TECHNOLOGY CONNECTIONS
PETROLEUM TECHNOLOGY TRANSFER COUNCIL

MANAGING CALIFORNIA'S OIL RESOURCES

BOTTOM LINE

Continued technology advancements and application are essential for continued profitability in mature US reservoirs. Current Department of Energy (DOE) stripper well projects provide some options for independents to participate in applied R&D. To maintain profitability in mature reservoirs, independents must optimally apply newer technologies such as horizontal well technology and 3-D visualization. Often, it is a buffet of technologies that must be applied. Three major California independents-Oxy USA in Thums Long Beach Unit, Nuevo Energy Company, and Berry Petroleum Company-shared their experiences in revitalizing leases through applying a mix of technologies.

PROBLEM ADDRESSED

With independents responsible for increasing percentages of drilling and oil and gas production, independents must take advantage of available applied R&D opportunities, and their role in encouraging human resource development must increase if academia is to deliver future geoscientists. To overcome hesitance that they can profitably apply newer technologies, independents rely heavily on other's experiences or case studies to develop the confidence they need to implement technologies. This workshop addressed the case study/confidence aspect by documenting specific results obtained when similar independents applied a buffet of technologies to revitalize production in mature leases.

KEY WORDS:
Cogeneration
Completion/Recompletion/Stimulation
Enhanced Oil Recovery
Horizontal Technologies
Research & Development
Stripper Wells
Waterflooding

TECHNOLOGY OVERVIEW

The workshop focused on technologies applicable to mature US reservoirs. All speakers confirmed the role of continuing technology advancements and application in maintaining profitability in mature reservoirs.

Based on a workshop sponsored by PTTC's West Coast Region on December 8, 2000 in Los Angeles, California

SPEAKERS:

Operating Without a Research Lab, New Infrastructure for Independent Producers
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DOE's Stripper Gas Well Program
Brad Tomer U.S. DOE National Energy Technology Lab

Optimal Application of Advanced Exploitation Technology
R. G. (Bob) Knoll , Maurer Engineering, Inc.

Technology Applications at Thums Long Beach Unit
James Eastlack , Thums Long Beach Inc.

Nuevo's Operations in California
Neal Livingston , Nuevo Energy Company

Berry Petroleum's Operations in California
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Since independents now drill 85% of the wells in the U.S., produce 40% of the oil and 65% of the gas, they must assume a role in fostering future R&D, including human resources aspects. The US Department of Energy (DOE) recognizes the importance of R&D for stripper wells and has several stripper well initiatives in place. For many reservoirs, horizontal technologies are appropriate for optimal exploitation. Three California producers shared their experiences in applying a buffet of technologies to improve profitability in mature California fields.

New R&D Infrastructure for Independents. With their increasing role in US production, independents now have a responsibility for encouraging R&D and human resource development. This includes supporting academic R&D since that is where future geoscientists learn problem-solving skills. Independents must also be open to campus recruitment and hiring, providing promising students encouragement to enter geoscience fields. Since computer skills are inherent to most technology solutions, new graduates with problem-solving skills can quickly make major contributions. The old adage of having to have years of experience to work for an independent no longer applies.

DOE's Stripper Gas Well Program. The National Energy Technology Laboratory (NETL) became DOE's 15th national laboratory in late 1999, the only one devoted strictly to oil and gas R&D issues. Within NETL's overall R&D program, about $27 million is devoted to gas, exploration and storage issues--$10 million for long-term hydrates research, $3 million for storage, and $14 million for exploration and production R&D. Near-term gas R&D is focused on topics that can make a difference within one to two years-enhancing production from existing stripper gas wells (< 60 Mcfd) and identifying bypassed/behind-pipe zones. There are about 190,000 stripper gas wells in the Lower 48 states, producing about 8% of U.S. production. Wells are concentrated in the Appalachian Region (Kentucky, Ohio, Pennsylvania, West Virginia) and the Texas/Midcontinent Region.

R&D effort is focused in three areas. First, working with the Energy Information Administration (EIA), DOE is developing a stripper well database. This database, which should be completed early in 2001, will be available through EIA's website or CD-ROM. Second, NETL has funded five field demonstration projects. Three projects are decline curve projects (in Ohio, Pennsylvania, and Texas) focusing on identifying under-performing wells and testing solutions to improve productivity. A fourth project is testing a web-based satellite communication and air pulse lift system for keeping fluids unloaded from marginal gas wells. A fifth project in Colorado is evaluating a coal-based filtration system for cleaning relatively fresh produced water to agricultural standards.

Through Pennsylvania State University is now implementing a stripper well R&D consortium. Member companies, who must pay nominal fees to join, can submit proposals. An executive committee formed from member companies will evaluate submitted R&D proposals and determine which projects receive funding. DOE is committing about $1 million per year initially and industry cost share is required.

Advanced Exploitation Through Horizontal Technology. Historically, about 88% of US horizontal wells have been in fractured carbonates, primarily the Austin Chalk and Bakken Shale. A recent DOE-funded study examined the potential from horizontal wells in the US in different geological settings. Total potential with a $24/bbl oil price was 965 million bbls. In addition to the potential of 318 million bbls from fractured carbonates, there are potential reserves of 401 million bbls from profile modification applications, 128 million bbls from thin bed applications, and 118 million bbls from continuity improvement applications. The study found that misconceptions concerning horizontal technologies were the biggest impediment to more widespread application by US independents.

A common misconception is that "rules of thumb" comparing horizontal to vertical well cost and performance are applicable. They are not; each situation demands a site-specific evaluation. Since most drilling problems are encountered in the curve section, the incremental cost of drilling further once horizontal is minimal. Incremental costs for drilling further are also kept low because most horizontal sections are open hole, even in relatively unconsolidated reservoirs. Driven to keep well costs low, Canadian operators employed open-hole completions and have found that they are much more stable than originally envisioned. High-cost settings are also very amenable to horizontal technologies since the incremental cost for horizontal technology is small relative to the total. For example, horizontal technologies are common offshore and in urban field development.

The driving force that encourages horizontal technology is employing the "line vs. point source" concept, recognizing that a line source makes more efficient use of reservoir drive energy. When employing horizontal technology, it is not just higher production rates but improved recovery. In clastic reservoirs, experience indicates that, once past the initial flush production stage, decline behavior in horizontal wells is similar to that experienced in vertical wells. Decline behavior is related to the reservoir drive mechanism and not whether a well is horizontal or vertical. Reservoir characterization and visualization technologies are critical tools for making site-specific evaluations. Except for complex situations, analytical models are sufficient for making screening decisions regarding "vertical vs. horizontal" wells. For complex situations, numerical simulation is probably warranted. Application service providers, such as Geonet, are a cost-effective option for accessing technical software needed for horizontal technology evaluations.

Experience confirms that several factors control success. First, exploitation efforts must employ fully integrated, multi-disciplinary teams, and these teams must incorporate the driller. There must be basic cross training such that members understand each discipline's limitations. Second, the team must not overlook the basic steps during the vertical well stage. Third, each well must be tailored to site-specific conditions. There is no such thing as a generic well plan. Fourth, one must work backward, that is, consider the reservoir first and the "why" of horizontal technology before getting into the "how" details. Fifth and importantly, expect and plan to make real-time adjustments in response to what is encountered during the drilling process.

Examples of Horizontal Exploitation in US Mature Reservoirs. Texaco's Aneth field in Utah was discovered in the 1950s and waterflooding with 40-acre five spots was initiated soon after. By mid-1990 the field was nearing its economic limit. Texaco employed multi-lateral, open-hole re-entries to convert the waterflood to a line drive pattern, overcoming vertical and lateral non-conformance problems. This comprehensive re-entry program reversed production decline, increasing production some 1,500 bopd over projected base line decline. Through mid-1998, about one million bbls of incremental oil had been produced. Important lessons learned in the Aneth field included the steep learning curve and the economy of scale achieved by placing multiple laterals out of each existing well.

Texaco applied knowledge gained from the Aneth field to the Bryant-G-Devonian field in the Permian basin. Originally discovered and developed in the mid-1960s, the field was developed with 19 wells in eight sections. The Devonian reservoir is a retrograde condensate reservoir. Gas cycling began in the mid-1970s but was found to be uneconomic because reservoir permeability was too low and too discontinuous to allow effective sweep. Gas cycling was stopped and primary production dropped to about 2 Mmcfd plus 100 bcpd and stabilized. In 1994 and 1995 a vertical well, infill-drilling program added 11 wells, each producing about 500 Mcfd (*World Oil*, October 2000). Texaco conducted their first horizontal re-entry in early 1996, with good results. This success resulted in 11 re-entries and 19 new wells during 1996 and 1997. 13 new wells were also added on the flanks of the structure outside the unit boundary. After a slow down during 1998, the 1999 program concentrated on adding second laterals to existing wells. Net result-gas production was increased to 60 Mmcfd, a 30-fold increase and condensate production was increased in nearly the same ratio. Expected recoverable reserves were increased about 300%. As in the Aneth field, there was a learning curve with final per well drilling and completion costs being about $650,000 less than initial wells.

Technology Applications by California Independents

Speakers from three prominent California operators-Oxy in Thums Long Beach Unit, Nuevo Energy Company, and Berry Petroleum Company-shared insights regarding how technology applications were integral to the production/financial results their companies are achieving in California's mature reservoirs.

Thums Long Beach Unit. Drilling began at Thums Long Beach Unit in 1965, reaching a peak rate of 150,000 bopd in 1969. The Unit has undergone extensive waterflooding. In the late 1980s, Arco (operator at the time) implemented a $100 million waterflood optimization plan. This plan focused on extension drilling in undeveloped areas and attaining injection targets in more mature areas. The optimization effort, which employed several technologies, increased production and is moderating decline. The Unit is now struggling to maintain 37,000 bopd (with 700,000 bwpd) from 700 producers and 375 injectors. During the recent period of reduced oil prices, drastic cost-cutting measures were taken to maintain profitability. Economic analysis indicates that present worth is maximized when activity levels are stabilized (i.e., don't slow down or ramp up activities depending on oil price), so Oxy is trying not to over-react to current higher oil prices.

Quality reservoir characterization is the key to success at Thums, and experience indicates the complexity of the description continually increases as more data become available. Established technologies that have made a difference at Thums include: (1) hydraulic fracturing of unconsolidated sands (incremental oil @ $3.25/bbl), (2) extended-reach and horizontal drilling, (3) ultra-slim (1.9-in) inner liners for well repair, (4) logging while drilling, and (5) gravel pack for sand control. Newer technologies now being implemented include: (1) bi-center reaming while drilling to incrementally reduce drilling cost, (2) hot water stimulation, (3) cavity completion, (4) re-shooting 3-D seismic (to replace known poor quality initial survey), and (5) facility automation. Increased automation allows real-time knowledge of well status (which will reduce lost production from unknown well shut-ins) and improves safety, compensating for reduced manning for cost control. Technologies being considered for future application include: (1) downhole oil/water separation, (2) profile control, (3) behind-pipe oil detection, (4) artificial lift improvements, (5) lower cost drilling, and (6) improved corrosion/scale control. Some, like downhole oil/water separation, are newer technologies that are not proven today but with evolution will some day be, while others like improved corrosion/scale control are areas needing constant attention.

Nuevo's Operations in California. Since being founded in 1990, Nuevo Energy Company has grown over tenfold-from 23 MM Boe reserves in 1990 to 289 MM Boe in 1999. Nuevo is the largest independent in California, producing about 46,000 bopd from California. Nuevo's exploitation strategy is to take "under loved" properties, give them some attention and focus on rapidly increasing production. It is not just quickly working on fields, but using technologies that help produce reserves faster, such as horizontal well technology and unique completion techniques. When production is accelerated, experience confirms that recovery is also increased. Integral to this philosophy, Nuevo strives to maintain and operate at or above the highest regulatory and safety standards, winning several safety/environmental awards for their offshore operations.

Technical competencies central to this exploitation strategy include: (1) infill/horizontal drilling, (2) extended-reach drilling, (3) fracture stimulation, (4) proprietary production technology, (5) secondary recovery, (6) tertiary recovery, and (7) reservoir simulation. As an indication of how central these technologies are, in 1996 Nuevo had only one horizontal well. Nuevo now drills 20 horizontal wells per year. In hydraulic fracturing, through expert services provided by contractors, Nuevo has special expertise in stimulating fractured Monterrey shales.

In the Star Fee Lease in the Cymric field, production was 400 bopd in June 1999 when Nuevo acquired the field. In less than 18 months, Nuevo drilled 103 multiple-completion wells employing proprietary completion technology developed, but never tested, by Unocal. Production is now 6,500 bopd from 90 wells. In the Hopkins Fee Lease in the Belridge field, there was no production when Nuevo acquired the lease in 1996. Since then, 21 horizontal wells have been drilled to a 10- to 25-ft Tulare Sand zone, extending the productive field limits. Current production is 2,100 bopd, and another 30 horizontal well locations have been identified. In a third example, pulsed neutron logs have helped identify behind-pipe zones for recompletions. In well A-21, recompletion in May 2000 boosted production from 2.4 to 7.9 Mmcfd. A second recompletion in November 2000 also had good results. In the Brea Olinda field, a gas turbine for power generation was installed, creating value from about 2 Mmcfd of previously flared natural gas. Payout occurred within four months and a second generator has been installed.

Berry Petroleum's Operations in California. Berry Petroleum is a core niche player in California's heavy oil production, producing about 17,000 bopd, much of that from thermal operations. Its main producing properties are in Midway-Sunset, Montalvo and Placerita. Three cogeneration plants produce 98 megawatts of electric power and 43,000 bbls per day of steam, about two-thirds of Berry's steam demand. Specific production targets are set when properties are acquired and results reviewed one year later. Adjusted to a months since acquisition basis, Berry has a track record of achieving a 40% increase in production within 10 to 12 months. Essential technologies for realizing increases of this magnitude are: (1) 3-D visualization, (2) horizontal drilling, (3) 3-D seismic, and (4) fracturing technology.

With a 3 to 4:1 steam-to-oil ratio, minimizing steam cost is essential. Cogeneration facilities provide a significant cost advantage, as much as 2.5:1, over conventional steam generation facilities, particularly when gas prices rise. With this cost disadvantage and recent upward spikes in gas price, Berry has been forced to shut-in some conventional steam generation capacity, representing about 25% of its total steam capacity. And some development plans have been put on hold. Active management of cogeneration facilities becomes even more critical. Berry has learned that managing the total energy complex (oil, gas and electric power), not just oil production, is the key. With evolving electric deregulation and spikes in natural gas prices, there is intense political pressure. Involvement and interaction through trade associations becomes important for achieving successful outcomes.

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