SCREENING CRITERIA DECIDE BEST PROCESS FOR ENHANCED OIL RECOVERY

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Abstract

The enhanced oil recovery processes discussed in this paper fall in the general areas of recovery of oil by thermal, gas drives, polymer flooding, and chemical flooding processes. General descriptions of the most widely used processes are given. Also, the conditions under which each process has been found to be likely successful (screening criteria) are included for each process. This helps the engineer to match processes to specific reservoirs.

Introduction

Enhanced Oil Recovery (EOR) holds promise for significantly increasing the nation's recoverable reserves. Approximately 70 percent of the oil discovered in the United States is unrecovered using current technology. In order to lower the U.S. dependence on imported hydrocarbons, our country should both conserve energy and develop techniques to recover oil and gas more efficiently.

Numerous methods have been developed to produce oil that has been trapped and left behind in the hydrocarbon reservoir rock. These EOR techniques include many processes. Some of these processes have been highly successful and some have not. Continued development of these processes, and especially how to apply them successfully in the field, should be part of our state and national energy policies because the EOR target is large. The target unrecovered oil in place has been estimated to be from 300 to 800 billion barrels. Thus, for every one-percent increase in recovery efficiency, three to eight billion barrels of oil are added to our recoverable reserves.

Oil Recovery Classifications

Oil recovery has traditionally been classified as primary, secondary or tertiary depending on the stage of depletion and the method of operation in the field. Primary, or first, recovery is that which uses the original reservoir energy to produce the fluids. The wells may be flowing or being pumped. Secondary, or second, recovery is that which depends on energy and material being injected into the reservoir to augment natural energy and help displace the fluids toward producing wells. Secondary recovery has traditionally been accomplished by injecting water, natural gas, or both into the reservoir through injection wells. Tertiary, or third, recovery has traditionally been those methods that can be used to mobilize residual oil left behind after secondary recovery.

It has long been recognized that secondary or tertiary recovery methods are economically more effective if initiated before primary (or secondary) production is completed. The early initiation of a method allows both ultimate recovery and rate of recovery to be increased. However, the early initiation of a secondary or tertiary process tends to make the names meaningless. Thus, the term enhanced oil recovery (EOR) was coined to overcome this difficulty and is normally used to refer to those methods that were called tertiary recovery processes.

Numerous enhanced oil recovery (EOR) techniques have been developed during the history of oil production. No attempt will be made in this paper to describe, or even mention, all the existing EOR processes. Several of the most successful, or at least the most popular processes will be discussed. The general categories that will be discussed are thermal, gas drives, polymer flooding, and chemical flooding processes.

Thermal Methods

Thermal methods are normally used to increase production rates of heavy oils. They include steam drive, steam soak, forward combustion, and reverse combustion. The first three methods have been quite successful in some fields. The fourth, reverse combustion, has been successful in some laboratory runs but has not shown any promise in the field. Because of its lack of success in the field, reverse combustion will not be discussed.

A. Steam Drive

Steam drive is an EOR process that involves pattern flooding where steam is injected in a group of wells located such that the steam and oil are driven toward producing wells. The primary benefit obtained by injecting steam is that the heat reduces the viscosity of the reservoir oil and allows it to flow more freely toward the producing wells. There is also evidence that heating a water-oil system shifts relative permeability in favor of oil. Some steam distillation will also occur for most oils.

Steam injection is one of the most successful EOR processes used to date and has improved oil recovery in many locations throughout the world. Best results have been obtained in high porosity sands/sandstones with good permeabilities of 150 md or greater and thicknesses of 20 ft or more. The oil in place may be less than 25° API, have a viscosity greater than 20 cp. The reservoir should contain 500 barrels of oil per acre-ft or more at reservoir depths of 300 - 4500 ft. It should be emphasized, however, that all screening criteria should be used to indicate to an operator the feasibility of using a process and should lead to sound engineering and geologic studies rather than replacing them.

B. Steam Soak

Steam soak is also known as cyclic steam injection, huff and puff, or steam stimulation. It is a single-well process that is carried out in three stages. During the first stage, steam is injected into the well for a period of time, usually two weeks or less. During the second stage, the well is kept shut in for several days to allow heat to diffuse throughout the region the steam contacted. The third stage involves producing the well. In many cases the oil rate after steam soak will be substantially higher (ten times, plus) than before the well was stimulated. The primary reasons that rates are increased is that heating lowers the viscosity of the oil and the steam injected cleans up the wellbore. The process has been successful in numerous locations, especially in California and Venezuela.

Steam soak has been mostly successful in fairly thick (40 to 1000+ ft) sand/sandstone reservoirs with good porosity (20 percent+) and permeability (500md+). It is often successful in conjunction with natural processes such as gravity drainage or compaction and depths have ranged from 200 to about 5,000 ft. Most successful projects have contained oils less than 25° API gravity and a wide range of viscosities up to several thousand centipoises. Most have contained high oil saturations, 60 percent or more.

C. Forward Combustion

Forward combustion, or fireflooding, in an oil reservoir involves injecting air, oxygen, or air enriched with oxygen into an injection well and igniting the hydrocarbons in the vicinity of the injector. By continuing to inject air and/or oxygen into the injection well, the combustion front can be propagated towards an injection well. The reservoir will be very hot at the combustion front and the heat front will drive the lighter hydrocarbons forward toward the producer. This process leaves behind a coating of very heavy hydrocarbons, called coke, on the reservoir rock. The coke is the fuel for the process. Fireflooding has not been as successful on as large a scale as steamflooding. However, several forward combustion projects have been both engineering and economic successes.

Successful combustion projects have been conducted in sand/sandstone reservoirs with high porosities (20-40 percent) and high permeabilities (100-5000 md) at depths from 500 ft to more than 4000 ft. Reservoir thicknesses range from about 10 ft to over 200 ft. Oil saturations were high (40-50 percent), oil API gravity ranged from 10-40 (most less than 25) and oil viscosities were normally less than 2000 cp.

Gas Drives

Gas drives may be used to maintain pressure in a reservoir or designed to be miscible with the oil. The most widely used gas drives are carbon dioxide, hydrocarbon gases, and nitrogen. Carbon dioxide is the most widely used and is becoming one of the more popular EOR processes in use today.

A. Carbon Dioxide Drive

Carbon dioxide flooding has become the most widely used gas drive during the past few years. This interest in carbon dioxide has become widespread primarily for two reasons: it is relatively inexpensive and it is applicable to many reservoirs. It is used as a displacing fluid that may or may not be miscible with the reservoir oil. Many applications, however, involve injecting carbon dioxide under conditions for which it is miscible, or at least partially miscible, with the oil. For each crude oil, there is some minimum miscibility pressure (MMP), at reservoir temperature, below which miscibility will not be achieved. Multiple-contact miscibility is achieved for miscible carbon dioxide flooding.

Carbon dioxide flooding works in sandstones and carbonates and is best for crude oils with an API gravity greater than 25, a viscosity less than 15 cp, and with a high percentage of C5-C12 hydrocarbons. It works best in thin pay sections, unless dipping, at depths greater than 2200 ft and for oil saturations of 30 percent or higher. Reservoir temperature should be less than 200 Deg F. Lower temperatures are better as MMP goes down with temperature. Permeability is no problem because the gas viscosity is so small. However, the high gas mobility does cause fingering problems and water slugs are often injected alternately with the gas (WAG process) to alleviate fingering.

B. Cyclic Carbon Dioxide Injection

The Cyclic Carbon Dioxide Injection (CCDI) process is a stimulation process that involves one well only. Carbon dioxide is injected for a period of several days, the well is shut in for a few days to allow the carbon dioxide-oil mixture to approach equilibrium, and then it is produced at a rate higher than before the treatment, until the effects of the stimulation decline to a level that indicates the process should be repeated. The carbon dioxide dissolves in the oil phase and causes the oil to swell and to attain a lower viscosity. The process has not been widely used but reports indicate a few highly successful tests have been conducted. Also, the process is not as expensive and resource intensive as most enhanced oil recovery (EOR) projects and thus offers an EOR process within the economic reach of small independent producing companies as well as large ones.

As the CCDI process can be expected to increase the radius of drainage of a well, it may be successful in replacing infill drilling needs in some reservoirs, thus saving the large expenditures of resources involved in extensive drilling programs. Also, being a one-well process, it works in zones where the pay is either continuous or discontinuous, whereas many EOR methods are frontal displacement processes and require good communication between wells.

The screening criteria for the CCDI process are simple. The oil saturation should be at least 30% PV and the depth should be at least 1000 ft. Reservoir temperature is not critical, but cool is better. The API gravity of the oil should be 18 or higher and it is helpful to have a mobile water saturation to aid in placing the carbon dioxide where needed. The injection pressure should be below the miscible pressure for this process because miscible injection will move too much oil away from the wellbore.

C. Nitrogen

Nitrogen injection into petroleum reservoirs has been used to some extent for many years. It is a very good material to maintain pressure if the structure is such that it is not produced back early. Nitrogen as an injection material has two distinct advantages: 1) it is inexpensive compared to other suitable injection gases, and 2) it is completely noncorrosive in contact with surface and downhole equipment.

Nitrogen, like carbon dioxide, can be used as a partially miscible drive. However, considerably higher pressures are required to achieve miscibility with nitrogen. It can be used in sandstones or carbonates if the beds are thin or dipping. It is best for oils with API gravities greater than 34, viscosities less than 10 cp and with high percentages of C1-C7 components. The oil saturation should be greater than 30 percent and is best at depths in excess of 4500 ft. Permeability and temperature are not critical, but cool is better.

D. Hydrocarbon Gases

Hydrocarbon gases have long been used as an injection material to stimulate oil production. The reinjection of produced gas upstructure in a reservoir has been used extensively to maintain reservoir pressure. Heavy hydrocarbon gases such as liquified petroleum gas have been used as first contact miscible slugs followed by a less expensive dry gas to move the slug through the reservoir. This approach became less attractive in the 1970's because of increases in the value of the solvent.

Gas injection projects have also been conducted in which miscible phases were developed in the reservoir (multiple-contact miscibility). The screening criteria are the same as for nitrogen except that the oil should be rich in C2-C7 hydrocarbon components. The process should be applied at depths of 2000 ft (if LPG) or greater so that higher pressures can be used.

Polymer Flooding

Polymer flooding consists of adding polymer to the water used to flood the reservoir and displace oil. The addition of polymer to water increases the apparent viscosity of the water and thereby reduces its mobility. An additional benefit that may be gained is that some polymers decrease the effective permeability to the water phase. The effect of both these changes in the aqueous phase is to reduce the mobility of that phase.

The result obtained by improving the mobility ratio is to increase the sweep efficiency of the waterflood. It should be noted that polymer flooding is a multiple well pattern process just as with regular waterfloods. The improved mobility ratios obtained with polymers increases both areal and vertical sweep efficiencies.

Polymer flooding is best used in sandstones with permeabilities greater than 15 md, depths less than 9000 ft and reservoir temperatures less than 200 deg F. The mobile oil saturation should exceed 10 percent and the oil API gravity should be greater than 25 with a viscosity less than 150 cp. Polymer flooding is an improved waterflooding technique and is widely used because it is relatively inexpensive compared to most EOR processes. It should also be noted that cross-linked polymer gels have been used to some extent to improve waterflooding profiles by selectively plugging high permeability flooded-out layers in the pay zone.

Chemical Flooding

Chemical flooding techniques refer primarily to 1) Micellar-Polymer flooding and 2) Alkaline flooding. Some authors include polymer flooding under the heading of chemical flooding, but it was preferred here to list it as a separate technique because the micellar-polymer flooding and alkaline flooding both reduce the residual oil saturation on the relative permeability curves, while polymer flooding does not.

A. Micellar-Polymer Flooding

A micellar-polymer (MP) process is any that involves injecting a surface-active agent (surfactant) into an oil reservoir to improve the oil recovery. The MP process is the same that is referred to in various places in the literature as surfactant-polymer flooding, microemulsion flooding or detergent flooding. The MP process is often applied as a tertiary flood and is a pattern flood involving a group of injectors displacing oil toward a group of producers. It is not used as a single-well huff and puff type process.

The process involves designing a micellar slug that is compatible with the reservoir rock-fluid system in which it is to be used. The discussion of the make-up of this slug is not included in the scope of this paper. However, it will be pointed out that the formulation of such a compatible slug is often a long, time-consuming, expensive undertaking. Also, the final slug will likely be expensive and, therefore, it will not be feasible to conduct a continuous flood using the slug. Thus, a relatively small slug will be injected and will be followed by a graded polymer flood which acts as a mobility buffer. The mobility buffer is designed to propagate the micellar slug through the reservoir without fingering and breaking up the slug.

The MP process is best applied in a clean sandstone less than 8000 ft deep with a permeability greater than 20 md and a thickness greater than 10 ft. The oil saturation should be greater than 30 percent PV and the oil API gravity should exceed 25 with an oil viscosity less than 30 cp. The reservoir temperature should be less than 175 deg F.

B. Alkaline Flooding

The alkaline flooding process, sometimes called caustic flooding, is one in which an aqueous solution of some alkaline material is injected into a reservoir that contains oil sufficiently acid to react with the alkaline. The alkaline material could be any one of many compounds, but the most widely used are sodium orthosilicate, sodium hydroxide, and sodium carbonate. The crude oils that are most likely to be sufficiently acid to be candidates for this process are fairly heavy oils. The process is dependent on the reaction between acid oil and alkaline injection water to produce surfactants in situ in the reservoir.

The acidity of the oil is characterized by a parameter called the acid number of the oil. The acid number is defined as the amount of potassium hydroxide (KOH), in mg, required to neutralize (to a pH of 7.0) one gram of crude oil. An acid number of 0.2 mg/gm is considered to be the minimum value to consider using the alkaline flooding process. However, a good candidate should have an acid number of 0.5 mg/gm or greater. The best oil to fit the alkaline flood requirements will have an API gravity in the range of 13-35 and a viscosity less than 200 cp. The best rock is sandstone at a depth less than 9000 ft and a permeability greater than 20 md. The reservoir temperature should be less than 200 deg F.

Many operators have been attracted to the alkaline flooding process because it is relatively inexpensive. However, in actual practice, few successful alkaline floods have been conducted, fewer have been successful and the process is not a significant contributor to EOR reserves in the United States or elsewhere in the world.