EOR Operations

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Welcome to the Enhanced Oil Recovery (EOR) Operations feature. This past year provided stimulating and rewarding times for all involved with EOR technologies. The interest in EOR technologies is higher than ever, despite the current fall in global crude-oil prices, which, by the way, is believed to be temporary by most analysts. This amplified attention in the EOR area results from the decrease of new discoveries and the ever-increasing number of maturing fields worldwide. It is expected that many EOR projects planned in the recent past will be implemented in the coming years. Thus, it is fundamental to revisit the lessons learned from previous EOR applications and to pay attention to the development of new techniques.

Regarding technical publications, this past year alone, more than 300 SPE papers related to EOR were presented at various SPE events. As a result, the EOR feature is divided this year: EOR Performance and Modeling published in January and EOR Operations published in this issue. The papers featured here will give you only a few examples of the immense amount of high-quality material that was published last year. I hope that you enjoy reading these paper highlights and that you will search for additional interesting contributions that are available in the SPE eLibrary (OnePetro as of 1 July 2009). JPT

EOR Operations additional reading available at the SPE eLibrary: www.spe.org

IPTC 11613 *• "Blending Optimization of Contaminated Gas in a Miscible Gasflood" by J.T. van Berkel, SPE, Shell International E&P, et al.*

Enhanced-Oil-Recovery Pilot-Testing Best Practices

Enhanced-oil-recovery (EOR) implementation is complex, and successful applications must be tailored to each reservoir. A systematic staged evaluation and development process is required to screen, evaluate, pilot test, and apply EOR processes for particular applications. Pilot testing can play a key role in this process. Before field testing, pilot objectives must be defined clearly and well spacing, pattern configuration, and injectant volumes determined.

Staged Process for EOR-Project Evaluation and Development

The EOR evaluation begins with screening-level-data collection, candidate-process selection, injectant-source identification, and screening economics. If favorable, EOR-project design and implementation require in-depth analysis of the most-promising processes. In addition to standard laboratory tests, specialized fluid characterization and reservoir-conditions coreflood tests with in-situ fluids and a range of injectants are performed to customize a process for each reservoir. Reservoir-characterization studies are conducted concurrently to identify key geological controls on field-scale sweep efficiency. Results from the studies then are used as input to geological and dynamic reservoir-simulation modeling of the process at various scales to evaluate options, define a preferred process design, and provide input to screening-level development and facilities planning. If anticipated rates, recoveries, and economics are favorable, pilot testing in the target field often is undertaken to resolve uncertainties and fine-tune operational and execution details. Additional laboratory, reservoir-characterization, and simulation work may be undertaken after pilot testing to resolve uncertainties further. If the technical and commercial outlook is still positive, commercial-scale implementation takes place. Stakeholder reviews are held after each stage of this process. This process is illustrated in Fig. 1 of the full-length paper. The example used in the paper is a CO_2 water-alternating-gas (WAG) process.

This article, written by Senior Technology Editor Dennis Denney, contains highlights of paper SPE 118055, "Enhanced-Oil-Recovery Pilot-Testing Best Practices," by ***G.F. Teletzke,*** *SPE,* ***R.C. Wattenbarger,*** *SPE, and* ***J.R. Wilkinson,*** *SPE, ExxonMobil, prepared for the 2008 Abu Dhabi International Petroleum Exhibition and Conference, Abu Dhabi, UAE, 3–6 November. The paper has not been peer reviewed.*

Pilot Objectives

Care should be taken when developing pilot objectives to ensure that the pilot is used appropriately as part of a long-term field-development strategy. Pilot tests should field test recovery processes that have been evaluated technically and economically beforehand. Also, the recovery process to be field tested should be optimized through both laboratory and reservoir-simulation studies to maximize oil recovery at the lowest possible cost. Before field testing, the most appropriate well spacing, pattern configuration, length and orientation of wells, injectant, and injection strategy should be defined.

Considerations for Pilot Design

Adequate time spent on pilot design and optimization can lead to earlier full-field implementation. A poorly designed and executed pilot may lead to condemning an appropriate EOR process incorrectly or promoting an inappropriate EOR process.

Pilot tests reduce uncertainties for decision making. When designing a pilot, care should be taken to understand and to minimize the effect of the scaled-down nature of the pilot. Reduced well spacing, judicious placement of observation wells, and elevated injection rates are techniques that provide performance information. The pilot must be scalable to full-field application. Pattern configuration, well design, the chosen injectant, and process operations should enhance confidence in scaleup to fieldwide implementation. Finally, the pilot location should be chosen to ensure, as much as possible, that it can be well characterized and is representative of the broader EOR target.

Types of Pilots: Advantages and Disadvantages

It is important to distinguish between data gathering, pilot, and phased implementation.

- Data gathering collects field data to address specific key uncertainties that could have significant effect on a business decision.
- The pilot validates the performance of a particular EOR process in the field. Before investing in a large-scale application, a pilot is conducted at a well spacing that is scalable to that expected for full-scale application.
- Phased implementation manages uncertainty by implementing a project in phases with appropriate adjustments in scope and optimization of design between phases.

Generally, a more complex and, therefore, more costly configuration will yield more data and be easier to scale up to commercial conditions. A balance must be established between the risks of a commercial project and the cost of information provided by data from a pilot.

Nonproducing Pilots. The simplest design is a single-well injectivity test to determine the ease with which gas can be injected into the formation and to evaluate injectivity losses resulting

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

from WAG processes. By adding an observation well, the vertical-sweep and local-displacement efficiency of the gas at the observation well can be determined. Adding a second observation well enables assessing vertical sweep over the distance separating the observation wells. The locations of the observation wells must account for reservoir heterogeneities and near-well pressure gradients that may result in the injected fluids moving away from rather than toward the observation wells. Because gas injectants are less dense than the in-situ oil, observation wells will provide valuable information on gravity override that may lead to poor sweep efficiency.

Producing Pilots. Pilots that incorporate production wells, provide direct data on oil recovery, fluid transport through the reservoir, and pressure drop between injectors and producers. Important factors to consider when designing and interpreting producing pilots include the following.

- Drift: Is the pattern acting as a confined flow system?
- Balance: Are the relative rates of injectors and producers allocated to maximize areal-sweep efficiency in the pilot area?
- Isolation: Is the zone that is taking injection the only zone that is producing?

The cost of running a confined, balanced, and isolated pilot may be considerable because offset production may need to be curtailed. This consideration is important in systems with gas or light oil and in which pressure gradients across the pilot site may result in significant fluid flux that will compromise pilot interpretation. A compromise may be needed between the best possible data and a situation that can be simulated later with reasonable confidence.

A producing pilot also provides experience with separation and handling of produced fluids. Small-scale facilities can be constructed, and easily modified, to gain experience with separation and recycling of fluids.

Observation wells provide a means of monitoring fluid movement at various points between the injector and producer wells. Information on conformance, fluid transport in the reservoir, and fluid mobilities can be gained from observation-well data.

Although unconfined producing pilots can provide production experience rapidly and at relatively low cost, the swept volume can be difficult to evaluate. Performance may not be representative of a repeated pattern and may be difficult to scale. These pilots are sensitive to fluid drift and can take as long to run as a full-pattern flood.

Better recovery estimates can be obtained with a single normal-five-spot pattern. In this design, water or gas is injected at the four corners of the pattern to confine the oil within the pattern. To reduce pilot duration, confined pilots typically use a closer well spacing than that planned for commercial application. Such small-scale confined pilots can provide good estimates of oil displacement and, when coupled with the use of observation wells, vertical-sweep efficiency as a function of distance from the injection well. However, the small pattern size may not sample representative heterogeneities, reflect the balance of a repeated pattern flood, scale to wider well spacings, or indicate long-term problems.

For improved confidence in scaling pilot results to potential full-field applications, repeated inverted-five-spot patterns have been used. This arrangement provides the best estimates of oil recovery and sweep efficiency, the best data for calibrating simulation models, and the most direct scaleup to commercial operations. However, this type of pilot will have the longest duration and will require extensive evaluation time.

Pilot Interpretation

A detailed reservoir-simulation model of the pilot area (with appropriate boundary conditions) helps to optimize the pilot design and the monitoring program, to anticipate data needed for history matching the pilot, to enable timely interpretation of the pilot, and helps to assess the need for selective use of additional observation wells and post-flood coring. The geology of the pilot area and a good understanding of the target oil distribution are critical inputs to the simulation model.

The following pilot design and operational best practices help to minimize uncertainties in test interpretation and facilitate history matching of pilot results.

- Production facilities, well completions, tubulars, and artificial lift should be representative of the anticipated commercial-scale development.
- Several good baseline logs and possibly a single-well tracer test should be run in wells before the test begins and at regular intervals to verify reproducibility of the log measurements and to ensure accurate determination of saturation changes during time-lapse logging at observation wells.
- An adequate period of steady baseline injection and production should be achieved before initiating the EOR process to reduce uncertainty in interpretation of injectivity, saturation changes, and incremental-oil production.
- Fluid drift should be minimized so that the pilot area acts as a confined system.
- The relative rates of injectors and producers should be allocated to maintain pattern balance and maximize areal-sweep efficiency in the pilot area.
- Steady and uninterrupted injection and production rates should be maintained.
- Injection and production zones should be isolated so that only the targeted production zone is taking injection.
- An adequate volume of EOR fluid should be injected to reduce uncertainty in interpretation of sweep efficiency, saturation changes, and incremental-oil production.
- The original pilot-operating and -monitoring plan should be continued until sufficient data are acquired to validate simulation models; do not attempt to optimize on the basis of early results.

Assessing incremental-oil recovery beyond a waterflood project should be a key objective of a pilot.

- In very mature waterflood cases (>90% water cut), an increase in oil cut can provide a direct measure of improved recovery. A disadvantage is that this may delay the pilot, or the waterflood may contact only part of the target zone.
- In less-mature waterfloods, the baseline waterflood recovery can be estimated by use of a reservoir-simulation model to history match the pilot area and extrapolate the prepilot-waterflood-production trend.

Summary

A staged approach to EOR development focusing on pilot-testing best practices includes factors to consider when determining whether a pilot is needed. Defining pilot objectives, requirements for a successful pilot, types of pilots and their advantages and disadvantages, and tools and techniques for assessment of key reservoir mechanisms (and minimizing uncertainty in pilot interpretation) are key steps. **JPT**

Characterize Scaling Damage From Pressure Measurements

Productivity-decline prediction is based on mathematical modeling with well-known model coefficients. The sulfate-scaling system contains two governing parameters: the kinetics coefficient, λ, characterizing the velocity of chemical reaction, and the formation damage coefficient, β, showing how the permeability decreases because of salt precipitation. This paper extends previous works with commingled injection of two incompatible waters into the same core with two different ratios of formation water (FW) to seawater (SW).

Introduction

Barium- and strontium-sulfate scaling is a major problem in waterflood projects with incompatible formation and injected waters. Barium sulfate and resulting scale causes formation damage near the production-well zone. This phenomenon is attributed to precipitation of barium and strontium sulfates from the mixture of both waters and the consequent permeability reduction resulting in loss of well productivity. The chemical incompatibility between the injected SW, which is high in sulfate ions, and the FW, which originally contains high concentrations of barium, calcium, and/or strontium ions, may reduce well productivity, making the waterflood project uneconomical.

This article, written by Senior Technology Editor Dennis Denney, contains highlights of paper SPE 112500, "A New Method To Characterize Scaling Damage From Pressure Measurements," by ***T. Carageorgos, M. Marotti,*** *and* ***P. Bredrikovetsky,*** *SPE, North Fluminense State University, prepared for the 2008 SPE International Symposium and Exhibition on Formation Damage Control, Lafayette, Louisiana, 13–15 February. The paper has not been peer reviewed.*

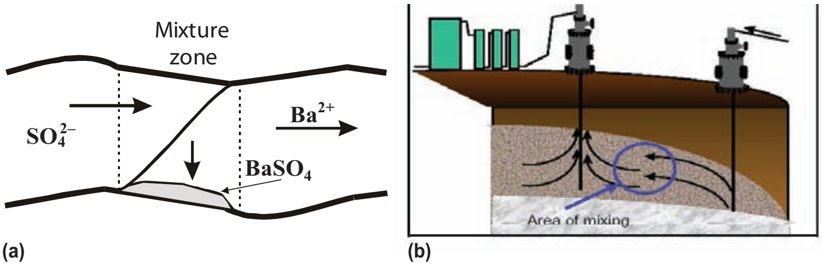

Fig. 1—Precipitation of barium sulfate in the mixing zone (a) in a stream tube during displacement of formation water by injection water and (b) in the reservoir.

A reliable model that is capable of predicting such scaling problems would help in planning a waterflood project. It also could aid in selecting an effective scale-prevention technique by predicting scaling tendency, type, and potential severity. A reliable predictive model must use well-known values of the model coefficients.

The mathematical model for sulfate scaling contains two phenomenological parameters: λ from the active-mass law of chemical reaction showing how fast the reaction and precipitation occurs, and β reflecting the permeability decrease caused by sulfate-salt deposit. Both coefficients depend on rock-surface mineralogy, pore-space structure, temperature, and brine ionic strength. Therefore, they cannot be calculated theoretically for natural reservoirs and must be determined from laboratory corefloods.

Reagent- and deposition-concentration profiles during reactive flows are nonuniform, so the sulfate-damage parameters cannot be calculated directly from laboratory measurements. They must be determined from laboratory coreflood data by use of inverse-problem solutions.

The λ can be calculated from breakthrough concentration in a quasisteady-state coreflood with commingled injection of FW and SW. Then β can be determined from the pressure-drop increase during flooding.

Previous work used results of coreflooding in identical artificial cores. Applying the method to real-reservoir cores is difficult because no identical natural cores exist. In this study, commingled injection of incompatible waters was done into natural Berea cores. If compared with results from identical artificial cores, stability of the method is lower.

Another method is proposed to characterize the sulfate-scaling system from coreflood and pressure measurements on the same core. Two sequential commingled injections of FW and SW were performed in the same core with different FW/SW ratios. Two sulfate-scaling damage coefficients were determined from different slopes of skin-factor increase during two injections. A sequence of two commingled waterfloods was performed, and the proposed method was applied to analyze the results. The obtained coefficient values are in reasonable agreement with those obtained from breakthrough concentration measured during the tests.

Formulation of the Problem

Formation damage from barium-sulfate precipitation is one of main physics mechanisms for production-well formation damage. Often, seawater is injected in offshore operations, which contains anions. If the formation water contains cations, mixing of injected and formation waters may cause barium-sulfate deposition as shown in **Fig. 1a.** The same reaction takes place between sulfate anions and cations of strontium, calcium, and other metals.

Sulfate-salt deposition takes place in the mixing zone of two waters. During waterflooding, the mixing zone moves continuously from injector to producer [i.e., deposit accumulation in any reservoir pattern takes place during the short time when the mixing zone passes the pattern (Fig. 1b)]. This deposit occupies a negligible fraction of porous space and does not cause permeability damage.

Continuous mixing of FW and SW takes place near the production wells where simultaneous production of injected water through high-permeability layers and of produced water through low-permeability layers occurs. Injected water and FW arriving by different-length streamlines also mix near producers. High-flow velocity near production wells intensifies the mixing and the resulting precipitation. It results in deposit accumulation near production wells and, consequently, in productivity decline.

Reliable prediction of sulfate-scaling productivity decline is based on mathematical modeling with values of the model coefficients. Model-coefficient determination can use laboratory coreflood with commingled injection of FW and SW.

Tests on commingled injection of FW and SW (at FW/SW ratios of 9:1, 3:1, 1:1, and 1:3) measured only flow rate and pressure drop in each flood. The results are presented in Fig. 4 in the full-length paper. The injected concentrations for barium in FW and for sulfate in SW were 210 ppm and 2,300 ppm, respectively. The injected barium/sulfate concentration ratios were 0.82, 0.27, 0.09, and 0.03, respectively. As the barium/sulfate concentration ratio decreased, there was a resulting decrease of formation damage.

Direct and Inverse Problems for Sulfate-Scaling Formation Damage

The main assumptions with mathematical modeling were as follows.

- Irreversible chemical reaction between sulfate anions and cations of barium, strontium, or calcium
- Active-mass law for kinetics of the second-order chemical reaction
- Instantaneous deposition of all appearing salt without its transport through rock
- Independence of reaction-rate constant from deposited concentration
- Volume conservation during chemical reaction for the system "aqueous solution of two reagents and solid deposit"
- Constant temperature
- Negligible reagent dispersion

It was assumed that the chemical reaction between barium and sulfate is irreversible and obeys the second-order active-mass law. This hypothesis is valid for small times, far away from thermodynamic equilibrium between the deposited salt and its aqueous solution. Short times correspond to low deposited concentrations. Kinetics of dissolution of the solid deposit into water must be taken into account for the case of high-deposited concentrations during long-time tests.

For low deposited concentrations, it was assumed that the reaction rate constant is independent of the deposited concentration. Instant deposition of formed sulfate salt also was assumed (i.e., kinetics of crystal growth is neglected).

The system of governing equations for flow of an FW/SW mixture with chemical reaction between two species consists of mass-balance equations for barium cations, for sulfate anions, and for deposited salt, and of modified Darcy's law accounting for permeability damage caused by salt deposition.

The full-length paper details these equations and presents an analytical model for quasisteady-state corefloods. It also details the method of determining sulfate-scaling-damage parameters from pressure data.

Sequential Injections Into the Same Reservoir Core

The method consists of two commingled injections of water with different FW/SW ratios with simultaneous pressure-drop measurement. Deviation of the pressure-drop curve with intensive sulfate precipitation from the modeling results (Curve 1 in Fig. 4 in the full-lenth paper) indicates that the salt deposition changes the matrix surface and conditions for further reaction and precipitation. Therefore, to keep the assumptions of the model during the second flood, it is necessary to minimize sulfate precipitation during first injection. In the performed coreflood, a linear form of impedance was established with dimensionless time, and the system was switched to the second flood.

A similar situation appears in deep-bed filtration of injected-water particles causing injectivity decline in waterflood projects. The modeled filtration coefficient reflects the intensity of particle capture by the rock. Decrease of permeability with retained particle accumulation is described by the same β. As with commingled coreflooding with FW and SW, both injectivity-damage parameters λ and β can be determined from effluent-particle concentration and pressure-drop evolution on the core. The additional information to substitute complex and cumbersome breakthrough-concentration measurements is pressure-drop history on the first core section, which requires additional pressure measurement at some intermediate point of the core. For oilfield sulfate scaling, the additional information is obtained from a commingled coreflood with two different FW/SW ratios.

Discussions

The mathematical model with constant λ exhibits linear pressure-drop growth during the commingled coreflood with FW and SW. The laboratory data show that it happens only at low deposited concentrations. At higher concentrations, the laboratory tests exhibit nonlinear behavior.

The proposed method of scale-damage-parameter determination from pressure measurements was validated for linear periods of corefloods for three tests. The method was shown to be invalid for a test with intensive deposition and nonlinear behavior from the very beginning of injection.

Nonequilibrium dissolution of salt in water and dependence of λ on deposit concentration must be accounted for in the mathematical model to treat nonlinear impedance curves from commingled corefloods by FW and SW.

Conclusions

Treatment of laboratory data from two sequential commingled corefloods with two incompatible waters with different FW/SW ratios in the same core allowed the following conclusions.

- Two sulfate-scaling-damage parameters—λ and β—can be determined from two commingled corefloods with two different FW/SW ratios in a single core.
- Stability of the method is significantly higher for artificial cores than for natural-reservoir cores. **JPT**

SAGD Gas Lift Completions and Optimization: Surmont Field Study

Gas lift completions for steam-assisted-gravity-drainage (SAGD) producers are unique. Conventional gas lift valves and mandrels with a packer completion cannot be used because of the extreme temperatures of the downhole environment. Most lift gas enters the production stream downhole through open-ended tubing or nozzles, which, if not properly sized, can result in operational issues that negatively affect the overall lift efficiency. Data were collected and analyzed to determine the efficiency of two types of gas lift nozzles used in the completions. The method for optimizing SAGD gas lift systems is presented, and recommendations are made for future improvement.

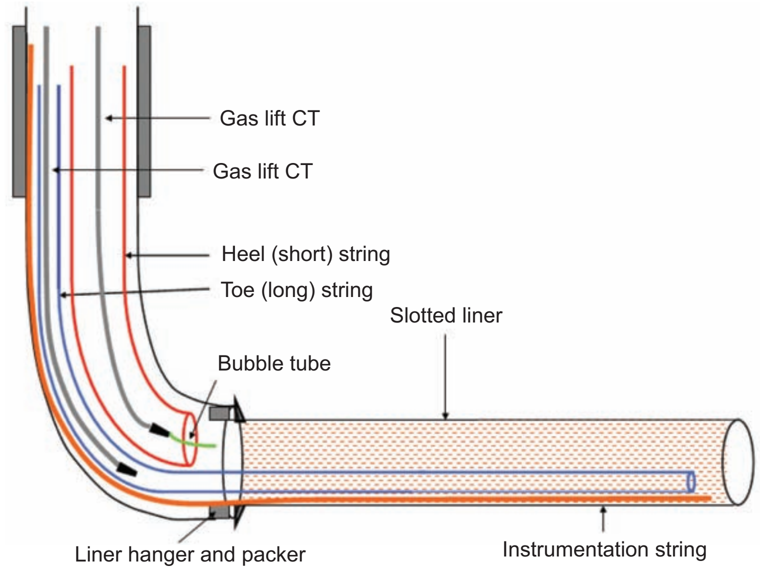

Fig. 1—Phase 1A completion schematic for a Surmont production well.

Introduction

Surmont, an oil-sands project, is approximately 37 miles southeast of Fort McMurray in the Athabasca oil sands in Canada. The Surmont pilot began steam injection in 1997, comprising three SAGD-well pairs that use a variety of artificial-lift methods. These wells were tested to determine the preferred method of artificial lift for the first commercial phase.

Main steam injection was initiated in mid-2007, and conversion to full SAGD production followed in late 2007. Phase 1A comprises 20 well pairs in which all the producers were completed to produce by use of gas lift for the initial life of the well. Phases 1A, 1B, and 1C have a capacity of 25,000 B/D and are expected to reach peak production in 2012. A second phase is slated for commercial startup before the middle of the next decade, which, upon completion and full ramp-up, is estimated to bring peak production from both phases to 100,000 B/D. Additional phases at Surmont are under study.

This article, written by Senior Technology Editor Dennis Denney, contains highlights of paper SPE 117489, "SAGD Gas Lift Completions and Optimization: A Field Case Study at Surmont," by ***T.C. Handfield, T. Nations,*** *SPE, and* ***S.G. Noonan,*** *SPE, ConocoPhillips, prepared for the 2008 SPE International Thermal Operations and Heavy Oil Symposium, Calgary, 20–23 October. The paper has not been peer reviewed.*

Historical Perspective

The Surmont gas lift experience began with trials in two of the three pilot wells. The completions consisted of a single production string varying in size from 3.5 to 5.5 in. with a 1-in. coiled tubing (CT) run concentrically for gas lift and landed at the heel of the well. The bottom 2 m of the gas lift string was constructed similar to a perforated stinger with ten 11-mm orifices. These gas lifted wells operated with reservoir pressure as low as 334 psi, producing fluid rates between 1,047 and 3,352 B/D, with gas lift rates ranging from 211 to 339 Mscf/D for a total combined operating time between the two wells of 35 months.

The conclusion from testing at the pilot was that gas lift at the higher reservoir pressures was effective. However, before making additional designs and sensitivity studies, the gas lift assemblies were removed to allow for testing and validation of other forms of artificial lift for Surmont SAGD.

Initial Gas Lift Design

Gas lift design is complex for the thermal wells because of its sensitivity to the fluid gradient and the effect of the steam providing a gas lift effect in the tubulars. Most gas lift design programs are unable to account for the steam-lift effect and as a result may overpredict the amount of lift gas needed to overcome the gradient.

A gas lift stability assessment was made that would in turn recommend a completion design to minimize slugging. Each stinger configuration (ori-

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fice size and quantity) was simulated, analyzed, and plotted to determine what surface lift-gas-injection rate would provide the necessary amount of pressure differential at the point of entry into the production stream for continuous injection. For this stability assessment, a transient gas lift program was used to model the dynamics on the lift-gas side and across the downhole chokes/nozzles. This method was used for single-point gas lift injection in subsea applications. The flowing bottomhole pressures on the downstream side of the "chokes" were matched to that calculated by a SAGD wellbore-hydraulics program.

Slugging may be induced by the gas lift system if the ports are too large (or there are too many of them). A very small pressure differential will result in a large amount of gas entering the production stream. It is believed that the slugging problem with the gas lifted pilot wells at the lower reservoir pressures was caused by the downhole lift-gas ports being too large (or too numerous), placing the well in an intermittent-lift regime instead of continuous gas lift.

The difficulty in determining the optimum total flow area of the gas lift ports is in satisfying the following requirements.

- A minimum differential across the ports of approximately 22 to 29 psi, allowing some flowing-bottomhole-pressure fluctuation.
- A flow area that allows continuous gas passage for injection rates between 106 and 353 Mscf/D.

The approach taken was to size the valve to pass, at most, 353 Mscf/D at the lower pressure differentials. For larger pressure differentials, the well must be choked back at the surface; however, if the flowing-tubing pressures just below the injection point begin to fluctuate, the holes are small enough to provide some gas-flow control.

The key recommendation from the gas lift study was that the total flow area for continuous gas passage at the end of the lift-gas-injection string should be in the range of 20 to 25 mm^2. This size is approximately equivalent to two 4-mm ports or a total of three 3-mm ports (not taking into account orifice-flow coefficients). Single ports were analyzed; however, the Surmont team wanted the redundancy of multiple ports to minimize the effect of possible plugging. It also was recommended to use nozzles with internal reverse-flow checks to prevent well fluids from traveling up the lift-gas injection tubing back to surface when the pressure inside the CT is less than that in the production tubing; however, these check valves were not used because of the addition of bubble tubes installed concentrically in the gas lift coils.

Startup and Optimization

Similar to most SAGD operations, the producer well is designed with dual tubing strings to allow increased operational flexibility. For Surmont Phase 1A, a parallel design with a heel (short) and toe (long) string was used, as shown in **Fig. 1.** An additional string was run parallel to the toe production tubing to house instrumentation for temperature measurement along the horizontal section of the wellbore. CT with gas lift valves was installed concentrically to the production strings and landed slightly higher than the horizontal section. A 0.25-in. bubble tube was added to the gas lift CT in the heel strings for bottomhole-pressure measurement. Blanket gas was placed in the annulus of the vertical section of the wellbore for thermal isolation between the production strings and the casing for increased well integrity.

Two gas lift nozzles were tested, one with vertically oriented ports and the other with ports oriented 45° upward. The vertically oriented design had four 4.77-mm-diameter ports, while the inline subassembly had two 4.09-mm-diameter ports angled upward at 45°. The flow capacity of these nozzles at a differential pressure of 29 psi is approximately 672 Mscf/D for the four-ported vertically oriented nozzle and 224 Mscf/D for the two-ported inline nozzle.

Leaking and damaged seals in the CT hanger have remained exclusive to the toe-production strings to date. The damage to the seal system was most likely caused by direct exposure to high-quality steam during circulation. Diagnosis of the leak or failure can be assessed from review of lift-gas-injection pressures at surface. Lift-gas-injection pressures below bottomhole pressure (BHP) reflect a negative pressure differential with respect to the BHP, and it is, therefore, evident that gas is not flowing downhole. Tightening of the coil packing following circulation is essential to obtain flow assurance and reduce seal failures. In the future, best practice may be to install the toe gas lift CT following the circulation period and reduce the exposure to high-quality steam.

Plugging of the CT or nozzle was evident when the gas injection pressure reached maximum capability; but even with this high differential above the BHP, it was not possible to reach the target gas-injection rate. The cause is under investigation. Plugging typically occurred following periods of shutdown, but this was not always the case. Often, under steady-state conditions, injection pressures would begin climbing over a period (days) indicating some sort of bridging effect from contaminants in the surface facilities. Flushing diluent down the gas lift CT with use of a pressure truck cycling between pressuring up and bleeding back was implemented to assist in agitating suspected debris and was successful in remediating the blockages for most of the cases. Following any well intervention, even if a new gas lift CT is installed, it is recommended to flush the CT with diluent to ensure that no blockage exists before restart of the well.

Lift-gas-injection rates, surface lift-gas-injection pressures, and flowing wellhead pressures in short time increments (i.e., seconds) are used to determine if a flow string is operating in intermittent or continuous gas lift. Slug flow is indicated by changes in pressure (bottomhole or at the wellhead) in response to slugs of fluid being built and then lifted intermittently. As an internal rule of thumb, fluctuations in pressure greater than 50 psi are deemed as slug flow. Pressure fluctuations of less than 50 psi can be expected under normal operation. Minimizing slug flow can be achieved by adjusting the backpressure on the well or by adjusting the lift-gas-injection rate.

Currently, there are no conclusive results to demonstrate superior design of either the vertically oriented nozzle or inline nozzle under current operating conditions. Stable production has been demonstrated with a variety of gas lift injection rates with both nozzles, under both choked and fully open positions, with wells of similar design and flow trajectories. Nozzle design may prove to be of greater importance as reservoir pressure decreases in the future. **JPT**