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RELATIVE PERMEABILITY TECHNOLOGY AND APPLICATIONS

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Matt M. Honarpour and Dan R. Maloney
IITRI/National Institute for Petroleum and Energy Research (NIPER)

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IIT Research Institute
National Institute for Petroleum and Energy Research
P. O. Box 2128
Bartlesville, OK 74005

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ABSTRACT

Relative permeabilities are among the most important petrophysical parameters used for reservoir management. They are used for reservoir characterization, reservoir engineering calculations, variables in numerical reservoir simulation models, determination of injectivities, productivities, water and gas coning behavior, and prediction of ultimate recoveries for various fluid injection schemes. Relative permeability investigations are also invaluable for predicting, identifying, and evaluating formation damage that may result from a number of fluid or rock-fluid interactions.

In this paper, the effects of rock and fluid properties, fluid saturations and saturation histories, temperature and pressure conditions, and wettabilities on relative permeabilities are discussed. Evaluation of formation damage by relative permeability measurements is also discussed. Relative permeability characteristics for heterogeneous rocks; gas-condensate systems; and chemical, thermal, and gas enhanced oil recovery (EOR) processes are presented. New advances in three-phase relative permeability measurements and technologies for laboratory measurements are summarized. Improvements in technology during the past decade have made it possible to study complex reservoir processes in the laboratory under simulated reservoir conditions. Fundamental relative permeability research continues to play an important role in the design and prediction of complex reservoir processes.

Microscopic and Macroscopic Fluid Distribution and Transport in Reservoir Rocks

Reservoir rocks contain countless pores of varying sizes that are often interlaced with reactive minerals, clays, micas, and iron compounds. These complex pore systems and the minerals therein are responsible for the entrapment of fluids and solids and for chemical reactions between fluids and solids. Understanding rock-fluid interactions is critical in designing and performing reliable relative permeability tests.

Fluid distributions and flow characteristics in reservoir rocks are influenced by rock heterogeneities. Laminations of only a few microns in thickness can cause portions of rock to have higher water saturations and different pore size distributions. Flow performance can be affected significantly as a result of even microscopic scale heterogeneities. Oil entrapment by advancing water is controlled by the interplay of capillary and viscous forces (Melrose, 1974; Mohanty, 1987) and, in some cases, gravitational and inertial forces. Pore geometry, pore-to-throat diameter ratio (aspect number), and coordination number are among the microscopic parameters that influence relative permeabilities and hydrocarbon saturations (Wardlaw , 1978).

Formation Damage and Relative Permeability Measurements

Practically every field operation, including drilling, completion, workover, stimulation, production, and injection, can potentially cause formation damage (Krueger, 1988). In enhanced oil recovery, damage to the conductivity of injection and production wells adversely affects sweep efficiencies, recovery factors, and technical and economic viabilities of projects. The effectiveness of formation damage preventive and corrective actions can be evaluated through laboratory relative permeability measurements. Changes in pressure, temperature, production/injection rates, and introduction of incompatible fluids in a reservoir are potential causes of formation damage (Sydansk, 1980). Some common causes of formation damage are precipitation and/or mobilization of constituents of the rock or reservoir fluids, ion exchange, chemical reaction, wettability alteration, and other rock-fluid interactions.

Mechanisms of formation damage often can be evaluated in the laboratory by relative permeability measurements. Anomalies in laboratory relative permeability/saturation curves such as non-monotonic trends, s-shape characteristics at high water saturations, changes in end-point relative permeabilities when the direction of flow is reversed (fines migration), and reductions in relative permeability values due to temperature, pressure, and fluid composition can be clear indications damage that may occur in the reservoir. Amaefule (1987) discussed the role of chemical interactions, hydrodynamic drag, electrostatic/capillary forces, dispersion forces, and bond repulsion forces as factors controlling the migration and trapping of fines. Abrupt changes in brine salinity, pH, and ionic strength are often incompatible with reservoir rock and create an environment for mineral alteration and mobilization of fines. High-velocity injection or production in reservoirs may provide a mechanical drag force for dislogging fines. Rock-fluid interactions causing changes in interfacial tension and wettability may contribute to the mobilization of fines. Organic compounds such as paraffin and asphaltene can precipitate or form emulsions during fluid injection and production, creating serious formation damage.

Effects of Rock, Fluid, and Rock/Fluid Parameters on Relative Permeabilities

Saturation--In a multi-fluid system, the wetting phase is mobile within a limited range under a finite pressure differential. This range depends in part on the rock characteristics and wetting tendencies of the system. As the wetting-phase saturation increases, continuity of flow paths for the nonwetting-fluids break down and residual saturations occur. Similarly, as the wetting-phase saturation decreases, the network through which this phase flows breaks down and becomes discontinuous and immobile. The dependency of relative permeability of a fluid on its own saturation or the saturation of other phases present in a core is not quite clear (Honarpour et al., 1986). Influencing parameters include rock wettability and other factors including those described below.

Rock properties--Pore geometry, pore size distribution, grain size distribution, clay type, pore roughness, surface area, packing, cementation, degree of consolidation, stratification, connectivity, ratio of pore size to pore throat , and other rock heterogeneities may influence the shape of relative permeability curves and residual saturations.

Wettability--The microscopic distribution of fluids and hydrocarbon trapping in a porous medium are greatly influenced by the degree of rock preferential wettability. In a uniformly water-wet system, the relative permeability to water is lower at any saturation when compared to that of an oil-wet system. In addition, the relative permeability to oil in an oil-wet system is lower than the oil relative permeability in a water-wet system. In displacement tests for water-wet rocks, oil production is usually piston-like, whereas in oil-wet rocks, the oil drainage is similar to film flow. Several investigators have shown that relative permeability becomes progressively less favorable to oil production as a rock becomes less water-wet. The residual oil saturation increases as a rock becomes less water-wet. Others have shown that weakly water-wet cores and cores with mixed wettability have more favorable relative permeability curves and lower residual oil saturation than strongly water-wet or oil-wet rocks (Treiber et al., 1972; Salatheil, 1973). The existence of a uniform, unchanging wettability in a reservoir throughout the production and injection life of a reservoir is rare. Rock mineralogy, fluid chemistry, rock-fluid interaction, and surface electrical charges may be partly responsible for the wettability characteristics of reservoir rocks. Buckley and Morrow (1990) discussed the effect of electrical properties (ionic strength) and pore surface roughness, pH on interface behavior. The wettability behavior of rocks may vary in various modes of production (Swanson, 1980). Pores with throats smaller than threshold sizes may stay filled with water at all times.

Mixed- and intermediately-wet rocks may not follow standard scaling laws (Mohanty et al., 1987). Standard scaling laws are most suitable for strongly wet systems (Heaviside, 1983).

Hysteresis--The relative permeability/saturation relationship is not a unique function of saturation for a given core but is subject to hysteresis. That is, several interstitial fluid distributions are possible for each level of saturation, depending on the direction of saturation changes (Colonna et al., 1972). Thus, values of relative permeability vs. saturation obtained for drainage (reduction of wetting-phase saturation) may be different from those for imbibition (increase in wetting-phase saturation) (Wang, 1986). There are two types of hysteresis: flooding phase and cycle hysteresis. Relative permeability hysteresis is significantly influenced by the pore size distribution and wettability of the rock. Jerauld and Salter (1990) indicate that pore-body to pore-throat aspect ratios strongly influence the pattern of hysteresis.

Initial saturation--The initial interstitial water saturation affects the starting point and the shape of oil-water relative permeability curves. The completion level in the reservoir and the rock type determine the initial fluid saturation.

Flow rates and capillary effects--Low injection rate floods are preferred in laboratory tests to model reservoir flow behavior where capillarity dominates. However, undesirable end effects or non-uniform saturation profiles occur during laboratory floods at low injection rates. Some researchers feel that waterflood tests should be conducted at low rates initially and high rates toward the end of the flood. It is reported that relative permeabilities in rocks having intermediate wettability are rate-sensitive; therefore, residual oil saturations and water/oil relative permeability ratios appear to be functions of rates. Huppler (1970) and Heaviside (1983) reported that waterflood results from cores with significant heterogeneities were sensitive to flooding rate, core length, and wettabilities. Design of the appropriate flooding rate depends on wettability, saturation history, rock type, and scaling laws. Options for dealing with capillary effects include (1) conducting relative permeability tests at field rates and accounting for capillary pressure by the use of a simulator (2) conducting tests at very high rates at the risk of influences from other effects such as fines migration, or (3) conducting tests at two rates and then extrapolating data to the field rates.

Relative Permeabilities of Heterogeneous Rocks

Intergranular, intercrystalline, fractured, and vugular rocks with different pore configurations may have similar relative permeabilities. On the other hand, rocks with similar permeabilities and porosities may have very different relative permeabilities. Reliable unsteady-state relative permeability data from heterogeneous core samples are difficult to obtain because of the sensitivity of the results to the nature of the heterogeneities, flooding rates, core lengths, and wettabilities. Sigmund and McCaffery (1979) have reported that standard relative permeability methods using core plugs cannot be applied when the reservoir media is heterogeneous. The use of reservoir simulators has been suggested for interpreting laboratory waterflood data.

Bedding--Corey and Rathjens (1979) studied the effect of bedding plane orientations on gas-oil relative permeabilities. They found that the relative permeability at a given saturation for flow parallel to a bedding plane was greater than that for flow perpendicular to a bedding plane. Bedding planes perpendicular to the direction of flow may in some cases reduce or eliminate viscous fingering and provide piston-like displacement of oil by water.

Vugs and Fractures--In vugular rocks, regions of saturation over which little change in relative permeability has been observed (Ehrlich, 1971). Multiphase flow in fractures is often simulated by oversimplified relationships, such as the direct and linear relationship between fracture relative permeability and saturation of each fluid phase. Fracture relative permeability may depend on fracture size, shape, roughness, stress condition, fracture orientation, fluid saturation, wettability, viscosity ratio, capillary and Reynold's number, viscous-gravity ratio, and density ratio.

Relative Permeability Measurements at Reservoir Conditions

Application--The degree to which laboratory-measured relative permeability data match reservoir performance often depends on the sensitivity of the rock, fluids, and rock-fluid system to laboratory flow conditions. It is most important to test core samples with reservoir-like fluids in a manner that represents the rock behavior at reservoir conditions.

The steady-state method is especially preferable for heterogeneous cores and cores with mixed wettability because dynamic displacement tests often fail to provide accurate permeability data for these rock types (Braun and Blackwell, 1981). Matching reservoir conditions and using live reservoir fluids in laboratory measurements of relative permeabilities are essential in duplicating true rock-fluid interactions. Knowledge of the relative permeability behavior under actual reservoir conditions with live reservoir fluids enables operators to define the most appropriate operational practices and to design remedial actions for production enhancements. In addition, such knowledge provides for more accurate input data for mathematical reservoir simulation. This does not mean that the costs of performing relative permeability measurements at reservoir conditions are justified in every situation (Rathmell et al., 1973). Probably the best compromise is to perform at least one test on fresh or preserved core at reservoir conditions and compare the results with those produced under more accommodating conditions. Significant differences in results may warrant additional reservoir condition tests or corrections of routine test results for reservoir condition effects.

Results--Water and oil relative permeabilities for preserved cores may be much different at a given saturation when tests are performed at reservoir conditions using reservoir fluids than those obtained with extracted cores and mineral oil at ambient conditions (Richardson, 1955). Changes in rock, fluid, and rock-fluid properties during relative permeability measurements at elevated temperatures may be attributed to changes in the following factors:

1. Rock properties - mineralogy, size and shape of grains, pore structure, mechanical properties, solubility of minerals, and fine mobilization.

2. Fluid properties - fluid composition, interfacial tension, viscosity ratio, and fluid/fluid interactions that can be either beneficial or detrimental.

3. Rock-fluid properties - capillarity, wettability, interfacial tension, mobility, solubility, and reactivity.

Many of these parameters are interrelated. For example, thermal strains may create changes in rock composition and mobilization of mineral fines and/or some organic components of the rock leading to alteration of the pore structure. The interfacial tension between fluids may change depending upon the composition of fluids, oil acidity, and brine pH. Crude oil/brine interactions sometimes enhance surfactant accumulation at the oil-water interface as a film. These properties are different from bulk properties of a fluid system and may become more active at elevated temperatures. Changes in viscosities yield different mobility ratios and, therefore, different residual oil and brine saturations. Changes in wettability as a result of temperature increase may result in changes in relative permeabilities and residual saturations.

A comparison of results from 25 reported relative permeability and capillary pressure tests conducted at elevated temperatures on both unconsolidated sands and outcrop cores using relatively inert fluids shows disagreement in effects of temperature on relative permeability measurements (Honarpour et al., 1986). However, temperature appears to have a definite effect on end point saturation and hysteresis.

Net confining stress in a reservoir also should be duplicated and maintained constant as much as possible during laboratory measurements of relative permeabilities. Rock mechanical properties, which affect variations in pore geometry and size, are temperature, pressure, and saturation dependent and vary depending upon the type of rock. Net confining pressure not only affects permeability but also may alter pore structure and flow behavior of some reservoir rocks. The effect of confining pressure is usually more pronounced at lower confining pressures than at higher values. Unconsolidated cores and rocks with fissures, fractures, and layers with appreciable permeability contrast may require closer duplication of reservoir net confining pressure than high permeability, well-consolidated cores.

Other difficulties--When live crude oil is used in relative permeability experiments, the oil and brine should be circulated through the rock in a closed system to prevent the oil from oxidizing or losing light ends. Fluid saturations are best determined using in situ techniques or by keeping track of the volumetric balance by using a high-pressure, oil-water separator in the system. Gas-oil experiments generally should be performed in the presence of water. Gas-oil results may not be wettability sensitive. Instability problems may occur, so results from tests at several rates should be evaluated. Other problems that may occur include the effects of fluid redistribution during temperature cycling, difficulties in achieving a steady-state condition, and improper scaling.

Relative Permeabilities of Gas-Condensate System

Gas retrograde-condensate reservoir performance (gravity drainage, aquifer influx, or water injection), fluid recovery, and well productivity are sensitive to two- and three-phase relative permeabilities. Gas-condensate relative permeability and critical condensate saturation information help in the design of production (straight depletion, gas recycling, or water injection) and stimulation strategies. Production from gas-condensate reservoirs can exhibit behavior similar to formation damage when conditions favorable to condensation exist in parts of a reservoir. This phenomenon is due to the condensation of the higher molecular weight components from the gas phase as the pressure is reduced (Gravier et al. , 1986). Such condensation can occur around wellbores where gas flow rates and pressure drops are high. This in turn can reduce the gas effective permeability appreciably, resulting in loss in productivity. Reduced injectivities due to the presence of three fluid phases have been reported in systems similar to gas-condensate at distances into a reservoir (Azer and Handy, 1983; Schneider and Owens, 1975).

Experimental results show that gas-condensate relative permeability is sensitive to rock type, interfacial tension (close to the critical point), capillary forces, gravity forces, wettability, depletion rates/velocity, connate water, and the method of condensate generation or condensate injection. Both pressure reduction and temperature reduction techniques have been used in laboratory experiments to cause condensation within core plugs. The pressure reduction technique most closely resembles the actual reservoir process. Saturation history has not shown much influence on relative permeabilities in condensate systems.

Difficulties include experimentally combining the complex elements of simulated in situ condensation, residual water saturation, simulated reservoir net confining pressure, temperature, fluid composition, and phase behavior to generate representative test results. Other difficulties include prediction of fluid viscosities and interfacial tensions under various reservoir conditions.

Three-Phase Relative Permeability

Three-phase relative permeability characteristics are necessary for the accurate modelling, simulation, and prediction of EOR flood performance such as chemical, CO_2, WAG, and steam flooding.

Results from three-phase measurements are influenced by wettability conditions, rock properties, state of initial fluid saturations and saturation hysteresis effects. A summary of a recent state-of-art review of three-phase relative permeability measurements (Maloney et al.,1990) is presented as follows:

1. In most three-phase relative permeability studies, the considerable data scatter often is identified as characteristic of three-phase relative permeability measurements. End-effects were often significant and influence the results. Most studies used some type of data-smoothing or curve-fitting technique to produce meaningful data.

2. The three-phase flow regions on ternary diagrams were shown to be small for brine, oil, and gas flow in Berea sandstone cores. Pore-throat size distribution has been reported to influence three-phase flow and the position of the relative permeability isoperms on ternary diagrams.

3. The presence of the third phase, even if immobile, has been shown to influence the other two phases profoundly.

4. Hysteresis plays a major role in both steady-state and unsteady-state tests. Recent work by Oak et al. (1990), shows the application of a fully automated, computer-controlled experimental system where flow rates are adjusted to attain saturations at selected relative permeability isoperms and provide good control of saturation hysteresis. They showed that two- and three-phase water relative permeabilities for water-wet Berea sandstone cores are very similar and show little hysteresis for any saturation history case. Two- and three-phase gas relative permeabilities for water-wet Berea cores are similar for saturation histories where gas saturation is increasing or is decreasing. The three-phase relative permeabilities to oil may be divided into two groups, with several histories representing each group, depending on their functional relationship with saturation.

5. The shape of the isoperms (curves of equal permeability values) on ternary diagrams varied in most studies. Some researchers reported the relative permeability of each phase was a function of its own saturation, whereas others considered relative permeability for each phase to be a function of all three saturations. In most cases, however, relative permeability to brine was reported to be a function of brine saturation alone, while oil relative permeability was thought to be a function of the saturation of all phases. The relative permeability to gas (nitrogen) could be interpreted either way because the curvature observed in some studies was too small to be considered beyond experimental error.

6. Significant differences between three-phase, gas-oil-brine relative permeability measured when gas is CO_2 and those conducted using nitrogen or air (oil relative permeabilities found to be identical and CO_2 relative permeabilities are much lower than those for nitrogen) have been reported. This may be due to higher CO_2 viscosity and complex fluid/fluid/rock interactions and may mean that total relative mobilities and consequently lower injectivities are expected when CO_2 is one of the fluids being injected (Dria et al., 1990).

Lack of repeatability is a common problem in three-phase relative permeability determinations because of both the dependency of results upon procedure and the difficulty to measure saturations of the three phases. Establishment of a reasonably accurate measurement of saturations during steady-state tests when two or more phases are involved is difficult. Material balance techniques for saturation determination are generally inadequate when pore volumes of injectant are large. Saturation determinations based on in situ measurements are most reliable. Unsteady-state and centrifuge measurement methods are not as rigorous and yield only approximate results because of the simplifying assumptions necessary for obtaining mathematical solutions. In the centrifuge method, the relative permeability to gas cannot be determined. In displacement tests, one of the three phases must be immobile. Hysteresis is one of the most serious parameters that researchers have ignored in the past. While it is relatively easy to either increase or decrease the saturation of a phase in a two-phase system, it is intrinsically difficult to change saturation conditions in a controlled sequence during three-phase flow experiments. Another difficulty in three-phase studies is interpreting isoperms, i.e., the lines of constant relative permeability as plotted on ternary diagrams. Experiments in which relative permeability values were obtained by randomly changing saturation conditions generally yielded insufficient data to draw well-defined isoperms on ternary diagrams. Several curve-fitting algorithms have been suggested for interpolation and extrapolation of laboratory data, with schemes ranging in complexity from simple linear fits to multiple power law functions (Parmeswar and Maerefat, 1988).

Relative Permeabilities of EOR Processes

Two sets of data are needed as a precursor to EOR process studies: relative permeability and mobility. These data are necessary input parameters for numerical simulators to model recovery processes for performance evaluation of the efficiency of improved recovery before fluid injection (Goodlett et al., 1986). Chemical, thermal, and gas flooding are all popular EOR processes; however, laboratory screening is needed for the selection of the most effective method of recovery for a particular reservoir.

Chemical Flooding--The use of non-Newtonian fluids for improving mobility ratios and sweep efficiencies has become fairly common in EOR processes. Rheologically complex fluids such as polymer solutions, gels, foams, and other additives are injected to divert displacing fluids and to block swept zones. Non-Newtonian fluid flow mechanisms in porous media are not well understood. Laws similar to Darcy's equation for flow of non-Newtonian fluids in porous media have not been developed. It is not clear that the traditional treatment of simultaneous injection of fluids or dynamic displacement for relative permeability calculations are meaningful. However, when these fluids are of the power-law type and the displacement at the pore level is controlled by capillarity, the concept of relative permeability becomes applicable (Salman et al., 1990). Various polymer-oil steady-state relative permeability data for both oil-wet and water-wet outcrop and reservoir sandstone cores have been reported (Schneider and Owens, 1982; Maloney et al., 1989). The presence of water-soluble polymers in the aqueous phase influences the properties of fluids as well as rock-fluid systems. The presence of polymers in the water phase consistently lowers the relative permeabilities of the aqueous phase in water-wet systems significantly. The oil relative permeabilities either have not shown any change from those measured before polymer injection or have shown some improvement at all levels of oil saturation. Injection of polymer at various flow rates and flow resistance has not shown much effect on residual oil saturation. However, the injection of polymer appears to have an effect on both water and oil relative permeabilities. The indicated effect for oil-wet systems on water relative permeabilities is of the same magnitude as that reported for water-wet systems; however, the effect on oil relative permeability is variable.

Surfactant flooding is one of the most complex oil recovery processes with a high potential for improving oil recovery from target reservoirs. Success of oil displacement with an aqueous, low-concentration surfactant solution is primarily dependent on the effectiveness of interfacial tension (IFT) reduction between the aqueous phase and the reservoir oil, phase viscosities, adsorption, and sweep efficiencies. In this recovery technique, miscibility is obtained when IFT is reduced to near zero on high-concentration soluble oil systems. This increases the capillary number and improves displacement efficiency. The surfactant effectiveness decreases with continuous depletion due to adsorption on the rock and precipitation with divalent cations in the brine. The mechanisms of oil displacement by surfactants may not be explained by Darcy's law alone in all regions of reservoir. Darcy's law applies only in regions where simultaneous flow of oil and water occurs in continous phases. Several steady- and unsteady-state displacement methods for aqueous low-concentration surfactant systems have been reported. The steady-state experimental results show that oil-water relative permeabilities are affected by reduction in IFT resulting from an increase in surfactant concentration (Amaefule, 1982). Oil-water relative permeability values at any saturation show an increase with decrease in IFT, especially at IFT below 1 mN/m. The residual oil and irreducible water saturations show a decrease as IFT decreases. The magnitude of hysteresis also decreases at lower IFT. Injection of micellar fluids in Berea sandstone showed that the relative permeability curve for the microemulsion has the same shape regardless of the carrier phase (water or oil) and appears to be the most wetting-phase in the presence of oil and water phases (Delshad, 1987).

Alkaline flooding has also been used for improving recovery from hydrocarbon reservoirs by increasing the pH of the injected fluids. The improvement in recovery is attributed to lowering the IFT between oil and water, wettability reversal, emulsification, and solubilization of rigid interfacial films (Ehrlich and Waygal, 1976).

Thermal--Injection of heated fluids such as steam and hot water into oil reservoirs to enhance recovery of light and heavy oil has been applied for several decades. Reliable relative permeability data are important to the planning and implementation of thermal recovery projects. Numerical steamflood simulations require three-phase relative permeability data. Two-phase relative permeability data have been used in the absence of three-phase data. Results of comprehensive simulation studies indicate that oil production and produced fluid ratios are very sensitive to relative permeabilities (Bennion et al., 1985). Nitrogen gas-water relative permeability data are often used for steam-water relative permeability data in steam reservoir simulators (Closmann and Vinegar, 1988). It is assumed that the steam permeability may be represented by gas permeability, and gas permeability is moderately sensitive to temperature. It is reported that gas-oil relative permeabilities near the residual oil saturation are extremely important for prediction of steamflood performance (Kumar and Doe, 1990). The gas-oil relative permeabilities should be measured at steam temperatures to simulate accurately the gas (steam) displacement of heavy oil. For water displacement, residual water saturation has been shown to be more important than residual oil saturation. Increases in oil relative permeability or decreases in water relative permeability with temperature increase may indicate better oil recovery for injecting hot water or steam into an oil reservoir. However, rock and rock-fluid interaction also should be evaluated for any formation damage resulting from the application of thermal recovery processes.

Injection of steam in reservoir rock often will vaporize oil, strip lighter components of the crude oil and thus change the oil properties. In addition, the pore structure of the rock may change due to thermal expansion, and rock dissolution/precipitation may take place. Fluid distribution also may be different in steam injection processes as compared to that of nitrogen gas injection.

The cyclic steam process involves continuously changing the saturation and pressure conditions during alternating imbibition and drainage cycles. Three-phase flow is expected to take place in these processes, where both steam and mobile water are found in the presence of oil due to steam condensation (Dietrich, 1981).

Prevention of heat loss during the measurements, nonuniform saturation distribution, and nonlinear pressure gradients give rise to inaccuracies in relative permeability calculations. Other experimental difficulties are measurements of three-phase relative permeabilities and relative permeability measurements near the end points, the effect of hysteresis in wetting phase relative permeability, especially in cyclic steam process, and the effects of pressure and temperature cycling on relative permeabilities.

Gas--Carbon dioxide and nitrogen gas injection have become two of the most technically and economically feasible EOR processes for light and heavy oil recovery. CO_2 injection has a favorable effect on oil relative permeability due to oil swelling. When oil swells within pore spaces, water will be displaced out of these pores, which is the drainage process. For water-wet porous media, the drainage oil relative permeabilities are higher than the imbibition values, which would favor additional oil recovery. However, in some cases, CO_2 injectivity in reservoirs and laboratory corefloods has been less than brine injectivity (Ehrlich, 1984). This behavior is attributed to rock-fluid interactions under certain wettability conditions resulting in low CO_2 injectivity. Patel, et al. (1987) have shown that mixed wettability and the resulting relative permeability hysteresis explain the low CO_2 injectivity observed in the Denver Unit, Wasson field pilot project. The process of trapping water as a non-wetting phase in a mixed-wet system reduces the water relative permeability on secondary drainage as well as the relative permeability to oil. Laboratory studies of highly water-wet, preserved cores from Little Knife field show that higher water relative permeabilities and lower CO_2 relative permeabilities in the presence of residual oil saturation occur. One explanation for this behavior is that the cores become less water-wet when CO_2 is injected (Christman, 1988). Another possibility is the formation of carbonic acid in the presence of brine and resulting changes in rock properties.

Design and measurement of phase properties of the fluid system, the dynamic nature of fluid and rock properties during the fluid flow processes, and definition and measurements of saturations are some of the difficult problems that have to be dealt with in gas EOR laboratory studies. The prediction of CO_2 solubility in oil and water in a core sample is difficult. This makes it difficult to predict oil swelling during a CO_2 flood. Gas phase viscosity also changes due to the vaporization of crude oil components by the CO_2 gas.

New Technologies in Laboratory Measurement

Relative permeabilities are measured by steady-state, unsteady-state, or centrifuge methods. Steady-state methods for determining relative permeabilities provide a wider range of saturation levels, have the greatest reliabilities because capillary equilibrium prevails, and employ measured saturations directly. The calculation scheme is based on Darcy's law. Unsteady-state is the quickest laboratory method of obtaining relative permeabilities. The centrifuge method is an unsteady-state method and provides relative permeability for the displaced phase only and may suffer from capillary end-effects. However, many difficulties are inherent in these methods. Operational problems such as capillary end-effects, viscous fingering, and channeling in heterogeneous cores are difficult to monitor and account for properly (Honarpour et al., 1986).

Injection of two fluids at a given ratio in a core sample does not mean the saturation in a core will be established at the same ratio. External or in situ saturation techniques are required to relate relative permeabilities to saturations (Honarpour and Mahmood, 1988). In external techniques such as volumetric and gravimetric methods, the saturation in the core is indirectly inferred by monitoring fluid production. These methods provide an average value and do not reveal the saturation profile in the core. Significant errors in saturation may be introduced by external measurements; especially when the pore volume of the core is small and the dead volume of the system is large. Fluid separation problems and evaporation losses are also of concern in the volumetric method. Extraction, distillation, or removal of a core from core holder for weighing subject a core to pressure and temperature cycling and saturation changes. Closed-loop systems are sometimes used to reduce errors associated with the volumetric method.

In situ saturation methods offer greater convenience, accuracy, and reliability than the external techniques. They are capable of providing more reliable fluid saturations if accurate calibration methods are used. Attainment of accuracies of ±2% is not unusual. These methods are capable of measuring point saturations which can be used in constructing continuous two- and three-dimensional saturation profiles. Some of the techniques used for in situ saturation measurements are single and dual-energy X-ray absorption, computed tomography (CT), nuclear magnetic resonance imaging (NMRI), microwave attenuation, gamma-ray attenuation, neutron bombardment, and tracer techniques. These methods generally use measurements taken on 15% of a sample's bulk volume to calculate saturations. CT techniques are capable of using data from as much as 100% of the core for saturation calculations. The microwave attenuation technique, unlike most other methods, measures water saturation without requiring any tag or dye.

Electrical resistivity is another method by which brine saturation can be determined. This method is based on interpolation of electrical responses between two calibration points by use of Archie's equation. Even though electrical resistivity is an in situ technique, in practice, it provides only average saturations along the core. Some of the shortcomings of this method include the possible dependence of the resistivities on direction of saturation changes, inaccuracies due to discontinuous flow channels at low brine saturations, and operational problems.

Advances have also been made in the design, fabrication, and automation of relative-permeability systems capable of performing tests under simulated reservoir conditions and for various processes such as gas-condensate and EOR. High-pressure and high-temperature sonic fluid level monitoring devices, reliable backpressure regulators, electronic flowmeters, transducers, constant-rate and constant-pressure pumps, and nonmetallic coreholders are some of the new technologies being used in laboratories. These new advances provide opportunities to investigate and evaluate various oil recovery techniques, leading to improvements in prediction of hydrocarbon recoveries.

Models and Field and Well Tests

Because of the unavailability of cores and the difficulties and costs involved in performing laboratory measurements, empirical models are sometimes used to estimate relative permeability. This alternative is not often a good substitute for laboratory measurements. However, it can be used for interpolation and extrapolation of limited laboratory data. Several idealized models have been developed such as Corey's model for drainage, Naar-Wygal's and Naar-Henderson's models for imbibition, and Land's model for both drainage and imbibition processes. Statistical models have also been used such as Stone's models I and II, and modifications by Dietrich and Bonder and by Nolen for three-phase relative-permeability calculations (Honarpour et al., 1986; Honarpour and Manjnath, 1985; Oak, 1988; Baker and Oak, 1988) . These models require two-phase relative permeability data as parameters.

Laboratory-measured end-point relative permeability should agree with transient well test, injection, and production data. The laboratory-measured relative permeability to water at residual oil saturation should be comparable with the water relative permeability of watered out zones measured with well testing techniques. Laboratory-measured oil relative permeability at initial water saturation should compare with oil relative permeability from well tests performed near discovery time. The degree of agreement between laboratory and field measurements is influenced by the representativeness of the plug samples as well as reservoir heterogeneities (Honarpour and Tomutsa, 1990).

Relative permeability data should be honored as much as possible. To develop a good history match, some engineers resort to adjusting with relative permeability values rather than searching for other reservoir parameters that were not included in their mathematical simulations. This is not an acceptable practice because even though a good history match may be obtained by altering the relative permeability data, a reliable performance prediction will not be attained. Curve-fitting algorithms have been suggested for interpolation and extrapolation of laboratory data, with schemes ranging from simple linear fits to multiple power-law functions (Parmeswar and Maerefat, 1987).

For simulation, laboratory data for each rock type with appropriate saturation history should be used. One-dimensional (1-D) laboratory relative permeability data when used in a grid cell of a simulator represent a situation where fluids are distributed equally throughout a grid cell. When a distinct interface exists between the two phases due to gravity, especially when the grid blocks have large dimensions or when a heterogeneous grid block is partially swept, the relative permeability and capillary pressure are distinctly different from laboratory curves (Saleri and Toronyi, 1988). By recognizing the nature of the fluid distribution, psuedo relative permeabilities may be developed to account for heterogeneous fluid distribution in reservoirs. The consistency in relative permeability and capillary pressure end-points should also be kept in mind.

CONCLUSIONS

Relative permeability measurements are needed to predict reservoir productivity, identify the causes of low productivity, minimize formation damage, and to understand rock-fluid interactions taking place as a result of enhanced recovery processes. The measurements should be conducted under reservoir-like conditions with emphasis on quality control. The utility of experimentally determined relative permeability results depends upon the manner in which the tests were designed and conducted as well as the interpretation of the results by qualified persons.

Significant advances have been made over the past decade in petroleum laboratory equipment and experimental techniques. These advances have allowed researchers to simulate complex reservoir processes in the laboratory, yielding data which have been instrumental in improving the prediction of hydrocarbon recovery.

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