Casing and Cementing

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The current trend in well construction technology is focused on reducing the risk associated with capital-intensive wells in deeper and/or increasingly hostile environments. With a water depth between 4,000 and 11,000 ft, total depth approaching 30,000 ft, and a total cost per well of USD 200 million to 300 million, the deepwater projects being developed around the world are a prime example. One significant design error or oversight can lead to well failure and have serious effect on a company's bottom line. With mudline temperatures as low as 34°F and production temperatures as high as 250°F, annular temperatures may increase by more than 100°F during production cycles. As the annular fluid heats up, it expands. If that fluid is in a confined section of casing/casing annulus, the annular pressure can exceed 10,000 psi. This phenomenon has led to rupture or collapse of casing strings and loss of some wells. One approach to mitigating this phenomenon is to use vacuum-insulated tubing to limit heat transfer to the trapped fluid. Another is the novel use of a new annular fluid that shrinks rather than expands as the annular temperature increases.

A greater proportion of our future energy will come from more-hostile environments as we increase the pursuit in deepwater, high-pressure/high-temperature, geothermal projects while using CO_2-storage wells to reduce CO_2 emissions. These wells may contain high levels of H_2S, CO_2, and/or chlorides and have temperatures in excess of 350°F. Proper selection of tubulars, anatomic seals, and cement will be critical to reducing total well cost and environment and commercial risk.

I asked one of Chevron's cementing experts (Robert Carpenter) for help with current cementing technology. With the growing concern about "carbon emissions" and "carbon capture," CO_2 injection for geological storage is our next big area of activity. The success of this industry segment is predicated on very-long-term isolation of injected CO_2. We are in the investigational stage of this rapidly growing industry segment, and the primary issue is ensuring the long-term integrity. There is extensive debate and conflicting laboratory and field investigations into the suitability of Portland cement for a CO_2-rich environment. Recent investigations indicate identifying and preventing existing cement defects as the primary concern, and the CO_2 attack on Portland cement as less of an issue. **JPT**

Casing and Cementing additional reading available at the SPE eLibrary: www.spe.org

SPE 115638 *• "Advanced Cement Systems Used to Improve Geothermal-Well Reliability in Java" by K. Ravi, Halliburton, et al.*

SPE 119504 *• "The Effect of Carbonic Acid on Well Cements as Identified Through Lab and Field Studies" by A. Duguid, SPE, Schlumberger.*

SPE 112624 *• "Analysis of Control Lines Strapped to Tubing" by Robert F. Mitchell, Halliburton, et al.*

Trapped-Annular-Pressure Mitigation: Spacer Fluid That Shrinks—Update

In subsea-completed wells, fluids commonly are trapped in casing annuli above the top of cement and below the wellhead. When these trapped fluids are heated by the passage of warm produced fluids, thermal expansion can create very high pressures and cause the collapse of casing and tubing strings. A successful field trial has been conducted in a 9,800-ft-deep gas well of a water-based spacer fluid that upon heat-triggered polymerization shrinks 20%, mitigating trapped annular pressure (TAP).

Introduction

TAP, also called annular-pressure buildup, is caused by the thermal expansion of fluids trapped in casing annuli between the top of cement and the wellhead. The pressure buildup usually is a result of heat transfer from produced fluids or from hot drilling fluids circulated while drilling a high-pressure/high-temperature well The pressure can exceed the collapse strength of the casing and production tubing. In land wells, the pressure is relieved easily by bleeding off some fluid through a casinghead valve.

This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper SPE 112872, "Trapped Annular Pressure Mitigation: A Spacer Fluid That Shrinks—Update," by ***B. Bloys,*** *SPE,* ***M. Gonzalez,*** *SPE,* ***J. Lofton, R. Carpenter,*** *SPE,* ***S. Azar,*** *SPE,* ***D. Williams, J. McKenzie,*** *SPE, and* ***J. Capo,*** *SPE, Chevron;* ***R. Hermes,*** *Los Alamos National Laboratory;* ***R. Bland,*** *SPE,* ***R. Foley,*** *SPE, and* ***F. Harvey,*** *SPE, Baker Hughes;* ***J. Daniel, F. Billings,*** *and* ***I. Robinson,*** *Lucite International; and* ***M. Allison,*** *Flow Process Technologies, originally prepared for the 2008 SPE Drilling Conference, Orlando, Florida, 4–6 March. The paper has not been peer reviewed.*

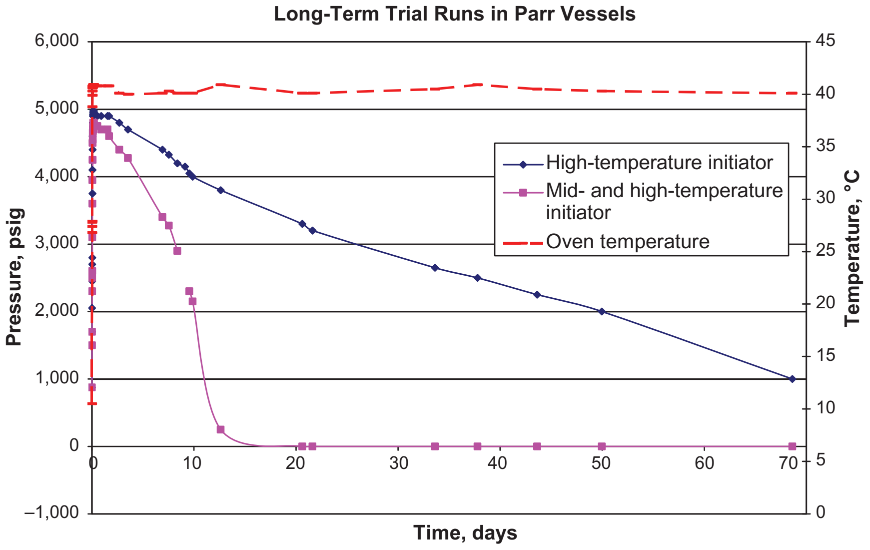

Fig. 1—Long-term reaction/shrinkage of MMA spacer at 105°F with two different initiators.

In subsea-completed wells, wellheads are much less accessible and generally not fitted with the necessary valves.

Perhaps the most successful mitigation approach has been the use of vacuum-insulated tubing (VIT). This technique generally has been successful in keeping the annular-fluid temperatures within an acceptable range. However, with the advent of deeper and hotter wells in deep water, the limits of the protection provided by VIT are being approached in two ways. First, deeper wells have much higher hanging weights that are reaching the stress limits of VIT designs. Second, the greater depths also are producing higher temperatures. Even with the insulating effects of VIT, the temperatures are sufficiently high that pressures are predicted to increase to unacceptable levels.

A new approach created a water-based spacer fluid to be used just ahead of the cement. The spacer contains 10 to 30% emulsified liquid methyl methacrylate (MMA) monomer. The liquid MMA shrinks 20 vol% upon polymerizing. The polymerization is triggered by heat and an appropriate chemical initiator. MMA is emulsified into a simple water-based fluid that is intended to be the last spacer pumped just ahead of cement, filling most of the open annulus. The monomer has a low flash point similar to methanol, and it must be handled carefully but has a long record of safe industrial use.

In preparation for the deepwater deployment of the shrinking spacer, it was necessary to extend the matrix of formulations to cover the full range of temperatures and densities that might be encountered in the next few deepwater wells. Long-term tests also were conducted to extend the understanding of inhibition and initiation of the key chemical reaction. Extensive compatibility tests were performed to ensure that no unexpected problems occurred when the spacer was exposed to various elastomers, cement, cement spacers, drilling fluids, and salts. It also was necessary to design, manufacture, and test several equipment skids needed to prepare and transfer the spacer/emulsion and to add the initiator as the spacer is pumped downhole. A detailed operations document was developed for preparing and pumping the spacer, and then a rigorous risk analysis was performed on every step by the health, safety, and environment personnel of the major companies involved.

Recent Laboratory Testing

Pressure vessels were used to test TAP spacer formulations as a function of composition, temperature history, and time. Formulations were tested ranging from unweighted to 14.6 lbm/gal with various concentrations and types of inhibitors and thermal polymerization initiators. Additionally, monomer concentrations ranged from 7 to 22 vol%. Higher MMA concentrations are possible if needed. The polymerization reaction was tracked by recording the pressure increase/decrease observed while heating over time. In a typical experiment, the pressure vessel was charged with the mud at room temperature, prepressurized to a predetermined level, and either heated quickly (boiling water) or placed in a convection oven. The type and amount of initiators and inhibitors can be adjusted readily to meet a broad range of downhole conditions.

A test was designed to show that the inhibited spacer, as shipped to the rig (no initiator), is very stable. A formulation with the current inhibition package was held at 140°F for more than 5 weeks with no appreciable sign of polymerization. This shows that even if there is a delay after the spacer is mixed, there is no danger of the polymerization occurring early.

Additional long-term experiments were run to determine the behavior of the spacer once the initiator had been added. In the field, the initiator would be added just before pumping the spacer downhole. Several long-term experiments (weeks to months) were performed to simulate the static conditions before a well is brought on production. **Fig. 1** shows the pressure trace for two TAP spacer formulations that were held at 105°F more than 70 days. Under these rather mild ambient conditions, the MMA will react/shrink very slowly (weeks/months), again depending on the nature of the initiator/inhibitor package. Under higher production temperatures, the MMA will react/shrink quickly (hours).

Spacer Preparation

The MMA was trucked to the mud plant from the Beaumont, Texas, manufacturing plant using standard MMA-transport equipment and procedures. The key to making the emulsion is the mixing skid. MMA is brought into the mixing skid with a gear pump through a calibrated turbine meter. Similarly, the base mud is fed to the skid by the mud-plant pumps. The mud is metered through a magnetic flowmeter. A second magnetic flowmeter checks the total flow. The mix then is pumped through a high-shear mixer that routinely makes a tight emulsion in one pass. A final check of the fluid is conducted with a Coriolis densitometer.

During the transfer of pure MMA, all equipment was grounded to prevent static sparks. After the mixing and transferring were complete, all of the hoses and mixing equipment were flushed with water to a closed 25-bbl “trash” tank. The collected fluids were treated with an aggressive activator to ensure polymerization before the fluid went to a disposal well. After polymerization, MMA is nonhazardous. When the hoses were removed from the equipment, very little trace of MMA was detected. This flushing technique should minimize personnel exposure to MMA, both at the mud plant and at the rigsite.

Test Well

The test well was a 9,800-ft gas well in the Carthage field in northeast Texas. A cast-iron bridge plug and 20 ft of cement were set in the $5^1/2$-in. casing at 8,495 ft to create a “pressure vessel” for the test. The casing (uncertain condition) was tested to only 2,000 psi, and this was set as the upper limit for the test. The tubing was $2^7/8$-in. diameter, and the well initially was filled with 2% potassium chloride (KCl) brine. Bottomhole static temperature (BHST) at the bridge plug was approximately 230°F. The surface equipment for the test included the following.

- Two ISO tanks with spacer
- Manifold for draining multiple tanks
- Tank of initiator solution
- Skid for accurately mixing the initiator and spacer
- Triplex pumping unit to displace the spacer into/out of the well
- Choke manifold for pressure control and pressure monitoring (gauge and recording chart)
- Generators for power
- Tank of KCl brine for cleaning out well
- Numerous hoses and plumbing adapters

The spacer volume was equalized between the two ISO tanks through the manifold to test the expected plumbing arrangements on most deepwater applications (more than two tanks). A delay was experienced when the gear pump on the metering/mixing jammed with large gravel that unexpectedly had been delivered with the mix water for the initiator solution. Once the problem was diagnosed and the debris screened out, the addition of the initiator to the spacer and the displacement into the wellbore with a triplex pumping unit went smoothly.

The hydrostatic pressure from the 11.3-lbm/gal fluid was 1,000 psi at the cast-iron bridge plug, so only another 1,000 psi could be added before the choke manifold was closed. Previous experience with wells in this field suggested that approximately 2,000-psi wellhead pressure would be expressed as the fluids in the well warmed up to the geothermal gradient. However, because the 230°F BHST was double the design temperature of the fluid (formulation for upcoming deepwater test), it was expected that the MMA in the bottom portion of the well would react quickly and no additional pressure would be seen. This is indeed what occurred. The applied 1,000 psi steadily bled down to zero psi in a few hours and remained at that value as the well was monitored overnight. As the spacer was circulated out of the well the next day, samples were taken at 5-bbl increments. MMA analysis confirmed that the MMA in the hotter portions of the well had reacted. The spacer in the top part of the well (similar to temperature in many deepwater annuli) showed no polymerization in the short time period, as was designed/expected.

The spacer was displaced out of the well back to the original ISO tanks and treated with aggressive initiator to consume any unreacted MMA. All of the surface lines and equipment were flushed with water (also to ISO tank) and contained only traces of MMA when disassembled. This is consistent with the intent to minimize the exposure of the rig crew to MMA. **JPT**

Integrated Approach To Optimize Material Selection for High-Rate Gas Wells

The RasGas Company North field wells typically have a true vertical depth of 9,000 ft with a sail angle up to 70°. The combination of 7-in. monobore and $9\frac{5}{8}$-in. big-bore wells is designed to handle hydrogen sulfide (H_2S) and carbon dioxide (CO_2) corrosion, hydrochloric acid (HCl) stimulation, and environmental cracking. The wells must accommodate high flow rates and through-tubing intervention. The full-length paper describes the technical development of an optimized operational envelope for L-80 carbon-steel tubulars for these high-rate gas wells in Qatar.

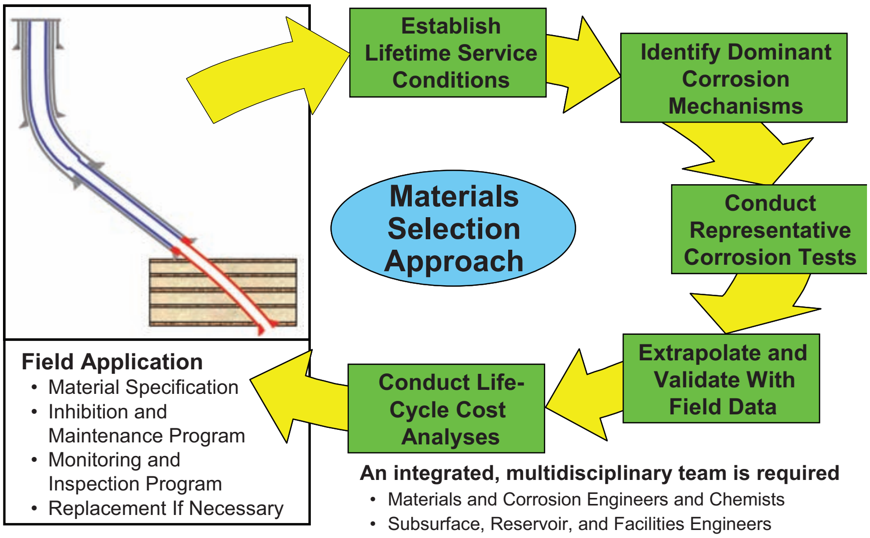

Fig. 1—Integrated approach to materials selection.

Introduction

The North field is offshore to the northeast of Qatar in the Arabian Gulf. It is the world's largest nonassociated-gas field, with reported reserves of more than 900 Tcf. The sour, abnormally pressured natural gas is contained in the massive Khuff carbonate formation. RasGas currently has 11 offshore platforms in the North field.

Two different types of production wells have been used on these platforms. The first type is a 7-in.-monobore well with 7-in. tubing and liner made of L-80 carbon steel. The second well type is referred to as the $9\frac{5}{8}$-in. optimized big-bore (OBB) well comprising $9\frac{5}{8} \times 7\frac{5}{8}$-in. tapered production tubing made of L-80 carbon steel and a 7-in. liner made of Alloy 28 corrosion-resistant alloy (CRA). More than 60 $9\frac{5}{8}$-in. OBB wells have been drilled and completed to date. The wells are more than of 9,000 ft deep with deviations from vertical of as much as 70°.

Well deliverability for the $9\frac{5}{8}$-in. OBB wells is greater than for the 7-in. monobore wells, and on the basis of reservoir modeling, it was determined that the target project production could be achieved with 25% fewer wells. At equivalent production rates, the $9\frac{5}{8}$-in. OBB wells have less wellbore pressure loss, resulting in an extension of the plateau life without surface compression.

All of these wells must be designed to handle H_2S and CO_2 corrosion, HCl stimulation, and environmental cracking. All of the acid used to stimulate these wells contains corrosion inhibitors to mitigate corrosion in the tubing and liners during acid stimulation. The tubular materials are designed to withstand the corrosive production environment on their own without chemical inhibition. Early in the design phase of the $9\frac{5}{8}$-in. OBB wells, the use of CRAs was considered for both the tubing and the 7 in. liner. However, it was determined that CRA materials could not be fabricated (on a commercial scale) to $9\frac{5}{8}$-in. diameter in usable lengths because of tubular-mill manufacturing limitations, so carbon steel would have to be used to enable the $9\frac{5}{8}$-in. OBB production advantages.

Over the last 10 years, RasGas, ExxonMobil Development Company, and ExxonMobil Research Company have used the highly integrated and scientific approach described in the full-length paper to optimize the use of carbon steel and CRA in these North field well completions. This approach was first used on the original 7-in.-monobore-well design when production data and corrosion-test results were limited,

This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper IPTC 12503, "Integrated Approach To Optimize Material Selection for North Field High-Rate Gas Wells," by ***W.A. Sorem,*** *RasGas Company;* ***E.J. Wright*** *and* ***J.L. Pacheco,*** *ExxonMobil Development Company; and* ***D.A. Norman,*** *ExxonMobil Upstream Research Company, originally prepared for the 2008 International Petroleum Technology Conference, Kuala Lumpur, 3–5 December. The paper has not been peer reviewed.*

and no field corrosion measurements were available for history matching. By the time the 9⁵/8-in. OBB well design was considered, more production and service-environment data were available from the 7-in.-monobore wells, and corrosion tests and modeling were built on the solid foundation of the previous work. Today, the work continues to build on the wealth of field experience, including detailed knowledge of the service environment, historical trends, and corrosion surveys, to broaden the approach to include higher H_2S and CO_2 concentrations.

Corrosion Prediction and Management

As shown in **Fig. 1,** this approach to predicting and managing corrosion has five primary elements.

1. Rigorously establish well environmental conditions and characterize how these conditions change over time.
2. Identify the local environmental conditions and types of corrosion that are expected to occur (e.g., weight loss, pitting, and environmental cracking).
3. Conduct realistic corrosion laboratory tests under the identified field conditions by simulating water salinity, dissolved CO_2 and H_2S concentrations, condensate effects, fluid shear stresses, and flow regime in appropriate laboratory equipment.
4. Analytically extrapolate the results of the laboratory tests to the field, and validate the results with field data.
5. Conduct life-cycle cost analyses.

At the completion of these five steps, the field application plan/program can be prepared including:

- Material specifications
- Inhibition and maintenance program
- Monitoring and inspection program
- Replacement criteria/frequency of the materials if necessary

It is important to identify at the beginning of the program, and certainly before Step 3, the overall strategy for corrosion protection. In general, corrosion can be mitigated or controlled either by selecting materials that are resistant to the service environment or by the use of chemical inhibition. The implications of selecting a strategy are crucial to the corrosion-control program in regard to the materials tested and the inclusion of inhibitors in Step 3, and especially in regard to the life-cycle costs in Step 5 (inhibition and maintenance program, monitoring and inspection, and replacement). The primary factors associated with these two corrosion strategies as they apply to downhole tubulars are summarized in the full-length paper. Whatever the method of corrosion control selected, it is important to assess the lifetime cost and operational impact of the corrosion control including the cost of the materials, the frequency and cost of inspection, the frequency and cost of replacement, the type and cost of inhibition, the complexity of operations, and most of all, the risks associated with the operations and potential failure. For these particular North field gas wells, the preferred approach to corrosion control was through proper selection of materials, eliminating the need for inhibition and more-complicated well designs.

It is also important to note that this cycle can (and likely should) be repeated periodically through the life of the application so that learnings can be incorporated and used to the advantage of the program.

During the initial use of this corrosion-engineering approach, the service-environment information and field data are often very limited. However, after the initial materials and corrosion-control program are selected, the installation is completed, the materials are put in service, and the corrosion-monitoring program is implemented, a wealth of field experience can be taken advantage of to refine the program, including the following.

- Better definition of service environment (e.g., H_2S, CO_2, Cl^-, water)
- Field corrosion-measurement data
- History matching of field data to confirm experiment-based predictions
- Wellbore-hydraulics measurements (e.g., temperature, pressure)

Manufacturing Quality

The integrated approach helped qualify tubular material for the OBB wells. However, manufacturing quality needs to be maintained so the material in the field does not deviate from the acceptable mechanical design and resistance to sulfide stress cracking.

A key factor that allows the use of L-80 carbon steel for these wells is the quality control and oversight used to ensure consistency in manufacturing. Each steel mill and associated tubular product is individually qualified to high standards. Inspectors are stationed in the steel mill during fabrication to ensure the high quality is maintained.

Storage, handling, and transportation guidelines are enforced to maintain the quality at the consistent level achieved during manufacturing. Use of special handling and transportation procedures further prevents additional mechanical or environmental damage from occurring while in transit from the steel mill to the well location. Inspectors verify tubular packaging, storage, and transportation handling. Tubular storage is controlled to prevent corrosion attacks that can reduce the quality.

Summary

There are many technical challenges associated with corrosion prediction, including the identification and characterization of the corrosion mechanisms that are relevant to the application and extrapolation of relatively short-term laboratory-test results to long-term material performance. However, understanding the chemistry and physics of corrosion has enabled representative corrosion tests to be set up in the laboratory and extrapolation of the results with confidence.

This integrated scientific approach to materials selection and corrosion control has enabled RasGas to take advantage of 9⁵/8-in. OBB wells with carbon-steel tubing and CRA liners.

Corrosion predictions and field inspection results indicate that the majority of these OBB wells should have a carbon-steel-tubing life of more than 40 years. On the basis of these predictions and early corrosion-surveillance results, the corrosion-inspection frequency has been set at 3 years. Corrosion rates for higher H_2S concentrations also have been predicted using this same method, but there has not been sufficient field data available to verify the predictions.

This integrated approach requires the use of multidisciplinary teams. During the different elements of the process, the efforts of each of these experts/disciplines vary, but it is important that the team be involved throughout the process.

This method can be used for virtually any corrosive application to optimize the life-cycle material and corrosion-mitigation costs and offers the potential to minimize costly alloy use and/or to eliminate facilities. **JPT**

Determining Long-Term CO_2-Containment Performance: Cement Evaluation

The full-length paper focuses on an in-depth evaluation of the annular material on the Otway CRC-1 well that is being used to inject CO_2 in the CO2CRC pilot geological-storage project. The evaluation will draw on the design and job data, and on a detailed analysis of the high-resolution 3D cement-imaging log, to characterize the cement and ensure the long-term risk of containment breach is minimized.

Introduction

Cement slurries are exposed to a number of phenomena during mixing and placement that can lead to set-cement properties that are very different from their design value. Density-control problems (both for continuous and batch mixing), contamination, channeling, and fluid loss can and do cause slurry dilution/concentration and chemical incompatibility, which in turn can have a major negative effect on the capacity of cement to guarantee hydraulic isolation.

Currently it is debated if 10 m or more of competent cement, well bonded to casing and formation, would degrade during the expected isolation time frame for CO_2-geological-sequestration wells (thousands to 10 thousand years). This is because competent cement, although reactive if exposed to CO_2, has a very low permeability on the order of 0.5 to 5 µd. This low permeability means that most CO_2 will travel by diffusion, a very slow process over the length scale of a meter. Cement with a high water/cement ratio, however, could have a much higher permeability, less resistance to CO_2 aggression, and more-frequent defects related to slurry settling. Defects such as liquid channels in cement can provide direct pathways for CO_2 leaks that could not be healed by calcite precipitation during the CO_2 attack.

Some of these phenomena can be predicted, but cannot be controlled easily; others (such as fluid loss) can hardly be predicted at all. In any case, they belong to the class of fault-free risk, sometimes called residual risk: events causing substandard system performance that cannot be engineered away and that may happen even when the job is executed well. Mitigation measures must be adopted in this case to ensure a robust design. This is especially true for wells entering CO_2-storage reservoirs, where storage containment is a key performance factor and CO_2/cement reactions may cause leaks to grow over time. The full-length paper studies a well recently completed in Australia for CO_2 injection, and identifies how fluid loss, contamination, and channeling affected the petrophysical properties (i.e., density, porosity, and permeability) of set cement.

Background

The Cooperative Research Centre for Greenhouse Gas Technologies is a joint venture engaged in research on carbon capture and storage, a proposed technology that captures CO_2 from fossil-fuel power-plant effluents and injects it into geological formations for permanent storage.

The Otway pilot project intends to inject 0.1 million metric tons of CO_2 over 2 years in a depleted sandstone gas reservoir to demonstrate the feasibility of geological storage. Injection was started on 2 April 2008. The top of the injection interval is in the Waarre C sands (2053 m), and the main containment objective was to isolate the $4^1/2$-in. casing in the 7-in.-hole section across the Belfast and Flaxmans caprock (2000 to 2053 m).

The design called for a tail-cement formulation resistant to CO_2 and with a 1900-kg/m^3 density to be placed from 2238 m total depth to 1816 m, preceded by a 3%-bentonite lead slurry with a 1500-kg/m^3 density up to 308 m. Mud removal was ensured by almost 10 m^3 of weighted viscous spacer. The tail cement gained resistance to CO_2 attack from the absence of portlandite (lime) and from the minimization of water in the slurry through optimized particle-size distribution.

The $4^1/2$-in. casing was cemented on 15 March 2007, and the job went according to design with fluid density, surface pressure, and injected flow rate being recorded throughout the placement. The cement was logged on 26 September 2007, more than 6 months after the job, with a novel multitransducer ultrasonic 3D imaging tool. This tool delivers two independent measures of the material in contact with the casing, and its compact wave packets allow 3D imaging of the annulus out to the cement/formation interface.

Using the characteristics of the pumped slurries, the properties of the set cements—density, compressional- and shear-wave speed—can be calculated easily; from these, the expected tool responses (acoustic impedance and flexural attenuation) also can be computed and compared to the average acquired values. Tool readings cluster well around the expected values, suggesting that the calculated cement properties are indeed correct.

This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper SPE 115707, "Assessing Long-Term CO_2-Containment Performance: Cement Evaluation in Otway CRC-1," by ***Matteo Loizzo,*** *SPE, and* ***Sandeep Sharma,*** *SPE, Schlumberger Carbon Services, originally prepared for the 2008 SPE Asia Pacific Oil and Gas Conference and Exhibition, Perth, Australia, 20–22 October. The paper has not been peer reviewed.*

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

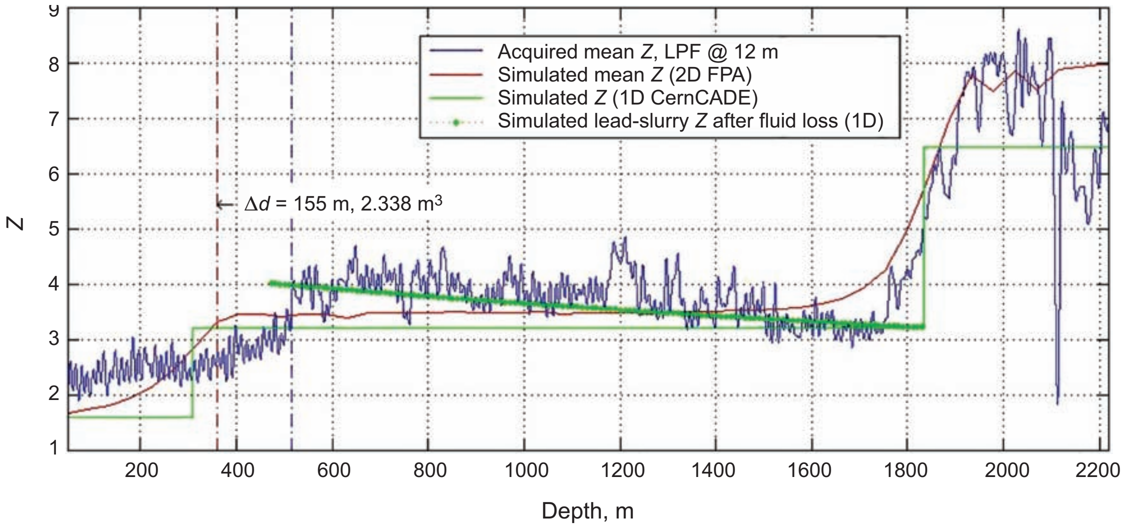

Fig. 1—Comparison of average acoustic impedance with values predicted by 1D (green) and 2D placement simulators.

Cement-Evaluation Log

Fig. 1 displays the average of acoustic impedance, *Z*, vs. depth for the whole well. The spacer/lead-slurry- and lead/tail-slurry-contamination fronts are clearly visible. Comparing the blue curve to the red one, which was generated by a 2D placement simulator that accounts for the fluid contamination during the downward path in the casing, a difference of 155 m is apparent between the bottom depths of the lead-slurry contamination fronts (the top of cement). The annular coverage of 155 m corresponds to 2.34 m^3, which is 9.9% of the 23.67 m^3 of lead slurry that was pumped.

Under two assumptions, it is possible to estimate what would be the effect on the log if the volume loss were indeed only caused by fluid loss (and not lost circulation, where the whole fluid is lost into the formation).

In one, the fluid loss affects only the lead slurry. In addition, the tail slurry had a shorter residence time in the annulus, less exposure (lower length and shorter time) to permeable formations.

In another, the fluid loss varies linearly from 19.8% of the slurry volume at the top of lead to 0% at the bottom: This assumption ensures that the total amount of water lost is 9.9% of the slurry volume and tries to account for the fact that the top of the lead slurry (injected at the beginning of placement) was exposed to a larger permeable surface for a longer time.

The calculation, applied to 1D-annular-fluid-placement profiles, results in the thick green curve on Fig. 1, which matches well the downward slope in the acoustic-impedance profile for the lead cement. The short green line segment to the left, as well as the portion of green curve below the blue curve to the right, is a result of the contamination front, a complex 2D phenomenon that was neglected in this simple calculation

On the basis of the observed volume lost at the end of the job, a rough estimate of the water that was lost earlier at the end of the U-tube (47.6 m^3 into the job) using the simple rule that water loss is proportional to the volume of lead slurry pumped, yields the result of 1.62 m^3. This suggests that at the end of U-tube, the top of the lead slurry was lower by 204 m, causing the pressure in the annulus to be 3 bar higher than the pressure in the casing. Because the U-tube ends when the annular pressure is equal to the casing pressure, the assumption can be made that the U-tube actually did end when half of that lost volume was still in the casing (i.e., 0.8 m^3 earlier than expected). Even with such a rough calculation, it is interesting to note that the difference between 0.8 and 0.6 m^3 (the observed value) is fairly small, giving another line of evidence to support the fluid-loss explanation.

Summary

Otway CRC-1 is a top-tier well, where well construction and the cement-job design and execution have been flawless, with one centralizer every other joint, which is rare in wells that are almost vertical. The cement-evaluation logs confirm more than 1500 m of almost uninterrupted solid material. In short, every risk-prevention measure has been deployed successfully.

Yet, small washouts and breakouts across the caprock, coupled with the small (less than 2°) hole deviation led to the tail slurry being contaminated by the lead slurry, in turn leading to high-porosity solid channels along the narrow side of the annulus across some of the primary caprock. Between zones affected by solid channeling, the log confirms 12 m of continuous tail cement across the caprock. The use of a cement formulation resistant to CO_2 chemical attack provides an additional barrier and should make this relatively short interval of competent cement sufficient to minimize leakage risks over a very long time.

The second phenomenon studied in the full-length paper, the contamination at the interface between lead and tail slurry, led to the top of the uncontaminated tail slurry being lower than expected, and within a few tens of meters of the top of the primary caprock. Both solid channeling and contamination represent fault-free risk factors that can compromise the containment potential of wells for CO_2 geological storage. Fault-free (or residual) risk requires robust cement-job design that incorporates risk-mitigation measures: in this case, excess tail-slurry volume and a tail cement formulation resistant to CO_2 chemical attack.

The full-length paper also identified solid evidence of fluid loss from the lead slurry, which led to a total lead-slurry-volume reduction of approximately 10%. Whereas fluid loss explains the low top of cement, it fortunately had no direct effect on the containment objectives of this job. **JPT**