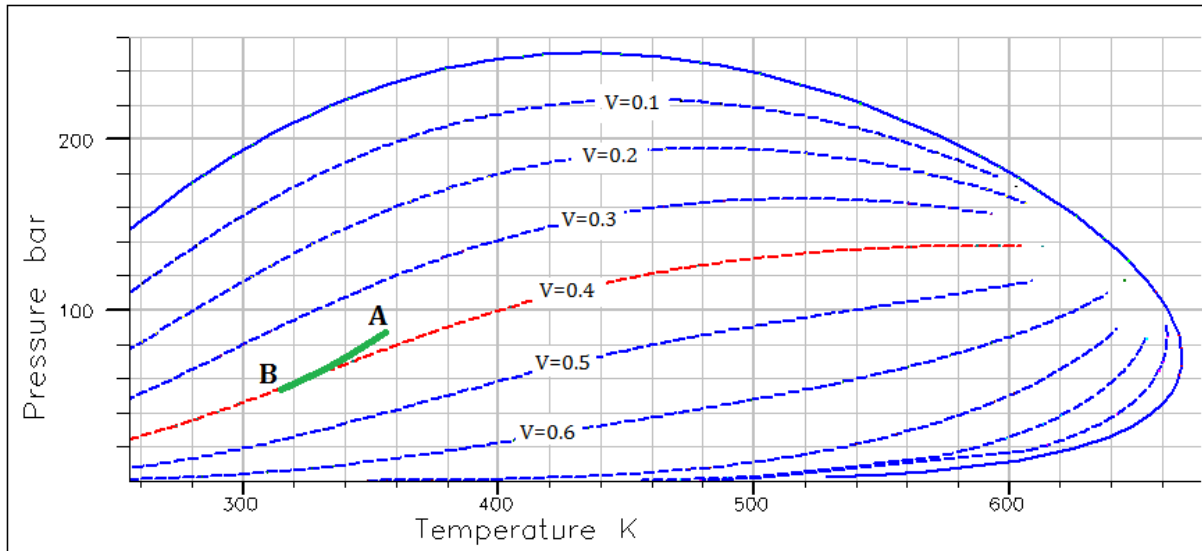


Fig. 15-The phase envelope for the mixture of reservoir fluid and injected nitrogen (the fluid above the injection point)

The dashed lines in Figures 14 and 15 represent the mass fraction of gas in the system. The A-B line also shows pressure and temperature change in the wellbore from the injection point (point A) to the surface (point B). Phase envelopes are completely different for the mentioned fluid mixtures. In the phase envelope for the mixture of nitrogen and reservoir fluid (Figure 15), the A-B line is located almost on the dashed line  $V=0.4$ . This implies that between the injection point and the surface, almost 0.4 of each mole of the well fluid is in the gas phase. However, in the phase envelope for the carbon dioxide-reservoir fluid mixture (Figure 14), the A-B line is located between the dashed lines which represents gas fractions of  $V=0.3$  and  $V=0.4$ . Therefore the gas fraction in each point of the well for this mixture is less than the gas fraction in the same point of the well as for the nitrogen-reservoir fluid mixture. As a result, when nitrogen is injected into the well, the phase envelope of the flowing fluid is changed so that there is more free gas in the system compared to carbon dioxide injection. Accordingly, when nitrogen is used as an injected gas, in comparison to carbon dioxide, a higher fraction of the well system is occupied by the gas phase, the liquid hold up is reduced and the weight of the fluid column in the well is lessened. Therefore when injecting nitrogen, the pressure drop along the wellbore is less than for injecting equal standard volume of carbon dioxide. Based on this phase behavior analysis, it is concluded that the results of Model A (i.e. proposed model in this study) are more reliable than Model B for the compositional simulation of gas lifting.

The slope of the A-B line in the phase behavior diagram for the carbon dioxide-reservoir fluid mixture is more than the slope of this line in the nitrogen-reservoir fluid phase envelope. Consequently, in the phase envelope for the carbon dioxide-reservoir fluid, more gas fraction lines are crossed by the A-B line compared to nitrogen-reservoir fluid. In other words, when carbon dioxide is injected in the well, the rate of vaporization between the injection point and the surface is higher than that of nitrogen injection. However, as mentioned previously, at the injection point there is more free gas in the system when nitrogen is injected. Based on this phase behavior analysis, it is concluded that by injecting gas into the well, the volumetric flow rate of free gas in the injection point increases more for nitrogen compared to carbon dioxide. However due to the greater slope of the A-B line for the carbon dioxide-reservoir fluid, the gradient of the increasing the volumetric flow rate of free gas against depth between the injection point and

surface is more for the well in which carbon dioxide is injected. These phase behavior analyses completely validate the results of the proposed model. In Figure 16, the profiles of the superficial velocity along the well are compared for the injection of carbon dioxide and nitrogen. The standard volumetric rates of injection are equal for both cases. Both profiles from well bottom hole to injection point are almost the same. In the injection point, the superficial velocity of gas for nitrogen injection is more than for carbon dioxide injection. The increased superficial velocity of the gas is simply a result of there being more free gas in the system. Therefore, the results obtained based on the proposed model agree with the results of the phase behavior analysis. Also, as shown in Figure 16, the superficial velocity for the carbon dioxide injection, increases with a greater gradient above the injection point compared to the nitrogen injection case. As it was discussed previously, this result is also validated by phase behavior analysis and as a consequence, the proposed model is also verified against phase behavior analysis.

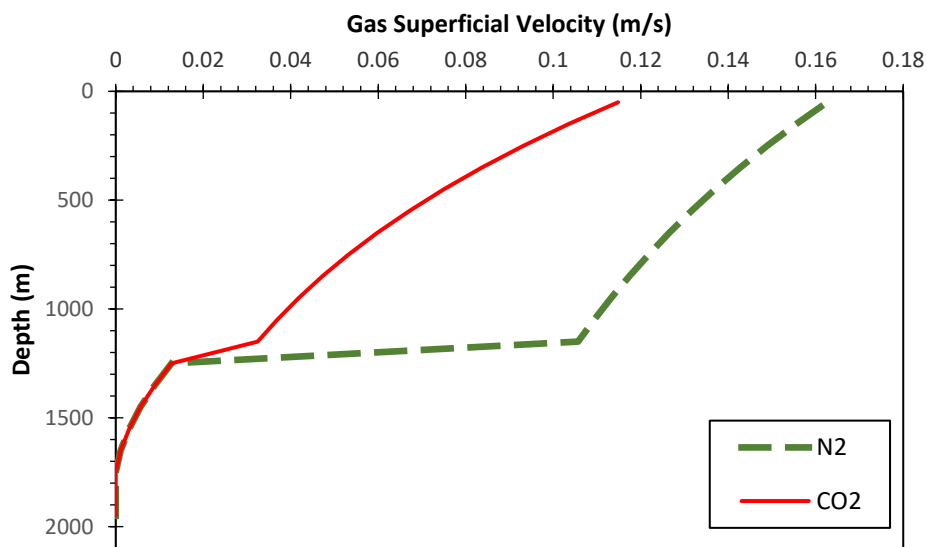


Fig. 16-The profiles of the superficial velocity along the well for the injection of carbon dioxide and nitrogen

## Conclusion

A compositional wellbore simulator with the ability of simulating gas lift was developed. This new simulator benefits from incorporating two terms for mass transfer between phases and the enthalpy of vaporization into its governing equations. These terms were neglected in some earlier compositional simulators presented in the literature. To investigate the effects of adding these terms to the governing equations, the results were compared with the results of three well-known simulators. Also two different production scenarios were simulated to show that neglecting the mentioned terms could potentially cause significant errors in the calculated pressure and temperature profiles along the wellbore in some cases. The results show that, although neglecting these terms does not cause considerable errors in the calculated results in wellbores with high gas hold-ups, it causes significant errors in calculating pressure and temperature profiles when the producing fluid pressure is close to its saturation point. In this case, gas hold-up values are small. It was also depicted that the added terms have a considerable effect on the calculated pressure results of compositional simulation of gas lifting. The results of the presented simulator have been analyzed based on realistic wellbore flowing fluid phase behavior. This analysis completely supports and verifies the results of the new simulator.

## Nomenclature

A	Wellbore area, $m^2$
$C_p$	Specific heat capacity in constant pressure, $kJ/(kg \cdot K)$
Dev	Absolute percentage deviation
f	Void fraction
g	Gravitational acceleration, $m/s^2$
$H_l$	Liquid hold up
$h^{lv}$	Enthalpy of vaporization, $kJ$
$m'$	Mass flow rate between well and reservoir, $kg/(m \cdot s)$
$m''$	Mass flow rate of injected gas in gas lifting, $kg/(m \cdot s)$
n	Number of calculated values
$n_c$	Number of components in well fluid
$n_p$	Number of phases
$n''_c$	Number of components in the injected gas
P	Pressure, Pa
$Q_{loss}$	Heat loss, $kJ/(m \cdot s)$
T	Temperature, K
V	Mass fraction of gas in system
$V''$	Velocity of injected gas in the injection point, $m/s$
v	Velocity, $m/s$
x	Molar fraction in liquid phase
y	Molar fraction in gas phase
z	Depth, $m$

### Greek Symbols

$\theta$	Wellbore angle, <i>radians</i>
$\rho$	Density, $kg/m^3$
$\rho''$	Density of injected gas in the injection point, $kg/m^3$
$\psi$	Rate of mass transfer from liquid to vapor phase, $kg/(m \cdot s)$

### Subscripts

d	Drift
g	Gas
i	Component
j	Phase
l	Liquid
m	Mixture
s	Superficial

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