Casing While Drilling (CwD): A New Approach To Drilling Fiqa Formation in the Sultanate of Oman—A Success Story

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Summary
Highly reactive Fiqa shale used to compel well engineers in the Sultanate of Oman to plan drilling phase of surface and intermediate sections primarily based on time exposure to aqueous drilling fluid water-based mud (WBM). The new approach of drilling the time-dependent Fiqa formation using casing-while-drilling (CwD) allows well engineers to plan prospective top/intermediate wellbore sections differently by enhancing the overall drilling performance. This reduces the risk of setting casing strings at unplanned depths, getting pipe stuck, or reaming continuously when drilling with conventional drillstring. The technical feasibility study, risk assessment, planning, execution, and the lessons learned during the process of drilling two top-section pilot projects are described in this document. The CwD team compares the drilling performance of several offset wells and suggests actions to improve the CwD technology in Oman.

Two $17^1/_2$- and 22-in. surface sections were drilled successfully with large-diameter casing strings and reached 754- and 894-m measured depths, respectively. The implementation of the CwD concept reduced the overall drill/case phase time up to 40%, in comparison with the average using conventional drilling in those fields. Exposure time of Fiqa to aqueous environment was reduced by eliminating conditioning trips and nonproductive-time (NPT) associated with wellbore instability. Drilling both sections with non-retrievable $17^1/_2 \times 13^3/_8$-in. and $22 \times 18^5/_8$-in. CwD systems did not require modification of well design or rig. The optimization of this technology will support its implementation as the conventional drilling approach in some fields in Oman.

Introduction
Fields A and B in Northern Oman present a host of drilling challenges in upper-wellbore sections. Wellbore-instability and reactive-shale problems are common when drilling the highly reactive, troublesome Fiqa shale formation. Preceding the introduction of CwD, drilling practices call for excessive reaming during drilling and before running casing, and use of oil-based drilling fluid oil-based mud (OBM) or especially formulated water-based drilling fluid (WBM) to mitigate borehole instability across Fiqa. This paper shows how applying CwD technology as an enabling tool will result in improved drilling performance indicators in both fields.

Two candidate wells in fields A and B were identified, where tophole sections were drilled from surface to bottom of the Fiqa shale formation. Extensive upfront engineering and real-time monitoring of operational conditions resulted in (a) the drilled/cased surface section with a maximum performance in both fields and (b) the leading cost-effective surface section in Field B. Monitoring real-time data, analyzing the tendency of mechanical energy consumption, and implementing optimum drilling parameters produced an efficient time-on-bottom top section in field B. Such outcomes were accomplished with no rig modification and by deploying standard American Petroleum Institute (API) casing grade/weight pipe and connection, fit-for-purpose casing drive mechanism (CDM), and polycrystalline-diamond-compact (PDC)-type drillable bits.

This paper (SPE 136107) was accepted for presentation at the SPE Abu Dhabi International Petroleum Exhibition and Conference, Abu Dhabi, 1–4 November 2010, and revised for publication. Original manuscript received for review 12 December 2010. Revised manuscript received for review 31 January 2012. Paper peer approved 6 February 2012.

Fiqa Formation
In the Sultanate of Oman, the Fiqa formation ranges from 50 to 1400 m in thickness and is formed by two independent layers: Upper Fiqa, known as Arada, and Lower Fiqa, known as Shargi, the thicker layer that causes a majority of drilling problems. Fiqa is a clay-rich member of the Upper Cretaceous Aruma group, which provides an effective seal for Wasia group reservoirs such as Natih, which was deposited in the Middle to Late Cretaceous (Harris and Frost 1984). The hydrocarbon migration commenced after the Fiqa was deposited.

The Fiqa formation is an efficient, impermeable, thick seal (Borowski 2005) with low hydrocarbon source-rock potential (Alsharhan 1995). It is a sequence of moderately shallow to deep marine shale, consisting of limestone, marl, and shale. The amount of clay varies, and Shargi has the maximum concentration. The clay portion is primarily dominated by kaolinite, while the nonclay part is dominated by calcite, quartz, and feldspar with traces of dolomite, pyrite, siderite, glauconite, and phosphate (Alsharhan 1995; Harris et al. 1984). Drilling Fiqa reveals complications similar to those encountered when drilling very reactive clay/shale formations.

The typical lithology in northern Oman is shown in **Table 1.** Fiqa is enclosed by three members of UeR, a limestone formation that, in many fields, is considered a potential loss zone. For years, well construction included very-large casing sizes to case off UeR and subsequently drill Fiqa with either expensive polymer WBM or OBM. That was the common combined-mitigation system used for decades to avoid drilling problems across Fiqa.

Operational Challenge
Drilling across reactive shale commonly causes borehole instability (Tan et al. 1999), and physicochemical interactions with WBM are responsible for such swelling phenomena. This validated fact has been discussed widely in the literature, along with all associated drilling problems (Santarelli and Carminati 1995; Civan 1999). To minimize the negative effect that shale swelling produces on drilling performance, two major chemical solutions were defined in the past: OBM (Santarelli 1992 et al.), or redefined-chemistry WBM (Santos et al. 1998). The drilling efficiency while drilling across reactive, time-dependent shale is still questionable, however.

The occurrence of mineralogical transformations while drilling Fiqa shale with WBM in northern Oman is prevented by use of chemical additives (inhibitors and polymers, for instance) in the drilling-fluid system. In addition to these specialized systems, the mud weight is designed to contribute to the stabilization of Fiqa by preventing it from collapsing.

Even though the refined WBM system assists in preventing wellbore instability, drilling operations are highly affected by NPT associated with stuck pipe or reaming continuously to ensure a stable borehole before running casing. The time to drill, case, and cement the casing before Fiqa swells and collapses is crucial; these stages must be achieved quickly. The average time to drill/case

TABLE 1—TYPICAL LITHOLOGY IN NORTHERN OMAN; THICKNESS OF EACH FORMATION VARIES

Formation/Layer	Depth-Average	Description (Composition)
Surface Sediment	Surface	Undifferentiated sequence of dolomites, limestone, shale, gypsum/anhydrates
UeR—Upper	219 m	Succession of variably chalky limestone
UeR—Middle	289 m	
UeR—Shammar	359 m	Shale
Fiqa Arada	369 m	Limestone
Fiqa Shargi	689 m	Shale
Natih	958 m	Limestone

tophole sections in Fields A and B (across Fiqa) ranges from 6 to 16 days, and casing depths range from 700 to 1500 m, respectively. In both cases, Fiqa covers up to 60% of the section. After reaching the section total depth (STD) with conventional drillstring and before pulling out of hole, operators perform conditioning trips to ensure wellbore stability. Excessive reaming and numerous conditioning trips—potential NPT—became part of the planned drilling time in both fields.

In the last decade, the tophole sections in Fields A and B were drilled successfully either with roller-cone or PDC bits. Formation drillability is not a concern when drilling this section up to the top of Natih.

Proposed Solution

Unplanned events in the past became planned or highly possible events in the last decade when drilling across Fiqa. Simple operations such as short trips, circulation, and back reaming were included in drilling programs, along with special drilling fluids, to remediate Fiqa swelling problems and to run casing strings successfully. Well-engineering groups, however, were open to solutions that allow them to enhance the overall drilling performance; for instance, specific solutions that reduce drill/case time of tophole sections by at least 50%. Although slimming down the casing size improves the drilling performance (smaller hole size), it was not deemed adequate because similar instability problems were still encountered.

To overcome wellbore instability and enhance drilling efficiency, CwD was proposed as an enabling technology. The proposed concept of drilling with casing and then cementing just after reaching STD allowed drilling teams to reduce both the drill/case phase and the exposure time of Fiqa to WBM. It was planned to drill a $17\frac{1}{2}$-in. top hole with $13\frac{3}{8}$-in. casing in Field A and a 22-in. top hole with $18\frac{5}{8}$-in. casing in Field B, using drillable PDC bits in both cases. The drilling rig was chosen on the basis of availability of a topdrive system (TDS) and expertise drilling in the local area with a conventional drillstem. The TDS made the casing string rotate by transmitting the required energy through a CDM connected in between.

The long-term scope of the CwD technology to enhance overall drilling performance in Petroleum Development Oman (PDO) relied on the success of first trials. During the planning phase, and to ensure a successful CwD operation, the team selected suitable CwD tools with conventional casing accessories, evaluated the mechanical properties of the drill-in string, and simulated drilling parameters by modeling torque/drag, hydraulics and hole cleaning, bottomhole-assembly (BHA) performance, and cementing operations. Along with all technical preparedness, several risk-assessment workshops were held to evaluate the risk associated with every unplanned event and identify the actions to be taken in case of occurrence.

Well Planning

Surface-hole sections in northern Oman, (i.e. deep gas wells) are regularly drilled with large-diameter bits ($17\frac{1}{2}$ – 23 in.; either roller cone or PDC) using WBM and a standard rotary BHA. The top holes are cased with $13\frac{3}{8}$-in. 72# L80 BTC or $18\frac{5}{8}$-in. 87.5# K55 BTC casing strings, with no well-control system in place. The following sections in both fields are commonly drilled with $12\frac{1}{4}$- or $17\frac{1}{2}$-in. PDC bits and cased with $9\frac{5}{8}$- or $13\frac{3}{8}$-in. casing, respectively. Intermediate sections are not included in this study, but they were relevant in the selection of CwD bits.

The feasibility study revealed that CwD should be planned for candidate top sections without modifying existing drilling-rig and casing design. The major components of drill-in strings and the CwD system are: (a) drillable PDC bit, (b) fit-for-purpose stabilizer in Field A to mitigate the risk of buckling (no stabilization required in Field B), (c) high-torque ring to increase the torque capability of BTC connection, (d) $13\frac{3}{8}$-in. 72# L80 BTC casing in Field A and $18\frac{5}{8}$-in. 87.5# K55 BTC casing in Field B, (e) CDM made up to rig's TDS, and (f) two conventional flow collars for Field A (high-flow-rate float systems not available) and one sting-in float for Field B. The selected BHA for the drill-in string is shown in **Fig. 1.** Local experience drilling in both fields revealed that surface openhole sections never exceeded 1° inclination at STD when drilling with drillpipe; it was expected that CwD would not change this trend.

Different tools were used to simulate drillstring mechanics and determine optimum drilling parameters such as maximum weight on bit allowed, rotary torque, critical rotary speed, and hydraulics. Simulations of conventional casing runs reported axial friction

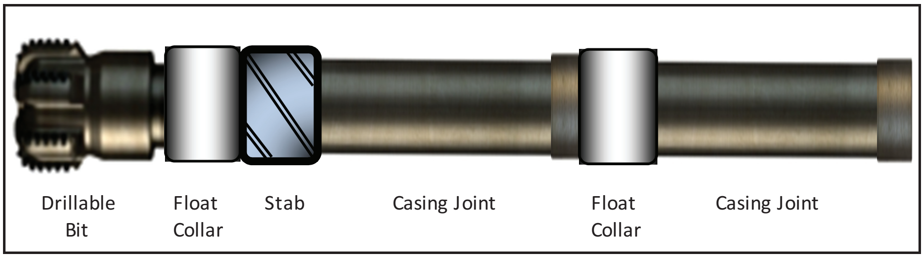


Fig. 1—BHA designed for CwD job in Fields A (as shown) and B (no stab needed and only one float collar, at 13 m from bit).

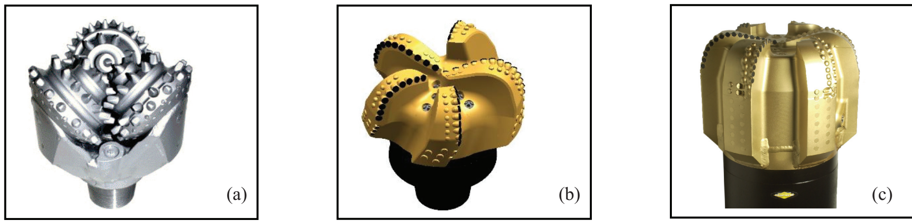


Fig. 2—(a) Roller-cone bit used in 19 wells. (b) Conventional PDC bit used in Well #20. (c) Drillable PDC bit used in CwD of Well #21.

factor in the openhole section of 0.3. To assess simulations accordingly, service companies employed proprietary software, and PDO used commercial well-planning applications.

Drillable Bit, CDM, and Casing Material/Connection

A comprehensive analysis was made corcerning local availability of the CwD components and casing accessories to strengthen reliability of CwD system in both fields. From surface to 40-m depth—rathole—conventional drillstem was used to preserve integrity of drill-in BHA and ensure total verticality across unconsolidated formations. The objectives for selecting (a) suitable drillable bits and (b) CDM for the first two trials in deep-gas-well areas are summarized as follows:

- Be able to drill though Fiqa with only one drillable PDC bit, cement the casing into place before borehole collapses, and avoid conditioning trips as well as bit balling. The bit's cutting technology is similar to that of a conventional PDC bit used in one offset well.

○ ***Field A.*** The $17\frac{1}{2}$-in. top sections of the previous 19 wells were drilled with roller-cone bits, and in Well #20, a five-blade, 19mm-cutter PDC bit was used. The recovered PDC bit was grade 2-5-WT-A X-I-BT-TD. This successful run led the CwD team to choose a PDC bit with similar cutter structure for Well #21, but with six blades instead. The $17\frac{1}{2}$-in. drillable PDC bit drilled from 40 to 754 m in 50 hours, with an average rate of penetration of 14.3 mph. **Fig. 2** shows the bits used in Field A.

○ ***Field B.*** As a result of the experience in Field A, along with the complexity of drilling a larger-diameter wellbore, the team improved the bit selection. Before use of CwD, six consecutive surface sections were drilled in Field B using standard 23- to 26-in. roller-cone (milled-tooth-tricone) bits; PDC bits were never used, as **Table 2** describes. **Fig. 3** shows the bits used in Field B.

– Dull descriptions suggest that most of the 23- to 26-in. bits came out of the hole in good condition after reaching STD. Some bits were pulled out of hole because of wellbore conditions and bit balling across Fiqa, and others were reused in less-expensive areas.

– Log-based rock-strength analysis was performed at top hole in only one well. **Fig. 4** shows the unconfined-strength (UCS) analysis completed from surface to base of Natih A/B. It is evident that UeR Middle, UeR Shammar, Fiqa Arada, and part of Fiqa Shargi contain a few isolated, hard stringers with UCS values ranging from 20,000 to 38,000 psi. These hard stringers correspond to different formation elements, as described in Table 1. Across the Fiqa formation, the average UCS is lower than 10,000 psi with a few potential stringers with UCS larger than 20,000 psi. On the basis of the bit supplier's rock-hardness classification, and even though a few hard stringers may be present, the entire section is not considered as a uniform hard-rock interval.

– The tricone bits used in the previous nine-well campaign are designed as 115-IADC. The results allowed us to state that formations with a few isolated hard stringers can be drilled successfully by milled-tooth soft-formation bits. The drillable PDC bit used in the CwD well, which is recommended to drill harder and more-abrasive formations (uncertain maximum UCS), was chosen to ensure success while drilling with casing.

- Be able to run efficiently and rotate casing with CDM, leading to improved drilling performance and enhanced health, safety, and environment (HSE) records. The same rig was employed in both fields.

○ Internal grappling CDM system was connected to the TDS to transmit rotation and axial movement to casing string. It included a set of link tilt arms with single-joint elevators. Once the internal system was engaged and the slips were energized, both sets of $13\frac{3}{8}$- and $18\frac{5}{8}$-in. joints were made up to 25,000-lbf-ft torque. Even though the CDM is conceptually designed to speed up the casing-handling operation, inexperienced rig crews limited connection time (t_{conn}) efficiency, which was optimized after the first few joints with an average of 7 minutes.

Implementation of CwD in northern Oman demands use of in-stock casing joints (i.e. API grades and connections). The uncertain capability of API tubulars to withstand while-drilling loads and the potential risk of premature failure led to proper analysis of mechanical properties, with the following outcomes **(Table 3):**

- Collapse and burst rating of large-diameter casing is many times lower than that of drillpipe (DP). The external- and internal-pressure rating of drill-in string is irrelevant while drilling because (a) unrestricted, large-internal-diameter casing reduces maximum standpipe pressure and (b) external pressure on casing is independent of annulus clearance, in common drilling operations.
- Body-yield strength, yield torque, J-polar moment, and toughness of $13\frac{3}{8}$-in. 72# L80 and $18\frac{5}{8}$-in. 87.5# K55 casing

TABLE 2—DULL GRADE FOR SURFACE-SECTION BITS IN FIELD B

Well	Surface Section in Field B			
	OD (in.)	Bit Type	Provider	Dull Grade
4	26	ST	A	1-1SS-A-E-I-NO-TD
5	26	ST	B	1-1-WT-S-E-I-BU-BHA
			C	1-1-WT-A-E-I-BU-TD
6	23	ST	C	2-2-BT-A-E-I-BU-TD
7	23	ST	C	2-2-WT-A-E-I-NO-TD
8	23	ST	C	4-3-WT-A-E-2-I-WT-TD
9	23	ST	A	2-3-WT-A-E-I-LN-HP
			C	2-3-WT-A-E-I-BU-PR

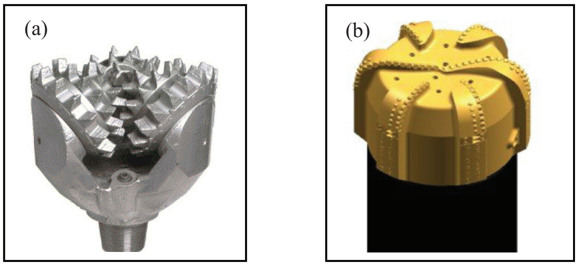


Fig. 3—(a) Roller-cone bit used in previous wells. (b) Drillable bit used in CwD of Well #10.

strings are several times larger than in API DP, allowing them to resist greater axial and torsional loads than traditional 5-in. 19# S135 joints. In other words, chances of twist-off during these CwD operations are negligible. Microalloyed L80 pipe material absorbs more energy (high toughness) than conventional DP material grades, fatigue-related washouts in the pipe body being unlikely. In the case of K55 grade steel, such a prediction is not valid. In any scenario, there is limited evidence in the industry on fatigue resistance of both casing strings.

• Makeup and yield torque of 13³⁄₈- and 18⁵⁄₈-in. casing joints with BTC connections are up to 85 and 70% lower, respectively, than common DP 5-in. 19# NC50. Obviously, the reasons are (a) connection profile, (b) lack of shoulder-contact point, and (c) gap between both pin ends once inside the coupling. Unpublished research data are used to argue that high-torque rings installed to fill up the gap between pin ends increase maximum yield torque of a BTC connection by up to three times.

Hydraulics

In comparison with conventional drilling, CwD with large-diameter casing increased the total internal fluid-flow area by more than 8 times and reduced the annular flow area by 2.2 times. Even

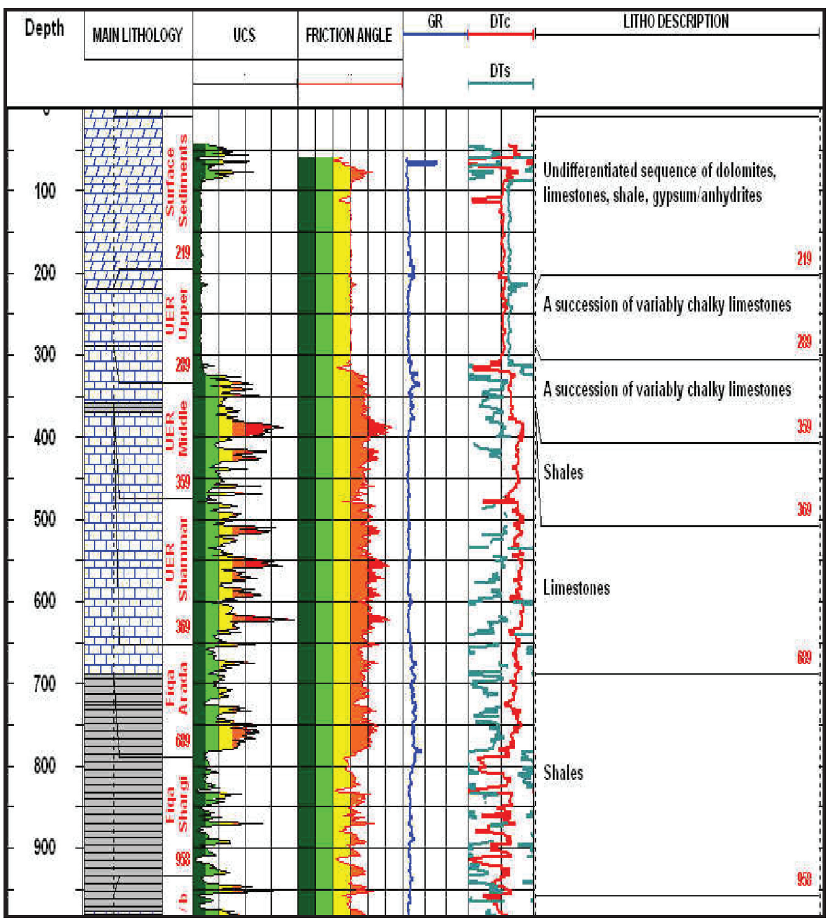


Fig. 4—Lithology (0–1000 m) and rock-strength analysis in Field B-West. Scale: unconfined rock compressive strength, 0–40ksi; FA, 0–60°; gamma ray, 0–300 GAPI; UTC and DTSM, 140–40 us/f. Source: bit provider.

TABLE 3—STANDARD MECHANICAL PROPERTIES OF CASING PIPE AND CONNECTION USED IN FIELDS A AND B

	Mechanical Properties					Connection Dimension/Properties			
Casing	Collapse psi (kPa)	Burst psi (kPa)	Body Yield Strength klbf (kton)	Impact Test (ft/lb)	Yield Torque (k ft/lb)	OD (in.)	ID (in.)	Length (in.)	Torque Yield w/HTR (ft./lb)
18 ⁵⁄₈-in. 87.5# K55 BTC	630 (4,398)	2,250 (15,708)	1,367 (617)	Unknown	500	19.625	17.755	12	Above 60K
13³⁄₈-in. 72.0# L80 BTC	2,670 (18,640)	5,380 (37,550)	1,661 (755)	100–130	400	14.375	12.347	12	Above 70K

TABLE 4—CALCULATED HYDRAULIC PARAMETERS AT DIFFERENT FLOW RATES

Parameter	Drilling With 13⅜-in. at 750 m			Drilling With 18⅝-in. Casing at 894 m		
Flow rate, m^3/min (gpm)	3.8 (1,000)	3.4 (900)	3.0 (800)	3.8 (1,000)	3.4 (900)	3.0 (800)
Stand pipe pressure, kPa (psi)	13,700 (1,992)	11,200 (1,629)	8,986 (1,303)	8,935 (1,296)	7,299 (1,059)	5,838 (847)
Casing ΔP, kPa (psi)	34 (5)	34 (5)	21 (3)	68 (9.7)	66 (9.4)	64 (9.14)
Bit ΔP, kPa (psi)	12,545 (1,819)	10,159 (1,473)	8,028 (1,164)	7,561 (1,096)	6,053 (877)	4,713 (683)
Annulus ΔP, kPa (psi)	566 (82)	545 (79)	524 (76)	706	689	670
HSI, HP/in.^{2}	4.47	3.26	2.29	1.71	1.23	0.84
Jet velocity, m/sec (ft/sec)	148 (484)	133 (436)	118 (387)	111 (365)	99 (326)	88 (288)
ECD at bit, kPa/m (ppg)	12.34 (10.5)	12.34 (10.5)	12.23 (10.4)	13.29 (11.3)	13.27 (11.3)	13.25 (11.3)
Annular velocity, m/min (ft/min)	59 (192)	53 (173)	47 (154)	55 (179)	49 (161)	43 (142)

though the equivalent circulating density (ECD) was higher, the maximum pressure drop was still recorded at the bit.

Drillability features of drillable PDC bits in Fields A and B were unquestionable. Consequently, the hydraulic energy was the major power-component used to optimize drilling efficiency of the system as an alternative to mechanical energy. Therefore, the team was focused on providing enough hydraulic energy to (a) clean the bit and prevent bit balling with high jet velocity, (b) remove cuttings rapidly to avoid accumulation inside tight-clearance annulus and flowline, and (c) reduce overall energy consumption.

Several simulations were completed to assess hydraulic parameters when drilling 17½- and 22-in. surface hole in both CwD jobs. The fluid gradient of the polymer WBM chosen to drill through Fiqa was 11.8–12.6 kPa/m (10- to 10.7- lbm/gal fluid density), but the maximum reported at STD was 12.2 kPa/m (10.3 lbm/gal). The total flowing areas at the 17½-in. and 18⅝-in. bits were 0.663 and 0.8836 in.^{2}, respectively. **Table 4** shows calculated parameters using a fluid gradient of 11.8 kPa/m (10 lbm/gal) and different flow rates.

Torque

Based on API standards, optimum makeup torque of 13⅜-in. 72# BTC is approximately 13,380 lbf-f (18 141 N·m). Assuming maximum torque generated by the drillable bit at bottom of 6,000 lbf-ft (8135 N·m), the maximum simulated rotary torque at the surface would range from 14,000 to 17,000 lbf-ft (18 982 to 23 071 N·m). The maximum rotary torque recorded when drilling with a 17½-in. PDC bit and conventional drillstem in previous wells in Field A was 15,000 lbf-ft (20 300 N·m).

Both calculated and recorded rotary-torque values at the surface are higher than optimum connection torque; as a result, the risk of connection damage while drilling with 13⅜-in. BTC casing and the CwD PDC bit is high. Hence, it was decided to install steel-based high-torque rings (HTR) in the connection box end to increase its torque capability. Unpublished data suggest that the limit torque of 13⅜-in. 72# BTC with rings is 73,590 lbf-ft (99 775 N·m), approximately 5.5 times the optimum torque. Similar analysis was performed in Field B, assuming bit torque of 9,000 lbf-ft (12 200 N·m;). Rings were also installed in the connection box end of 18⅝-in. BTC joints.

BHA, Stress Analysis, and Critical Speed

Field A. To assess the effect of 13⅜-in. BTC couplings on string stabilization while drilling the 17½-in. surface hole, a BHA engineering analysis was performed. It revealed that the stiffness of the drill-in casing string is high enough to drill 754-m STD of the surface hole with no sinusoidal-buckling tendency when the weight on bit (WOB) does not exceed 21,000 lbf (9.3 kN). This indicates that 14.375-in-outer-diameter (OD) couplings, simulated every 12.5 m (41 ft), add sufficient stabilization to the drill-in string below the tension/compression neutral point. The maximum WOB recorded in the field using either roller-cone or PDC bits is 22,500 lbf (10.0 kN); however, a lack of local expertise drilling with casing and uncertain actual parameters suggest the need for extra stabilization. A couple of integral, 1-in. under-gauge stabilizers, 0–25 m (0–82 ft), added to the 13⅜-in. drill-in string increased the minimum WOB before buckling to 33,780 lbf (15.0 kN). The new configuration added an extra 38% operational margin (1.62 factor) to the drilling plan in terms of WOB in an ideal, vertical, straight hole. In the previous twenty 17½-in. surface sections in the field, the maximum recorded inclination and dogleg severity were 1.2° and 1.35°/100 ft, respectively. Assuming the same parameters, the calculated bending, axial, torsional, and equivalent (von Mises) stresses never exceeded the yield strength of the 13⅜-in. Grade L80 casing.

The BHA analysis also suggests that the drilling speed—critical speed—required to avoid vibration damage on the drill-in string when applying up to 20,000-lbf (8.9-kN) WOB, ranges from 65 to 70 rev/min and from 88 to 100 rev/min. For this analysis, only stabilizers and casing couplings were included and large-OD float collars were excluded.

Contractual restrictions led the CwD team to select two conventional float collars to ensure reliability during drilling and a minimum cement track of approximately 13 mt (43 ft). High-flow float collars were not available locally**.** Fig. 1 shows BHA designed for CwD job in Field A.

Field B. On the basis of the results discovered in Field A, a similar engineering approach was performed before drilling with the 18⅝-in. 87.5# K55 BTC string. The CwD team carried out similar simulations to evaluate the drilling parameters and induced stresses while drilling the 22-in. section. Two directional surveys from previous wells were used to simulate wellbore geometry. The collected data presented the maximum value of inclination angle of 2.5°, and it was recorded underneath the top of Fiqa Shargi. Drilling the reactive, troublesome shale with a conventional drillstem leads to continuous reaming and permanent circulation across the entire formation that produces, consequently, large washouts and discontinuities in the wellbore geometry.

The effect of coupling size on centralization of the CwD drillstem in 22-in. borehole was assessed by a similar BHA analysis.

TABLE 5—PIPE-EXTERNAL-DIAMETER/WELLBORE-INTERNAL-DIAMETER RATIO AND ITS EFFECT ON BHA STABILIZATION TO PREVENT SINUSOIDAL/HELICAL BUCKLING

	Casing Drill-in String		ODcsg/IDhole Ratio			Conventional Drillstem		
Borehole (ID, in.)	Body OD (in.)	Coupling OD (in.)	Body	Coupling	Required Stabilization	Drillcollar OD (in.)	ODDC/IDhole Ratio	Required Stabilization
22	18.625	19.625	0.85	0.89	No	9.500	0.43	Yes

Couplings placed every 12.5 m (41 ft) were included in the simulated 18$^5/_8$-in. drill-in string. The outcome suggested that additional stabilization is not required even for high values of WOB. It supports the fact that stiffness (the ratio of casing OD to borehole inner diameter) of large-diameter-drillstem reduces the risk of buckling while drilling, in comparison with a conventional drillstem **(Table 5).** Fig. 1 shows the BHA designed for Field A, but for the CwD job in Field B, no stabilizer and only one float collar was included in the BHA design.

Before spudding the well, the CwD team agreed that, even under unexpected drilling conditions, an 18$^5/_8$-in. drill-in string with torque rings would drill the planned 22-in. borehole and keep the mechanical integrity of its body and connections. Because of limited literature available on the fatigue life within API's casing joints, however, the team referred to two accessible sources of information:

- The only published fatigue-life data on 18$^5/_8$-in. BTC casing suggested that such connection failed at approximately 580-MPa (84,000-psi) stress amplitude after only a few revolutions. This accelerated laboratory-condition test was performed using L80 grade (Teodoriu et al. 2008), which has different chemistry and mechanical properties in comparison with the K55 material.
- At the time of the job, the longest and deepest 18$^5/_8$-in. CwD job in the region was performed from surface to 350-m depth in Saudi Arabia, while 620-m depth was reported in Latin America as the world record (source: bit supplier). Although the team faced diverse drilling environments, in terms of ROP and the total number of revolutions, it accomplished a susceptibility analysis to chronicle the experience worldwide as a suitable reference.

The CwD team concluded that because available fatigue-life data could not be adapted to the PDO's CwD job, all drilling parameters, including the total number of revolutions, must be monitored cautiously. On the other hand, simulated wellbore geometry reported maximum bending stress of 20 MPa (3,000 psi) at a level with maximum dogleg severity (i.e., top of Fiqa Shargi). It was proved that in Field A, the stiffness of the drill-in string and the CwD dynamics would reduce dogleg severity, consequently minimizing the bending stresses. In a conservative mode, the maximum speed of 60 rev/min was chosen to minimize the total number of revolutions and mitigate the risk of premature fatigue failure of the casing.

Risk Assessment

To identify the risk of drilling with casing in both fields and recognize the critical path while implementing the selected CwD system, two hazard-identification (HAZID) workshops were conducted with global expertise holders. Operational and design engineers were actively involved in the discussion, and four major groups of potential risk events were clearly identified: wellbore instability, casing handling, cementing, and post-cementing. The team evaluated the probability of occurrence of each event and its consequences, highlighted their impact on drilling operations, and elaborated on a list of potential mitigation systems.

Because of lack of local expertise in CwD, the list of potential risks was influenced by the data recorded when drilling with a conventional drillstem. Consequently, the potential threats with greater than 15% likelihood of occurrence were (a) bit balling, (b) excessive bit vibration, (c) wellbore collapsing, (d) plugged flowlines, (e) reduced drilling performance, (f) premature damage of casing connection, (g) damage of conventional float collars, (h) deficient cement job, and (i) problems encountered while drilling out drillable bit. Mitigation systems were put in place to minimize the risk and impact of such events on both trials; for instance, to drill a rathole from surface to 40-m depth with a conventional drillstem and prevent premature failure of the bit. Before the commencement of the operation, several prespud meetings were held at the rig location to communicate to rig crews the potential risks associated with CwD and the actions required.

Cementing Drill-In String

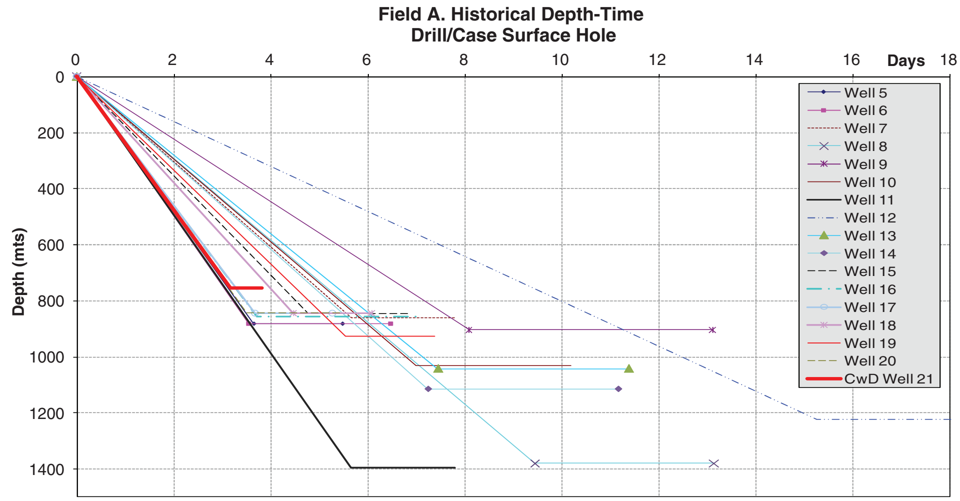
Field A. Conventional cementing operations were performed after the drill-in string reached the planned STD (754 m) and the wellhead was successfully installed. Although some difficulties were expected when executing the cementing job, because of possible premature damage to float collars, no problems were reported. Cement slurries were displaced through bit nozzles as per the plan. The total cement returned to the surface recorded 92% of pumped excess in comparison with the 20% average in the field. After drilling the next 12$^1/_4$-in. section, openhole logging tools were run including a cement-bond log (CBL), which showed good cement bonding.

Field B. Sting-in cementation is commonly used in very-large casing sections such as 18$^5/_8 \times 22$ in. A dedicated risk-assessment session was conducted to evaluate the cementing procedure. The high risk of damaging a commonly used sting-in system after lasting circulation could result in an ineffective sting-in trip. Consequently, the CwD team suggested a conventional cementing job, to hold pressure after cement slurries were displaced, and wait on cement. The total volume of the cement recovered at the surface reached up to 98% of the pumped excess, in comparison with 25% average in the field, which indicated the in-gauge quality of the wellbore. Such characteristics could be associated with the uncertain concept of smear effect, but that analysis is excluded from this document. Nevertheless, the ratio of casing OD to borehole inner diameter was higher than 0.8 and, as suggested by some authors, could be linked to wellbore strengthening (Watts et al. 2010).

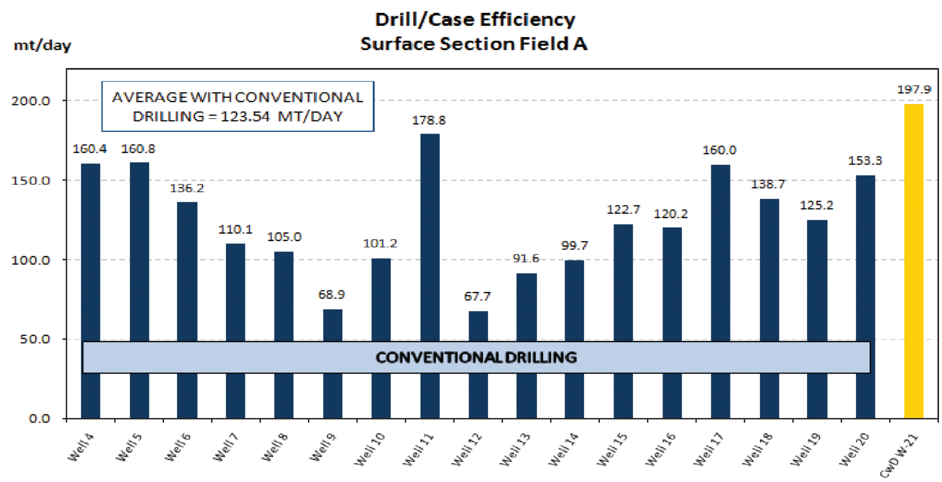
The CwD with 18$^5/_8$-in. string was successfully implemented until an incorrect procedure was detected 20 m before the bit reached the planned STD. Making up the connection with inappropriate hand slips (i.e., 288 instead of 300 circular bottoms) caused the casing to collapse, leading to an unplanned casing-setting point of 894 m. This resulted in NPT of 0.83 days in the surface section, and no NPT in the intermediate section associated with the shallow casing depth was reported.

Results and Lessons Learned

Field A. The total time for drilling the surface hole and cementing the 13$^3/_8$-in. casing at planned STD was 3.8 days, with an average rate of penetration of 8.27 m/h, in comparison with the average reported in the field of 5.15 m/h. No additional trips were required to improve the borehole conditions as in the previous 20 wells drilled with conventional methods. **Figs. 5a** and **5b** illustrate that the drill/case efficiency within the field using a conventional drillstem averaged 123.5 m/d, while in Well A21 it was 197.9 m/d.



(a)



(b)

Fig. 5—Field A, historical data and drill/case efficiency $17^1/_2$- × $13^3/_8$-in. surface section. This includes only those activities required before casing string is cemented in place.

Such statistics include the time drilling the rathole, and exclude the time required to drill out the drillable bit before resuming drilling operations. This CwD job was the first in PDO's northern areas and allowed the drilling group to improve the overall drill/case efficiency of $17^1/_2$-in. sections in Field A by 60.5%. Well A21 represents the evidence to label CwD as an effective mitigation system against wellbore instability across the Fiqa formation. Additional time was required to drill out the drillable bit. In addition, the lessons captured throughout the drilling/casing operation will lead to a similar overall progression to subsequent jobs. Extra-time events, such as fit-for-purpose TDS alignment, makeup of casing joints and BHA components, optimum rathole drilling, drillout of CwD bit, and wellhead installation, will be improved.

Contractual limitations, initial investment in new- technology implementation, additional time attributable to learning curves, and trial-condition cost led to the top hole of Well A21 being an expensive section within Field A. In comparison with the average in the field, an additional 76% was spent on the surface section. Leadership teams, however, conspicuously neglected the outcome and pursued the long-term strategy of CwD in PDO.

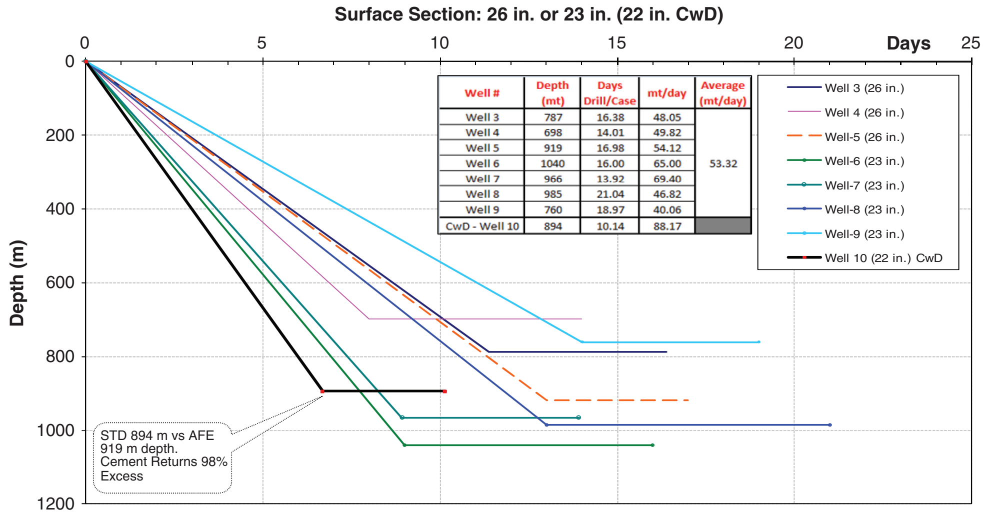
The determined planning and execution of this first CwD job in PDO established a fit-for-purpose solution to the historical wellbore-instability problems in northern Oman, with limited changes to conventional drilling setups. The main objective of this pilot project was to prove the concept of CwD as a mitigation system against the risk of wellbore instability and related NPT, resulting in certain innovations in deep-gas development and exploration wells. It also opened new horizons toward enhanced well integrity, slim-down designs (Sánchez et. al. 2011), and minimum HSE-related NPT and concerns in terms of OBM usage.

Field B. The 22-in. surface section was drilled to an unplanned STD of 894 ms in 6.68 days with an average rate of penetration of 5.58 m/h, when the average reported in the field was 3.55 m/h. **Fig. 6** shows that the drill/case efficiency in the previous nine-well campaign with conventional drilling methods of 23- or 26-in. hole size averaged 53.32 m/d, but in Well B10, the drill/case efficiency was 88.2 m/d. It included the rathole, casing collapse, and connection damage owing to TDS misalignment and related NPT, and the drillout of the drillable bit. As explained for Field A, drilling conventionally for the first 40 m prevented premature bit damage and early borehole deviation.

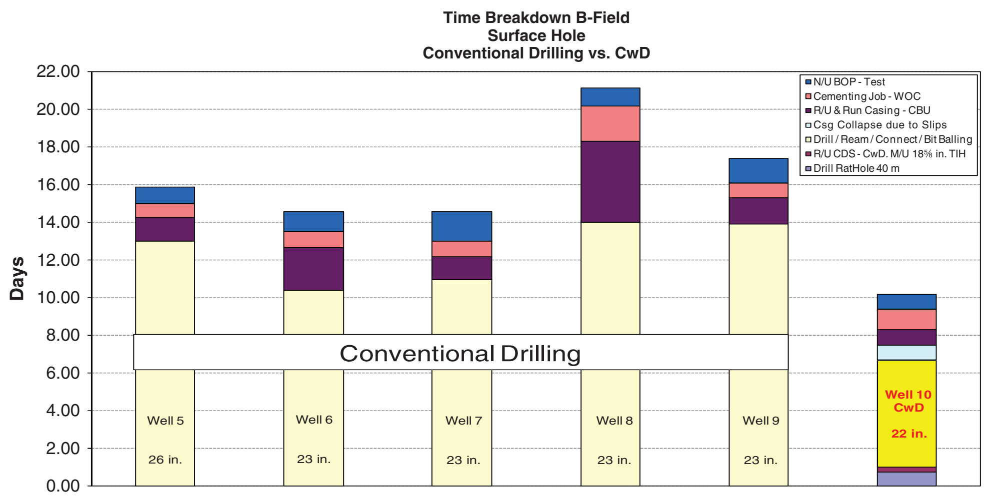
The lessons captured in Field A and the implementation of good drilling practices resulted in a 65% improvement in drill/case performance. The use of an automatic drilling instrument system, along with the best possible and steady ROP range, permitted the drilling team to optimize the total mechanical energy. Common practices used in the previous nine wells, such as back reaming and circulation for hole cleaning, were eliminated.

Mechanic Specific Energy (MSE) in Field B

MSE, recognized as a drilling-efficiency-optimization (DEO) and benchmarking tool, was implemented for the first time in



(a)



(b)

Fig. 6—Drill/case efficiency (a) and time breakdown (b) for surface sections in Field B. CwD-Well 10 includes rathole and NPT. Total time until crew picks up bit for next section.

PDO to drill the 22-in. surface section with an 18⅝-in. casing string. Instead of considering precise values of energy required to drill rocks of varying UCS, the overall trend across specific formations was taken into account. Local survey instruments were unable to record the real-time MSE, and such a scenario compelled the CwD team to manually calculate MSE values every 3 hours.

Common key performance indicators (KPIs) when drilling surface hole with a conventional drillstem in northern Oman are well-delivery time, overall cost, and drilling efficiency across the Fiqa formation. In Field B, DWC and the trend of mechanical energy consumption across all the formations were added to the drilling- performance analysis. A benchmarking process was conducted with two conventionally drilled offset wells to identify the benefits of CwD in terms of the energy required to drill the surface holes. **Table 6** shows the characteristics of the surface section in Wells B6, B9, and CwD-B10.

Fig. 7 shows that the MSE consumption when drilling with 18⅝-in. casing is steady and less than when drilling with the conventional drillstem. The maximum energy required in Well B10 was reported across isolated, hard stringers in the UeR formation. On the other hand, low values and steadiness of MSE across the Fiqa formation suggest that CwD, along with suitable drilling practices, reduces mechanical-energy consumption. The impact of hole size and hydraulic power on total energy required while drilling surface holes in northern Oman has not yet been measured; however, mud properties are directly related to the efficiency of CwD operations (Sánchez et. al. 2011).

In Well B10, drilling across Fiqa Shargi with the intermediate 17½-in. bit and a conventional drillstem produced the maximum mechanical energy, as reported along the entire interval, which includes the Natih formation. This indicates that drilling across unstable, reactive Fiqa shale requires higher consumption of mechanical energy. That is certainly related to necessary reaming and circulation to reduce the effect of bit/BHA balling as well as wellbore conditioning before running the casing. Similar energy consumption was reported in Wells 6 and 9 across Fiqa. On the other hand, drilling the top interval of the intermediate section of Well 9 with a 16-in. milled-tooth bit presented no indication of wellbore instability and related NPT. It is evident that time exposure to the polymer-based WBM is a key catalyst of wellbore instability in northern Oman.

Maximum MSE values in Well 10 were reported across UeR, but the two critical intervals are diverse: (a) the presence of hard stringers is evident from 160 to 190 m, and (b) the prehydrated bentonite WBM was replaced by polymer-based WBM at 300 m and per-plan mud properties were not achieved until the bit reached a depth of 550 m. It is also evident that the best drilling performance across Fiqa is possible with CwD, along with suitable WBM for annulus-cleaning purposes.

At a depth of 550 m, the CwD team decided to optimize the drilling performance by setting a uniform, steady, instantaneous

TABLE 6—CHARACTERISTICS OF SURFACE SECTION (AND TOP INTERVAL OF SUBSEQUENT SECTION) AND DRILLING PROBLEMS ACROSS FIQA IN OFFSET CONVENTIONALLY DRILLED WELLS 6 AND 9; SURFACE SECTION OF WELL 10 WAS DRILLED WITH 18⅝-IN. CASING STRING

CwD Well 10	Well 6, Highest Drilling Efficiency in the Field (Conventional-Drilling)	Well 9, Latest Conventionally-Drilled Well and Lowest Drilling Efficiency in the Field
22-in. Surface Hole	23-in. Surface Hole	23-in. Surface Hole
Drilled with 18⅝-in. csg from 40 to 894 m.	Highest ROP reported historically in top sections in the field.	Highest non-productive time historically reported.
Because casing damage was caused by hand slips, only 82% of Fiqa Shargi was drilled.	Deepest surface hole in the field.	Drilled only 11% of Fiqa Shargi formation, leaving the rest for next wellbore section.
	Surface hole covered 95% of Fiqa Shargi.	
17½-in. Intermediate Hole		16-in. Intermediate Hole to drill 89% Fiqa Shargi formation along with planned intermediate formations. Tricone bit.
Partially drilled with conventional drill string to 1060 m across 88 m of Shargi and 78 m into Natih formation before running logging tools.		

rate-of-penetration window from 13 to 17 m/h. Consequently, from 550 m to STD, MSE was steady and lower than in benchmark wells in the same formation. This suggests that Fiqa needs to be drilled with casing to ensure high drill/case efficiency and the low consumption of mechanical energy by eliminating unnecessary drilling practices, such as reaming and circulation, and by setting the casing string quickly.

The CwD team monitored the real-time data of mud properties and flow rate to ensure optimum annulus-cleaning efficiency and drilling performance, as well as to mitigate the risk of losses

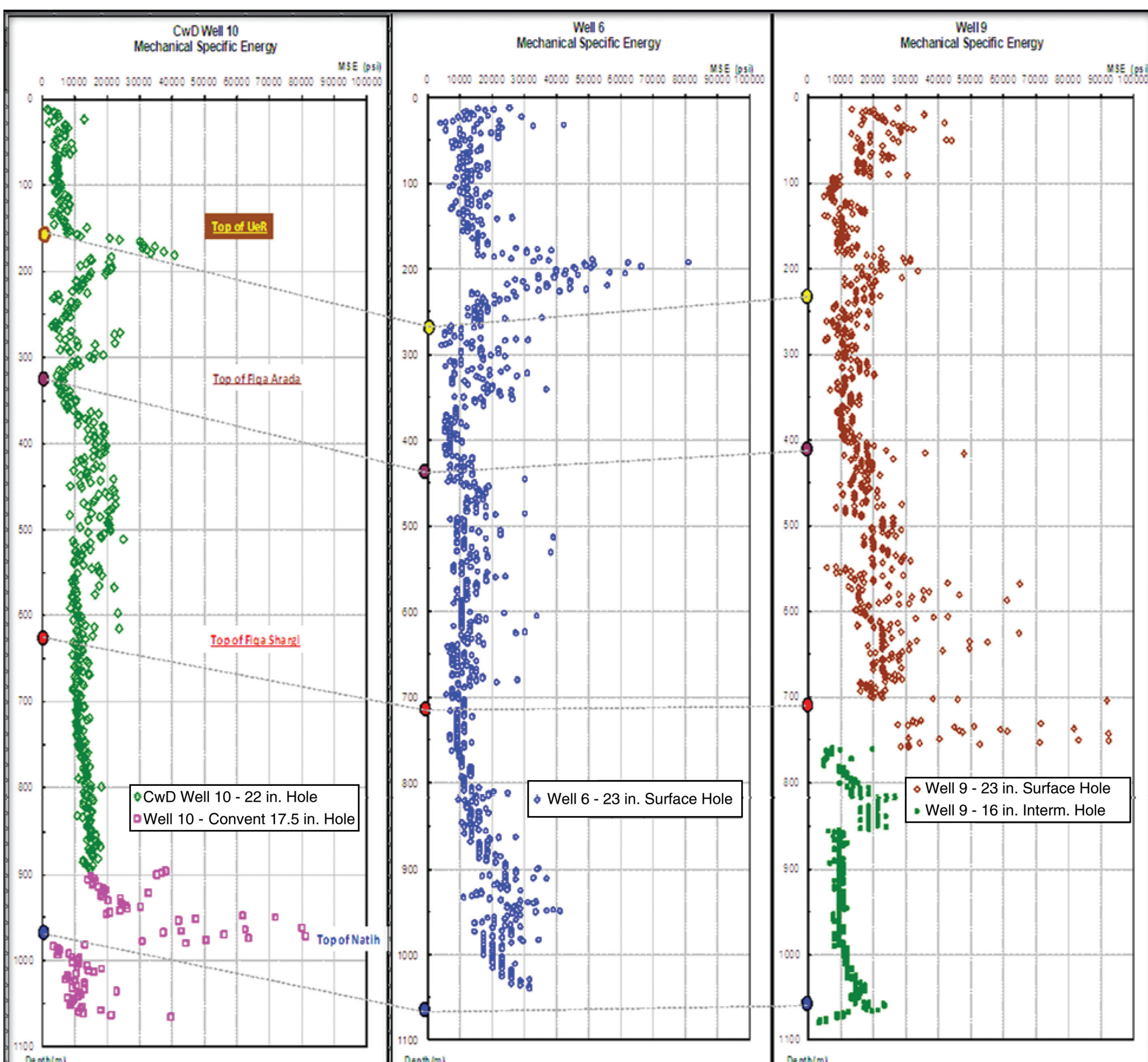


Fig. 7—MSE benchmarking in Field B. Surface sections of Wells 6 and 9 were dilled with conventional drillstem and Well 10 was drilled with casing.

across most top formations. A comprehensive analysis of the effect of mud properties on CwD performance is outside the scope of this document; however, the authors accept as fact that the success of CwD implementation in northern Oman respond not only on the mechanical drilling parameters, but also to the polymer-based drilling-fluid properties and the hydraulic power achieved at the bit and along the casing/hole annulus (Sánchez et al. 2011).

Conclusions

- Fiqa-related drilling problems in northern Oman can be overcome with the introduction of CwD technology. Both pilot trials in Fields A and B proved CwD as the most effective solution against wellbore instability in all areas where the Fiqa formation is present.
- Appropriate engineering planning, correct selection of CwD components and personnel, and implementation/monitoring of real-time DEO tools led PDO to consider CwD as the innovative concept to optimize not only the overall drilling performance, but also the long-term oil/gas drilling campaign in terms of standard well types and fit-for-propose drilling-rig fleet.
- The objectives of the project to reduce (a) overall drill/case time and cost, (b) wellbore-instability-related NPT, (c) total required mechanical energy, and (d) the negative effect of tubular handling on HSE statistics when drilling across the Fiqa formation were achieved successfully by implementing state-of-the-art drilling-optimization tools and exemplary engineering and leadership skills.

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