Journal of Petroleum Science and Engineering 163 (2018) 199–210

Contents lists available at ScienceDirect

Journal of Petroleum Science and Engineering

journal homepage: www.elsevier.com/locate/petrol

# Flow simulation of the mixture system of supercritical $CO_2$ & superheated steam in toe-point injection horizontal wellbores

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A R T I C L E I N F O

*Keywords:*
Toe-point injection
Horizontal wellbore
Supercritical $CO_2$
Superheated steam
Inner heat exchange
Friction loss
Energy balance

A B S T R A C T

Conventional heavy oil recovery method of saturated steam injection at heel-point of horizontal wellbores is facing comparatively more serious fingering phenomenon. With this, oil companies are now actively developing new recovery method of supercritical $CO_2$ - superheated steam injection in horizontal wellbores with toe-point injection technique.

Firstly, considering the heat exchange between the inner tubing (IT) and annuli, a pipe flow model comprised of energy and momentum conservation equations is developed for the mixture flow in both IT and annuli. Then, coupled with the S-R-K real gas model, variable mass flow model and transient heat transfer model in oil layer, a comprehensive mathematical model is established. Numerical solutions of the mixture flow in toe-point injection wellbores are obtained through straight forward numerical method. Finally, model validation and sensitivity analysis are conducted.

The results show that: (1). there exists a good agreement between predicted results and field data. The predicted temperature is higher when the heat exchange between IT and annuli is neglected. The predicted temperature is lower when the friction loss item is considered in the energy balance equation. (2). the temperature of the mixture increases when the mixture flows from toe-point to heel-point in annuli due to heat flow from IT to annuli. (3). While the absorption rate of the mixture in formation increases with increasing of the content of supercritical $CO_2$, it can be offset by the decrease of temperature and enthalpy of the mixture. (4). Both of the mixture temperature and formation mixture absorption rate increase with increasing of injection pressure.

## 1. Industrial background of usage of $CO_2$ for heavy oil recovery

As climate changes, the impact of carbon dioxide on the greenhouse effect has attracted wide attention (Jacobson, 2009; Li et al., 2017). However, carbon dioxide storage is a huge cost. Therefore, how to make rational use of carbon dioxide is a widely discussed problem in the industry (Wang et al., 2012; Boot-Handford et al., 2014). Carbon capture and sequestration has been proved to be effective methods in $CO_2$ reduction (Chen et al., 2015, 2016; Li et al., 2017). In oil & gas development industry, $CO_2$ injection has been proved effective in EOR (enhanced oil recovery) as well as artificial fracturing, which brings economic benefits to the industry (Dai et al., 2013; Middleton et al., 2015).

When it comes to $CO_2$ assisted steam injection for heavy oil recovery, huge amount of experiments were carried out by scholars to reveal the oil displacement mechanisms of $CO_2$ ($CO_2$ – steam mixture) in heavy oil recovery. When the $CO_2$ was dissolved in heavy oil, the volume of heavy oil will increase accordingly. As a result, the viscosity of heavy oil decreases and the fluidity increases (Welker et al., 1963; Simon, 1965; Chung et al., 1988; Li, 2015). Besides, $CO_2$ can extract light components from heavy oil and then form the rich gas phase. Therefore, the interfacial tension between the $CO_2$ and heavy oil becomes smaller and the oil recovery ratio is improved (Zheng et al., 2013; Zhang et al., 2014; Seyyedsar et al., 2016; Wang et al., 2017b; Rostami et al., 2017). Therefore, $CO_2$ is always selected as an auxiliary additive for thermal injection for heavy oil recovery (Li et al., 2011; Wang et al., 2017a).

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https://doi.org/10.1016/j.petrol.2017.12.085
Received 8 July 2017; Received in revised form 29 December 2017; Accepted 29 December 2017
Available online 3 January 2018
0920-4105/

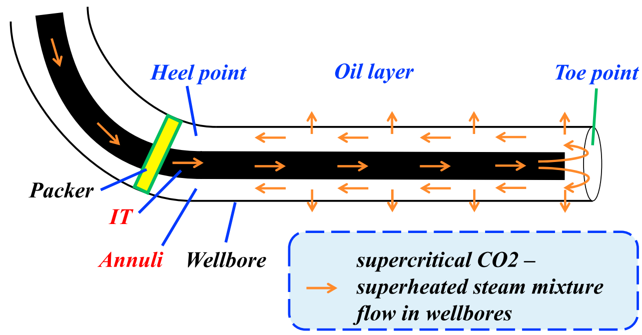


**Fig. 1.** A schematic of supercritical $CO_2$ - superheated steam mixture flow in IT and annuli.

Huge amount of experimental and numerical researches were carried out in $CO_2$ assisted steam injection for heavy oil recovery. Sohrabi et al. (2007) compared the displacement efficiency of $CO_2$ injection, water injection and $CO_2$–water alternating injection with numerical method. They found that compared with $CO_2$ injection or water injection, $CO_2$–water alternating injection can increase the oil recovery ratio by 30%. Tao et al. (2009) studied the oil displacement mechanism of cyclic $CO_2$–steam stimulation and found out that the viscosity of super heavy oil was very sensitive to the change of temperature. Besides, after the injection of $CO_2$, the volume of super heavy oil expands and the elastic energy increases. Ouyang and Du (2010) studied the interaction mechanism of $CO_2$ and heavy oil. They found out that the viscosity of heavy oil decreased greatly after $CO_2$ dissolved and the greater the pressure, the greater the drop in viscosity. Li et al. (2013) studied the mechanism of viscosity reducing by $CO_2$ injection and the effect of viscosity reduction. They found out that when the solubility of $CO_2$ is up to $55\ m^3/m^3$, the viscosity reduction rate is over 95%.

## 2. Literature review

When it is come to thermal recovery of heavy oil reservoirs, saturated steam is always selected as the thermal carrier (Sun et al., 2017a). In recent years, the mixture of supercritical $CO_2$ - superheated steam system is proved effective in heavy oil recovery (Sun et al., 2018a). However, there is a lack in mathematical model for simulating supercritical $CO_2$ - superheated steam mixture flow in horizontal wellbores with toe-point injection method.

Ramey (1962) established a model for describing saturated steam flow in conventional vertical wellbores, which laid the foundation for wellbore modeling. Focusing of the heat loss rate form thermal fluid in wellbores to the surrounding formation, Holst and Flock (1966) proposed a steady-state heat conduction model for estimation of heat loss rate. Later, Willhite (1967) developed a comprehensive model for estimating the heat loss rate by proposing a formula for overall heat transfer coefficient calculation. For the convenience of programming, Ejiogu and Fiori (1987) and Tortike and Farouq (1989) fitted the thermal physical parameters of the saturated steam and proposed empirical formulas. Later, Sagar et al. (1991) proposed an improved model for temperature estimation of saturated steam along the entire vertical wellbores. Alves et al. (1992) proposed a model that revealed the relationship between steam pressure and enthalpy based on the C-B equation. However, these models failed to take the vertical heat conduction into consideration. Therefore, Bahonar et al. (2010, 2011) proposed a heat transfer model in which the effect of vertical heat conduction on overall heat loss was discussed. Focusing on the two-phase flow of saturated steam in wellbores, Satter (1965) presented a model for estimating steam quality along the vertical wellbores. However, in their model, the kinetic energy change along the wellbores was neglected. Considering the effect of friction loss on fluid temperature, Pacheco and Farouq (1972) proposed a model for estimating steam temperature along the wellbores. Focusing on both downward and upward flow, Farouq (1981) proposed a comprehensive model for estimating steam pressure along the vertical wellbores. By adopting the superposition method, Durrant and Thambynayagam (1986) proposed a model for estimating the transient thermal conductivity of wellbores. Then, Livescu et al. (2010a, 2010b) developed an improved model for predicting steam pressure with semi-analytical method. Hasan et al. (1991, 1992, 1994, 1995, 2007a, 2007b, 2007c, 2009, 2010) did a series of studies on the heat conduction rate from thermal fluid to formation and the heat loss rate in the formation, which laid a foundation for calculation of heat loss rate (Cheng et al., 2011, 2012, 2013, 2014). However, these previous studies were focused on the conventional saturated steam flow in wellbores. The pressure of saturated steam is a function of its temperature. Therefore, heat loss only has an influence on steam quality. When it comes to supercritical/superheated fluid, heat loss can directly influence fluid temperature, which is beyond the capacity of previous models.

Zhou et al. (2010) proposed a numerical model for simulating superheated steam flow in vertical wellbores. However, their model showed limitation in precisely estimating temperature of superheated steam when the injection rate is large enough. Xu et al. (2013a, 2013b) proposed an improved model considering the effect of superheated steam on EOR. Fan et al. (2016) proposed a model for simulating superheated steam flow in the vertical and horizontal section of the wellbores. However, these models also showed limitation in precisely estimating temperature of superheated steam when the injection rate is large enough. Sun et al. (2017b, 2017c, 2017d, 2017e, 2017f, 2017g, 2017h, 2018b) did a series of works on superheated fluid flow in onshore or offshore vertical wellbores (single-tubing or dual-tubing). The calculation precision under high injection rate was improved in their models by re-establishing the energy balance equations.

Dong et al. (2014) and Gu et al. (2015) proposed models for simulating superheated fluid in the horizontal wellbores. However, their models cannot be used to analyze the effect of higher temperature fluid flow in IT on the profiles of thermophysical properties of superheated fluid in annuli. Dong et al. (2016) proposed a model for superheated multi-component thermal fluid flow in horizontal wellbores with toe-point injection technique. However, the heat exchange between IT and annuli inside the wellbores was neglected in their model. Beside, also showed limitation in precisely estimating temperature of superheated fluid when the injection rate is large enough (Sun et al., 2017i, 2018c). Sun et al. proposed a numerical model for simulating single-component of superheated steam flow in toe-point injection horizontal wellbores. However, their model cannot be used to analyze the effect of supercritical $CO_2$ on superheated steam flow in IT and annuli.

This paper has mainly three contributions to the existing body of literature: (1). New energy balance equations are developed for supercritical $CO_2$ - superheated steam mixture flow in IT and annuli. (2). Heat exchange between the IT and annuli is taken into consideration. (3). Effect of the supercritical $CO_2$ is studied in detail.

## 3. Model description

### 3.1. General assumptions

A schematic of supercritical $CO_2$ - superheated steam mixture flow in the horizontal wellbores with toe-point injection technique is shown in Fig. 1. Some basic assumptions are given below (Gu et al., 2015; Dong et al., 2014, 2016; Sun et al., 2017i, 2018c):

(1). The injection parameters of supercritical $CO_2$ - superheated steam mixture at heel-point of the wellbores is constant.
(2). Heat loss rate of annuli is steady-state, while the heat flow rate in oil layer is transient state.
(3). Heat transfer in the horizontal direction is ignored.