Chapter 12

A Review on the Application of Enhanced Oil/Gas Recovery through CO_2 Sequestration

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Abstract

Global warming is considered as one of very important problems in the last few years. This phenomenon is caused primarily by increase in greenhouse gases such as carbon dioxide (CO_2). Natural events and human activities are believed to be the principal sources of this problem. A promising long-term solution for mitigating global heating is to inject CO_2 into oil field geological formations for combination between CO_2 sequestration and enhanced oil recovery. This chapter aims to give an extensive literature survey and examines research papers that focus on EOR-CO_2 processes and projects that have been tested in the field.

Keywords: CO_2 sequestration, EOR, global warming, energy

1. Introduction

The growing concern over the climate change caused by global warming due to a high emission of greenhouse gases (essentially carbon dioxide (CO_2)) has increased the interest in finding various techniques to resolve this problem. The injection of this gas for enhanced oil recovery has been tested with full success in several fields over the world.

Traditionally, oil recovery operations have been subdivided into three stages: primary, secondary, and tertiary as shown in **Figure 1**. Historically, these stages described the production from a reservoir in a chronological sense. Primary production, the initial production stage,

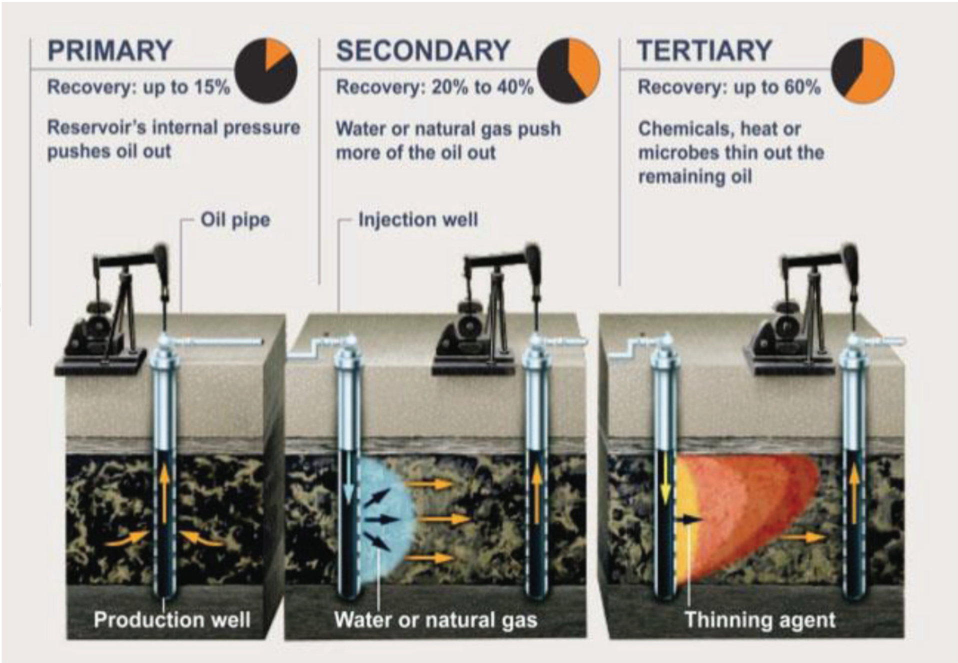

Figure 1. Oil recovery stages [1].

resulted from the displacement energy naturally existing in a reservoir; the driving energy may be derived from the expansion of the gas cap or an active aquifer, from the liberation and expansion of dissolved gas, from gravity drainage, or from a combination of all these mechanisms. Secondary recovery, the second stage of operations, usually was implemented after primary recovery declined. Traditional secondary production processes are gas injection, water flooding, or water alternative gas injection (WAG). Tertiary recovery or enhanced oil recovery (EOR) is a term used to describe a set of processes intended to increase the production of oil beyond what could normally be extracted when using conventional oil production techniques, while traditional oil production (primary and secondary stage) can recover up to 35–45% of the original oil in place (OOIP). The application of an EOR technique is typically performed toward what is normally perceived to be the end of the life of an oil field, and tertiary production used miscible gases (e.g., CH_4, CO_2), chemicals, and/or thermal energy to displace additional oil (5–15%).

2. Carbon dioxide properties

Carbon dioxide is formed from the combination of two elements: carbon and oxygen. It is produced from the combustion of coal or hydrocarbons. CO_2 is a colorless, odorless, and non-toxic stable compound found in a gaseous state at standard conditions. In petroleum engineering application, it can be in a gas or a liquid state depending on the PVT conditions. **Table 1** gives the main properties of carbon dioxide. The phase diagram (**Figure 2**) of CO_2 is

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Property	Value
Molecular weight	44 g/mol
Critical temperature	31°C
Critical pressure	73.77 bar
Critical density	467.6 kg/m^3
Triple point temperature	−56.5°C
Triple point pressure	5.18 bar
Boiling (sublimation) point (1.013 bar)	−78.5°C
Critical Z factor	0.274
Solid phase	
Density of carbon dioxide snow at freezing point	1562 kg/m^3
Latent heat of vaporization (1.013 bar at sublimation point)	571.1 kJ/kg^1
Liquid phase	
Vapor pressure (at 20°C)	58.5 bar
Liquid density (at −20°C and 19.7 bar)	1032 kg/m^3
Viscosity (at STP)	99 μPa s
Characteristics of CO_2 gas phase	
Gas density	2.814 kg/m^3
Gas density (according to STP)	1.976 kg/m^3
Specific volume (according to STP)	0.506 m^3/kg
C_p (according to STP)	0.0364 kJ/(mol K)
C_v (according to STP)	0.0278 kJ/(mol K)
C_p/C_v	1.308
Viscosity (according to STP)	13.72 μPa s
Thermal conductivity (according to STP)	14.65 mW/(m K)
Enthalpy (according to STP)	21.34 kJ/mol
Entropy (according to STP)	117.2 J mol/K

Note: STP stands for standard temperature and pressure, which are 0°C and 1.013 bar.

Table 1. Carbon dioxide properties [3].

also a key data since we can inject it under different temperature and pressure conditions. The three phases are shown in this diagram, with the triple and critical point. Above the critical point, the CO_2 is considered as a supercritical fluid.

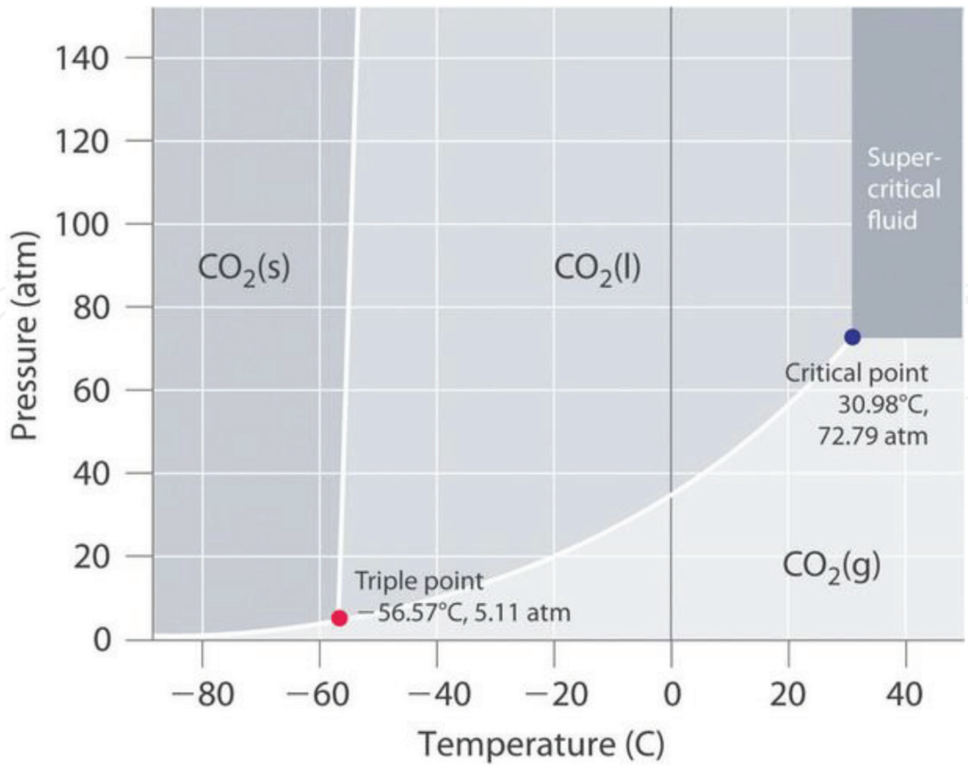

Figure 2. CO_2 phase diagram [2].

3. Carbon capture and storage

Carbon dioxide is the most important greenhouse gas, because it is emitted into the atmosphere in large quantities [4]. Carbon capture and storage (CCS) has been recognized as a new project around the world that should help mitigate CO_2 emissions significantly. The idea behind CCS is simple and can be divided into three steps: capture of CO_2 (e.g., from a fossil fuel power plant), transportation of the captured CO_2, and permanent storage into different geological formations (e.g., saline aquifer and oil and reservoirs), with the aim of isolating CO_2 from the atmosphere [5] (**Figure 3**).

Several scenarios describing the emission of greenhouse gases and models for the estimation of their influence on the global climate have been examined by the members of several association interests by this subject like the Intergovernmental Panel on Climate Change (IPCC) and the International Energy Agency (IEA). Based on the assumptions of IPCC, the climate model global temperature increases between 1 and 6°C were predicted by the year 2100, while some regions might benefit from higher temperatures [6]. The IEA Agency estimates that CCS projects should contribute to about 15–20% of the total greenhouse gas emissions mitigation by 2050, and without the application of CCS, the overall costs to halve CO_2 emissions by 2050 would rise by 70% [5]. It has been estimated that geological formations worldwide are able to store more than 10,000 Gt of carbon dioxide; this huge quantity is large compared to the cumulated anthropic emissions of carbon dioxide [3].

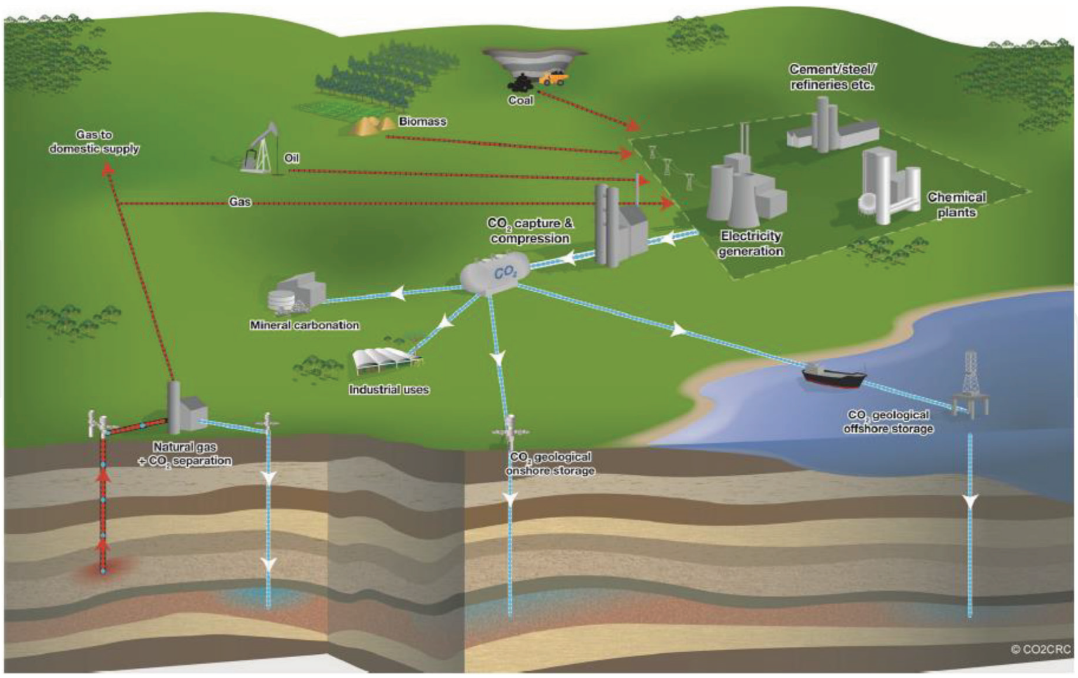

Figure 3. A schematic diagrams of possible CCS projects [5].

4. EOR methods

Many EOR methods have been used in the past, with varying degrees of success, for the recovery of light and heavy oils, as well as tar sands. There are two main categories of EOR: thermal and non-thermal methods (include gas and chemical methods). Each main category includes some individual processes [7].

Thermal methods are primarily intended for heavy oils and tar sands; these methods recover the oil by introducing heat into the reservoir. Thermal method is based on a set of displacement mechanisms to enhance oil recovery. The most important mechanism is the reduction of crude oil viscosity with increasing temperature [8]. However, the viscosity reduction is less for lighter crude oil. Therefore, thermal methods have had limited success in the field of light crudes.

Non-thermal methods (gas and chemical methods) are normally used for light oils <100 cp. In a few cases, they are applicable to heavy oils <2000 cp, which are unsuitable for thermal methods.

Gas methods, particularly carbon dioxide (CO_2), recover the oil mainly by injecting gas into the reservoir. Gas methods sometimes are called miscible process or solvent methods. The reservoir geology and fluid properties determine the suitability of a process for a given reservoir. Currently, gas methods account for most EOR production and are very successful especially for the reservoirs with low permeability, high pressure, and lighter oil [9].

Vapor extraction (VAPEX) is among the gas methods (**Figures 4** and **5**). It is a promising technique for the recovery of heavy oils and bitumen in reservoirs where thermal methods,

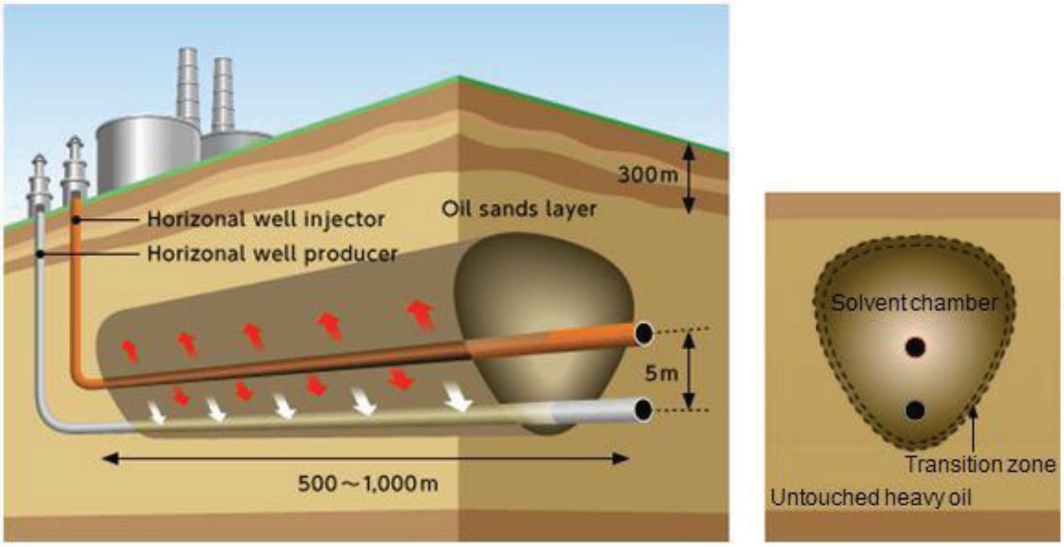

Figure 4. The VAPEX heavy oil recovery process [11].

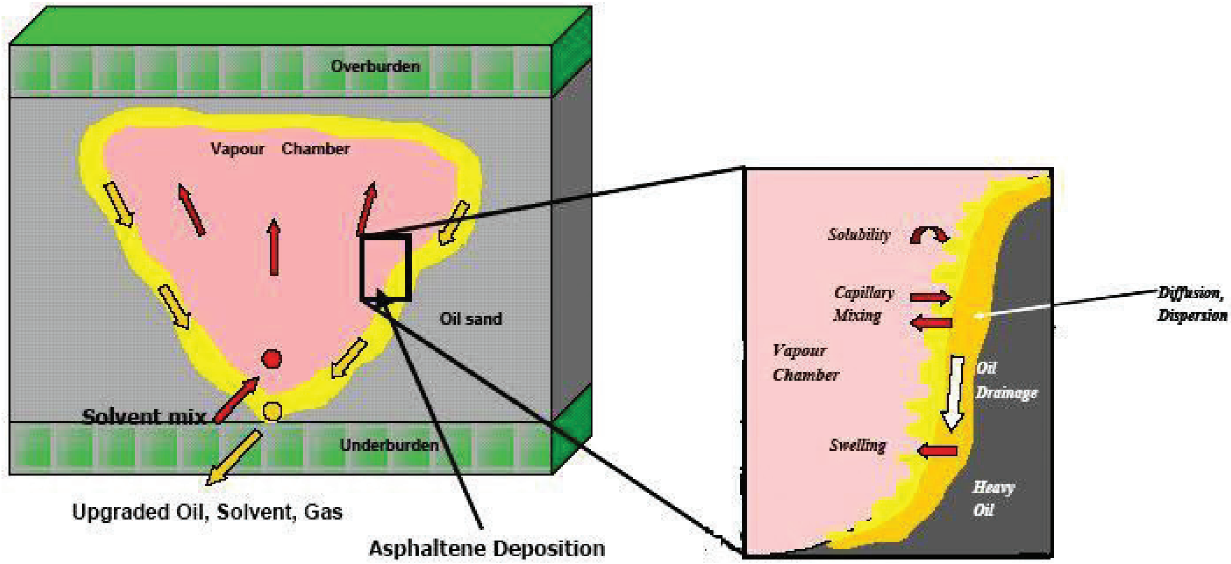

Figure 5. Mechanism involved in the VAPEX process [12].

such as steam-assisted gravity drainage (SAGD), cannot be applied. In the VAPEX process, a pair of horizontal injector-producer wells is employed. The gaseous hydrocarbon solvent (propane, butane, or a mixture of them) is injected into the deposit from the top well, and the diluted oil drains are gravitated downward to the bottom producing well. Recently, an attractive option was developed using CO_2 as a solvent in the VAPEX process. The high solubility and viscosity reduction potential of CO_2 could provide improvement to VAPEX performance. It also creates new opportunities for CO_2 sequestration [10].

Chemical methods include polymer floods, surfactant flooding, alkaline flooding, and so on. The mechanisms of chemical methods are dependent on the chemical materials added into the reservoir. The chemical methods may provide one or several effects: interfacial tension

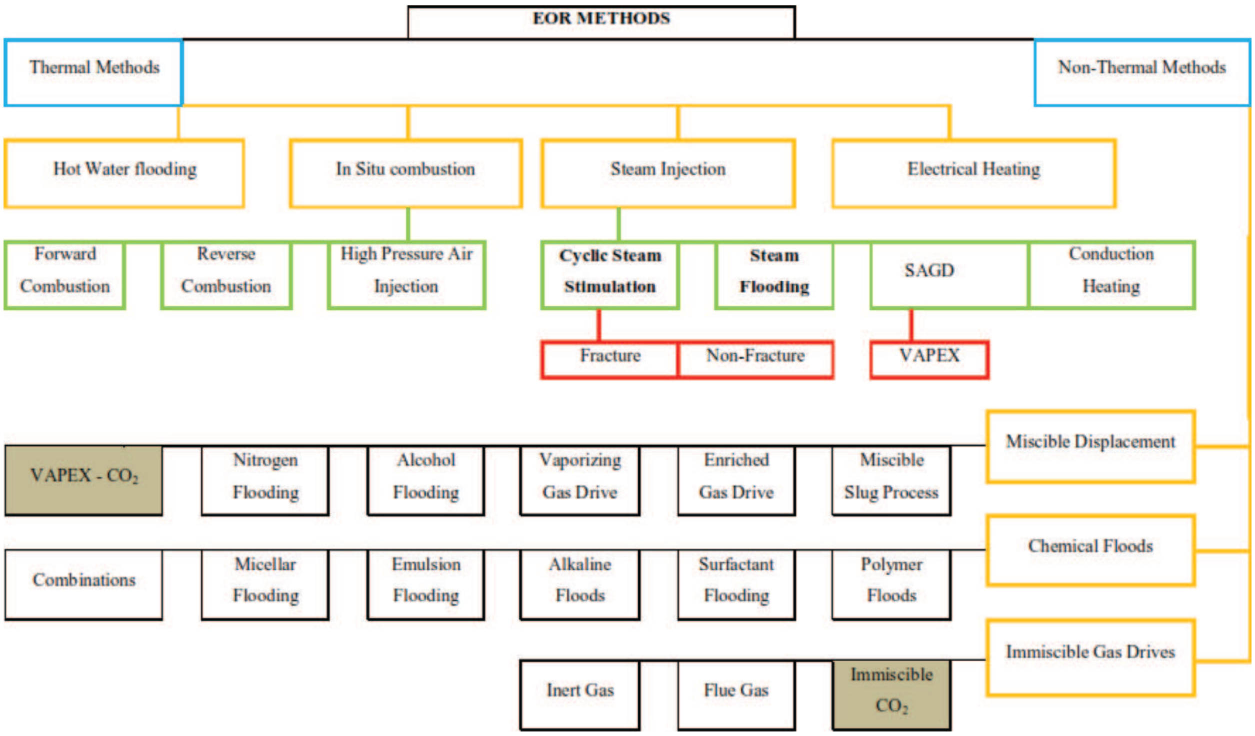

Figure 6. Classification of EOR methods.

reduction, viscosity reduction, wettability alteration, and mobility control. Meanwhile, there are many researchers on the background of EOR process; for a detailed review of enhanced oil recovery, we refer the interested reader to Thomas [7], and general classifications of these methods are shown in **Figure 6**.

5. Oil recovery by CO_2 injection

5.1. CO_2-EOR: definition and advantages

The combustion and flaring of fossil fuels produce large quantities of CO_2. The Intergovernmental Panel on Climate Change stresses the need to control anthropogenic greenhouse gases in order to mitigate the climate change that is adversely affecting the planet. Moreover, in some fields, the hydrocarbon gases produced along with the oil are re-injected into the reservoir to enhance oil production. Nevertheless, in some fields, the hydrocarbon gas is sold, and the gas itself is considered as a source of energy. An attractive option is the use of CO_2 as one of the main components of the solvent mixture for EOR process.

Enhanced oil recovery using CO_2 is an attractive oil recovery process that involves the injection of CO_2 to oil reservoirs and produce petroleum substances that would otherwise remain unrecoverable [13]. Typically, only around one-third of the oil is produced after primary and secondary oil recovery methods. Much of the remaining oil are trapped by capillary forces as disconnected drops, surrounded by water, or as a continuous phase at low saturation with gas occupying the larger fraction of the pore space. EOR operations using carbon dioxide have been practiced for more than 50 years; the results revealed that 6–15% of original oil in place can be recovered by these kinds of processes [14].

The low saturation pressure of CO_2 compared to CH_4 or N_2 and its low price compared with other hydrocarbon solvents are the incentives for the use of CO_2 in the EOR process. Moreover, a mixture of hydrocarbon solvents with CO_2 may be less likely to precipitate asphaltene, which is a great problem in enhanced oil recovery [15]. Furthermore, at high pressures, CO_2 density has a density close to that of a liquid and is greater than that of either nitrogen (N_2) or methane (CH_4), which makes CO_2 less prone to gravity segregation compared with N_2 or CH_4 [16].

5.2. Oil recovery mechanisms by CO_2 dissolution

When CO_2 is injected into the reservoir, it interacts physically and chemically with rocks and fluids that are present in the reservoir, creating favorable mechanisms that can make enhancement in oil recovery. Among these mechanisms include a high dissolution of CO_2 into crude oil via mass transfer followed by the following aspects: an increase of oil density, a reduction of the viscosity of the original crude oil, vaporization of intermediate components of the oil, a reduction of CO_2-oil interfacial tension, oil swelling, a reduction of water–oil interfacial tension, and an improvement of reservoir permeability [17].

The main scenario followed by CO_2 sequestration is the mechanism of fluid density increasing caused by the dissolution and mixing of injected CO_2 into fluid. In the past, there are a set of studies that have not taken the effect of density increase from mixing into account; this mechanism in the modeling of CO_2 injection has been ignored [18–21]. However, as shown in other studies, this may not be true; CO_2 has an effect on the density of fluid that is present in the reservoir [22, 23]. Its dissolution and mixing leads to density increase followed by density-driven natural convection phenomena. There are several published studies which reported that this phenomenon has a significant enhancement in hydrocarbon recovery and sequestration potential [24–27].

5.3. Literature review on EOR/EGR-CO_2

CO_2 storage studies started almost two decades ago. Despite this fact, still vast areas of research have not been covered in detail in the area of coupled enhanced oil recovery with CO_2 sequestration [28].

DeRuiter et al. [22] studied the solubility and displacement of heavy crude oils with CO_2 injection; they have found that the oils exhibit an increase in density due to CO_2 solubility. The two samples in their study with API gravities of 18.5 and 14 exhibited an increase in density upon CO_2 dissolution.

Morel et al. [29] and Le Romancer et al. [30] studied the effects of diffusion of nitrogen (N_2) and CO_2 on light oil using an outcrop core system. During 2010, Jamili et al. [31] simulated these previous experiments. These authors reported that diffusion was the main mass transfer mechanism between the matrix and fracture during nitrogen (N_2) injection. On the other side, CO_2 experiments conducted have shown that both diffusion and convection were important mechanisms.

Mehrotra and Svrcek [32–34] during the 1980s reported extensive experimental data on the dissolution of carbon dioxide on different bitumen samples in Alberta reservoirs. Their experimental data confirm a higher solubility of carbon dioxide in bitumen, and they found that this solubility increases as the injection pressure increases.

Darvish et al. [35] performed a set of experiments of CO_2 injection in an outcrop chalk core saturated with oil and was surrounded by an artificial fracture at reservoir conditions. These authors observed the production of gas enriched with methane at an early stage. Next, the amount of intermediate components increased in the production stream, and during the end of the experiments, the heavier components were recovered. Their results were also confirmed by simulation study performed by Moortgat et al. [36].

Malik and Islam [37] conclude that in the Weyburn field of Canada, horizontal injection wells have showed to be efficient for CO_2-flooding process to improve oil recovery while increasing the CO_2 storage potential. Besides employing horizontal wells, Jessen et al. [38] have applied different well control techniques including completion equipment for both injection and production wells, at the same time improving the amount of injected and stored CO_2 as well as enhancing oil recovery.

Recently, Li-ping et al. [39] conducted an evaluation study around Ordos Basin in Yulin city of China; this Basin was divided into 17 reservoirs and is considered as the first largest low-permeability proliferous onshore basin in China with proved reserves more than 10^9 t. These authors conclude that Ordos Basin has good geographical and geological conditions for CO_2 storage, and it has nine reservoirs suitable for CO_2 immiscible flooding and eight reservoirs suitable for CO_2 miscible flooding. The average incremental oil recovery ratios for immiscible and miscible flooding are 6.44 and 12%, respectively.

The booming development and production of shale gas largely depend on the extensive application of water-based hydraulic fracturing treatments. Hence, high water consumption and formation damage are two issues associated with this procedure. More recently, Pei et al. [40] investigated the feasibility of using CO_2 for reservoir fracturing and enhanced gas recovery (EGR) in order to reduce water usage and resource degradation, guarantee the environmental sustainability of unconventional resource developments, and create new opportunity for CO_2 storage. This study shows that this proposed CO_2-EGR process was mostly like to be successful in the Barnett shale reservoir, but there are some scientific and engineering questions that need to be further investigated to push the proposed technology to be applicable in practice.

Song investigated the effect of operational schemes, reservoir types, and development parameters on both the amount of incremental oil produced and CO_2 stored in high water cut oil reservoirs during CO_2 water-alternating-gas (WAG) flooding by running a compositional numerical simulator. The author's study shows that the five-spot pattern is more suitable for WAG flooding. Appropriately expanding well spacing improves the economic efficiency, even though the recovery factor decreases slightly. In addition, oil price, rather than CO_2 injection cost, is considered as the parameter that impacts the economic efficiency of WAG flooding more significantly [41].

Er et al. [42] investigated the effect of injection flow rate of CO_2 on oil recovery using synthetic micro-scale fractured system saturated by normal decane (n-C_{10}). The authors concluded that for immiscible CO_2 displacement, the amount of oil trapped in the system was reduced as well as increasing injection rates of carbon dioxide. They also observed that for miscible CO_2 conditions, higher CO_2 injection rates yielded faster oil recovery.

Coal bed methane is also tested for enhanced gas recovery and CO_2 storage; Blue Creek and Pocahontas are two fields of coal bed methane in USA. Pashin et al. [43] employed a diverse suite of well testing and monitoring procedures designed to determine the heterogeneity, capacity, injectivity, and performance of mature Blue Creek coal bed methane reservoirs. A total of 516 m^3 of water and 252 t of CO_2 were injected into coal in a battery of slug tests. The author's results demonstrate that significant injectivity exists in this reservoir and that reservoir heterogeneity is a critical factor to consider when implementing CO_2-enhanced methane recovery programs. Based on the study by Grimm et al. [44], CO_2-CBM project can be conducted in the stratigraphic interval below the Hensley Shale where this confinement horizon is greater than 183 m below the surface and is above the level of hydraulic fracturing in CBM wells.

6. Conclusion

With the decline of oil production and apparition of global warming problem caused by excessive emission of carbon dioxide during the last decades, it is believed that EOR/EGR-CO_2 technologies will play a key role to meet the energy demand and better mitigation of climate change in the years to come. If we investigate at the great number of studies cited in this study, the subject of EOR-CO_2 is being very important. Several physical and chemical mechanisms are associated with CO_2 injection, and the most important mechanism is the dissolution of carbon dioxide into fluid formation. It has been accepted from previous studies that the dissolution of CO_2 increases fluid density, which results in a downward density-driven convection and consequently greatly enhances oil recovery and CO_2 potential sequestration.

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