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Effects of salinity and slug size in miscible CO_2 water-alternating-gas core flooding experiments

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ABSTRACT

This experimental study focuses on the variation of the salinity and the injected volume of individual WAG miscible flooding scheme for the improvement of oil recovery. In total, three slug sizes and five salinities were investigated in WAG flooding cycles and the recovered oil was measured accordingly. A response surface function was introduced for the purposes of estimating the available design and finally optimizing the variables. The experimental results indicated the unstable performances of oil recovery to the variations in the design parameters, confirmed the dependence of the oil production on a nonlinear function of the salinity and injected volume.

Introduction

The division of an oil production project into three stages has been approved and is commonly carried out in most oil fields; these processes leave a large amount of oil in the reservoirs after the primary and secondary stages, especially when the crude oil is not the light-oil type. Thereby, the methods for recovering the remaining oil in the tertiary stage need to be prudently considered since they depend on a large number of factors such as the reservoir conditions, well operating conditions, or economic feasibility. Among highly technical methods, thermal conduction, chemical flooding, and gas injection are the most widely applied with the purpose of effectively mobilizing the trapped oil from the pores to the production well. Thermal methods are utilized most appropriately in heavy-oil reservoirs, whereas chemical flooding can be deployed in either light or heavy oil reservoirs [1,2]. Nevertheless, chemical adsorption, a slow response in the producer when injecting a viscous polymer solution, environmental concerns, and the uncertainty in the economic feasibility are restrictions for employing chemical flooding in enhanced oil recovery (EOR) projects [3]. The employment of CO_2 in the oil fields has been demonstrated as an efficient measure to partly compensate for the decrease in the pressure in the reservoir during oil production and enhances the oil recovery as a consequence of reducing the residual oil saturation [4]. In terms of the environment, the use of CO_2 from anthropogenic sources for injection underground, where CO_2 can be stored permanently, will significantly reduce global greenhouse-gas effects; therefore, combined CO_2-EOR promises a highly attractive profit from investment [5,6,7]. Indeed, the most recent practical report of the Farnsworth field for history performance and anticipation has demonstrated the substantial benefits of applying CO_2-EOR in both enhancing oil production and CO_2 storage, with the possibility of recovering over 30% original oil in place and sequestering more than 75% anthropogenic carbon underground [8,9]. Among the major uses of CO_2 for enhancing oil recovery such as CO_2 huff-n-puff, continuous CO_2 injection, and WAG, the use of multicycle injection for water and supercritical CO_2 seems to be employed more popularly and efficiently owing to the ability to control the fluid mobility to the proper value [10,11]. During the WAG process in suitable reservoirs where the crude oil contains a sufficient amount of light hydrocarbon components, the occurrence of compositional exchange between the gas and the oil will result in swelling of the oil and a reduction in the oil viscosity; thus, the oil becomes moveable [12,13,14]. Further, the use of water after the injection of each designed volume of CO_2 aims to mitigate the mobility of the displacing fluid, even though viscous fingering is unavoidable during the process. Depending on the reservoir pressure and crude-oil properties, the gas EOR method can be subcategorized as immiscible and miscible flooding; generally, the miscible process is more efficient because it results in greater improvements in both microscopic and macroscopic displacement than immiscible flooding [15,16,17]. Theoretically, miscibility is only achieved when the domain pressure is equal to or higher than

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minimum miscibility pressure (MMP), or it can be defined as the point at which the practical maximum recovery efficiency is observed [18]. As in He et al., the MMP is the most important criterion in screening procedures for CO_2-EOR for determining whether the reservoir pressure is adequate for developing miscible flooding [19]. Another concern of the WAG process is the loss of CO_2 in the aqueous phase, or more precisely, the injected gas is partly dissolved in water [20]. Chang et al. have concluded that the solubility of CO_2 in water is much higher than that of the hydrocarbon components and should not be neglected during investigation [21]. They also confirmed the dependence of the CO_2 solubility in water on temperature, pressure, and salinity. Following their results, increases in these variables decrease the solubility of CO_2 in the injected brine [22]. In the work of Tadesse et al., the injection of low-salinity water after seawater flooding significantly produced additional oil, and the following CO_2 injection possibly further improves the recovery [23]. Furthermore, the mathematical studies of Jalal et al. argued that when carbonated water contacted the crude oil during the EOR processes, CO_2 would migrate from the water into the oil phase, as it has higher solubility in hydrocarbons, thereby improving the oil mobility in the reservoir [24].

Regarding prediction methods, the gravity-enhanced process suggested by Liwei et al. has successfully estimated oil recovery and CO_2 storage capacity by response surface models (RSMs) from scaling group development [25]. They also pointed out the predominant use of Latin hypercube sampling (LHS) for obtaining reliable estimates rather than the Box–Behnken method. In addition, the work of Feng et al. demonstrated the application of an RSM integrated with Monte–Carlo simulations for optimization and its utilization for an uncertainty analysis within an acceptable range [26]. Since this mathematical tool has been successfully derived for assessment and estimation, presumably it can be developed in a more complicated framework to assist the economic assessment in clearly understanding the impact of reservoir uncertainty in both oil recovery and effective carbon sequestration [27].

Even though the gas solubility has been investigated by numerical simulation in previous studies, there is still a lack of knowledge about the effects of the salinity on the other design parameters and oil-production performance. This work focuses on the impacts of the water salinity in WAG processes for the alternation of an injected slug size in experimental core-flood processes. The WAG ratio of 1:1 is fixed; thus, the water slug size is equal to that of the CO_2 for all injection cycles initialized by water injection. A viscous oil sample is used for the experiment, and the pressure in the tests will be maintained at a higher value than the MMP after it has been determined by the slim-tube method, thereby maintaining the miscible condition during the tests. For the purposes of compensating for the lack of experimental data and optimization by computation, this work proposes the application of the response surface methodology to each of the specific available recorded data sets. Presumably, the combination of experimental testing and a mathematical tool will significantly decrease the time, costs, and materials while obtaining highly reliable results before application to real fields.

Experimental procedure

Minimum miscibility pressure determination

Currently, there are many possible methods for determining the MMP, including the use of a rising bubble apparatus, interfacial tension, or the slim tube and mathematical methods using empirical calculations or simulation programs based on the available components of oil samples. Because of the lack of oil composition information, this study employs a slim-tube apparatus for simply measuring the MMP, which is also practically used in the oil industry. Fig. 1 shows a schematic of the Inha slim-tube apparatus (INST) used for the MMP measurement, which was constructed by winding a long steel tubing with a diameter of 0.457 cm and a length of 18.5 m in the form of a spring. Uniform-size glass beads or sand can be used as a filler inside the steel tubing. In the MMP measurement experiment, a 60–70 mesh filler was used, which is within the range obtained from literature research [28,29]. After filling the inside of the steel tubing with glass beads, the porosity and permeability were measured. The measured values are listed in Table 1.

The oil sample used in the experiments is Van Gogh (VGH) crude oil with a viscosity of 355.5 cP at 71 °C, as detailed in Table 2. Geographically, the Van Gogh oil field is located 53 km north of Exmouth, Western Australia. The reservoirs of this field virtually belong to Upper Triassic, Jurassic and Lower Cretaceous sandstones beneath the Lower Cretaceous seal. It is possible that the oil sample used in this work might fall out of range of the screening criteria of oil properties, where crude oils have gravity greater than 18 °API and viscosity less than 10 cp (reservoir condition), to achieve miscible gas flooding, whereas the oil can be feasibly recovered under the immiscible scheme when its gravity is higher than 12 °API and viscosity is lower than 600 cp [15]. However, since some practical heavy oil field testing has demonstrated the feasibility of achieving the partially miscible gas injection process [30], in particular there is always a big gap between laboratory tests and field applications in terms of controlling the flooding scheme. The utilized samples and procedures of carrying out experiments in this work can also result in well validated conclusions and reliable references for other CO_2 injection projects.

Before measuring the MMP, the inside of the steel tubing was cleaned and dried before the injection of oil to obtain accurate experimental results. The properties of the oil used in the MMP measurement experiment are listed in Table 2. After saturating the steel tubing with oil, CO_2 was injected at the designated pressures. The injection pressures were 3.45, 6.89, 10.34, 13.79, 15.86, and 17.93 MPa, and the MMP was measured at 70 °C, which is the same temperature as that used in the core experiment. The CO_2 injection rate was maintained at a constant value of 0.2 ml/min while measuring the MMP. Although the measurement experiments using a slim tube have the disadvantage of requiring a relatively longer time compared to other methods, it is the simplest experiment for determining the phase behavior effects of CO_2 and the oil.

MMP measurement experiments were carried out to measure the pressure at the point where the oil recovery factor is 80% or

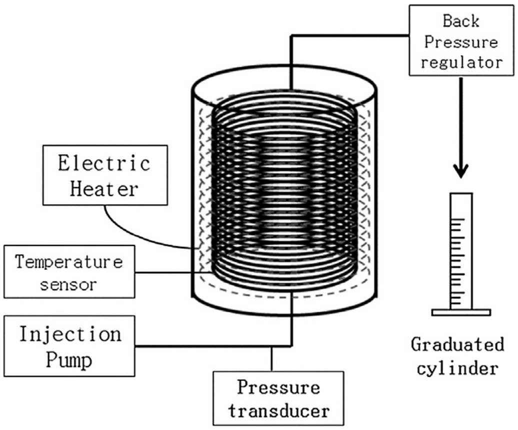

Fig. 1. Schematic of the Inha slim-tube apparatus (INST).

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