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A Study of Enhanced Oil Recovery

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Abstract- **In this paper we are presenting a study of enhanced oil. Enhanced oil recovery is the heart of oil production. Based on the enhanced oil recovery (EOR) study in Oil and Gas (2010), approximately 280,000 bbl of oil per day or 6% of US rough and ready oil production was produced by carbon dioxide (CO2) EOR. Any other gas injection processes, field CO2flooding this paper put up with from poor sweep efficiency due to early gas breakthrough, unfavorable mobility ratio, reservoir heterogeneity, viscous fingering and channeling, and gravity segregation. Many of these problems are believed to be alleviated or overcome by foaming the injected CO2. The fraction of oil recovered from an oil-filled calcite powder packed column by injection of aqueous surfactant solution depends on the phase behavior and surface chemical properties of the surfactant system.**

Index Terms- **Recovery; Oil; Production; Heart; Enhanced etc.**

I. INTRODUCTION

CO2-EOR recovers this additional oil by injecting slugs of CO2 at high pressure into the reservoir, usually alternated with slugs of water. The injected CO2 mixes with the reservoir oil, thereby reducing capillary forces that trap the oil in pores of the rock and allowing oil that would otherwise remain stranded to flow towards production wells.3 Most of the CO2 resurfaces with the recovered oil and is separated, recompressed, and reinjected. In every pass through the reservoir, however, a fraction of the CO2 remains sequestered underground. In order to maintain a given CO2 injection rate, operators of CO2-EOR papers4 therefore need reliable sources of CO2 over extended periods of time—it is common for an EOR paper to take 20 years or longer. As a result, EOR creates a derived demand for relatively pure CO2 gas.

Why does injecting carbon dioxide (CO2) into the minute opening spaces of a rock help move crude oil out. The implementation of EOR is personally tied to the price of oil and overall economics. EOR is capital and resource intensive, and expensive, primarily due to high injectant costs. The timing of EOR is also important: a case is made that advanced secondary recovery (improved oil recovery or IOR) technologies are a better first option before full-field deployment of EOR. The decline in oil discoveries during the last decades it is believed that EOR technologies will play a key role to meet the energy demand in years to come. This paper presents a comprehensive review of EOR status and opportunities to increase final recovery factors in reservoirs ranging from extra heavy oil to gas condensate. Specifically, the paper discusses EOR status and opportunities organized by reservoir lithology (sandstone and carbonates formations and turbiditic reservoirs to a lesser extent) and offshore and onshore fields. Risk and rewards of EOR methods including growing trends in recent years such as CO2 injection, high pressure air injection (HPAI) and chemical flooding are addressed including a brief overview of CO2-EOR paper economics.

II.ENHANCED OIL RECOVERY

It is well known that EOR paper have been strongly influenced by economics and crude oil prices. The initiation of EOR papers depends on the preparedness and willingness of investors to manage EOR risk and economic exposure and the availability of more attractive investment options. In the U.S., chemical and thermal EOR papers have been in constant decline from mid 1980's to 2005 (Figure 1). It is important to indicate that statistics on EOR activity is often masked because it goes unreported. In this article, all statistics and reports are based on available data from published articles, conference proceedings and other references. EOR gas injection paper statistics remained constant since mid 1908's and exhibited a growing trend since year 2000, especially with the increase of CO2 papers. Indeed, since 2002 EOR gas injection papers outnumber thermal papers for the first time in the last three decades. However, thermal papers have shown a slightly increase since 2004 due to the increase of High Pressure Air Injection (HPAI) papers in light oil reservoirs. Chemical EOR methods still have not captured the interest of oil companies with only two papers reported in 2008 [1–5,7–18]. EOR methods would not likely take place for at least a decade or two. Surface facility constraints and environmental regulations (e.g., chemical additives for EOR) also represent major hurdles for large EOR applications in offshore fields. Offshore EOR papers are capital-intensive. If we add the volatility of energy markets, the risk associated with this type of papers is high, reducing the probability of implementation.

Hydrocarbon gas injection (continuous or in a WAG mode) continues to be the preferred recovery process in offshore fields, gas condensate reservoirs, or fields in remote locations without access to gas markets. N2 EOR papers seem to be in decline except in the Campeche Bay Area in Mexico because of the availability of vast installed N2 generation capacity. CO2 injection is getting most of the attraction as an EOR method and potentially as a sequestration strategy in recent years. However, CO2-EOR papers in operation are mostly concentrated in the U.S. (especially in the Permian Basin) and associated to natural sources of CO2. CO2-EOR/sequestration papers are not expected to grow in the near future until industrial sources of CO2 are produced at much lower costs and the proper regulatory framework is in place.

III.EOR HEART OF OIL PRODUCTION

EOR is a heart of oil production. EOR in offshore fields is not only constrained by reservoir lithology, as was described in earlier section of this article, but also by surface facilities and environmental regulations, among other factors In chemical EOR or chemical flooding, the primary goal is to recover more oil by either one or a combination of the following processes: (1) Mobility control by adding polymers to reduce the mobility of the injected water, and (2) Interfacial tension (IFT) reduction by using surfactants, and/or alkalis.

Albacora, one of the offshore giant fields, contains an estimated STOIIP of 4.4 billion bbl (by 1989, time of the development plan) at water depths ranging from 230 m up to 1,900 m. The field was expected to develop in 3 phases for a peak production of 288,000 bopd from 188 completed wells. The idea being to prepare exploitation phases for successively deeper water, as technology development and learning curves required progressed. This is tendency in offshore operations in the Campos basin, because water depths grow substantially reaching ultradeep waters in some of the new discoveries. Phase I comprised the production of six exploratory wells, at water depths ranging from between 252 and 419 m. At the time, oil and gas production reached 33,000 bopd and 430 m3 /d, respectively. Phase II would add 95 wells, completed in Namorado, Eocene and Oligocene 1, 2, and 3 reservoirs, and a few in Miocene and Oligo-Miocene units, to gather information. 39 injectors will be activated. This phase was divided in 2 steps. First, all possible alternatives and economical screening was used. The remaining cases were then optimized. Although Brazil experimented with several of the tertiary recovery alternatives proposed internationally, only a few methods actually moved from pilot evaluation to field scale. Commercial EOR in Brazil includes steam injection, carbon dioxide and polymer flooding. All these papers were executed on onshore fields, all of them in sandstone reservoirs, many in good quality. It should be noticed that many of the papers were implemented between 1969 and 1985, time period that preceded the fall of oil prices with the known effects on EOR activities at the time worldwide, including Brazil. carbon credits will definitively not offset costs associated with CCS in saline aquifers (without EOR), at least in the near future. Additionally, the cost of CO2 storage (including monitoring) in saline aquifers might be too high because of the lack of reservoir characterization and existing infrastructure (wells and surface facilities) compared to oilfields. As shown in Figure 6, CO2 capture and compression represent capital-intensive phases of any CCS paper. Therefore, it is believed that with the refinement of current capture technologies and/or the development of new technologies, the opportunity will exist for major cost reductions in CCS papers. CO_2 capture costs around or below $30/ton are considered necessary in order to justify the economic feasibility of CCS papers in the near term, assuming that the proper regulatory environment and carbon market framework, among other issues (e.g., public perception) are in place. Therefore, we do not foresee an important increase in the number of papers implementing CO_2-EOR from anthropogenic sources in the near future. Finally, acid gas (mixtures of H_2S and CO_2) injection has been also reported as an injectant for EOR applications in carbonate formations [18]. Zama Field in Canada], Tengiz Field in Kazakhstan and Harweel Cluster in Oman (O'Dell et al.,) are a few examples of carbonate reservoirs with ongoing or planned sour or acid gas injection as EOR strategies.

IV.EOR IN CARBONATE FORMATIONS

Carbonate reservoirs are naturally fractured geologic formations characterized by heterogeneous porosity and permeability distributions. For example, in the case of low porosity and low permeability carbonate rocks (more specifically rock matrices), the fluid flow in the reservoir can be completely dependent on the fracture network, while the matrix only plays a source role, analogous to tight sand formations and natural gas flow. In the case of porous carbonate rocks, fracture networks can still cause uneven sweeping of the reservoir leading to early breakthrough of injected fluids in the producing wells, resulting in low recovery factors. Given the abundance of carbonate reservoirs, they have been the subject of numerous studies that have made attempts to characterize the heterogeneities of carbonate reservoirs, classify the different types or classes of fractured reservoirs and determine how rock and fluid properties of carbonate reservoirs impact ultimate recovery [1-6]. The latest developments in the surfactant-based cEOR techniques applied in carbonate formations are discussed, contemplating the future direction of existing methodologies. In connection with this, the characteristics of heterogeneous carbonate reservoirs are outlined. Detailed discussion on surfactant-led oil recovery mechanisms and related processes, such as wettability alteration, interfacial tension reduction, microemulsion phase behavior, surfactant adsorption and mitigation, and foams and their applications is presented. Laboratory experiments, as well as field study data obtained using several surfactants, are also included.

V.CARBON DIOXIDE ENHANCED OIL RECOVERY

As the world simultaneously faces an increasing concentration of CO_2 in the atmosphere and a higher demand for fossil fuels, the CO_2 -EOR process continues to gain popularity for its efficiency as a tertiary recovery agent and for the potential for having some CO_2 trapped in the subsurface as an unintended consequence of the enhanced production (Advanced Resources International and Melzer Consulting, 2009). More extensive application of CO_2 -EOR worldwide, however, is not making it significantly easier to predict the exact outcome of the CO_2 flooding in new reservoirs. The standard approach to examine and manage risks is to analyze the intended target by conducting laboratory work, running simulation models, and, finally, gaining field experience with a pilot test. This approach, though, is not always possible. For example, assessment of the potential of CO_2 -EOR at the national level in a vast country such as the United States requires making forecasts based on information already available. Although many studies are proprietary, the published literature has provided reviews of CO_2 -EOR papers. Yet, there is always interest in updating reports and analyzing the information under new perspectives. Brock and Bryan (1989) described results obtained during the earlier days of CO_2 -EOR from 1972 to 1987. Most of the recovery predictions, however, were based on intended injections of 30 percent the size of the reservoir's hydrocarbon pore volume (HCPV), and the predictions in most cases badly missed the actual recoveries because of the embryonic state of tertiary recovery in general and CO_2 flooding in particular at the time. Brock and Bryan (1989), for example, reported for the Weber Sandstone in the Rangely oil field in Colorado, an expected recovery of 7.5 percent of the original oil in place (OOIP) after injecting a volume of CO_2 equivalent to 30 percent of the HCPV, but Clark (2012) reported that after injecting a volume of CO_2 equivalent to 46 percent of the HCPV, the actual recovery was 4.8 percent of the OOIP. Decades later, the numbers by Brock and Bryan (1989) continue to be cited as part of expanded reviews, such as the one by Kuuskraa and Koperna (2006). Other comprehensive reviews including recovery factors are those of Christensen and others (2001) and Lake and Walsh (2008). The Oil and Gas Journal (O&GJ) periodically reports on active CO2 -EOR operations worldwide, but those releases do not include recovery factors. The monograph by Jarrell and others (2002) remains the most technically comprehensive publication on CO2 flooding, but it does not cover recovery factors either. Among chemical EOR techniques, surfactant flooding aims to lower the mobility ratio by reducing the interfacial tension between oil and water and mobilizing the residual oil to the production well. This is feasible via adsorption of the surfactants on the reservoir rock.7,Surfactant flooding has been tried for a number of conventional oil reservoirs around the world with some success but it has largely proved inefficient due to the cost of surfactant loss in the porous medium as well as issues with adsorption efficiency and negative reactions with the reservoir rock.36−38 Surfactants can be classified into different groups based on the ionic nature of the headgroup, namely anionic, cationic, nonionic, and zwitterionic. Nonionic surfactants are generally nonvolatile and benign environmentally and are considered as suitable alternatives for traditional solvents due to their ability to separate organic compounds from solid samples. Nonionic surfactants have effective solubilization toward water-insoluble or moderately soluble organic compounds. This property makes nonionic surfactants proper candidates for the separation of polar and nonpolar compounds from different solid materials such as separation of aromatic hydrocarbon from solid environmental phases. Other factors affecting the rate of surfactant adsorption include rock surface charge, fluid interface, and surfactant structure.

VI.CONCLUSION

This paper presents a study or overview of EOR. Some of the enablers for EOR are also discussed in this paper. This paper presents a review of EOR status and opportunities to increase final recovery factors in reservoirs ranging from extra heavy oil to gas condensate. the number of papers implementing CO2-EOR from anthropogenic sources in the near future. Finally, acid gas (mixtures of H2S and CO2) injection has been also reported as an injectant for EOR applications in carbonate formations.

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