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EOR Returns To Mainstream Recovery

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and John Campanella

GOLDEN, CO.–Enhanced oil recovery projects traditionally ebb and flow in sync with commodity prices. With oil prices in the range of $40-$75 a barrel over the past few years, it is no surprise that the number of projects combining EOR processes with advanced monitoring and well technologies are increasing.

Advances in monitoring systems and well technologies in the oil and gas industry have allowed innovative reservoir performance and production operation tracking, which leads to improved sweep efficiency, increased oil recovery and extended reservoir production life. However, reservoirs with poor financial performance generally do not justify the use of advanced monitoring and well technologies, especially when prices are low. Therefore, the decision to acquire the data needed in monitoring systems and to install smart completion technology or downhole sensors, among others, should always provide for a cost/benefit analysis.

Without a doubt, advanced monitoring and well technologies have contributed to maximizing oil recovery and asset values. However, to evaluate their impact on EOR, it is first necessary to analyze onshore and offshore field experiences separately. This analysis then leads to a review of improved oil recovery (IOR) techniques, new drilling and production technologies, and primary and secondary recovery processes (Figure 1).

Recognizing that primary and secondary production schemes generally result in recoverable reserves in the range of 30-40 percent, the gas and oil industry has been focused more on IOR and related technologies in the past decade (with the exception of EOR projects), especially in offshore field development plans.

Onshore Versus Offshore

EOR onshore projects have been influenced strongly by economics and crude oil prices during the past two decades. Initiating EOR projects depend on how prepared and willing investors are to manage EOR risk and economic exposure, and to weigh the availability of more attractive investment options. The history of EOR field projects clearly shows that they have been applied mainly in onshore fields because of the constraints of offshore platforms, the cost per barrel of offshore production facilities, and the volatility of oil prices.

In addition, steam injection, carbon dioxide, and polymer flooding have dominated onshore EOR projects. Although the number of steam injection projects has declined in the United States since the late 1980s (Figure 2), steamflooding still is the dominant EOR process in heavy oils worldwide. At the same time, steam-assisted gravity drainage (SAGD) was consolidated as an in-situ recovery process in the Athabasca oil sands. Carbon dioxide floods, mainly as water-alternating gas (WAG), are becoming more widespread, and CO_2 sequestration combined with EOR methods contribute to the growing interest in this recovery strategy.

With regards to EOR chemical methods, oil production has

FIGURE 1
Overview of Improved Oil Recovery

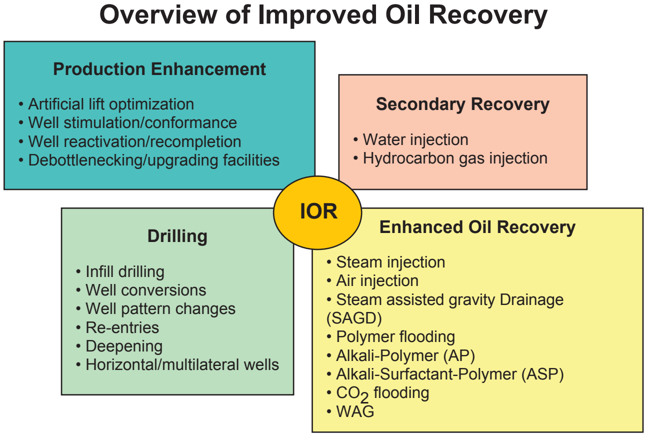
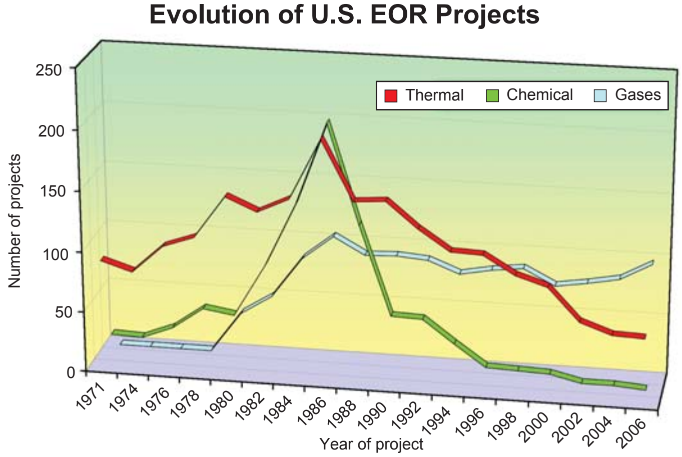


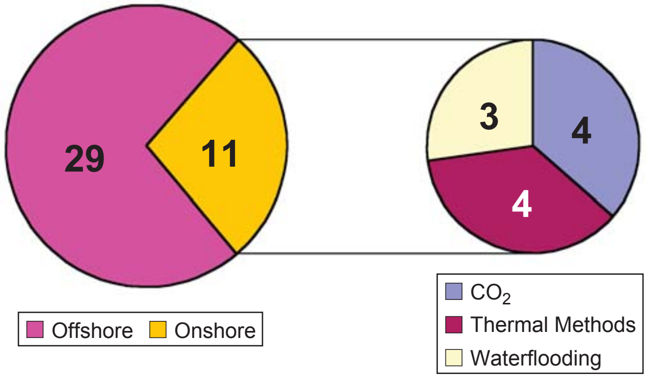
FIGURE 2
Evolution of U.S. EOR Projects



Source: Oil & Gas Journal and Norwest Questa Engineering database.

FIGURE 3

Sample of International 4-D Seismic Projects



been negligible around the world except in Russia and China, where polymer flooding is the most important EOR chemical process. However, at current oil prices, some operators are looking at chemical methods such as alkali surfactant polymer (ASP) to revitalize mature waterflooded reservoirs. Finally, it must be recognized that the application of EOR processes (other than steam flooding, SAGD, CO_2 and polymer flooding) has been limited, either in the number of projects or the size of the projects.

Offshore field development relies more on drilling and well completion technologies and comprehensive monitoring programs for primary and secondary recovery (gas flooding and waterflooding). Regarding offshore EOR experiences, WAG floods have been the most-used EOR method in the past decade, especially in the Norwegian North Sea.

Among different WAG projects ongoing or proposed in offshore fields, one of particular interest began in November 2002 at Dulang Field, Malaysia. This project re-injected produced gas with CO_2 content close to 50 percent. It represents a project that may provide key operational insights for combined CO_2 EOR/sequestration floods in offshore fields in the future. The other most important offshore EOR project has been the massive nitrogen injection begun in 2000 in the giant Cantarell complex, Yucatán Peninsula, in the Bay of Campeche, Mexico.

An IOR survey for the North Sea determined most of IOR's future potential relies on:

- Hydrocarbon injection, WAG, simultaneous water and gas injection (SWAG), foam-assisted WAG, CO_2 flooding from anthropogenic sources, and microbial EOR/IOR (MEOR/MIOR), based on the field experiences reported at Norne and Bokor fields in Norway and Malaysia, respectively;
- Waterflooding, massive depressurization, and air injection; or
- Gas condensate, water additives, nitrogen, and flue gas injection.

It is important to note that the average recovery factor in the Norwegian Continental Shelf is reported to be 45 percent, and has been targeted for 50 percent by the Norwegian Petroleum Directorate. This average recovery factor has been achieved mainly with waterflooding, gas injection and WAG, combined with advanced monitoring and well technologies.

On the other hand, offshore heavy oil reservoirs (API gravity lower than 19 and/or oil viscosity greater than 10 cp at reservoir conditions) are a challenge for operators in Brazil, China and other regions, and no more than a 20 percent recovery factor is expected at present. The proposed alternative is to use cold production in high productivity wells (long-reach extended horizontal wells) and water injection at a later stage. Monitoring by means of time-lapse or 4-D seismic is being considered to diminish infill drilling risk and consequently improve reservoir management.

Preliminary analysis, however, seems to show that classical monitoring attributes are not sensitive enough (low contrast in elastic properties) to track displacement fronts with fluid substitution for medium or heavy oil deep offshore fields under water injection because of their similar densities.

During the past 15 years of using advanced monitoring and well technologies, trends clearly suggest that few projects combine these technologies with EOR processes.

Reservoir monitoring can be implemented using conventional or unconventional methods. Monitoring methods vary from simple fluid production and injection history, pressure and temperature measurements, production/injection logs, changes or differences in production fluid chemistry, composition (e.g., estimates of commingled production using organic geochemistry methods), and tracer injection. However, only the use of advanced monitoring methods such as 4-D seismic and optic fibers in IOR processes will be discussed in this article.

4-D Seismic

4-D seismic reservoir monitoring, or time-lapse seismic, has the potential to significantly increase recovery in existing and new fields. Changes in fluid saturation, pressure and temperature during production can induce changes in a reservoir's density and compressibility that can be detected by differentiating repeated seismic data. As a result, seismic data can be used to track fluid movement in the reservoir, identify unswept areas or bypassed oil, delay injection fluid breakthrough, and optimize infill well locations.

Most of the successful 4-D examples are sandstone reservoirs, with carbonate and chalk reservoirs successful to a lesser extent. Additionally, most of the 4-D seismic surveys have been run in offshore fields. A review of 4-D seismic projects developed by Norwest Questa shows that out of 40 surveys, only 11 were run in onshore fields (Figure 3).

While large scale offshore 4-D seismic has been performed mostly in reservoirs under water and WAG injection, onshore 4-D seismic has been developed in waterflooding, steam injection (e.g., Cold Lake cyclic steam injection and Christina Lake SAGD projects) and CO_2 injection (e.g., Weyburn and Hall Gurney fields). However, it must be recognized that onshore 4-D seismic mostly evaluates EOR pilots prior to full-field implementation, except for the steamflood monitoring program established at Duri Field in Indonesia.

Although several 4-D seismic projects have been successful, some limitations of the technology have been reported, including 4-D application in stiffer and low-porous rocks such as carbonate rocks. One of the main reasons using 4-D seismic is difficult in this type of rock is that the changes in seismic parameters are smaller than the background 4-D noise level. However, carbonate reservoir field experiences in Canada (Weyburn Field), Kuwait (Sabiriyah Field), and the United States (Vacuum and Hall Gurney fields), in combination with recent joint industry project initiatives and research programs on 4-D seismic feasibility in carbonate rocks, will provide a better understanding of the technology in these types of rocks.

Carbonate rocks also represent a crucial issue for future CO_2/EOR sequestration projects, given that at least half of the CO_2 floods ongoing in the United States are in carbonate formations in the Permian Basin of Texas and New Mexico. Therefore, safety and environmental issues will drive technology developments for CO_2 storage and monitoring for a long time. At the first industrial scale CO_2 storage project in Norway (Sleipner Field), 4-D seismic proved that the technology can be used successfully to track CO_2 movement in sandstone reservoirs.

Other documented limitations of 4-D seismic are those related to the repeatability and resolution of seismic data and the associated costs to justify the investment. However, some methodologies for estimating the value of the information on 4-D seismic acquisitions have been proposed. These methods are based on decision-risk analysis compared to the expected economic value (e.g., optimum well location, increased oil reserves) with and without the seismic information.

Despite the reported limitations of 4-D seismic, operators, especially in offshore fields, are considering integrating advanced monitoring and well technologies with 4-D seismic to increase their projects' total value. Among the technologies considered for improved reservoir surveillance is permanent ocean-bottom seismic combined with downhole instrumentation for fast updates of geological and reservoir models. In Valhall Field in the Norwegian North Sea, a fieldwide permanent seabed seismic array was installed. From October 2003 to the end of 2005, six surveys over five months demonstrated that the technology is already in place to monitor a chalk reservoir under water injection. This approach is part of the concept of "field of the future," i.e., fields or smart fields proposed by several operators.

Fiber Optics

Real-time downhole flow data have been widely acknowledged to be of significant value for optimizing well and reservoir performances. This is particularly important in controlling high well costs and the high costs of deferred production in complex multizone and multilateral completions. To assist in gathering this data, the number of permanent fiber optic monitoring systems has dramatically increased, and they have been installed worldwide in high-pressure and high-temperature environments.

Ten years ago, fiber optics technology was considered to be expensive and difficult to install, with limited applicability. One example of the difficulties occurred in Tia Juana Field, Venezuela, when the fiber broke during steam injection because of thermal expansion. After this experience, a new fiber optic was installed and successfully used to monitor steam channeling into the producer as well the progressive development of the steam chamber over time. Today, fiber optics has multiple applications in the oil and gas industry and the cost of the technology has decreased because of the experience gained and the number of installations around the world.

Permanent optical monitoring systems that include pressure and temperature and distributed temperature sensing have been reported extensively in onshore and offshore fields. Other fiber optic applications involve single and multiphase flow-meters, steam quality and seismic sensors, while future technology applications include distributed pressure sensing and sand production, among others.

Permanent fiber optic monitoring systems are being or have been installed in offshore fields in the North Sea (Douglas Field, U.K.; Sleen Field, Netherlands), the Gulf of Mexico (Marco Polo Field), Asia (Azeri Field, Azerbaijan), and South America (Trinidad), among others, as part of intelligent completions of multiple zones. Although most of the applications are for tracking temperature and pressure measurements in water and/or gas injection, optical flow meters also have been reported but to a lesser extent. Mars Field (Gulf of Mexico, October 2000), Nimr Field (Oman, May 2001), and Mahogany Field (Trinidad, March 2002) reported the installation of optical flow meters in producing wells. Most recently (May 2004), a single-phase flow meter was reported in a WAG injector at Veslefrikk Field in the Norwegian North Sea. Optical flow meters have been operating successfully for two years in water and gas injection ranging in temperatures from 125 C (reservoir temperature) to between 15 degrees C and 30 degrees C during the water injection period.

Most of the onshore EOR applications documented are, as expected, in steam and CO_2 injection projects using fiber optic technology to monitor well and pattern performance for reservoir management. Some of the EOR field experiences that have been reported are:

- Steam injection at Duri Field (Indonesia) and Cymric, Kern River, McKittrick and West Coalinga fields (California);
- SAGD projects in Canada and a pilot at Tia Juana Field (Venezuela); and
- CO_2 WAG pilot (one injector and four producers) at Cogdell Field (Texas).

Again, EOR field experiences with fiber optic monitoring technologies have been limited. The main reasons are because of the risk of failures, lack of documentation and the high initial costs because of both the technology and the volatility of crude oil prices during the past decade. However, that could turn around with the acquired experience of the past few years and the rising prices of energy markets.

Since fiber optic monitoring technologies can be implemented gradually on a well-by-well basis and provide desirable asset life-cycle (primary, IOR, EOR) information, they appear to have the potential for the greatest near-term impact, both offshore and onshore. Historically, conventional and unconventional primary production efficiencies have been depressed through the lack of affordable and reliable production data from individually completed intervals. Injection and the subsequent production of expensive secondary and EOR fluids only compound the importance of this data. As implementation costs decline, interpretation techniques progress, and equipment robustness improves, this technology will increasingly become standard operating procedure throughout the industry.

Well Technologies And EOR

Drilling and well technology advances have contributed to the development of major offshore and onshore fields. Infill drilling of horizontal wells, multilaterals and smart well technology have been some of the reservoir management strategies implemented at many mature fields to produce remaining reserves and improve reservoir sweep efficiencies.

Given the level of maturity of horizontal well technology in water and gas flooding and in EOR processes (steam injection, SAGD, WAG), this discussion will focus specifically on the use of multilateral wells and smart completions in EOR processes.

The use of advanced drilling technologies such as multilateral wells–with and without smart well completions–has been widely reported in Brazil, China, Indonesia, the Middle East and the North Sea. Most of these fields either are under water or gas injection or both. A few cases either are developing or considering the use of WAG processes with multilateral wells, especially in the Norwegian North Sea (Gullfaks and Oseberg fields). On the other hand, the use of multilateral wells in heavy oil fields has been reported in onshore Venezuela (Zuata) and Canada (Pelican Field). In the near future, we may see EOR thermal projects combined with these advance wells–a new challenge for the operators of these resources.

Intelligent ("smart") well completions enable operators to monitor and selectively modify producing zones while on stream and without intervention. With intelligent well completions, it is possible to collect, transmit, and analyze completion, production and reservoir data for dynamic reservoir management that provides better well control and production/injection processes.

Smart completions have been reported in Angola, Brazil, Brunei, China, Malaysia, Nigeria, Norway, and the Gulf of Mexico. In some cases, smart well technologies are combined with monitoring techniques such as 4-D seismic, downhole measurements, tracer injection, and/or special logging programs to facilitate better production control and reservoir characterization that access bypassed reserves mainly under secondary recovery methods. Again, most of the fields using smart well completions either are under primary or secondary recovery, with the exception of some WAG projects reported in the North Sea. Finally, in the last SPE/DOE symposium on IOR, an application of smart well technology in a CO_2 WAG project at SACROC Unit, Texas, was reported. Results are promising after a year in operation, especially because of the presence of hydrogen sulfide.

Status And Outlook

Advanced monitoring and well technologies have made small contributions to oil production in EOR projects. Although there is consensus on the benefits of advanced technologies in terms of increased reserves and recovery efficiencies and reduced costs and risks associated with well interventions (deferred production), the industry has not maximized the value of these technologies. Low crude oil prices and the high volatility of energy markets have joined with high EOR and advanced technology capital investments to limit projects combining both technologies, with some exceptions.

However, we believe that EOR and advanced monitoring and well technologies will continue to develop in natural environments (onshore versus offshore) until more pilots and full-field deployments combining both technologies are a reality. The latter will strongly depend on future energy demand and crude oil prices. Therefore, the continuous evaluation of EOR opportunities and development of methodologies to estimate the economic value of advanced monitoring and well technologies will be required.

From the perspective of EOR projects, we think steam injection, including SAGD, and CO_2 EOR/sequestration will continue to grow along with future projects that combine advanced monitoring and well technologies. CO_2 EOR/sequestration is expected to be the driver of high technological EOR projects in offshore fields in years to come, especially if carbon sequestration in geologic formations becomes a strategy used to reduce CO_2 emissions from anthropogenic sources. However, this will depend on the purchase price of man-made CO_2 and the development of a proper legal framework in individual countries. Recent evaluations have indicated the break-even price for CO_2 injection in a North Sea field is in the range of $23 to $33 a barrel. Therefore, a combination of high oil prices and new low-cost CO_2 separation technologies from industrial emissions, especially coal-fired power plants, will be required to justify the capital investment required to develop such projects in the near future. ❒

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