IMPROVED OIL RECOVERY FOR INDEPENDENTS

BOTTOM LINE

The presentations featured in this session highlighted processes and recent projects being pursued by independents with a focus on the mature Midcontinent area. For the most part, technologies are proven in other applications. In some cases, the IOR concepts are leading edge and are just now moving from laboratory to the field. Processes included horizontal drilling, de-watering, alkaline-surfactant-polymer flooding, gravity stable CO2 flooding, and fluid pulsation. Presented information outlined screening criteria, laboratory and design work, and elements of pilot projects.

PROBLEM ADDRESSED

With oil prices having held strong for some period of time, independent operators are re-examining their IOR opportunities. Purpose was to inspire confidence and convey knowledge leading to other independents implementing IOR projects. The targeted audience included owners, engineers, geologists or those making property development and IOR decisions.

KEY WORDS:

Alkaline-Surfactant-Polymer
CO2 Gravity Drainage Process
De-watering
Fluid Pulsation (Deep Wave)
Horizontal Drilling
Improved Oil Recovery
Screening Criteria

TECHNOLOGY OVERVIEW

Horizontal Drilling to Access Bypassed Oil in Mature Midcontinent Reservoirs

Grand Directions LLC has been using horizontal wells to solve various reservoir problems for the past five years. Everything starts with the reservoir—from reserve estimates to reservoir simulations. Grand Directions' application of horizontal wells has consistently generated a profitable investment. This presentation focused on the engineering pre-planning utilized prior to drilling any horizontal wells in a project.

Based on a half day Independents' Day session sponsored by PTTC's North and South Midcontinent Regions at the SPE/DOE Improved Oil Recovery Conference in Tulsa, Oklahoma on April 25, 2006.

SPEAKERS:

Continued Success Using Horizontal Drilling to Access Bypassed Oil in Mature Midcontinent Reservoirs,
Scott Robinowitz, Grand Directions, LLC

Pilot Project and Eventual Development of a De-Watering Project in the Red Fork Zone,
Don Unruh, Sullivan and Company

Gas-Assisted (CO_2) Gravity Drainage IOR, The Process and a Louisiana Field Project,
Dandina Rao, Louisiana State University

Early-Stage Surfactant-Polymer (SP) Projects in Oklahoma and Texas, Lessons Learned in Screening Flood Design and Implementation,
Tom Cochrane, Cano Petroleum

Alkaline-Surfactant-Polymer (ASP) Potential in Wyoming High Viscosity Crude,
Daniel Wilson, Surtek Inc.

An Introduction to Deep Wave (Fluid Pulsation) Technology,
Brett Davidson, WaveFront

Those operating mature oil properties often ask questions like the following: Aren't horizontal wells too expensive to drill? Will my reservoir benefit from horizontal wells? Where is the remaining oil in mature reservoirs? The answers lie within the planning process for horizontals, which first begins with understanding the reservoir using a team concept employing geologists, reservoir engineers and drilling engineers.

In screening candidates, the geologist looks at 3-D distribution of porosity and permeability, structure and isopach maps, continuity and fracture orientation. In the Midcontinent looking at fractures in surface features provides good clues to the subsurface. The reservoir engineer must look at drive mechanism and recovery efficiency, what the reservoir's development history has been. Rock mechanics properties must be examined to ensure the reservoir is competent enough for an openhole horizontal. Permeabilities must be sufficient for adequate delivery from an unstimulated horizontal. There must be at least some pressure. In Grand Directions' experience 70% of potential projects do not pass the initial screening process. For those that do pass the initial screening process, reservoir simulation is the next step. Once an adequate history match is achieved using "reasonable" reservoir parameters, performance predictions are made for horizontals and economic analyses performed.

Grand Directions has developed a "low cost" approach to drilling horizontals. This starts with them owning the drilling rig. An initial decision is whether to drill a side track from an existing well or to drill a new well. Costs for re-entry operations must be risk-weighted. For new wells their approach is to drill a vertical conventionally, setting casing above the formation. A short radius curve (about 70 ft) is drilled using a gyroscopic surveying tool to orient. This is pulled after the curve is completed. The lateral is then drilled underbalanced with an air/foam mixture, which minimizes formation damage that is a concern when drilling mature often under-pressured reservoirs. An air hammer enables good penetration rates to be achieved. Rather than real-time measurement of location, periodically a surveying tool is run down the drill string (without pulling the air hammer) to get direction and inclination information across the entire horizontal wellbore. This intermittent location data has provided accurate well survey data for the up to 1000 ft laterals drilled to date. Laterals are logged with small diameter tools pushed to the end using rods with roller rod guides, then logged back—another low cost innovation. Well cuttings and "shows on the pit" provide valuable information about whether the lateral is penetrating the hydrocarbon-saturated interval and the well's future productivity.

Grand Directions has drilled multiple horizontal wells in the Bird Creek Field, Tulsa County, Oklahoma to overcome relative permeability problems, water coning and reservoir heterogeneity in an approximately 1,300 ft deep, 60 ft thick sandstone reservoir. Permeability is in the 300 - 500 md range, bottom hole pressure is just over 100 psi, and there is an aquifer present. A typical vertical well (perf'd and frac'd) may initially produce only 3 BOPD/100 BWPD. The increased reservoir exposure with several hundred foot horizontals provides sufficient productivity for open hole laterals to be completed without stimulation. Known compartmentalization became even more apparent as Grand Directions drilled five horizontals. Not all laterals have been successful (pit shows during curve and lateral are excellent indicators of subsequent success), but successful laterals have had initial tests of 15 or more BOPD with relatively low water production. Overall, the program has been quite economically attractive. Keys to that economic success are developing the in-house expertise for all steps in the process, paying attention while drilling as the well is telling a story, and continual updating of the reservoir model as new data become available.

De-Watering Project in a Red Fork Zone (OK)

The Masham Field (Red Fork) is one of the largest recent discoveries in northeast Oklahoma, having produced more than 14 million barrels of oil and 48 Bcf of gas. Although there were some early wells, commercial development did not really occur until the 1980s and there were definite reasons why: Drill stem tests recovered only water. Conventional completions with short-term production tests resulted in high water production with only a "trace of oil and gas." Only later when extended high rate production tests occurred did industry learn that oil cut increased with time, reaching highs of 15% with increasing gas rates. This is de-watering, a concept that has been so successful in the Hunton in Oklahoma.

Sullivan and Company has discovered and is developing a 12-producer pilot project for de-watering in a Red Fork field located further northward on the channel trend. The initial test of the pilot area involved drilling and flaring four wells. These demonstrated productivity of 15 bopd per well and gas rates of 300 mcfd per well. Reservoir parameters and drilling results are nearly identical to those experienced in the Masham Field. The proof of similarity is ultimately in performance. Pilot operations will begin in June 2006. Cost for the pilot is $14 million. After a period of production, the duration yet under discussion, further expansion will be pursued. A further Phase I expansion would involve 67 producing wells and cost an additional $43.6 million.

Parameter	Masham Field	Grayhorse Field
Zone	Red Fork (Burbank sand)	Red Fork (Burbank sand)
Depth	3,400 ft (2400 ft subsea)	2,810 ft (1890 ft subsea)
Log average thickness	40 - 80 ft	40 - 110 ft
Log average porosity	18%	18%
Log average Sw saturation	74%	74%
Shows while drilling	Yes	Yes
Sample shows	Over entire interval	Over entire interval
Typical DST results	SW w shows of O&G	SW w shows of O&G
Core average permeability	60 md	67 md
Core average porosity	14%	18%
Core residual oil	6 - 20%	6 - 19%
Core residual water	30 - 55%	44 - 80%

Gas-Assisted (CO_2) Gravity Drainage IOR

From 1984 to 2004 CO_2 gas injection projects in the U.S. increased from 17 to 71 with the share of IOR production coming from CO_2 projects increasing from 7% to 31%. Conventional CO_2 IOR technologies (continuous gas injection, water-alternating gas (WAG), hybrid WAG) will improve recovery from 10 to 15% of OOIP. A recent study by Advanced Resources International notes that with the implementation of advanced CO_2 IOR technologies it is possible to improve oil recovery by about 40-50% of OOIP. Advanced technologies, which in large part address CO_2's natural tendency to break through and exhibit poor sweep, include higher pore volumes of CO_2, vertical gravity stable gas injection/horizontal wells for production, miscibility development and effective mobility control in horizontal floods. This same study notes that 65% of large reservoirs that cover all the 10 basins in the U.S. are favorable for implementing CO_2 IOR. In the Midcontinent 59% of the large field resource was found to be favorable to CO_2 IOR.

Louisiana State University has been developing a gas-assisted (CO_2) gravity drainage process that, rather than fight CO_2's natural tendency toward breakthrough, takes advantage of physical properties. Existing vertical wells are used to inject CO_2 in the upper portion of the reservoir where the CO_2 tends to segregate, then move downward and outward. Horizontal wells in the lower portion of the reservoir can produce at high rates yet have very low drawdown. Good volumetric sweep is achieved without WAG injection. Since there is no water injection, there is no increase in water saturation, which mitigates water-shielding and increases gas injectivity. Unlike conventional flooding, recovery is insensitive to fractures. Actually, fractures may help by assisting gravity segregation. Laboratory tests indicate that recovery is higher in oil-wet reservoirs (78% OOIP recovery) than water-wet reservoirs (65% OOIP recovery). Core flood recoveries are higher than with conventional CO_2 flooding processes (WAG, hybrid WAG, continuous gas injection). The process is applicable to secondary or tertiary floods and can be miscible or immiscible. Screening criteria are relatively straightforward.

Reservoir Screening Criteria

Parameter	Preferable Range
Oil API Gravity	Miscible: > 22° Immiscible: > 12°
Oil Viscosity	Miscible: < 10 cP Immiscible: < 600 cP
Pay Zone Thickness	> 10 ft sand without isolating shale breaks
Lateral Continuity	More than 1000-1500 ft for horizontal well placement
Overburden/Underburden	Well sealed to prevent loss of injected CO_2
Permeability	Kv/Kh > 0.3

The process will be field-tested in a Louisiana oil field having a 30-35 ft thick sand. Primary and secondary recovery combined produced 24% of OOIP. The field has been shut-in for some time. Reservoir simulation using one million grid blocks has history-matched primary depletion and waterflooding well. Two potential zones for drilling horizontal wells have been identified and effort is now focused on optimizing location of CO_2 injection wells. Recovery projections and economic analysis continue. Field implementation is anticipated during 2006.

Early-Stage ASP Projects

Cano Petroleum specializes in applying IOR to mature oilfields. This presentation focused on the screening process for Surfactant-Polymer (SP) and Alkali-Surfactant Polymer (ASP) IOR projects and design considerations. Case studies from two Oklahoma projects, the Nowata project in Northeastern Oklahoma and the Davenport in Central Oklahoma, both of which are moving into the pilot phase, were presented.

The three steps in a successful project are (1) lab work, costing up to $250 thousand to provide the optimal chemical mix, (2) pilot, costing up to $3 million to prove the process, and (3) full field development, which can be $100 million or more. The first consideration for screening is the recovery efficiency, including vertical and areal (enhanced by polymer) and pore sweep (enhanced by alkali/surfactants). Other considerations include:

- Must be a fairly clean sandstone, with good permeability
- Cannot be too hot, or the chemicals will not be effective
- Must have reasonable vertical and areal sweep, possibly indicated by a successful waterflood
- Fairly homogeneous - fractures, high permeability streaks, high Dykstra-Parsons are not conducive to SP or ASP
- Must have low Ca++ and Mg++ for ASP
- Must have access to fresh water

The lab work is conducted to find the surfactants that will achieve the desired reduction in interfacial tension and not degrade, alkali that propagates throughout the reservoir, and polymers to increase viscosity, fit in the pore space, survive losses and resist bacterial degradation.

The Nowata lab tests had interesting results. They showed a relatively low correlation between surfactant concentration and final oil concentration. On the other hand, the key to recovery in the high 20s% were achieved at relatively high pore volumes (PV) injected (0.8 PV) and the strongest correlation was between the PV of the injected ASP mix and the final oil saturation. Bottom line of the radial corefloods with the optimal mix was recovery of 22% of the original oil in place.

The construction of the pilot has begun. The broad guidelines for the pilot are to build the facilities to mix the chemicals in the right concentrations and proportions, treating and softening the water, and do what is necessary to make sure the wellbores put the chemicals in the right place, reviewing completions, tests, injection profiles and tracer survey.

A more limited pilot project is underway in Prue sandstone at a depth of 3,300 feet in the Davenport Unit. The pilot is challenged by the fact that not enough wells are available for a full five-spot, the high permeability interval takes water and chemicals very fast and there appears to be a porous limestone below the pay zone.

Lessons learned include (1) cleaner reservoirs and fluids generally have cheaper solutions, (2) regardless of the areal sweep, polymers are needed as surfactants increase water mobility, (3) the surfactants that work are unique, (4) water treatment is very important, (5) the equipment is not standard oilfield, and (6) you have to get the sweep right the first time—one slug, one shot, the chemicals do not cycle through.

ASP Potential in Wyoming High Viscosity Crude

In a DOE-supported project, Arnell Oil through laboratory screening performed by Surtek, Inc., evaluated the ASP potential in a relatively high viscosity oil in a Wyoming field. The goal was to determine the optimal chemical mix to achieve the necessary reduction in interfacial tension and mobility ratio to economically produce incremental oil.

The Poison Spider field in Wyoming is a relatively high viscosity (150 - 300 centipoise) 22 °API oil field, originally discovered in 1919. It produces from a lower horizon of the Crow Mountain sand at a depth ranging from 1,400 to 1,500 feet. Current production is 100 barrels/day at a 7 ½% oil cut. Volumetric calculations show an original oil in place (OOIP) of 11.25 million stock tank barrels at an average saturation of 76.5 percent. 4.2 million barrels, or 37.3% of OOIP, has been produced. The target for the ASP flood then, is the current oil saturation of 48.0%—7 million barrels.

To begin the study, a detailed analysis of the produced oil, produced water and cores is performed. Basic calculations are performed: Oil Recovery, which is a function not only of polymer enhanced vertical and horizontal sweep, but the alkali and surfactant improved pore-to-pore displacement efficiency; the Capillary Number, which is a function of the viscous forces divided by the surface forces; and the Taber Number to determine the change in interfacial tension (IFT) required to allow the oil to pass through the pore throat. For this project the shift was from 21.025 to 0.067 dyne/cm or 313.8.

The next step in the laboratory analysis is to test the produced crude oil with different alkaline-surfactants at varying concentrations to measure the IFT shift to determine if the needed shift is possible, the best chemical combination, and the optimal concentration of the chemical to achieve the shift and the phase behavior at varying chemical levels.

Once the optimal alkaline-surfactant and concentration is determined, a linear coreflood study is run to measure the resistance factor ratio versus the fluid frontal advance rate for different polymers and versus polymer concentration.

Finally, the selected system is tested in a radial coreflood to measure the effectiveness of the alkaline-surfactant in reaching the oil trapped in the pores and the ability of the polymer mix to displace the IFT-modified oil to the producing well. This study concluded that the NaOH plus surfactant is most effective and, based on the radial coreflood, as much as 31.8 % of OOIP of incremental oil can be produced with chemical costs in the $3.50/produced barrel range. The ASP flood has not yet been initiated. Other exploitation opportunities and crude pricing differentials are affecting Arnell's decision not to start the ASP flood. Arnell did make the statement that it's a question of "when," not "if."

DeepWave (Fluid Pulsation)

The proven DeepWave (fluid pulsation) technology uses pulsed fluids to enhance both production and injection. It has shown to be effective in all types of geological formations, including consolidated and unconsolidated sediment, sedimentary soils and fractured rock. It can enhance production from waterfloods, light and heavy oils, and is applicable in wells of any depth and angle from vertical to horizontal.

Production response to earthquakes has been well documented. In 1999 Lost Hills, California responded with a 16% production over several months following an earthquake. Similar responses have been seen in Kern and Northridge fields. The DeepWave technology is a large energy controllable pulse placed in the reservoir through either jointed pipe or coiled tubing. The applications include an add-on to waterflood injectors to improve sweep efficiency, well intervention, improved water disposal rates and groundwater remediation. The theory dates back twenty years and the initial field demonstration took place in 1998. To date 150 single well and 5 field-wide applications have taken place.

The physics of the technology lie in the dynamic excitation device that creates a fluid displacement wave that is propagated down the arteries into the capillaries. The rise time of the pulse is short with a longer fall time. This results in an elastic response that expands the aperture, which leads to accelerated flow and greater over all distribution of injected liquids. Unlike pressure injection, it is not affected by high permeability channels. Laboratory injectivity tests show it to be effective in water-wet reservoirs, and particularly effective in oil-wet reservoirs. It can be applied to the reservoir with pinpoint accuracy to maximize the results. A typical stimulation would be applied through coiled tubing at a rate of 1 barrel/minute, generating 1,000 to 1,200 psi amplitude waves at 17 pulses per minute.

A case study was presented of a naturally fractured shale in California with 600 feet of net pay. Other stimulation techniques had been tried in the area with poor results. A DeepWave service tool was used to apply 12,000 gallons of FE acid and 25,000 gallons of 12% HCL/3% HF acid. Daily production before treatment was 7 barrels of oil and 144 barrels of water. After treatment, production was 22 barrels of oil, 117 barrels of water.

A second case study was presented of a well in Oklahoma. Initial production was 1.7 MMCF/Day and 50 barrels of water. Within 3 weeks production had fallen to 0 MCF/Day and 225 barrels of water and was constrained by sand. The DeepWave tool was used in conjunction with temperature-activated chemicals for sand consolidation and water shut off. Five months following the treatment the well was still economical.

Deep Wave is in the process of implementing a pilot in the Chelsea-Alluwe Field in Rogers County, Oklahoma.

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