Drilling and Completion of Horizontal Wells in a Diatomite Formation—A Systematic Approach to Addressing Challenges

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ABSTRACT

Drilling and completion of horizontal wells in any formation is often challenging. However, typical challenges are magnified in the diatomaceous Opal A Monterey Formation in the Belridge Field of Central California. Soft formations tend to be enlarged during wiper trips, while cuttings-bed deposition, lost circulation, and gas migration can complicate cementing. Because of these challenges, horizontal-well cement jobs in this field may not have been capable of providing effective containment of proppant fracture treatments within the target zones. Each well has several subzones, and each subzone is fractured separately. However, due to lack of containment, production results have been difficult to interpret because determining which fracture stage is producing the fluids is impossible. This paper outlines the methods used to greatly improve zonal isolation between subzones.

Reducing the number of wiper trips and improved drilling fluid, directional drilling techniques, and tools helped provide improved hole geometry without cuttings bed accumulation. Fully automated foamed cementing technology was applied to help achieve complete zonal isolation and full cement returns to the surface. Cement jobs were evaluated with special logging techniques and
leading-edge cement-bond logging tools with nontraditional interpretation algorithms. Finally, tracer materials were incorporated in proppant fracture treatments to verify that fractures were maintained in the appropriate zones. Detailed descriptions and actual job data are provided to document the significant improvements in drilling horizontal wells in this challenging field.

INTRODUCTION

Drilling horizontal wells in the Monterey formation in central California, outside of Bakersfield, allows operators to recover oil from the margins of a structure that would be uneconomic to complete with vertical wells. Between 1995 and 2001, seventeen Diatomite horizontal wells that required cemented and fractured completions were drilled. The quality of the cement jobs before 2001 was generally unsatisfactory. These wells were drilled in the Opal A and Opal CT segments of the Monterey formation (Fig. 1). The Opal A wells are drilled in the more shallow 700- to 900-ft (213- to 274-m) total vertical depth (TVD) range. The Opal CT wells are drilled in the deeper 2,300- to 2,600-ft (701- to 792-m) TVD range (Fig. 2).

Hole enlargement and lack of cuttings removal caused channeling in the completion interval in some of the wells. Fracture treatments did not always stay in the desired treatment zone, indicating that mud and solids displacement in the annulus was incomplete. The poor cement jobs in these wells were most likely caused by the following:

- Hole enlargement
- Cuttings bed
- Inadequate displacement of mud and drill cuttings

For the drilling of four horizontal West Flank Pilot wells and three horizontal Opal CT Nose wells in 2001, obtaining zonal isolation across the horizontal completion interval to isolate fracture stages was important. An attempt was made to address all the potential causes of poor cement jobs while designing the 2001 horizontal wells.

BACKGROUND

Belridge field was discovered in 1911, but production from the fractured shales of the Monterey Formation did not become significant until advanced sand-fracturing techniques became available in the late 1970s. The crest of the anticline is developed on very close spacing [approximately \(\frac{5}{12}\)-acre (1,699.67-m\(^2\)) spacing]. The vertical development is waterflooded, both to reduce subsidence to economically manageable levels and to enhance production. The flanks of the anticline are less economic to produce because the payzone is thinner. Well cost is not substantially less on the flanks than on the crest because drilling the overburden causes a large part of the drilling costs to remain fixed. Essentially, a slightly greater amount of overburden is drilled on the flanks to complete the thinner payzone on the flanks.

Although both Opal A and Opal CT are parts of the Monterey Formation, they are distinct reservoirs with different drilling and production characteristics. Both are comprised of the remains of diatoms, along with very fine-grained silts, clays, and volcanic ash layers. The diatom frustules are siliceous. In the more shallow Opal A, the silica is amorphous. The deeper Opal CT has undergone more diagenesis than the Opal A, and the silica has been crystallized into Opal CT, or cristobalite and tridymite. The Opal A is softer and is prone to mechanical gouging from the drillstring and BHA. The Opal A produces light oil and gas. The Opal CT is harder and somewhat more resistant to hole enlargement, but produces more gas than Opal A. The entrainment of gas in some drilling muds produces serious challenges when this formation is being drilled.

In 1995, the previous operation drilled and completed four horizontal wells in the Opal A. These wells differ from the current drilling program because they were in the heart of the field rather than in the thin pay section on the flank. One well was completed with an un cemented (slotted) liner, and the other three were cemented using mud-to-cement conversion. A competitor drilled a well to exploit thin pay on the flank in 1992, but used a slotted liner.\(^1\)

In 1996, the previous operation drilled and completed three Opal CT horizontals in the high gas-oil ratio (GOR)
“nose” of the anticline, followed by two more horizontal wells in 1999. All the wells were cemented and fractured completions. Traditional lightweight cements were used.

In 1997, two previous operations merged in California. Before the merger, both companies had drilled and completed horizontal wells at Belridge Field. The geology is such that one operation’s wells had been drilled and completed in Opal CT, while the other operation’s wells had been drilled and completed in Opal A. The current operation continues to drill horizontal wells in the same target reservoirs as the previous companies.

Like most producers, the current operation faces declining production. As depletion progresses, they are looking for pay in areas previously considered too marginal to complete. Advances in ordinary and state-of-the-art process improvement are necessary to extend the life of the Belridge Field.

In 2001, the operation drilled four Opal A and three Opal CT wells. Previous Opal A wells had been drilled within the main area of the field. The objective of drilling the 2001 Opal A wells was to prove the economics of using horizontals to develop a wedge of thin pay along the west flank of the anticline. The Opal A wells have very shallow TVD. Because the weight of the casing in the vertical hole provides the force to push the pipe to the end of the lateral, limited TVD limits the weight available to overcome drag forces in the lateral. Drag data collected during the 2001 drilling program is being used in scoping the shallower wells to be drilled in 2002. Because technical feasibility analysis of the horizontal development depends on further simulation, calibration of the simulator was critical.

The Opal CT horizontal development has been active for several years, and the objective of the 2001 wells was to improve the cementing and prevent frac-to-frac communication and gas migration. Better isolation was needed to improve well test data, which would help improve reservoir characterization before full scale development.

DRILLING SYSTEMS AND PROCEDURES

Drilling in the diatomite formation involves a unique set of challenges. Soft formations make achieving and maintaining hole angle difficult when drilling in the deviated sections of the well. Achieving good hole cleaning without washing out the open hole section is also difficult. For the shallow Opal A wells, the needed directional drilling guidance was achieved with electromagnetic (EM) technology. The EM directional drilling was also used on one of the Opal CT wells (deeper) with the use of a repeater in the drillstring to transmit the information to the surface. When EM technology is used instead of measurement-while-drilling (MWD) technology, the pumps can be lowered when the dogleg is not achieved, and the operation can still drill if a pump goes down. For the rest of the Opal CT wells, MWD technology was used (Fig. 3).

EM technology worked best in these wells, primarily because it allowed for the use of higher-viscosity muds (Table 1). These higher viscosity mud systems (XCD) provided better solids transport properties, which maintained better cleaning of the hole while drilling. This high-viscosity mud could not be used with the MWD directional drilling system because it caused excessive gas entrainment in the mud system, which in turn made transmitting the MWD information through the mud to the surface impossible. One technique used on the Opal CT wells was to run periodic viscous sweeps to clean the hole and minimize the yield point (YP) of the mud while drilling the horizontal section of the well.

Another technique implemented in drilling the wells in 2001 was drilling a pilot hole of 8.75 in. (56.45 cm) through the build section of the well. These techniques allowed the hole angle to be built easier and more quickly. This hole section was then enlarged with a 12.25-in. (79.03-cm) hole-opening run.

DRILLING FLUIDS

Various drilling fluids have been used in the horizontal wells drilled at Belridge (Table 2). In the 1995 Opal A wells, the lateral was drilled with an 8 3/4-in. (56.45-cm) bit, and 5 1/2-in. (35.48-cm) casing was run and cemented using mud-to-cement conversion. Numerous wiper trips
were made to counteract drag of up to 60,000 lb (27,216 kg) over string weight [total hook load of about 120,000 lb (54,431 kg)]. This caused justified concern about sticking because the doubles rigs used for these holes have small pulling capacities. The wiper trips with a roller reamer were thought to help clean the hole, but drag continued to be a problem after numerous trips. Caliper logs that were run later revealed that the hole, made rugose as the formation was abraded by the BHA and pipe during wiper runs, was enlarged to as much as 21 in. (53.34 cm). Bond logs indicated questionable zonal isolation. Zonal isolation as judged by production tests varied.

The mud system used on these wells consisted of a gel-based mud with a viscosifier added for fluid loss. In 2001, the viscosifier was replaced with XCD to help improve low shear-rate gel strength and enhance cuttings removal. For example, the average of the 10-second gel strengths on the 2001 wells was 13.5, whereas the average of the 10-second gels from the 1995 wells was 4.5. The result of this change was a dramatic increase in removal efficiency. This efficiency resulted in less drag, and wiper trips were almost eliminated. With the elimination of wiper trips, the abrasion of the hole was controlled. Removing the mud from the smaller annulus that resulted was easier, and the ultrasonic cement log showed excellent bond. Tracer was run with the fracture sand, and the tracer log showed excellent separation of the fractures in the various subzones.

When the Opal CT wells are drilled, mud weights are typically near 10 lb/gal (1.2 g/cc) to control gas. Background gas becomes entrained in the mud if the low shear-rate gel strengths are overly increased. Mud pit volumes of 100 bbl or less are typical for the doubles rigs used to drill these wells, so the gas does not have time to break out of the mud before it is recirculated. Circulating gas-cut mud can compromise well control and make obtaining a signal from the directional drilling tools impossible.

Because the background gas problems prevent the use of XCD systems, a gel system was used that is typically used for vertical wells and supplemented the low shear-rate gels by adding a small amount of XCD. This resulted in 10-second gels averaging about 8, as compared to an average of less than 4 for the previous wells. A balance point between the need for carrying capacity and the need to allow the gas to break out of the mud must be found for each well.

Ultrasonic logs for the Opal CT horizontals showed good isolation. However, some channels were noted on these wells.

**CEMENTING**

The following sections describe past challenges and problems, a foamed cement solution, and the casing equipment used on these wells.

**Past Challenges and Problems**

Previous cement systems used for these wells included conventional lightweight cement and mud-to-cement conversions (slag mud) that set to provide zonal isolation. Past cementing challenges and problems encountered during drilling and completion operations in the diatomite formations of California include lost circulation, lack of cement returns to the surface, gas migration, displacement/removal of drill solids on low side, and hole size/washed-out hole and centralization.

**Lost Circulation**

Because of lost-circulation problems at Belridge Field, low-density cements must be used. Low-density cement systems should be carefully designed. Although more water is typically added to lighten a slurry, this procedure can reduce compressive strength. Hollow microspheres can be used to lower the density and still provide significant compressive strength, but they present a unique set of challenges.

**Lack of Cement Returns to Surface**

Because of the lost circulation problem, the annulus may only partially fill with cement. Even with the lightweight cement systems used, cement to surface was not always achieved. Outside of California, striving for sufficient annular fill is more conventional than striving for cement to surface. Cement to surface was needed because the California Department of Oil, Gas and Geothermal Resources typically requires 500 ft (152.4 m) of annular fill above the highest oil zone. Because
reservoirs shallower than 500 ft (152.4 m) exist in California, wells must typically have cement to surface to satisfy this requirement.

**Gas Migration**

Gas migration is a potential problem in Diatomite formations. Typically, a fluid-loss additive is used to help prevent gas migration. However, making the cement slurry compressible, either by injecting gas (as with foamed cements) or by adding a gas-generating additive to the cement, is a better way to prevent gas migration and loss of overbalance pressure while the cement is transitioning from a liquid to a solid.

**Displacement/Removal of Drill Solids on Low Side**

Previous wells were drilled with low yield-point drilling fluid. These fluids typically do not provide adequate solids-transport properties to clean out drill solids in a horizontal well. These drill solids will collect on the low side of the hole and be very difficult or impossible to remove during the cement job.

**Hole Size/Washed-Out Hole and Centralization**

Washed-out holes are more difficult to cement than holes that are closer to the original gauge bit size. Because of the nature of the diatomite, drilling horizontal wells without this problem occurring is very difficult. Also, without proper centralization of the casing, a uniform cement sheath cannot be obtained. The casing lies on the bottom of the hole and drilling fluid or solids are not displaced during placement of the cement. The undisplaced drilling fluid/cuttings causes a channel, leading to noncontainment of fracture treatments, loss of fluids, etc. Centralization is impossible in extremely overgauged holes, such as those encountered in the 1995 Opal A drilling program, because a centralizer that has fins large enough to centralize the pipe will not fit through the previous string of casing.

**Foamed Cement Solution**

Foamed cement is an excellent choice to address the multiple cementing challenges in this project because of (1) its high strength at low densities, (2) its compressibility, and (3) the viscous nature of the energized foamed fluid.

**Lost Circulation**

Because foamed cement can provide ultra-lightweight cement with good compressive strength, it can help control lost circulation by lowering the circulating density during the cement job and allowing the cement to be lifted above the horizontal hole section.

**Mud Displacement**

Foamed cement can greatly improve mud displacement by providing an energized, high-YP fluid. During pumping operations, foamed cement can develop higher dynamic-flow shear stress than conventional cements, which increases its mud-displacement capabilities. Fig. 4 shows plastic viscosity (PV) and YP of the slurry used for these foamed cement jobs as a function of cement slurry foam quality.

**Gas Migration**

Because of its compressible nature, foamed cement can also help prevent gas migration by maintaining overbalance pressure as cement transitions from a liquid to a solid. The gaseous phase of the foamed cement can expand to compensate any volume reductions occurring in the cement column as a result of hydration or fluid loss. This allows the slurry pressure to remain almost constant during the cement’s transition period. Consequently, the system effectively controls gas migration and formation-fluid influx, which helps limit migration channels in the set cement sheath and helps ensure maximum integrity of the cement sheath.

Cement returns to surface were obtained on all wells except Well 16, which lost circulation after approximately 60 of the 100 bbl of preflush surfaced. All wells were successfully reciprocated except for Well 7, which was stuck.

**Casing Equipment**

The centralizer placement on the previous wells was deemed inadequate with the prior spacing program, which used one centralizer per joint. Coupled with poor standoff, this placement was not sufficient to allow proper cuttings removal on the low side of the hole. The uniform flow necessary to achieve maximum zonal isolation was not established on the low side of the hole. The solution to this problem was to run two dual-contact (ridged) centralizers per joint, which improved the
standoff in the annulus to 86%. Because of its high restoring force with very little deflection, the dual centralizer is excellent for deviated and horizontal wellbores. Some of these centralizers had turbo fins to aid in establishing a flow pattern. The fins were placed 20 ft (6 m) apart immediately below each proposed perforation depth. It was believed that running the fins on the entire string of pipe would exert more pressure on the formation during the execution of the job.

On the first well, problems were encountered with the size and starting force of the centralizer. The proposed centralizers had a starting force of 697 lb (316 kg), a running force of 798 lb (362 kg), and a restoring force of 2,150 lb (975 kg) [compared to the API restoring force of 620 lb (281 kg)]. After three joints were run into the hole under very tight and forceful conditions, the decision was made to pull the casing. At this time, the OD of the bow on the centralizers was measured and determined to be 9.3 in (23.62 cm). The 9 5/8-in. (24.45-cm) surface casing had an ID of 8.921 in. (22.66 cm), which indicated that the bow was too large. However, with 5 1/2-in. (13.97-cm) casing at 15.5 lb (7.03 kg), one 40-ft joint is only equivalent to a 620-lb (281-kg) starting force, which is very close to the required starting force of 697 lb (316 kg). The decision was then made to replace the centralizers on location with a centralizer with less starting force. The new centralizers arrived and were run in the hole according to service company recommendations.

Because the kickoff point was as shallow as 400 ft (122 m) on the Opal A wells, problems running in the hole were anticipated. However, the main objective was to achieve excellent standoff in the hole, which could be accomplished by running the additional centralizers (two per joint). The well path was deviated to 103° at 1,395 ft (425 m) measured depth (MD) and back down to 94° at 2,566 ft (782 m) total depth (TD). This made getting to bottom on the first well very difficult; casing was run within 200 ft (61 m) of TD. According to the driller, not reaching TD was unrelated to the additional centralizers. They felt that the casing was differentially stuck.

On the next well a combination string consisting of 500 ft (152 m) of 7-in.(17.78-cm), 26-lb × 5 1/2-in. (11.79-kg × 13.97-cm), 15.5-lb (7.03-kg) casing to TD was run to help get pipe to bottom. However, whether the results were improved by better hole conditioning or the extra weight to the string is undetermined. The remaining wells were completed with the same spacing recommendation (Fig. 5), with good results.

**High-Port Up-Jet (HPUJ) Float Shoe**

A HPUJ float shoe (Fig. 6) was run to help improve the likelihood of a successful cement job at the casing shoe and through the lateral section. The HPUJ float shoe jets the formation face to help remove detrimental mud cake and cuttings, allowing the cement to form a stronger bond with the formation. The HPUJ float collar can be run with a 2 3/4- or 4 1/4-in. (6.99- or 10.80-cm) valve to help achieve turbulent flow without damaging float equipment with high circulation or cementing rates.

In this case, the 2 3/4-in. (6.99-cm) valve was run for the 5 1/2-in. (13.97-cm) casing. The ports of the shoe are strategically positioned to jet the cement perpendicular to the casing, helping enhance fluid turbulence well above the floating equipment. Six up-jet ports and four down-jet ports distributed the fluid in the annular space above and below the float shoe to help prevent channeling near the shoe. About 40% of the fluid pumped through the equipment is discharged at high velocity through the bottom of the float shoe. The force of this fluid removed material in its path, which helped allow the casing to be maneuvered past ledges or through tight sections of the wellbore. This jetting action in conjunction with foamed cement helped remove debris from the bottom and low side of the hole, allowing good zonal isolation to occur between the formation and cement.

The HPUJ float shoe has the following dimensions:

- Casing OD—5 1/2 in. (13.97 cm)
- Tool OD—6.050 in. (15.37 cm)
- Minimum ID—5.044 in. (12.81 cm)
- Tool Length—17.91 in. (45.49 cm)
BOND LOGGING

This section describes special stab-in/cups used, processing/special algorithms, and bond logging for the West Flank wells and Opal CT wells.

Special Stab-In/Cups

The tools were placed using tubing-conveyed methods for both the openhole and cased-hole logging runs. The first openhole well had a well track in excess of 105°, which posed a problem for the latching of the spear. The mud pumps were run below 10 bbl/min to avoid washing out the hole and creating potential sticking problems. This low rate was not enough to overcome the 105° climb needed to latch the top of the tools; thus, the tools could not reach TD. On subsequent wells, a modification was made to the latch assembly to increase the surface area, allowing this low pump rate to achieve the push needed to climb the high angle and latch the tools to the wireline. This modification was used successfully on the remaining wells.

Processing/Special Algorithms

For the post-cement analysis, cementing control software\(^1\) was used to evaluate the foamed cement for all the wells logged. This software uses two processes on the ultrasonic data: (1) variance processing and (2) impedance curve generation. Also, to help in the evaluation, the use of the variance technique\(^2\) is used on the cement bond-log (CBL) data. Both methods are processed and displayed for analysis. The evaluation of lightweight cements is a unique challenge for any environment.

Special attention should always be given to prejob planning and job execution. Correct ultrasonic transducer frequency and scanner head size is critical for best results in the horizontal environment. Eccentering measurements are generally presented in Track 1 of the log presentation. Track 1 shows measurements of tool eccentering relative to the wall of the casing, which is calculated by comparing the difference between opposing radii. If the tool gets too far out of center, the signals can strike the casing ID curvature at an angle and will not be reflected directly back into the transducer face. This can produce a distorted energy measurement, and thus faulty cement quality measurements.

Because the ultrasonic sondes are relatively short, stiff, and light compared to bond-logging tools, with proper precautions and planning centralization generally does not pose a problem, even in horizontal holes. A guideline for maximum allowable eccentering of the ultrasonic tools is 4% of the casing OD. For example: in 5.5-in. (13.97-cm) casing, maximum allowable eccentering is 0.22 in. (.04 \(\times\) 5.5) (0.56 cm); in 9 5/8-in. (24.45-cm) casing, maximum allowable eccentering is 0.385 in. (.04 \(\times\) 9.625) (0.978 cm). However, these measurements are just guidelines, and the best rule of thumb is to minimize eccentricity as much as possible. Keeping the eccentricity less than 0.1 in. (0.254 cm) is highly recommended for accurate determination of the cement sheath.\(^{13}\) For all logging runs, the tools were configured to provide the maximum centralization possible at the ultrasonic scanner while still allowing tool flex for the well deviation.

West Flank and Opal CT Wells

Cement analysis for the wells included both ultrasonic and radioactive tracer logs.

Ultrasonic Logs

The cement map for the ultrasonic logs was processed with “good” cement defined as impedance \(\geq 2.0\) (at the operation’s specification). Although there is some variation from well to well, the West well ultrasonic logs generally look good. The first two wells had poor impedance numbers; generally only 40% or less of the values were above 2.0. Combined with the derivative values, the cement map appeared to improve, but a moderate amount of channel-like structures were present (Fig. 7).

These channels sometimes ride the top or bottom of the holes, each side (simultaneously), or in other combinations, but most importantly, they appear to be discontinuous. A correlation of caliper log and CBL readings can be seen on Well 5, where the amps get noticeably worse (from 25 to 70) when the caliper is larger than 11 in. (27.94 cm) (3,841 to 3,848) (Fig. 8). A typical hole profile is shown in Fig. 9.

The Opal CT Nose ultrasonic logs vary significantly. The first well looks excellent, with no channels and only a few isolated mud pockets. Impedance is higher than that found in the West wells, with 90% of the section readings...
greater than 2 (Fig. 10). This finding was expected, because the cement was foamed 1 lb/gal (0.12 g/cc) higher density than the West well cement (taking advantage of the higher fracture gradient). The impedance and cement map correlate to the caliper in that the isolated mud pockets are mostly found in the spots where the maximum caliper peaks above 11 in. (27.94 cm).

The last well had a better ultrasonic log, high impedances, and appears similar to the first two West wells, with a moderate amount of mostly unconnected channels in all orientations. No obvious correlation to the caliper log exists, including any difference in log quality between the “undergauge” hole on the caliper and bigger hole. None of the ultrasonic logs appear to indicate that the turbo fins had any positive effect on the quality of this cement job. No difference on the ultrasonic logs between grit-blasted pipe and regular pipe could be found, but this is not unexpected or diagnostic.

COMPLETION OF WELLS

The original set of wells was fracture-stimulated, and tracers were incorporated in the fracturing fluid. Results indicated that the fracture treatments were not staying in the zone, which suggested that zonal isolation had not been achieved with the cement. The new set of wells also incorporated tracer material in the fracturing fluids (Figs. 11 and 12). Results indicated that the fracture treatments did stay in the zone, which suggested that the cement job did provide zonal isolation.

REVIEW OF SIGNIFICANT ADVANCEMENTS AND IMPROVEMENTS

- **Cement to Surface:** Cement to surface was achieved using foamed cement. The use of foamed cement lowered the weight of the cement sufficiently to allow cement to surface without losses.

- **Zonal Isolation:** The combination of improved drilling fluid properties and the foamed cement used resulted in wells that provided zonal isolation for subsequent fracture stimulation and production. The drilling fluids provided better carrying capacity of drill cuttings when the use of XCD polymer mud was possible. Also, the enhanced hole-cleaning capabilities of the foamed cement most likely aided in hole cleaning and the removal of any remaining drill cuttings.

- **Bond Logging Lightweight Cement Systems (Foamed Cement):** The use of specialized logging tools and processing allowed for more accurate evaluation of difficult-to-log foamed cement.

CONCLUSIONS AND RECOMMENDATIONS

The following conclusions and recommendations were drawn from drilling the West Flank and Opal CT wells:

- Minimizing wiper trips can help prevent hole enlargement.

- A hole elongation of less than 11 in. (27.94 cm) appears to be a key objective. Above this level, cementing can be problematic.

- The use of high yield-point mud can greatly help in hole cleaning while drilling.

- The use of foamed cement addressed a number of the drilling challenges for this project. The high YP of the foamed cement can greatly aid in mud displacement. The compressible nature of foamed cement can help prevent gas migration. Also, the capability to greatly reduce the fluid density and still obtain good compressive strengths helped prevent lost circulation during placement and subsequent cement fallback.

- Proper centralization of the pipe is critical in achieving effective zonal isolation during the cementing process. Dual-contact bow-spring centralizers were used at a rate of two per joint of casing to achieve 86% standoff.

- The use of HPUJ float equipment aided in both cementing of the wells and getting casing to bottom. The redirection of fluid at the shoe can help ensure that uniform flow around the entire annulus is achieved during cement placement. Also, if difficulty in running casing is encountered due to deposition of drill solids, etc., more
effective cleaning of the hole can be achieved with the directional flow out of this float shoe than with conventional float equipment.

- Specialized logging technology allowed for accurate evaluation of foamed cement. Good correlation between the cement bond logs and caliper logs was seen.
- Pipe-conveyed logs should be pulled at a slow, steady rate of approximately 20 ft/min (6.096 m/min) or less to maintain log quality.
- To help obtain an effectively completed well, implementing all best practices possible in the drilling, cementing, and completion of the wells is critical. No single practice can guarantee success.

**Ultrasonic Tool Running Recommendations**

- The ultrasonic tool should not be run in water-based drilling mud weights greater than 17 lb/gal (2.03 g/cc) or in oil-based muds with densities greater than 15 lb/gal (1.80 g/cc). The tool has been run in 16-lb/gal (1.92-g/cc) water-based mud and 16.3-lb/gal (1.95 g/cc) zinc bromide brine.
- The log presentation is automatically oriented so that the low side of the hole is located at the center of the image map, which corresponds to Section E. The high side of the hole is present at both A and I in the segmented presentations.
- A bit and scraper should be run before running the ultrasonic tool.
- Eccentricity (Track 1) should be observed and corrected by slowing tool speed and or increasing centralizers.
- The maximum temperature for the ultrasonic tool is 350°F (176.67°C).

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**REFERENCES**


<table>
<thead>
<tr>
<th>Formation</th>
<th>Well No.</th>
<th>Year Drilled</th>
<th>Mud Type</th>
<th>Plastic Viscosity (cP)</th>
<th>Yield Point lb/100 ft² (kg/100 m²)</th>
<th>10 Sec Gel lb/100 ft² (kg/100 m²)</th>
<th>10 Min Gel lb/100 ft² (kg/100 m²)</th>
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<td>Opal 1</td>
<td>1995</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
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<tr>
<td>Opal A 2</td>
<td>1995</td>
<td>Gel, changed to XCD</td>
<td>8.6 (1.031)</td>
<td>7</td>
<td>21 (103)</td>
<td>10 (49)</td>
<td>11 (54)</td>
<td>Very overgauged due to trips (coring). Changed mud systems toward end of well to improve hole cleaning.</td>
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<tr>
<td>Opal A 4</td>
<td>1995</td>
<td>Gel and Polypac</td>
<td>9.6 (1.150)</td>
<td>26</td>
<td>23 (112)</td>
<td>05 (24)</td>
<td>10 (49)</td>
<td>90,000 lb (22,980 kg) drag due to solids buildup.</td>
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<td>Opal A 5</td>
<td>2001</td>
<td>OBM, changed to XCD</td>
<td>8.8 (1.054)</td>
<td>9</td>
<td>20 (98)</td>
<td>12 (59)</td>
<td>15 (73)</td>
<td>Some overgauge sections, generally good hole cleaning. Well drilled along frac azimuth. Fracs connected on tracer log.</td>
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<tr>
<td>Opal A 6</td>
<td>2001</td>
<td>XCD</td>
<td>8.6 (1.031)</td>
<td>8</td>
<td>21 (103)</td>
<td>22 (107)</td>
<td>26 (127)</td>
<td>Excellent isolation apparent from frac tracer log.</td>
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<td>Opal A 7</td>
<td>2001</td>
<td>XCD</td>
<td>9 (1.078)</td>
<td>5</td>
<td>16 (78)</td>
<td>10 (49)</td>
<td>13 (63)</td>
<td>Casing stuck on bottom; could not reciprocate. Well drilled along frac azimuth. Fracs connected on tracer log.</td>
</tr>
<tr>
<td>Opal A 8</td>
<td>2001</td>
<td>XCD</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>A few slight channels, good bond in general. Excellent isolation apparent from frac tracer log.</td>
</tr>
<tr>
<td>Opal CT 9</td>
<td>1996</td>
<td>Gel / XCD</td>
<td>10.3 (1.234)</td>
<td>21</td>
<td>14 (68)</td>
<td>1 (5)</td>
<td>5 (24)</td>
<td>Problems with gas entrainment, limited yield point. No centrifuge, PV high. Out of gauge in upper section where multiple wiper trips took place, in gauge near toe.</td>
</tr>
<tr>
<td>Opal CT 10</td>
<td>1997</td>
<td>Gel</td>
<td>10.5 (1.258)</td>
<td>16</td>
<td>12 (59)</td>
<td>5 (24)</td>
<td>12 (59)</td>
<td>Some communication visible on tracer log. Channels on CBL. CBL not under pressure (pipe-conveyed log).</td>
</tr>
<tr>
<td>Opal CT 11</td>
<td>1999</td>
<td>Gel / XCD</td>
<td>10.3 (1.234)</td>
<td>22</td>
<td>11 (54)</td>
<td>4 (19)</td>
<td>6 (29)</td>
<td>Problems with gas entrainment, limited YP.</td>
</tr>
<tr>
<td>Opal CT 12</td>
<td>1999</td>
<td>Gel / XCD</td>
<td>10.2 (1.222)</td>
<td>21</td>
<td>13 (64)</td>
<td>3 (15)</td>
<td>4 (19)</td>
<td>Problems with gas entrainment, limited YP. Tracer log shows fracs confined to zones. Pumped 2 sweeps with minor increase in cuttings to surface during sweeps.</td>
</tr>
<tr>
<td>Opal CT 13</td>
<td>2000</td>
<td>Gel / XCD</td>
<td>9.8 (1.150)</td>
<td>22</td>
<td>22 (107)</td>
<td>5 (24)</td>
<td>7 (34)</td>
<td>N/A</td>
</tr>
<tr>
<td>Opal CT 14</td>
<td>2000</td>
<td>Gel / XCD</td>
<td>9.4 (1.126)</td>
<td>19</td>
<td>14 (68)</td>
<td>5 (24)</td>
<td>8 (39)</td>
<td>N/A</td>
</tr>
<tr>
<td>Opal CT 15</td>
<td>2001</td>
<td>Gel / XCD</td>
<td>10 (1.198)</td>
<td>27</td>
<td>28 (127)</td>
<td>6 (29)</td>
<td>15 (73)</td>
<td>Problems with gas entrainment, limited YP. Some channeling, tracer log shows some fracs out of zone. Added XCD to mud system at 2,500 ft to enhance rheology.</td>
</tr>
<tr>
<td>Opal CT 16</td>
<td>2001</td>
<td>Polymer</td>
<td>9.5 (1.138)</td>
<td>7</td>
<td>14 (68)</td>
<td>15 (73)</td>
<td>16 (78)</td>
<td>Stuck drillpipe. Tracer log shows fracs confined to zones.</td>
</tr>
<tr>
<td>Opal CT 17</td>
<td>2001</td>
<td>Gel / XCD</td>
<td>10 (1.138)</td>
<td>20</td>
<td>25 (122)</td>
<td>5 (24)</td>
<td>35 (171)</td>
<td>Moderate amount of mostly unconnected channels. Tracer log shows some fracs out of zone. Pumped 2 sweeps with minor increase in cuttings to surface during sweeps.</td>
</tr>
</tbody>
</table>
Table 2—Previous Drilling Systems

<table>
<thead>
<tr>
<th>Year</th>
<th>Opal A</th>
<th>Opal CT</th>
</tr>
</thead>
<tbody>
<tr>
<td>1995</td>
<td>Gel and Polypac</td>
<td>N/A</td>
</tr>
<tr>
<td>1996</td>
<td>N/A</td>
<td>Gel and XCD</td>
</tr>
<tr>
<td>1999</td>
<td>N/A</td>
<td>Gel and XCD</td>
</tr>
<tr>
<td>2000</td>
<td>N/A</td>
<td>Gel and XCD</td>
</tr>
<tr>
<td>2001</td>
<td>XCD</td>
<td>Gel and XCD</td>
</tr>
</tbody>
</table>

Fig. 1—Belridge Field, California.
Fig. 2—SE Nose Opal CT geology.
• EM signal is generated by injecting current across the downhole antenna
• Signal travels to surface much like that in a coaxial cable - drillstring acts as internal conductor with formation as external conductor

Fig. 3—EM-MWD signal propagation.

Fig. 4—Foamed cement PV and YP vs. foam quality (1 lb/100ft² = 4.9 kg/100 m²).

PV (cP) and YP (lb/100ft²) vs foam quality (%)

Foam Quality (%)
Proper dual-contact centralizer installation (installed over a stop collar)

Improper dual-contact centralizer installation (installed over a casing collar)

Fig. 5—Dual-contact centralizer installation.

Fig. 6—High-port up-jet float shoe.

Fig. 7—Ultrasonic bond log for case study well.

Fig. 8—Ultrasonic bond log for case study well.
Fig. 9—Typical caliper log profile.

Fig. 10—Bond log for case study well.

Fig. 11—Tracer log for Well 6.

Fig. 12—Tracer log for Well 8.