



Application of 'Best in Class' Technology in the Cement Field: A Case History

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Abstract

The paper describes one operator's use of "Best in Class" services to change drilling practices in the Mid-Continent region of Caddo County, Oklahoma and establish a new benchmark field performance that reduced drilling time by 50 days.

In the Cement Field of Caddo County, which is known for its complicated geology with highly dipped and faulted lithology, the operator sought to drill a straight hole control well to approximately 14,000 feet in less than 60 days, lowering total well cost while maintaining directional deviation control.

To improve performance in this application, where the previous drilling time to 14,000 feet was 98 days, required utilization of aggressive drill bits with high pressure differential and high flow rates, along with "premium services" to optimize the drilling process.

The paper addresses the factors that most directly contributed to achieving that goal, including comprehensive well planning; optimization of rig capabilities, mud program and operating parameters. Drilling performance is detailed, describing use of "best in class" equipment that included a drilling rig with high pressure, high volume pump capability; as well as drill bits and directional tools that could handle the high flow rates and high pressure differential with a wide range of operating parameters.

Analysis of earlier offset well performance reveals this approach significantly increased drilling efficiency, resulting in a nine-day reduction in AFE days on the well (48 actual vs. 57 AFE'd). Finally, economic analysis shows the significant savings in drilling cost realized, which totals an estimated \$250,000 off the AFE and close to \$1 million compared to earlier wells.

Introduction

The Cement Field of Caddo County is located within the Anadarko Basin of south-central Oklahoma, one of the great producers of the mid-continent petroleum province.

The Basin is a down-sag in the crust that has allowed up to 50,000 ft of Paleozoic sedimentary rock to accumulate. Structurally, the Basin is an asymmetrical geosyncline (a regional-scale downfold), with the

deepest part near the south edge. Oil and gas are present in porous rocks associated both with structural (anticlines; fault blocks) and stratigraphic traps. Large gas fields occur mainly along the Basin's western half, with oil more common in the eastern half. Wells as deep as 25,000 ft have recovered both hydrocarbons, although most pay zones are between 9,000-15,000 ft.

The dominant structure at Cement Field is a northwest to southeast trending asymmetric anticline situated in a regional east to west left-lateral wrench fault zone. Numerous subsidiary cross faults have resulted in significant reservoir compartmentalization along the productive trend, creating a complex geology.

Typical practice in the field required vertical wells to be drilled to approximate depths of 14,000-15,000 ft. The subject well was a gas development well planned to be drilled through a number of sand, shale and limestone formations including Thirteen Finger, Morrow, Primrose, Cunningham, Britt and Boatwright, achieving TD at 14,010 ft MD (13,983 ft TVD). Steering is required to land the BHA in the designated target zone.

Background

Wells drilled in the Cement Field prior to introduction of best practices required as many as 100 days to drill to a depth of approximately 15,000 feet.

Rigs capable of drilling to 25,000 ft, equipped with 4½-in. drillpipe (DP), typically were used, however, seldom at full capacity. Typically, for example, flow rates in 12¼-in. hole remained under 600 gal/min, with less than 2500 psi SPP, which consistently resulted in slow drilling.

A typical well in the field, represented by an earlier offset, had 20-in. casing set at 1008 ft, with 13⅜-in. casing at 4042 ft, 13⅜-in. casing at 9620 ft, and 7-in. casing at 14,824 ft. This well required a total of 37 BHAs using 50 drill bits, and more than 100 days to drill to TD at 14,824 ft MD.

Clearly, a change in practices was required to optimize performance in these wells. Introduction of new practices included using a rig with high pressure, high volume pumps capable of achieving 1000 gal/min in 12 – 14-in. hole, with 4000 psi SPP. In addition, 5-in. drillpipe and 5-in. heavy-weight drillpipe (HWDP) was used. This

also required use of motors, bits and MWD tools capable of withstanding the increased flow rates and drilling pressures.

New Approach

To affect an increase in drilling rate using the higher pump-capacity drilling rig, a number of other necessary changes were identified. Specifically, the casing program, mud program and BHA design, including bit and motor, were altered.

Casing Design

In the subject well, 20-in. conductor was set at a significantly more shallow depth of 76 ft, compared to 1008 ft in the earlier well. The subject well had 13 $\frac{3}{8}$ -in. casing at 1130 ft, with 9 $\frac{5}{8}$ -in. casing at 9795 ft, and a 5 $\frac{1}{2}$ -in. production casing string run to TD at 14,010 ft MD. (Table 1)

Drill Bits

In the subject well, introduction of aggressive bit designs were key to improving performance, allowing for high bit pressure drops to optimize jet impact force and increase energy at the bit.

Based on an exhaustive well prognosis, the bit application and selection process included a rock-strength analysis and design optimization for the drilling program outlined. In particular, bit hydraulics were examined closely to ensure selection of the right bit for the application.

Selection of cutting structure and hydraulics options was focused on getting the best possible performance from the specified mud system under designated higher operating parameters. The objective was to operate at the upper end of the operating parameter range while delivering a safe, quality borehole.

Both steel and tungsten carbide bit designs were used, enhanced with various features to improve performance: Cutting structure was selected to allow maximum energy to be directed at drilling the hole bottom. Active gauge trimmers remove the uncut rock ribs between the heel teeth, allowing bit cutting structure to retain drilling effectiveness as it wears.

In addition, sealed bearing roller cone bits were introduced that used a metal face seal design to provide for a dynamic sealing interface between two hardened steel rings, rather than elastomer. The metal-faced seal design provided a low-friction sealing surface for use in the high RPM application.

To ensure efficient bit cleaning, the hydraulic system featured a new nozzle configuration that simultaneously cleans multiple rows of teeth and directly impacts the bottom of the borehole. Continuous flow efficiently forces cuttings outward towards the borehole wall and upwards past the bit, providing higher ROP than other nozzle systems.

Motors

Earlier wells were drilled with 8-in. standard adjustable bent housing mud motors. The earlier comparison well, for example, used 1.83° bent housing motors run at 580 gal/min (2300 psi SPP) in 12 $\frac{1}{4}$ -in. hole. Standard 6 $\frac{3}{4}$ -in. adjustable bent housing motors were used in the 8 $\frac{1}{2}$ -in. hole with 335 gal/min (2400 psi SPP).

In the 12 $\frac{1}{4}$ -in. hole, the subject well introduced use of 9 $\frac{5}{8}$ -in. DynaDrill motors with a diamond-bearing pack capable of handling high flow and pressure. In the 8 $\frac{1}{2}$ -in. hole, 6 $\frac{3}{4}$ -in. SperryDrill motors with the DynaDrill diamond-bearing packs were used to handle the increased hydraulic requirements.

These motors operated with flow rates ranging from a low of 382 gal/min in the 8 $\frac{1}{2}$ -in. hole, to as high as 820 gal/min in the 12 $\frac{1}{4}$ -in. hole, with SPP from 3150 to 4000 psi. (Table 1).

Mud Program

In the comparison well drilled prior to introduction of best practices, the mud program utilized a water-based system with the following parameters:

In 12 $\frac{1}{4}$ -in. hole, mud weights ranged from 9 to 9.8 lb/gal with SPP of 2100 to 2400 psi. In 8 $\frac{1}{2}$ -in. hole, mud weights ranged from 11 to 15 lb/gal with maximum SPP of 2500 psi.

By contrast, the subject well maintained slightly lower mud weights with reduced solids improving fluid rheology and wellbore cleaning. The water-based system was a chrome-free lignosulfonate system with additions of cellulose fiber lost circulation material to control seepage and lost circulation. The 8 $\frac{1}{2}$ -in. hole section was drilled with an oil-based system in the production zone.

In the 12 $\frac{1}{4}$ -in. hole, the mud weights ranged from 8.8 to 9.6 lb/gal with a maximum SPP of 3900 psi. In the 8 $\frac{1}{2}$ -in. hole, mud weights from 10.9 to 13.4 lb/gal were utilized, with SPP up to 4000 psi (Table 1).

The subject well encountered abnormal gas pressures from 12,033 ft to 12,580 ft requiring the mud weight to be raised from 10.7 lb/gal to 13 lb/gal. Increasing the mud weight to 13 lb/gal caused the weaker formations fracture gradient to be exceeded and creating seepage to the formation while drilling. As drilling continued (approximately 13,000 TVD) the mud weight was gradually raised to 13.5 lb/gal to control the additional intake of gas. The 13.5 lb/gal mud weight again exceeded the formation fracture gradient and lost circulation occurred. The cellulose fiber lost circulation material was utilized to control the mud losses to the formation.

Drilling Operations

The subject well was spudded on January 19, 1999, and reached TD on March 8, after only 48 days drilling

time.

With 20-in. conductor pipe set, the 17½-in. hole was drilled to 1130 ft in one day, after which the 12¼-in. hole was initiated.

12¼-in. Section. This section was drilled from 1130 ft to 9795 ft in 19 days, utilizing a combination of seven bits total, run in BHA configurations that included DynaDrill and SperryDrill medium speed motors with 1.5° bent housing and MWD. This compares to the earlier well, which used a total of 10 bits in this section and required 31 days.

When lost returns occurred at the top of the 12¼-in. section at approximately 6239 ft, an LCM pill was pumped to regain circulation and drilling continued with no problems.

In addition, the well was steered to correct a tendency to walk to the north, requiring a build and turn to orient the hole properly for the next section.

8½-in. Section. In the 8½-in. hole, the subject well was drilled from 9795 ft to TD at 14,010 ft using a total of just nine bits, compared to the offset, which required 24 bits to complete this section. Maximum dogleg through the 8½-in. section was 5.72 degrees.

For a number of reasons, some lost circulation occurred in this section also, including loss to the formation at approximately 13,000 ft TVD, requiring LCM up to 13.5 lb/gal to control.

The 8½-in. section was drilled in 28 days, after which a 5½-in. production string was run to complete the well.

Specific Drilling Parameters

No single technique or feature can be used to increase performance. However, in order to optimize performance in this Cement Field application, the following parameters were run on the subject well:

Mud System. A combination of water-based and oil-based systems were used, with mud weights ranging from 8.8 lb/gal in 12¼-in. hole, to a high of 13.4 lb/gal in 8½-in. hole.

WOB. Approved drillbit operating procedures were used to reduce whirl and downhole vibration so as to extend bit life. Weight on bit ranged from 40-65 klb for 12¼-in. bits, and 20-55 klb for 8½-in. bits. By contrast, the earlier well ran a maximum WOB of 45 for both 12¼-in. and 8½-in. bits.

Bit HP. High bit hydraulic horsepower (HHP) was maintained to optimize drilling performance, with 12¼-in. bits ranging from 400 to 1300 psi HHP, while 8½-in. bits delivered 148 to 871 psi HHP.

RPM. The drilling team worked to maximize penetration rate and extend bit life, usually running medium speed motors at 130-137 rpm, with total rpm from 100-210 rpm. By contrast, in the earlier well rpm was held to a maximum 130 rpm, with 40 rpm while rotating.

BHA. In the subject well, the bottomhole assemblies

were designed to maximize rotating time while minimizing sliding. Generally, sliding times were reduced to less than 35 percent of the overall drilling time.

Conclusions

Drilling performance improvement typically is defined as either longer bit runs with fewer costly trips to replace worn bits, increased rate of penetration, or more commonly, both. Use of aggressive bit designs and motors with ruggedized diamond-bearing pack, in combination with innovative drilling practices, provided a clear advantage to the operator in terms of improved performance in the Cement Field.

Utilization of aggressive drill bits with high pressure differential and high flow rates, along with "premium services" enabled the subject well to be drilled nine days ahead of schedule, resulting in a savings of \$250,000 off the AFE.

Compared to performance on the earlier well, the subject well produced savings of 50 days. At an average cost of \$20K/day, this performance amounts to total savings of \$1 million.

The performance gained from the new more aggressive operating parameters used in this well has been the step change necessary to facilitate consistent good runs in the punishing formations of Cement Field, where the pay zone can be encountered as deep as 15,000 ft TVD.

In addition, the strategy employed by the operator in this case, delivered not only extended bit life but also better directional capabilities. Prior to the subject well, doglegs could reach as high as 6°/100 ft due to the complex lithological changes. Doglegs in the subject well never exceeded 5.72 degrees.

As additional Cement Field wells are drilled this way, the data trend consistently illustrates substantially improved performance, which ultimately allows the operator to adjust economic planning and drilling strategy to fully realize the gains from these operational advances.

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Nomenclature

<i>BHA</i>	=	<i>bottomhole assembly</i>
<i>BOP</i>	=	<i>blowout preventer</i>
<i>ECD</i>	=	<i>equivalent circulation density</i>
<i>EMW</i>	=	<i>equivalent mud weight</i>
<i>RKB</i>	=	<i>rig floor kelly bushing elevation</i>
<i>ROP</i>	=	<i>drilling rate of penetration</i>
<i>rpm</i>	=	<i>revolutions per minute</i>
<i>TD</i>	=	<i>total depth</i>
<i>TVD</i>	=	<i>true vertical depth</i>

WOB = weight on bit

HHP = hydraulic horse power

Table 1. Comparison of Subject Well vs. Earlier Offset

Subject Well

<u>Hole size</u> (in.)	<u>Depth in/out</u> (ft)	<u>Flowrate</u> (gal/min)	<u>Mud Wt</u> (lb/gal)	<u>SPP</u> (psi)	<u>Solids</u> (%)	<u>Days to</u> <u>Depth</u>
17½	76	784	NA	1000	NA	
17½	1130	784	9	1500	4.9	1
12¼	1130	765	8.8	2200	3.4	
12¼	9795	820	9.6	3900	9.7	19
8½	9795	468	10.9	4000	12.5	
8½	14,010	382	13.4	3150	22.9	28

Earlier Offset

<u>Hole size</u> (in.)	<u>Depth in/out</u> (ft)	<u>Flowrate</u> (gal/min)	<u>Mud Wt</u> (lb/gal)	<u>SPP</u> (psi)	<u>Solids</u> (%)	<u>Days to</u> <u>Depth</u>
17½	1005	NA	9.1	NA	5.6	
17½	4040	NA	9.3	NA	6.8	8
12¼	4040	580	9	2100	4.8	
12¼	9820	580	9.8	2300	10.5	31
8½	9820	335	11	2200	17	
8½	14,014	335	12.9	2400	27.5	59

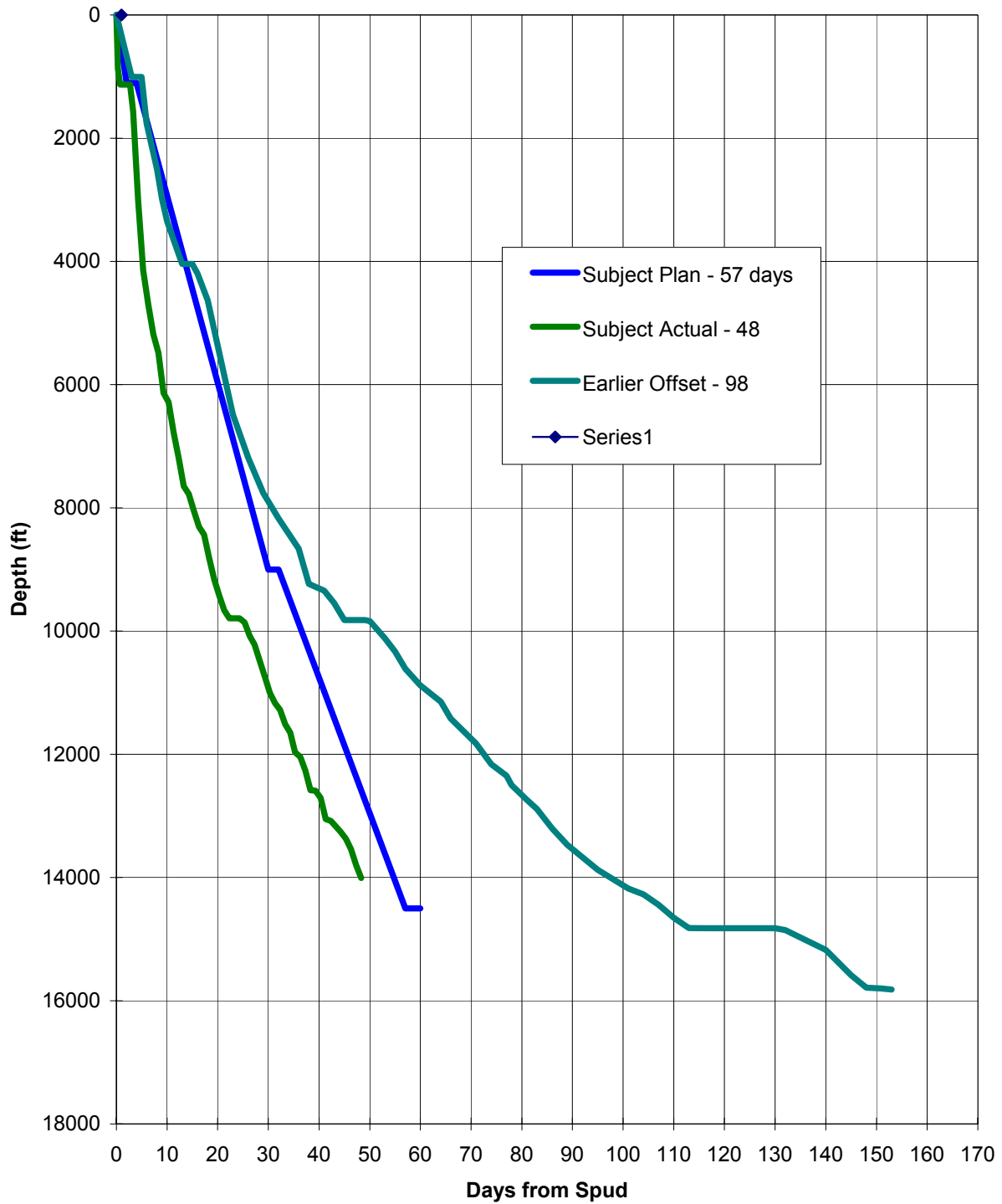


Figure 1. Subject Well Days vs. Depth