EOR Performance and Modeling

The demand for oil continues to grow, and it is forecasted that oil will continue to dominate the world share of energy supply for the next 3 decades. Accordingly, new discoveries tend to decrease on an annual base, and enhanced oil recovery (EOR) has the potential to reclassify unrecoverable and contingent reserves. EOR is viable because there are many available mature technologies, its implementation usually does not require drilling and completion cost, and most of the existing infrastructure can be used.

When I selected the EOR papers to highlight this year, I classified the papers into the categories of gas injection, chemical methods, thermal methods, conformance control, microbial EOR, carbonate-reservoir EOR, reservoir-problem-identification technologies, and novel EOR methods including low-salinity waterflooding, imbibition EOR, alkaline/surfactant/gas injection, and CO_2-miscible combined with alkaline/surfactant/polymer injection. Not surprisingly, CO_2 EOR and polymer floods have drawn great interest this last year because CO_2 sequestration has been a great interest to the community and polymer flooding is a proven cost-effective chemical-EOR method. The published polymer papers cover mainly the topics of thermal-stability evaluation of different polymers, novel polymer-flooding modeling, polymer-rheology database, and the formation effects on polymer properties. The CO_2 publications discussed mainly the feasibility-evaluation results of CO_2-EOR projects in different oil fields worldwide.

An EOR project is not just a matter of injecting materials, with many factors affecting whether the project is successful. The design and implementation of an EOR project require a systematic integration from a multidisciplinary team. It is critically important to identify the problems of mature oil fields for a successful EOR project, and, thus, the papers to identify channels in mature oil fields were included in this EOR feature. **JPT**

EOR Performance and Modeling additional reading available at OnePetro: www.onepetro.org

SPE 121460 *• "Stability of Partially Hydrolyzed Polyacrylamides at Elevated Temperatures in the Absence of Divalent Cations" by R.S. Seright, SPE, New Mexico Institute of Mining and Technology, et al.*

SPE 123971 *• "Streamline-Based Simulation of Non-Newtonian-Polymer Flooding" by Abdulkareem M. AlSofi, SPE, Imperial College—London, et al.*

SPE 123930 *• "Identification and Characterization of High-Conductive Layers in Waterfloods" by C.S. Kabir, SPE, Hess, et al.*

SPE 124930 *• "Mechanistic Modeling of Emulsion Formation and Heat Transfer During the Steam-Assisted Gravity-Drainage (SAGD) Process" by Prince N. Azom, University of Texas at Austin, et al.*

SPE 124946 *• "Pore-Level Mechanics of Forced and Spontaneous Imbibition of Aqueous Surfactant Solutions in Fractured Porous Media" by Amar J. Alshehri, SPE, Stanford University, et al.*

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Industry Experience With CO_2-Enhanced-Oil-Recovery Technology

This summary shows how the oil/gas industry has achieved success in engineering the process to capture, transport, and inject CO_2 in enhanced-oil-recovery (EOR) projects. Some 37 years of safe and environmentally friendly large-scale operations, lessons learned, technical advancements, and millions of tons of CO_2 injected demonstrate this success. With carbon capture and storage (CCS) being widely considered and with a few countries implementing commercial-scale CCS projects, technology transfer shares the experience of the oil/gas industry and the major contribution it can make as part of the solution for climate change.

Fig. 1—US CO_2-pipeline network.

Introduction

Since the first CO_2-EOR patent was granted in 1952, the oil/gas industry has spent many tens of billions of dollars developing and implementing CO_2-EOR technologies, asset development, and operational experience. As new sources of CO_2 have become available, field-testing and demonstration or pilot-project activities have been conducted. These development and improvement efforts have been continuous since the first project in 1964. The first large-scale, commercial CO_2-EOR project began operations in 1972 at the SACROC field in west Texas, which is still in operation. Many more projects have started since that time, and by 2008, the count reached 112 projects. Innovative, cost-effective materials, equipment, and methods continue to be developed and implemented, such as the introduction of real-time smart-well operations at SACROC.

This article, written by Senior Technology Editor Dennis Denney, contains highlights of paper SPE 126446, "Industry Experience With CO_2-Enhanced-Oil-Recovery Technology," by ***R.E. Sweatman,*** *SPE, Halliburton;* ***M.E. Parker,*** *SPE, ExxonMobil; and* ***S.L. Crookshank,*** *American Petroleum Institute, prepared for the 2009 SPE International Conference on CO_2 Capture, Storage, and Utilization, San Diego, California, 2–4 November. The paper has not been peer reviewed.*

CO_2-EOR Technology for CCS Deployment. Underground geological storage of CO_2 is a promising technology for reducing greenhouse-gas (GHG) emissions because much of the technology developed by the oil/gas industry that is associated with natural-gas processing and CO_2 EOR can support the sound implementation of CCS. Large storage capacity exists in deep saline formations, depleted oil/gas reservoirs, and unmineable-coal seams. According to a report in 2005 by the Intergovernmental Panel on Climate Change, as much as 55% of a worldwide GHG-mitigation effort through 2100 could be achieved safely by use of CCS.

In CO_2 EOR, storage occurs as the CO_2 displaces hydrocarbons from reservoir pore spaces and the injected CO_2 becomes trapped within the reservoir's pore spaces by capillary forces and other mechanisms. CO_2-EOR projects can be converted into CCS projects at the end of their operating lifetimes. Accordingly, the petroleum industry can make substantial contributions to improve and accelerate the deployment of CCS projects.

The petroleum-industry processes and experiences that are relevant to CCS include separating (or capturing) CO_2 from oil or natural-gas production, pipeline transportation to EOR projects, and design and operation of surface and subsurface systems for injecting CO_2. **Fig. 1** shows a map of the more than 3,500 miles of CO_2 pipelines in the USA and Canada. The yellow shaded areas represent many of the sources of CO_2 both from underground reservoirs and from aboveground sources such as plants processing ammonia, treating natural gas, or gasifying coal.

Industry CCS Activities

Oil/gas companies participate in research consortiums and fund research at major universities to answer technical and policy questions surrounding GHG management, including CCS. The American Petroleum Institute (API) continually develops recommended practices, standards, and other information to ensure ongoing safe and environmentally sound operation of CO_2-EOR operations. These same standards and practices, based on extensive industry experience, should help government agencies or regulators prepare reliable rules for CO_2-injection facilities and wells. Additionally, API and the International Petroleum Industry Environmental Conservation Association have developed guidance for accounting of CO_2-emission reductions associated with CO_2-storage projects.

CCS and CO_2-EOR Studies

Several groups have voiced concerns about embracing geologic storage of CO_2 without a thorough understanding of the potential effect on underground sources of drinking water (USDW). Although sufficient evidence exists to argue that CO_2 injection and storage over long periods presents very low risk to USDW, API recognized the need for a comprehensive publication to document CO_2-EOR best practices and technologies, and the need to substantiate the case for sustained well integrity and CO_2 containment within oil/gas and other reservoirs. Key arguments supporting this case include that oil and natural gas (including CO_2) have been trapped in geologic structures over geologic time frames and that numerous gas-storage projects (e.g., sour-gas injection and natural-gas storage) are successful without adverse effects on USDW. Years of EOR experience have produced technologies, expertise, and procedures for safe and environmentally sound CO_2 handling and injection-well construction, operation, and maintenance.

API conducted a study of CO_2-EOR-project operators with questions designed to capture best practices and operational performance. Survey results included many findings not presented clearly before, particularly in the context of the concerns around CCS. For example, to cement wells, CO_2-EOR operators have used Portland-cement-based well-cement systems almost without exception and, significantly, without adverse loss of CO_2 containment. These cost-effective conventional cements were designed to provide sealing and structural-support properties suitable for the CO_2-EOR application. No evidence of chronic leaks into USDW zones or into the atmosphere was found.

It is generally accepted that injected CO_2 will react with the in-situ formation water to create a weak carbonic-acid solution, which is the basis for many of the concerns raised regarding CCS. Following the formation of the weak-acid solution, several potential chemical reactions are possible, some of which could occur concurrently.

The in-situ-formation-water salinity and mineral content can substantially affect the amount of carbonic acid formed because CO_2 molecules have difficulty hydrating and CO_2 molecules in the formation are easily buffered compared with those mixed in fresh water in metal or glass laboratory containers or testing devices. For example, the carbonic-acid-induced pH of CO_2 mixed in pure or other inert-water solutions in laboratories is lower (more acidic) than the pH that actually would be present in underground formations, primarily because of the lower CO_2-induced carbonic-acid content from buffering action by materials found in formation fluids and on the reservoir-rock surfaces.

The weak in-situ acidic conditions help explain why operators have used Portland-cement-based systems to seal and support wells successfully in CO_2-EOR projects. The extreme degradation of cement common in many laboratory-test results is likely a result of the absence of mineral buffering and of not matching other reservoir conditions.

Zonal Isolation and Well Integrity. During the last 9 years, representatives from government, academic, and industry organizations of the API Task Group on Annular-Flow Prevention studied causes and prevention of annular-flow incidents and sustained casing pressure in wells, which are recognized indicators of poor well-cement integrity. Two API Recommended-Practice publications (*RP-65* Parts 1 and 2) were prepared and approved that describe preventive measures for any potential flow zone in any type of well, including those in CO_2 zones. Preventive measures include key well-planning, drilling, mechanical-barrier, and cementing practices designed to help ensure cement integrity and isolation of potential flow zones. Application of *RP 65* practices can minimize the risk of CO_2 migration as a result of the multiple pressure barriers installed in wells in the form of multiple casing strings from the surface of the well to its total depth, mechanical pressure-barrier devices, and the cemented sections around each pipe.

Minimized Pipe Corrosion. The oil/gas industry has more than 60 years' experience in protecting carbon-steel pipe from corrosion by acidic fluids in well tubing and flowlines by lining the pipe with Portland-cement-based systems. This cement-lined pipe prevents both dry and wet CO_2 from contacting the inner surfaces of carbon-steel pipe in both EOR-injection and -production wells.

US EPA Funded Studies. Reports at US Environmental Protection Agency (EPA) and International Energy Association (IEA) meetings in March 2007 stated that in injection-well mechanical-integrity tests (MITs), there were no USDW effects associated with wells with known internal or external MIT failures from 1983 to 1992. MITs measure the pressure-sealing performance (maximum 5% loss in 30 minutes) in any one part of the well (e.g., "Annulus A," which is the area sealed at the top by the wellhead and at the bottom by the packer and between the injection tubing and the well casing. The significance of the data is that MIT failures are rare, and where they do occur, effective response or repair technologies exist that protect underground water resources.

Other Studies of CO_2 Containment. The IEA GHG R&D program's monitoring network reported on soil-gas-sampling measurements at the Rangely field CO_2-EOR project in Colorado, USA, and concluded that the total amount of CO_2 leakage from the EOR zone was less than 0.01% over 15 years of CO_2-EOR operations. The IEA report also stated that there is no evidence of CO_2 leakage from storage reservoirs at other CCS projects including Weyburn in Saskatchewan, Canada; Frio in Texas, USA; and Sleipner offshore Norway. One depleted oil well in the West Pearl Queen field in New Mexico, USA, was leaking CO_2 at less than 0.1%/yr because of sealing-integrity damage caused by an overpressure event.

API Collaboration

For CCS projects, API provided valuable information to the US Department of Energy, EPA, and environmental nongovernmental organizations on CO_2-EOR technology and best practices that will help ensure successful health, safety, and environment (HSE) performance. API's activity in CCS also includes providing comments to government authorities in the US legislative and executive branches. Accordingly, information from API and other studies may benefit the decision process for developing and commercializing CCS projects and gas-storage-well-construction, -operations, and -abandonment technology.

Reliable Development Practices for CCS. The oil/gas industry has an excellent record of reliable development for operational surface facilities and wells in environmentally and politically sensitive locations. This practice usually involves the use of HSE and standard industry practices for well integrity along with more oversight by local regulators and community representatives.

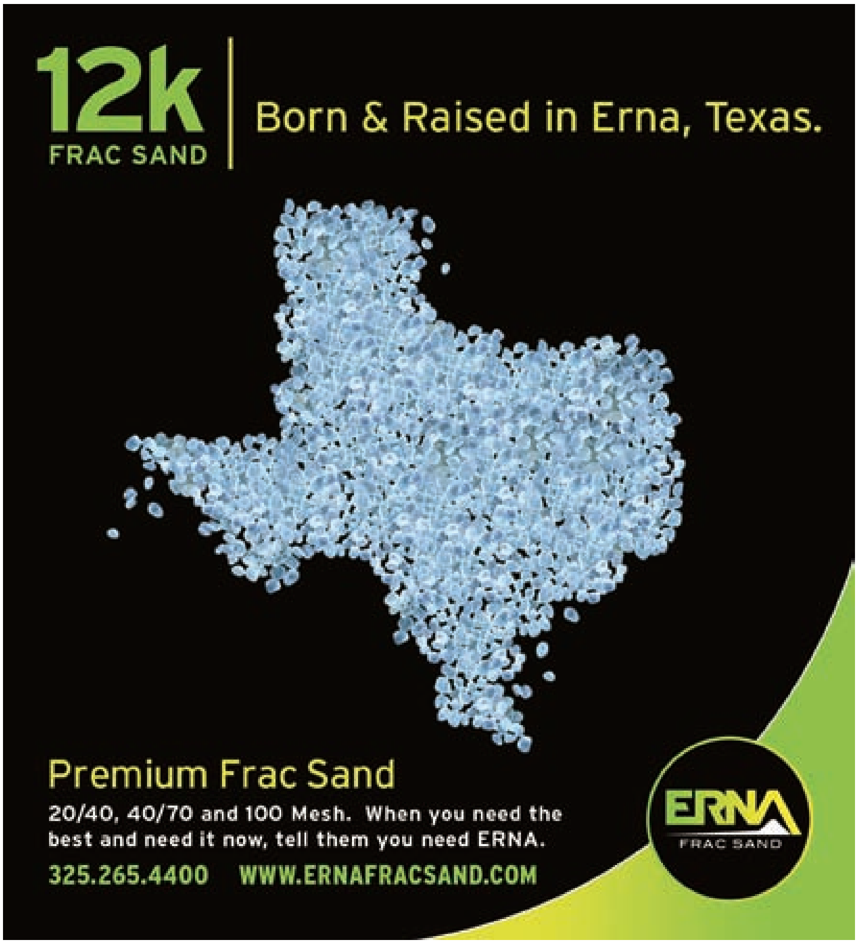
Sensitive Sites. Unlike solar- and wind-energy equipment and facilities, oil/gas wells, rigs, and other structures can be hidden from public view to satisfy concerns regarding unattractive industrial facilities and the effect on community interests such as tourism and residential-property values. Oil/gas surface facilities and wells also can avoid environmentally sensitive locations, such as wildlife habitats in marshes and other wetlands, by drilling many directional wells from a single location that is outside the sensitive area.

Well- and Reservoir-Integrity Assurance

Highly sophisticated technologies enable monitoring CO_2-storage integrity. Intermittent- and long-term-monitoring methods include wireline-conveyed-logging tools run in production, injection, and monitoring wells; seismic-array data imaging; wellbore-pressure monitoring by use of wellhead and downhole gauges; injection- and production-volume monitoring with flowmeters; subsurface-to-surface deformation measurements by use of tiltmeters and satellite radar; and gravity surveys. Applicability is site-specific, and selection thereof requires an understanding of the site's subsurface characteristics as well as the measurement capabilities of the various techniques to match the site's monitoring, verification, and accounting objectives. Monitoring practices should be consistent with the leakage-risk assessment made during the site-characterization phase.

Monitoring Results. Monitoring data include geological, geochemical, geophysical, and satellite data. Standard oil-industry geological-characterization data have been acquired, including wireline and logging-while-drilling logging suites, core sampling, and 3D seismic. Geochemical-monitoring data include surface- and soil-gas monitoring, downhole gas measurements, and production monitoring. Tracer chemicals (perfluorocarbons) are used to "tag" injected CO_2, so that any detected CO_2 can be differentiated from the natural CO_2 in the subsurface and traced back to an individual injection well.

Perhaps the most valuable, and initially surprising, monitoring method is the use of satellite airborne-radar interferometry to detect subtle ground deformation above the injection wells. Permanent-scatterer interferometry is a multi-interferogram approach that draws on the phase changes occurring between a series of radar images and is specifically designed to overcome the effects of atmospheric noise and, thereby, to determine surface-movement histories over periods of several years. Permanent-scatterer interferometry provides an accuracy of approximately 5 mm/a, and 1 mm/a for a longer-term average. Another related approach is differential interferometry, which measures changes in a single interferogram developed from two radar images. JPT



Systematic Study of Alkaline/Surfactant/Gas Injection for EOR

Alkaline/surfactant/polymer (ASP) flooding is a popular enhanced-oil-recovery (EOR) method. However, foam can be an alternative to polymer for improving displacement efficiency. The use of foam as a mobility-control agent by coinjection or alternating injection of gas and chemical slugs is termed here an alkaline/surfactant/gas (ASG) process. Foam reduces the relative permeability of the injected chemical slug that forms a microemulsion at ultralow oil/water interfacial tension (IFT) and generates sufficient viscous pressure gradient to drive the foamed chemical slug.

Introduction

In the ASP process, polymer provides mobility control during ASP slug and polymer-drive injection. However, the use of polymer has disadvantages.

- High-molecular-weight polymers can plug rocks with very low permeability.
- Many of the commercially available EOR polymers can be unstable at high temperature.
- Some polymers can degrade mechanically from high shear stress through chokes or perforations at high flow rate.

One potential alternative to polymer is foam, which can provide mobility control in chemical-EOR processes. Liquid saturation is reduced with increased gas saturation and trapped gas in the foam, resulting in lower liquid relative permeabilities. In foam, gas bubbles are trapped in thin films of fluid called lamellae. The surface tension on the individual lamella, as well as the drag force on it as it slides along the pore walls, causes it to resist movement out of the pore throats. This resistance to movement, when combined with relative permeability reduction of the displacing fluid, results in a favorable mobility ratio and improved displacement efficiency.

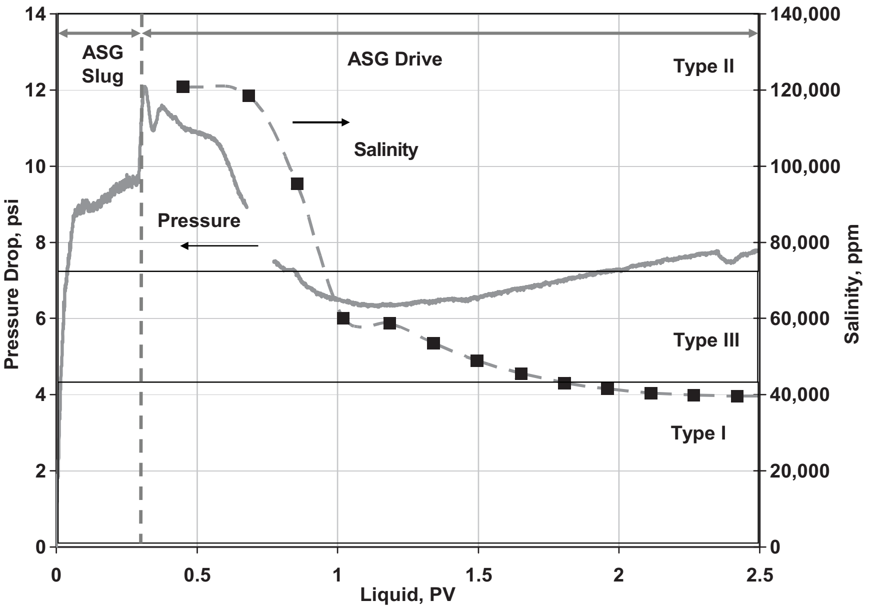


Fig. 1—Pressure drop and effluent salinity vs. liquid injected for an ASG coreflood.

This article, written by Senior Technology Editor Dennis Denney, contains highlights of paper SPE 124752, "A Systematic Study of Alkaline/Surfactant/Gas Injection as an EOR Technique," by ***Mayank Srivastava****, SPE,* ***Jieyuan Zhang****, SPE,* ***Quoc P. Nguyen****, SPE, and* ***Gary A. Pope****, SPE, University of Texas at Austin, prepared for the 2009 SPE Annual Technical Conference and Exhibition, New Orleans, 4–7 October. The paper has not been peer reviewed.*

In ASG flooding, as in conventional chemical flooding, the mechanism of residual-oil mobilization is IFT reduction. One of the main criteria for the success of the ASG process is the formation of stable foam with adequate mobility-reduction characteristics. The full-length paper details the results of experimental work studying the ASG process to evaluate its potential as a feasible EOR technique.

Experiment

Materials. The chemicals used in the ASG corefloods were identified in previous ASP studies for their effectiveness in residual-oil mobilization and mobility control.

Surfactants. Two surfactants, an alcohol propoxy sulfate and an internal olefin sulfonate, were identified as main surfactants for the corefloods. Their selection was based on the results of aqueous stability, phase behavior, and foam-stability tests. Previous studies showed that these surfactants give the best result in ASP corefloods conducted at low temperature and with light oil. In addition, an alpha-olefin sulfonate surfactant was tested as an alternative foaming agent in one of the experiments.

Alkali. Alkali generates soap in the presence of reactive crude oil and reduces surfactant adsorption on rock surfaces. Two alkalis, sodium carbonate and sodium metaborate, were used

For a limited time, the full-length paper is available free to SPE members at www.spe.org/jpt.

in the ASG corefloods. Sodium carbonate is a conventional alkali speeds microemulsion equilibration, resulting in quick mobilization of residual oil. It also aids in polymer hydration. However, sodium carbonate reacts with divalent cations in the solution to form insoluble salts (carbonates) that precipitate. In reservoirs with formation brine having high concentrations of calcium and magnesium ions, carbonate is replaced with sodium metaborate.

Polymer. To study the effect of polymer on foam stability, a low-concentration polymer was used in one of the ASG corefloods. The concentration of this low-molecular-weight polymer was not high enough to cause any increase in fluid viscosity.

Cosolvents. Cosolvents are mostly small-carbon-chain (C_3 to C_5) alcohols. The presence of alcohol may have a destabilizing effect on foam stability. Therefore, use of alcohol in ASG flooding is not always favorable. However, alcohol reduces microemulsion equilibration time and prevents gelation. The omission of alcohol may result in less-than-optimal phase behavior.

Formation Brine and Crude Oil. Two synthetic formation brines, representing formation fluid of separate reservoirs, were used in corefloods. Two crudes, one for sandstone and another for dolomite corefloods, were used. The crude oil used for sandstone ASG corefloods had a viscosity and density of 1.9 cp and 45°API, respectively. The crude used for dolomite ASG coreflood had a viscosity and density of 7.09 cp and 28°API, respectively.

Procedure. ASG-coreflood experiments were conducted after the optimal chemical formulation was identified through aqueous-stability, phase-behavior, and foaming tests. Four corefloods were conducted on Berea sandstone cores and one on Silurian dolomite core. The coreflood procedure was the same in every experiment. The main objectives of corefloods were to study the ASG process and effects of slug size, surfactant type, polymer, and rock type on the process. Successful coreflood criteria include high oil recovery, low pressure gradient, and low surfactant retention.

Aqueous-stability tests showed good compatibility of chemicals in the aqueous solution within the desired salinity range. One phase-behavior test used sodium carbonate, while the other test used sodium metaborate. Phase-behavior tests resulted in the determination of the optimal salinity range in which low IFT between microemulsion-oil and microemulsion-water phases was observed. From the results of the phase-behavior tests, the salinities of injected slug and drive fluids were determined. The optimal salinity was 45,000 ppm. In all corefloods, the slug was injected at the optimal salinity, while the drive was injected at low salinity.

ASP Coreflood. ASP corefloods were carried out on Berea sandstone core samples. Pressure profile across the core in ASP coreflood exhibited an increased pressure drop during slug injection. This is the result of relative permeability effects from mobilization of oil. Pressure starts to stabilize during polymer drive and reaches the steady-state value associated with continuous polymer drive. A 0.3 pore volume (PV) slug of was injected into the core and followed by polymer drive until oil cut reached 100%. A typical sequence of effluent recovery observed in an ASP coreflood is waterflood brine, oil bank, microemulsion, and injection brine. On average, oil recoveries in ASP corefloods varied from 85 to 95%.

ASG Coreflood. The pressure gradient increased during slug injection because of relative permeability effects associated with oil mobilization. The pressure decreased as soon as the drive injection started because the total surfactant concentration in the slug was 10 times that of the surfactant concentration in the drive (foam is stronger in the slug).

An increase in pressure drop across the core occurred during drive injection. After an initial decline, the pressure drop across the core stabilized. With continued injection, the pressure drop exhibited an increasing trend until it reached steady-state pressure drop. This pressure behavior was attributed to mobilization of trapped surfactant. Because of the designed gradient in salinities of injected fluids, the salinity condition in the core changed from Type-II- to Type-III-phase environment, and then from Type-III- to Type-I-phase environment, as shown in **Fig. 1.** Transition from Type-II- to Type-III-phase environment resulted in the mobilization of surfactant trapped in the immobile Type-II microemulsion phase. As the salinity decreased further from the Type-III to the Type-I region, additional trapped surfactant was mobilized. Mobilization of trapped surfactant in the aqueous phase improved foam stability and increased foam strength.

The increase in pressure gradient during the drive injection highlights the mobility and conformance-control potential of the ASG process. The formation of strong foam, resulting from surfactant mobilization, improves the mobility ratio and diverts the injected fluids to other regions of the core. Thus, maintaining a negative salinity gradient in chemical flooding also assists the ASG process by making conditions conducive for foam stability.

ASG Oil Recovery. The oil recovery in the base-case ASG experiment was 67% of the oil remaining after waterflood. The maximum oil cut was 25%, observed at 0.4 PV of liquid injection. The oil recovery obtained in ASG corefloods was comparable to ASP-coreflood oil recovery. This result highlights the potential of ASG flooding as an effective EOR technique. Surfactant concentration in the effluent was not measured. However, the effluent salinity was measured. The effluent-salinity data indicated no early breakthrough of the injected-slug salinity. The breakthrough of injected-slug salinity occurred after injection of 1 PV, indicating the absence of viscous fingering and the presence of favorable mobility control in the process. The oil recovery varied from 62 to 82% in sandstone ASG corefloods.

In the dolomite test, oil recovery was approximately 87% of the oil remaining after waterflood. The coreflood demonstrated successful application of the ASG process in dolomite rocks, highlighting the feasibility of the ASG process for chemical EOR in carbonate rocks such as dolomite and limestone.

Future Work

Overall, ASG results compared well with ASP corefloods, indicating the potential of the ASG process as a feasible EOR method. However, more corefloods performed under varying conditions of rock properties and injection methods are required to ascertain the full potential of the process. Because polymer may not be used in tight fractured carbonates, these formations are candidates for ASG flooding. Hence, as a continuation of this work, future ASG corefloods are planned on fractured dolomite and limestone rocks. **JPT**

Mapping Fractures and High-Permeability Channels in Waterfloods by Use of Injection and Production Rates

This paper extends previous work for managing waterfloods by estimating flow characteristics from only injection and production rates. The method estimates the finite-impulse-response (FIR) curve corresponding to the fluid flow between all injector/producer pairs. Reservoir parameters, such as connectivity between wells, can be estimated from this curve, which can be used to characterize variations of relative flow as a function of storage capacity, thus making it possible to quantify the heterogeneity of flow paths between wells.

Introduction

In waterflooding, injection rates often can be correlated with gross rates of the surrounding producers by monitoring pressure data. To estimate this correlation, the whole region of injectors/producers is viewed as a system, with the injectors as the system input and the producers as the system output. Methods to estimate the directional transmissivity of flow on the basis of injection- and production-rate data are desirable because injection- and production-rate data are routinely available with high temporal resolution for many reservoirs.

The problem of estimating reservoir properties from injection/production rates is considered a system-identification problem, where injection rates are input and production rates are output. This method could be considered a standard multiple-input/-output (MIMO) system. It is reasonable to assume that the effect on production of each injector can be modeled as a linear FIR filter applied to the injection rates. This FIR curve can be analogous to the response obtained from pulse testing. Modeling the reservoir as a linear FIR-MIMO system is proposed, for which system identification can be solved by use of the least-squares method with truncated order. The main contribution is providing a dynamic approach to estimate the flow characteristics between wells by use of only injection and production data.

This article, written by Senior Technology Editor Dennis Denney, contains highlights of paper SPE 121353, "A Novel Method for Mapping Fractures and High-Permeability Channels in Waterfloods Using Injection and Production Rates," by ***Kun-Han Lee,*** *SPE,* ***Antonio Ortega, Amir Mohammad Nejad,*** *SPE,* ***Nelia Jafroodi,*** *SPE, and* ***Iraj Ershaghi,*** *SPE, University of Southern California, prepared for the 2009 SPE Western Regional Meeting, San Jose, California, 24–26 March. The paper has not been peer reviewed.*

Injector/Producer Relationships

In a waterflood, production rates are influenced by reservoir transmissibility, bottomhole flowing pressures, and the pressure changes caused by fluid injections. To capture the injector/producer relationships, various models describe the production rates resulting from injection rates and other factors.

Injector/Producer Model. A general linear-FIR model was used in which production rates were determined partly by a linear combination of the surrounding FIR-filtered version of injection rates. This FIR-MIMO model is very general and can be used to approximate many different models developed by previous researchers, such as a streamline model that describes the relationship between injectors and producers by many imaginary streamlines and capacitance models that use only two parameters to describe the relationship between each injector/producer well pair.

With many injectors and producers, the system can be modeled as a standard linear FIR-MIMO system. Given this assumption, the problems are how to estimate the FIR coefficients in a robust manner and how to relate these estimated FIR coefficients to important characteristics in the reservoir.

FIR Coefficients

The FIR coefficients represent how each producer is influenced by its surrounding injectors. The first problem is how to estimate the FIR coefficients between all injector-/producer-well pairs. This method must handle some degree of noise because there are potential sources of error in production data. Estimating the FIR coefficients of a linear FIR-MIMO system is a classical problem in system identification, and many robust methods are available that deal with different kinds of noise. Because production data are a major source of error in the system, an output-error model was used. A conventional prediction-error approach, the least-squares method with truncated FIR order, was used to estimate the FIR coefficients.

Flow Characteristics

To relate the estimated FIR coefficients to important flow characteristics in the reservoir, the procedure uses the FIR curves (formed by FIR coefficients), which are analogous to the curves obtained with pulse testing. Also, the proposed FIR curve for each injector/producer pair can be interpreted as an estimate of the flow influence from a specific injector to a specific producer, thus providing information similar to that provided by the tracer-concentration curve. Therefore, this FIR curve was used as a rough estimate for the tracer-concentration curve.

Applications of FIR Curve. Estimating Effective Flow Units. Effective flow units, also called interwell connectivity, or well-allocation factors, are a set of weight factors that characterize

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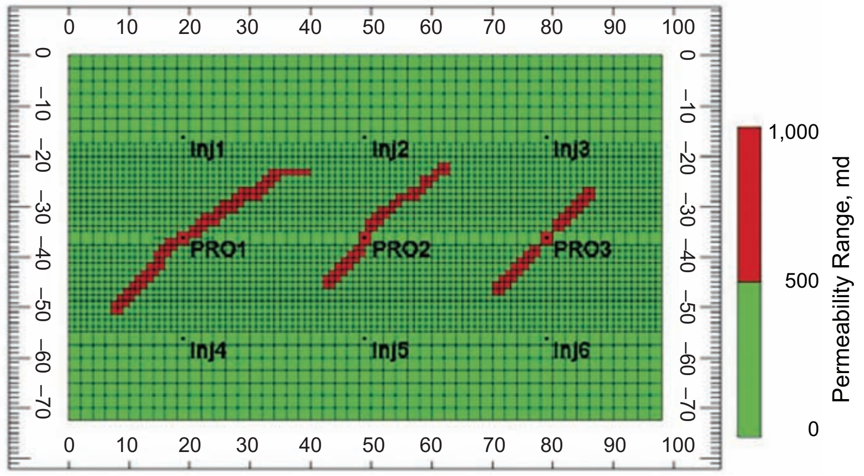

Fig. 1—Numerical-simulator model of a single-layered reservoir with three high-permeability channels.

the effective contribution of injection wells to the total gross production in surrounding production wells. For the general injector/producer model (FIR model), effective flow can be computed directly as the sum of the FIR coefficients corresponding to the injector/producer well pair.

Flow/Storage Capacity. Plotting flow capacity vs. storage capacity was proposed in the early petroleum literature as a way to estimate the injection-sweep efficiency. This method was usually shown in a flow/storage diagram to highlight the relative flow to its associated volume. The flow-/storage-capacity graphs can be used to characterize the degree of heterogeneity in a reservoir.

Predicting Production Rates. The estimated-FIR curve describes the influence on production rates from surrounding injection rates for each producer. Thus, the FIR curve, combined with only injection rates of surrounding injectors, can be used to predict future production rates of each producer.

Results

Estimating Interwell Connectivity. The procedure was applied in a numerical simulator with a linedrive injection pattern with a six-injectors/three-producers scenario. In all cases, a two-component water and oil system was simulated considering only vertical wells. Oil viscosity was set to 4 cp.

Homogeneous Case. In this case, a single-layered homogeneous reservoir was simulated. This reservoir had a homogeneous permeability of 100 md, and the reservoir pressure was set to 1,000 psi.

The injection rates were based on selected Haar wavelet sequences. Sequences in the set were highly noncolinear, and this design resulted in much smaller measurement errors compared to the situation in which injection rates are highly colinear. Because the reservoir is homogeneous, it was expected that the estimated effective flow units would be almost symmetric across the plane of symmetry and would decrease as the distance between injection and production wells increased. All estimates matched well with the chosen reservoir conditions.

Multiple-High-Permeability-Channels Case. This single-layered reservoir, with an isotropic permeability of 0.1 md, included three high-permeability channels with different lengths, all oriented at approximately 45°, as shown in **Fig. 1**. The injection rates were set the same as in the homogeneous case.

Because the lengths of the three channels were different, it was expected that Injectors 1 and 4 would have larger effective flow units with respect to Producer 1, compared with the effective flow units between Injectors 2 and 5 and Producer 2 or with the effective flow units between Injectors 3 and 6 and Producer 3, which should have the smallest effective flow units. Because all the channels are at 45°, it was expected that the Injector-2 to Producer-1 pair should have larger flow units than the Injector-5 to Producer-1 pair. The simulation results agreed. The estimated effective flow units capture the trend of high-permeability channels oriented in the 45° direction, which was not captured from previous work. For this application, the new approach was an improvement over previous work.

Flow-/Storage-Capacity Graph. For this application, the same scenario (linedrive-injection pattern with six injectors and three producers) and simulator settings were used. The flow-/storage-capacity graphs depicted all injector-/producer-well pairs in both the homogeneous case and the multiple-high-permeability-channels case. Also, the estimated FIR curve between all well pairs in the multiple-channels case was shown.

Multiple-High-Permeability-Channels Case. In this case, the flow paths were much more complex than in the homogeneous case. The flow-/storage-capacity graphs were no longer a straight line. Injector 1 had more flow paths to Producers 2 and 3 than to Producer 1. In the flow-/storage-capacity graphs, the Injector-1 to Producer-2 pair and the Injector-1 to Producer-3 pair deviated more from the straight line than the Injector-1 to Producer-1 pair. For Injector 3, the Injector-3 to Producer-1 pair deviation from the straight line was even greater than for the Injector-3 to Producer-2 pair and the Injector-3 to Producer-3 pair. Finally, for Injector 6, the Injector-6 to Producer-1 pair deviation moved farther away from the straight line than the Injector-6 to Producer-2 pair and the Injector-6 to Producer-3 pair.

Prediction of Production Rates. A scenario with five injectors and four producers was used, and the simulated reservoir had two areas: one with 10-md permeability and the other with 500-md permeability. The injection rates were obtained from a real oil field.

Approximately 3,000 days of total data was available. The first 1,000 days was used as the training period to simulate the FIR curve, and the balance of time was used as the predicting period to verify predictions. The prediction results matched the production rates generated by simulator very closely. This match validated the FIR-MIMO model and its applicability for production prediction. It is important to emphasize that the simulator was not based on the FIR-MIMO model, so the results did support the assumption that this model provides a sufficiently accurate, yet simple, representation for the purpose of establishing injection/production relationships. **JPT**

Polymer Flooding in Unconsolidated-Sand Formations: Fracturing and Geomechanical Considerations

A study was carried out to determine the geomechanical effects of polymer flooding in an unconsolidated-sand reservoir. The work provided a geomechanical perspective on the generally complex problem of polymer flooding unconsolidated formations containing viscous oil. The work offers insights into critical issues that must be examined in such situations to avoid catastrophic failures and highlights the existing technological gaps in the current predictive capabilities.

Introduction

Some unconsolidated-sand formations, both onshore and offshore, contain high-viscosity oil and could be considered for polymer flooding to improve recovery. Flooding unconsolidated sand could lead to "fracture" propagation. Although such formations typically have permeability on the order of several darcies, minute quantities of impurities and solids in the injection fluid can plug the sandface over time and lead to fracturing if the injection rate is maintained. Even in the absence of fines and solids in the fluid, the high in-situ oil viscosity and low polymer mobility could instigate fracture propagation if the injection rate is sufficiently large.

Polymer flooding was proposed as an option for an offshore field to enhance sweep efficiency and production of viscous 200-cp oil. Aside from the relatively high oil viscosity, the formation characteristics include unconsolidated and highly compressible sand, relatively thick pay zone (gross nominal thickness of 100 m), and relatively small stress contrast between the sand and the caprock (potentially leading to containment loss). The primary goal of the laboratory experiments was to identify the fracturing mechanisms and establish a net propagation pressure in such formations. The findings from the laboratory tests provided empirical input (e.g., equivalent fracture toughness) for numerical simulators.

This article, written by Senior Technology Editor Dennis Denney, contains highlights of paper SPE 121840, "Polymer Flooding in Unconsolidated-Sand Formations: Fracturing and Geomechanical Considerations," by ***Mohamad Khodaverdian,*** *SPE,* ***Tibi Sorop,*** *SPE,* ***Sophie Postif,*** *SPE, and* ***Paul Van den Hoek,*** *SPE, Shell E&P, prepared for the 2009 SPE Europec/EAGE Annual Conference and Exhibition, Amsterdam, 8–11 June. The paper has not been peer reviewed.*

Injectivity Mechanisms

Previous R&D. Industry and research institutions have carried out several research projects to address injectivity and hydraulic-fracturing issues in unconsolidated sand. Investigations have focused on several types of field activities, including cuttings reinjection, hydraulic fracturing, frac packing, produced-water reinjection, and water and chemical flooding.

Polymer-Injection Tests. In this work, several experiments were conducted in which polymer was injected into oil-saturated sand to investigate the injectivity mechanisms and equivalent fracture toughness under the specific field conditions. Test samples were cubic (45 cm) sand blocks.

After reviewing scaling issues with the selected test parameters and performing coupled injection/mechanical simulations for the laboratory-scale model, it was concluded that the effective stresses at the block boundary must be scaled down from the field values. This scaling was related to the test-block boundaries being close to the injection point and the leakoff at the boundaries intensifying the effective stresses in the vicinity of the fracture compared with a model with infinite boundary.

Numerical analyses of polymer injection at the laboratory scale indicated that shear rates in the vicinity of a small-scale fracture were approximately an order-of-magnitude larger than those for the field scale. This effect was related primarily to the small size of the laboratory model combined with the high injection rates needed to overcome leakoff at the block boundaries. Because of the higher shear rates at the laboratory scale, the test-polymer rheology was selected such that viscosity was similar to the expected field values in the vicinity of the fracture.

Four polymer-injection tests were performed on different blocks. Two sand mixtures were used, for which the initial oil-injection cycles resulted in stable pressures. Permeabilities of 3.0 and 1.8 darcies were obtained at the scaled field stresses.

Key findings from the injection tests were as follows.

- Step-rate polymer-injection tests indicated fracture extension or near-wellbore permeability increase at net injection pressures between 0.7 and 1.5 MPa. Reducing the sand permeability from 3.0 to 1.8 darcies did not result in any significant change in the net pressure. Shear-induced dilation and effective-stress reduction both led to increased permeability.
- Analysis of the net propagation pressures from step-rate data, considering the frac-pack geometry, indicated equivalent-fracture-toughness values between 0.5 and 1.5 MPa/m^2, the range of values used in the simulations.
- Tests indicated large-scale sand-shear failure and localization during injection. This failure was particularly evident in the post-test horizontal cross

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section. While the potential block-boundary effects on the shearing process cannot be ignored, similar shear banding was observed in earlier injection tests with nonwall-building fluids.

- Oil displacement by polymer was approximately radial, with no indication of fingering at the block boundaries. This was despite the test blocks containing a small frac pack. Radial pressure distribution was evident near the block boundaries and was consistent with the polymer-invasion geometry. From observations, it was concluded that any fracture extension or directional-permeability increase during injection was local and limited to a few centimeters near the borehole.

Fracture Predictions

From previous research and experimental work, the concept of a pseudofracture in unconsolidated sand was introduced. This pseudofracture consists of an oriented band in the formation encompassing subparallel short fractures, shear-failure planes, or permeability-enhanced zones. Such a feature would be aligned with the general direction of the maximum horizontal stress, as in the case of a single fracture in hard rock. A pseudofracture might be driven by fluid mobility or by formation damage, although in reality both mechanisms are expected.

Shell's in-house fracture simulator was used for fracture predictions during polymer flooding. Fracture analyses were performed assuming injection rates between 640 and 1280 m^3/d per well for a vertical hole. It was assumed that injection would continue for 20 years. Depending on the injection rate, the bottomhole pressure (BHP) increased to between 29.5 and 29.7 MPa, followed by a decrease over the injection time to values between 28.6 and 29.0 MPa. The initial pressure increase was caused primarily by near-wellbore mobility because the polymer displaced the 200-cp oil. The injection pressure tended to reduce as the polymer front moved into the formation. Note that at all times the predicted BHP was greater than the average minimum in-situ stress of 27.1 MPa. The excess pressure was caused primarily by poroelastic backstress as the pore pressure increased in the vicinity of the fracture. Other factors such as the in-fracture frictional effects and equivalent fracture toughness also contribute to the excess pressure, although these effects were deemed relatively small or negligible for unconsolidated sand.

Although at injection rates up to 950 m^3/d, the fracture remained contained for at least 20 years of injection; at 1110 m^3/d the fracture broke through the caprock after approximately 18 years of injection. These results pertain to a sand/shale stress contrast of 1.4 MPa for the base-case parameters. Further analysis suggested that for an injection rate of 950 m^3/d, sand/shale stress contrasts of 0.7 and 1.4 MPa resulted in containment loss after 22 years and 28 years, respectively. At 2.1 MPa stress contrast, the fracture remained contained for 40 years because the fracture-tip pressure never reached the shale minimum horizontal stress. Nevertheless, because the exact mechanism of fracture containment at the sand/shale interface remains unknown for unconsolidated sands and is the subject of future research, these findings should be interpreted with care.

Geomechanical Modeling

A major concern related to flooding unconsolidated sand is the potential of shear failure and localization, which could lead to fault reactivation or loss of caprock integrity. The issue of production-induced compaction in unconsolidated- and poorly-consolidated-sand formations is well documented. The potential of injection-induced geomechanical failure during polymer flooding was investigated. A numerical simulator was used that has the capability to model sand plasticity and shear failure, finite-strain deformations, and coupled two-phase flow. The 2D model was designed for simultaneous fluid injection into a static fracture and production from a horizontal hole approximately 200 m away. The rock deformation, pressures, and stresses were monitored during injection to determine the mode and magnitude of the induced failures.

During early injection, the sand underwent shear failure in a large portion of the model. The predicted pressures suggested that the change in pore pressure was small in the affected gridblocks. Therefore, shear failure in these blocks was not induced by pore-pressure change.

Further evaluation of the deformation data led to the conclusion that shearing occurred as a result of sudden fracture pressurization, which pushed the soft unconsolidated sand away from the fracture, thus causing shearing as the sand above the fracture moved downward. The shearing phenomenon could occur as a result of high-rate polymer injection into sand containing high-viscosity oil, which would create a large mobility-driven fracture early in the injection. This failure mode would also occur upon shut-in and restart if a large fracture already existed in the sand. The relatively small Young's modulus for the sand exacerbates this mode of shear failure because it facilitates large lateral movements during fracture pressurization.

The shear-failure zone identified around the fracture was a result of pore-pressure increase in the same region. Continued injection caused the shear-failure zone to progress toward the producer, but this phenomenon stopped after approximately 17 months.

One of the risks associated with large-scale formation failure is casing buckling in vertical or inclined wells. The caprock appeared to subside by more than 0.5 m. The total vertical deformation for the sand interval also was approximately 0.5 m. Depending on the details of well design, this deformation was sufficient to cause potential completions failure in a vertical hole.

Conclusions

Formation parting and fractures do occur in unconsolidated formations, and the fracture tip advances primarily by shear failure or liquefaction. Such fractures propagate at relatively small net pressures. The concept of pseudofracture represents an oriented band in the formation encompassing shear-failure planes, permeability-enhanced zones, and subparallel fractures. During polymer flooding, pseudofractures could be induced through a combination of low fluid mobility and formation damage by solid impurities and fines, as in the case for more-consolidated rocks.

The limited geomechanical modeling that was performed suggested that potential exists for large-scale shear failure in unconsolidated formations during polymer or high-viscosity-fluid flooding. The analyses further indicated that the sheared zone could extend into the caprock and result in localized compaction and settlement above the injector. **JPT**