Increasing Hydrocarbon Recovery Factors

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Introduction

Conventional and unconventional hydrocarbons are likely to remain the main component of the energy mix needed to meet the growing global energy demand in the next 50 years. The worldwide production of crude oil could drop by nearly 40 million B/D by 2020 from existing projects, and an additional 25 million B/D of oil will need to be produced for the supply to keep pace with consumption. Scientific breakthroughs and technological innovations are needed, not only to secure supply of affordable hydrocarbons, but also to minimize the environmental impact of hydrocarbon recovery and utilization.

The lifecycle of an oilfield is typically characterized by three main stages: production buildup, plateau production, and declining production. Sustaining the required production levels over the duration of the lifecycle requires a good understanding of and the ability to control the recovery mechanisms involved. For primary recovery (i.e., natural depletion of reservoir pressure), the lifecycle is generally short and the recovery factor does not exceed 20% in most cases. For secondary recovery, relying on either natural or artificial water or gas injection, the incremental recovery ranges from 15 to 25%. Globally, the overall recovery factors for combined primary and secondary recovery range between 35 and 45%. Increasing the recovery factor of maturing waterflooding projects by 10 to 30% could contribute significantly to the much-needed energy supply. To accomplish this, operators and service companies need to find ways to maximize recovery while minimizing operational costs and environmental imprint.

This paper provides an overview of the options that oil and gas operators and service companies are considering as they look for solutions to the above needs and plan possible technology development scenarios. Emerging developments in such sciences as physics, chemistry, biotechnology, computing sciences, and nanotechnologies that are deemed capable of changing the hydrocarbon recovery game are highlighted.

Scales of Observation

To maximize hydrocarbon recovery, it is critical first to have a clear depiction of the static properties and dynamic behavior of the hydrocarbon system on various scales, ranging from the pore scale to the reservoir scale, as illustrated in **Fig. 1**. The selection of the type, number, and placement of wells to achieve optimum reservoir drainage requires detailed knowledge of reservoir geology (on a scale of hundreds to thousands of meters). Geological models, however, suffer from uncertainties that hinder simple deterministic predictions of their flow behavior. Complex geological reservoirs (layered, compartmented, etc.) increasingly have been developed using deviated, horizontal, and multilateral wells. Progress in both geophysical imaging and geological modeling will enable such complex well architectures to be applied more widely.

Oil recovery processes involve the interplay of flow, transport, rock/fluid interactions, and thermodynamic processes on the meso-scale (several to tens of meters). The understanding of such processes relies on physical and numerical modeling. Advances in computational methods and increased computational power (Dogru 2008; Habiballah and Hayde 2004) will allow numerical simulations using unprecedented degrees of spatial and temporal refinements. A full appreciation of the new tools will lead to the development of a novel generation of numerical simulators that can capture the physics of the oil recovery processes better and thus can better predict the behavior of reservoir systems. Such simulators should be based on improved mechanistic modeling of physical-chemical processes underlying enhanced oil recovery. As a first step, the derived mechanistic models will be upscaled to the core scale and validated by dedicated laboratory experiments. Finally, the models thus developed will be upscaled to the field scale.

The oil displacement phenomena as observed on small scales (several micrometers to tens of meters) form the basis of the oil recovery mechanisms. Experimental and theoretical studies relevant for hydrocarbon recovery have traditionally focused on the lower end of this small scale. This practice has been dictated by the need to have well-defined systems for which the physics can be described with the highest degree of confidence. A broader use of visualization techniques, such as high-resolution and x-ray computed tomography (Akin and Kovscek 2003) and nuclear magnetic resonance (Oswald et al. 2007; Castelijns et al. 2006) will necessarily lead to new insights into the recovery mechanisms, such as chemical EOR.

The bridging of the different spatial measurement scales is achieved using upscaling techniques. This approach still has some weaknesses, but in many cases, it provides a reasonable insight to assess the strengths of recovery processes and their mode of implementation. In recent years, much progress has been made in the modeling of the earth system. However, there is still a needed to improve upscaling techniques to meet the robustness required to model complex improved and enhanced oil recovery processes.

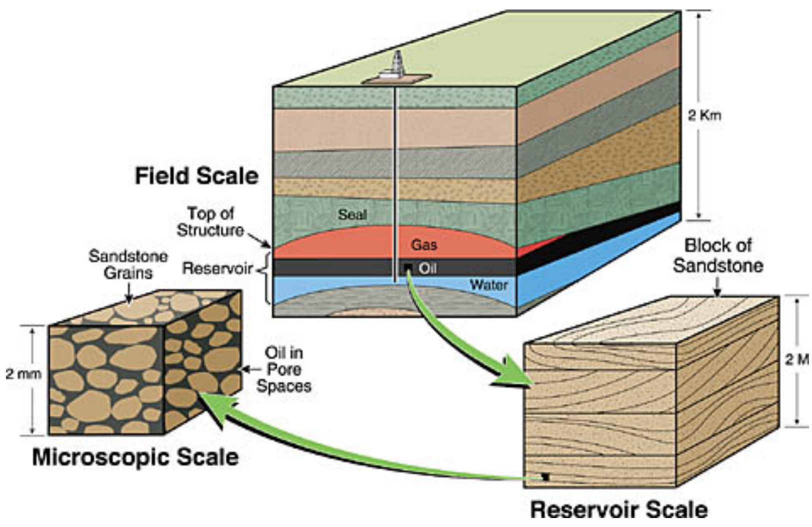

Fig. 1 - Different scales involved in hydrocarbon production.

Primary Recovery

The physical-chemical properties (density, viscosity, PVT properties, etc.) of hydrocarbons vary over a wide range, and hydrocarbons are found in a variety of formation types (clastic sandstones, fractured carbonates, etc.). In the simplest case, the production of hydrocarbons by natural depletion (primary recovery) involves a single-phase flow by fluid expansion from the reservoir to the surface, through the wells. This requires that pressure drawdown between the reservoir and the bottom of the well is sufficient to overcome viscous forces in the formation. It also demands that pressure drop over the wells be larger than hydrostatic forces and frictions in the production tubing. When the pressure drop over the well is not large enough, artificial lifting methods (pumps, gas lift, ESP, etc.) can be used to enhance the flow of the oil to the surface. These techniques are generally deemed mature, but progress is still required to increase the reliability of the lifting systems. This improvement could be achieved using intelligent systems that allow fully automated production.

Secondary Recovery

The first step in improving the oil recovery beyond natural depletion relies on injecting fluids that are initially not present in the reservoir for pressure maintenance. Although primary recovery may rely on the expansion of an aquifer or a gas cap that supports the pressure maintenance, in secondary recovery fluids are injected into the reservoir for this purpose.

Waterflooding is the most commonly used secondary oil recovery method for both conventional and heavy oil reservoirs because of its relative simplicity, availability of water, and cost-effectiveness. In the case of heavy oil, water is combined with “thermal energy injection” either as hot water or steam, but this is usually treated as a tertiary oil recovery method.

Like primary recovery, the efficiency of waterflooding is determined by intrinsic factors, such as hydrocarbon properties, microscopic oil displacement efficiency, rock/fluid properties, and reservoir heterogeneities. Ultimately, the recovery factor for waterflooding is determined by a number of external factors, including the architecture, number, and placement of water injection and production wells. The choice of these parameters to maximize the reservoir sweep is the first step of waterflooding optimization and an essential part of profitable field development planning. Such choice should result in optimized micro- and macroscopic oil displacement and sweep efficiency.

The optimization of waterflooding over the lifecycle of the reservoir has traditionally relied on the updating of reservoir models over large time intervals based on historical production data. Recently, the smart field concept was introduced. In this closed-loop optimization paradigm (**Fig. 2**), passive measurements of well and reservoir parameters (pressure, temperature, flow rates, water cuts, gas/oil ratios, etc.) and control of wells inflow and outflow (opening or closing of valves) are replaced by active measurement and flow control systems. This helps the propagation of the water/oil displacement front to achieve maximum reservoir sweep efficiency (Jansen 2010). It also enables updating of geological models at much shorter time intervals and faster reduction of their uncertainties. Both effects result in considerable improvement in the reservoir sweep efficiency. As the cost of equipment decreases, we may expect the number of reservoirs developed using closed-loop production optimization and reservoir management to grow considerably.

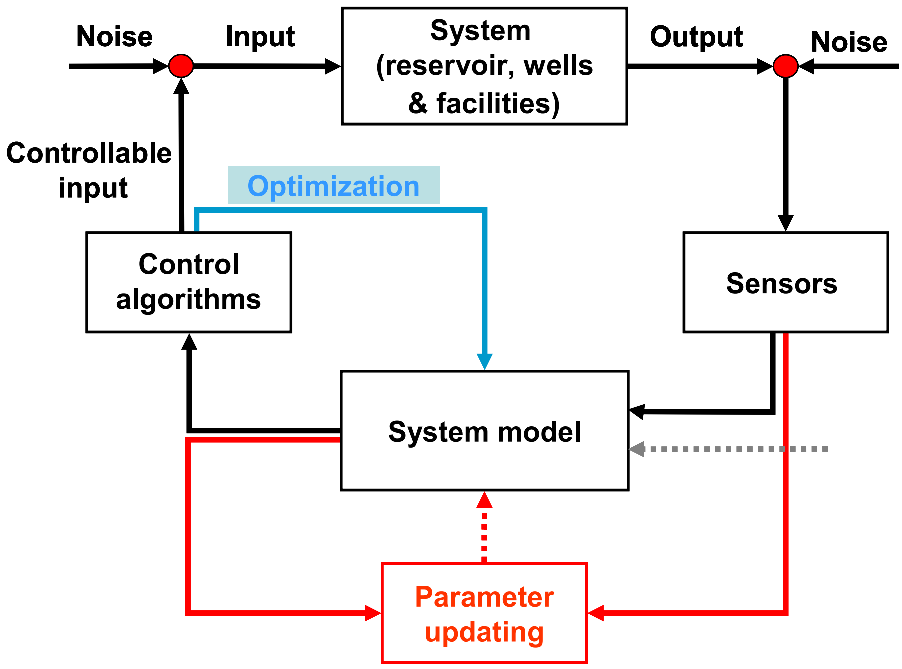

Fig. 2 - Closed-loop production optimization (Jansen 2010).

Enhanced Oil Recovery

The aspiration of operators of maturing waterflooding fields is to maximize the profitable recovery of the remaining oil after waterflooding at the lowest investment cost possible. This requires both the optimization of reservoir sweep efficiency and putting physical, chemical, or thermal mechanisms at work that will improve the microscopic oil displacement. Enhanced oil recovery (EOR) methods can be divided into thermal methods (e.g., steam methods) and nonthermal methods. Nonthermal methods include in chemical methods (e.g., designer water, polymer flooding, alkali/surfactant/polymer (ASP) flooding, surfactant flooding) and nonchemical methods (e.g., miscible or immiscible gasflooding).

To place EOR methods in a proper physical context, recall that hydrocarbons are trapped in the pores either by an unfavorable viscosity ratio or by capillary forces acting on different scales. For instance, waterflooding or gasflooding (CO_2, N_2, etc.) with a high oil viscosity leads to an unfavorable mobility ratio between displacing and displaced fluid. A large fraction of the oil is not contacted by the injected fluid[1] and the oil that is contacted is poorly displaced. The rock/fluid interactions are responsible for the adhesion of fluids to the porous medium, which can be oil-wet, water-wet, or mixed-wet. In mixed- or oil-wet formations, oil is retained in the pores due to the affinity of the oil to the rock. Capillarity makes it difficult to mobilize oil blobs so that they can be displaced over macroscopic distances (**Fig. 3**).

[1] Waterflooding in light oil reservoir can have a high reservoir sweep efficiency. The sweep efficiency deteriorates as the viscosity of the oil increases.

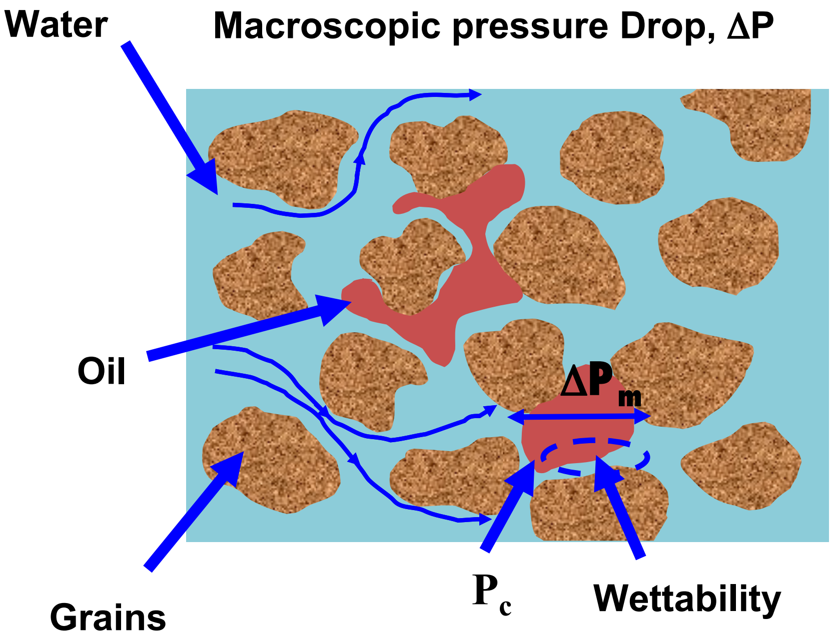

Fig. 3 - Microscopic trapping of oil in rocks.

Thermal recovery

Thermal recovery methods are based on adding heat to the oil, mainly to decrease its viscosity. In this way, the mobility ratio between oil and the displacing fluids becomes more favorable. The most common thermal methods are steamflooding and steam cycling. These techniques experienced enormous development in the last few decades and have grown to be the largest contributor to oil output by EOR. They are effective for the oil viscosity range between 100 and 100,000 cp. The reservoir sweep efficiency of steamflooding is limited by gravity segregation. One way to overcome this problem is using the steam-assisted gravity drainage (SAGD) method. SAGD is limited by the reservoir thickness needed to develop a steam chamber. Ongoing SAGD research is aimed at improving the displacement efficiency and speed by using solvents. In-situ combustion techniques are being developed, but controlling the process is a challenge.

Other EOR techniques that are considered complementary to steam injection or cyclic steam stimulation include direct electrical resistive (ER) or electromagnetic radiation (EM) heating. These techniques are still in the early development phase and have not been tested extensively in the field. However, when fully developed, they could be particularly useful to recover medium-heavy to extra-heavy oil. The ER methods pass current through the reservoir, which behaves like a resistor, and thus heat is produced directly in the reservoir by ohmic effect. In EM heating, hyper-frequency electromagnetic waves propagating through the reservoirs are absorbed directly by water molecules (similar to microwave ovens). Both ER and EM heating suffer from the fact that when they are applied, heat is released locally and is not distributed uniformly in the reservoir. One idea to overcome this is to combine ER or EM heating with waterflooding. Owing to its high heat capacity, water can carry thermal energy deeper into the reservoir. Another limitation of EM is poor propagation in presence of salt water due to high absorbance of salt water. Considerable progress is likely to be made if the resonance frequency can be tuned so that only oil molecules are heated. This requires further fundamental studies on EM oil/water interactions.

Designer Water

The simplest of the nonthermal oil recovery is designer water; i.e., the manipulation of the mineral composition of the drive water to achieve high microscopic displacement efficiency. In the early days of this technique, low-salinity field trials were reported by BP (Seccombe et al. 2008), and since then study of designer water has grown to be of interest to the industry. Low salinity implies low ionic strength, especially of the divalent ions. Designer water may mean increase in concentration of certain ions and reduction in composition of other ions. The fundamental mechanisms for the improvement of the oil displacement are far from well understood, and there has been debate about the true benefits. There is sufficient evidence to assume that modification of the rock surface could be a responsible factor for the improved microscopic displacement. Much more research, combining surface chemistry and rock/fluid interactions, is needed to detail the mechanism and assert whether further gain can be obtained from the application of designer water.

Surfactant Flooding

In surfactant flooding, surfactant molecules act on the solid/fluid or oil/water interfaces. They are used either for wettability alteration or for lowering the oil/water interfacial tension (IFT). In the latter case, the molecules adsorb on the oil/water interface and reduce the IFT and capillary pressure responsible for the trapping of the oil in the pores. When used together with an alkali, surfactants reduce the IFT to an extremely low value and, in principle, the reduction of the residual oil to nearly zero. This alkali/surfactant (AS) method was extensively studied in the past and tried in many fields. One of the limitations of AS is that AS solutions have low viscosities, and thus reservoir sweep efficiency is poor, however, the addition of polymer viscosifiers has improved process performance. Furthermore, low IFT implies that oil can be easily emulsified, which may offset the gain obtained from improved displacement because of the need to separate the produced oil by chemical methods. Emulsions also lead to high viscosities and higher energy requirements for fluid displacement. This is more so in the AS method than in surfactant flooding. Use of polymers in ASP methods gives mobility control to the displacement fronts and minimizes emulsion production. Typically adsorption of surfactant limits breakthrough and also minimizes this issue. Limitation of application is more from economics and complexity. From the displacement point of view, chemicals are prone to chromatographic effects that lead to separation of the components. Work at various research institutes (Levitt et al., 2009) on designer surfactants is getting around much of this concern. Surfactants can be injected into fractured carbonate reservoirs to improve oil recovery by spontaneous imbibitions into the matrix by wettability alteration (Adibhatla and Mohanty 2008). Extensive meso-scale experiments (meters), along with modeling and numerical analyses are needed to improve the predictive power of the tools used to design operations.

Polymer Flooding

In recent years, polymer flooding has become a significant EOR method, thanks mainly to its massive application in China, where use of polymer floods account for a reported improvement of oil recovery by about 12% (Wang et al. 2009). This improvement can be explained by the fact that it is relatively easy to increase water viscosity by up to an order of magnitude by adding relatively low amounts of polymer. This improves the mobility ratio and leads to good reservoir sweep efficiency for oil viscosities in the range 10 to 100 cp. Traditional polymer flooding has several limitations. Polymer adsorption may deplete the displacement front of polymer and thereby diminish the efficiency of the oil recovery process. Polymers used so far have a limited temperature range because they undergo thermal degradation at high temperatures, typically above 200°F for polyacrylamides. Polymers with a higher thermal stability tend to be rather sensitive to the salt content in the water. Novel polymer chemistries that are more tolerant to high temperatures and to high salinities have been proposed recently and are undergoing extensive research. A considerable gain can be made by combining polymer and AS flooding; i.e., the ASP process, where polymer ensures good reservoir sweep efficiency and AS ensures a good microscopic displacement (Nasr-El-Din et al. 1992). However, this approach suffers from the same disadvantages as AS flooding.

Gas Flooding

The basic improved recovery mechanism for gas flooding EOR is the fact that the residual oil for gas displacement is lower than that for waterflooding. In principle this could result in an incremental recovery in the range 10 to 15% over the recovery by waterflooding. The difference in the residual oil for gas- and waterflooding, and thus the incremental recovery, could be much greater when gas and oil are miscible. However, the most efficient recovery mechanism by gasflooding relies on injecting the gas (N_2, CO_2, etc.) at high pressures so that it is miscible with oil. In this case, the incremental recovery can theoretically exceed 50% of the oil initially in place (OIIP) (or reach 100% of the residual oil). This theoretical value is difficult to achieve by continuous gas injection: the unfavorable mobility ratios between gas and oil/water leads to poor reservoir sweep due to gravity override, viscous fingering, and channelling through high-permeability streaks, resulting in gas recycling that is expensive due to compression costs. A modest improvement can be obtained using water-alternating-gas (WAG) schemes. A step-change in the recoveries by gasflooding requires the use of more robust methods of mobility control. One such method is foam; i.e., a dispersion of the gas obtained by co-injecting a surfactant solution and gas (Farajzadeh et al. 2010). There is a major reason why foam should remain a research priority for both industry and academia: the abundance of flue gas combined with the requirement of zero greenhouse emission could be a strong enabler of relatively cheap gas or, better, foam flooding. If we surmise that the surfactant could be a polymer solution or an AS solution with or without polymer, or even a suspension of nano-particles (Wasan and Nikolova 2008), there are numerous unexplored possibilities for foam flooding. One of the challenges has been to ensure good foam stability in the presence of oil. The key to working foam EOR, and to a truly new EOR era, lies in the unsolved mysteries of the physics and chemistry of surfactants.

Other Upcoming Technologies

A re-emerging EOR approach, microbial enhanced oil recovery (MEOR), is the use of microorganisms to generate chemicals (surfactants, polymers, etc.). MEOR relies either on injecting bacteria strands together with nutrients or on injecting nutrients to stimulate growth of bacteria naturally present in the formation (Bryant and Burchfield 1989; Awan 2008). The specific surfactant- and polymer-generation process depend strongly on the type of microorganism and rock and fluid properties. Extensive studies have been done to identify the most suitable microorganisms.

Finally, there is an extensive body of ongoing research (see for instance: http://www.beg.utexas.edu/aec/projects.php) devoted to developing new nanotechnologies in the oil industry. Fruition of such research could bring about considerable changes on way oil exploration and production is done (Kong and Ohadi 2010). For instance, swarms of nano-devices transported by flood water could aid real-time mapping of reservoir fluids, resulting in unprecedented accuracy. Nano-devices are also being contemplated as carriers of chemicals (e.g., surface-active compounds) that can be delivered directly to the oil/water interface to modify the microscopic displacement pattern.

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