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Eliminating Non-Productive Time Associated with Drilling Trouble Zones

Patrick York, Weatherford Int'l., David Pritchard, Successful Energy Practices, Int'l., James K. Dodson and Ted Dodson, James Dodson Company, and Steven Rosenberg, Deepak Gala, and Budi Utama, Weatherford Int'l.

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Abstract

Cost overruns can easily manifest during well construction due to unexpected issues including lost returns, differential sticking, and narrow pore pressure/fracture gradients. To better plan for potential overruns, operators sometimes earmark 10 to 25% of the Authorization for Expenditures (AFE) to cover the unexpected, which can significantly impact drilling budgets. Technical and operational risks versus the potential return on investment (ROI) are critical factors in determining whether a project proceeds.

Too often the best drilling practices used to address trouble zones are limited to a few conventional methods with a narrow range of effectiveness. Also, a lack of rock mechanics knowledge can prevent the most efficient solution being applied.

Some operators are implementing planning programs that assess and integrate the latest processes and technologies to address drilling risks up-front. Cutting-edge technologies such as managed pressure drilling methods, drilling with casing / drilling with liners, and solid expandable casing have been highly effective. Implementing proactive evaluation processes and applying the latest tools and techniques can efficiently address operational risks and trouble zones to ultimately reduce NPT and associated costs.

Employing common practices and technologies that are typically ineffective and that drive up NPT cost should be considered unacceptable. Common sense well construction evaluation processes used in conjunction with validated conventional and new technologies have proven their worth by reducing expenditures and risks, preventing the loss of wells, and increasing the operator's ROI.

This paper will review real drilling challenges that have been encountered and the common practices that were employed to address these drilling hazards. This paper will compare and contrast how these same circumstances have and can be addressed much more efficiently with engineering evaluation processes that help determine the best drilling tool and/or technique to mitigate risks and reduce NPT.

Introduction

Wells containing trouble zones come in all forms, shapes, and complexity. Trouble zones lurk in all drilling environments from deepwater wells that require ten casing strings to reach TD to inland wells that only require four casing strings but whose economics limit spending CAPEX and OPEX money to obtain the objectives. Successfully quelling drilling challenges requires combining unique technologies with good practices "honed" through familiarity with the local drilling environment.

Successful construction of wells containing potential or encountered trouble zones depends on accurate analysis of all available well data to deliver the well and its objectives. Often data and learnings from previous well construction attempts within a project are ignored. The next well design is left unchanged and the well is drilled with the same mindset that was used on a previous failed attempt, expecting different results. Although this approach may seem illogical it has too often been the norm in many offshore environments as proven by the amount of money spent combating known and expected drilling trouble zones.

Maintaining the drilling status quo boils down to habit, an unwillingness to try varied design philosophies or drilling practices, or the reluctance to implement new or under-utilized technologies. With the state of technology, the tired cliché of "that's the way it has always been done" no longer passes as a plausible excuse. In an up market, maintaining ten to 20 percent contingency fund within a well's AFE has been rationalized as a "standard" well construction practice. However, a leaner economic market calls for a ten to 20 percent improvement in drilling efficiencies to prevent many good prospects

from being delayed, canceled, or labeled as “undrillable”. To compete in tight economic times, solid risk assessment is best practiced with an open-minded drilling philosophy inclusive of evolving technologies capable of mitigating difficult drilling conditions, improving wells economics, and rescuing shelved or canceled wells.

When drilling trouble zones, the drilling hazards must first be clearly understood (Drilling Hazard Understanding), which is accomplished through analysis of the well data. Next, the drilling hazard must be managed (Drilling Hazard Management). This entails creating a plan as to what are the best drilling practice and/or technology that should be applied to either avoid or deal with the drilling hazard. Finally, if the drilling hazard can't be avoided completely, then the drilling hazard needs be successfully dealt with (Drilling Hazard Mitigation). The following sections discuss this process, elaborate on various drilling best practices, and review several applications of effective well construction technologies to mitigate drilling hazards.

Drilling Hazards and Non Productive Time Analysis

The following section discusses non productive time (NPT) in Gulf of Mexico deepwater operations, exclusive of weather, with data supplied by James K. Dodson Company.

The analysis focuses on the total NPT of key drilling hazards created by wellbore instability—stuck pipe, well control and fluid loss; all exacerbated by ballooning. **Table 1** summarizes Dodson Mechanical Risk Index™ drilling complexity levels:

Key Well Factors - Median				
Complexity Level	WD – ft ss	Well Depth – ft KB	No. of Casing Strings	Percent of Salt Penetration
1	3,200	19,000	5	78
2	4,300	23,000	5	72
3	4,400	28,000	5.5	81
4	6,000	29,500	6	85
5	6,700	30,000	7.5	100

Table 1 – Well Complexity Level

Figs. 1 through 6 indicate that sustained learning decreases with increasing complexity levels of the well (Kotow and Pritchard 2009).

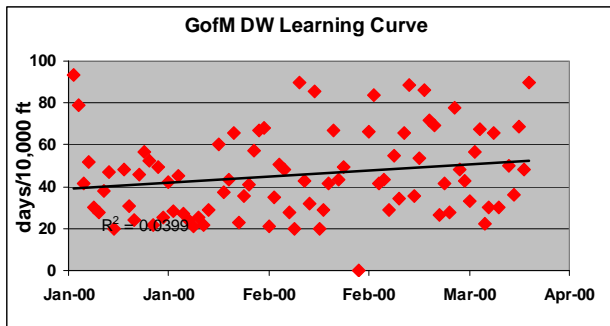


Fig: 1

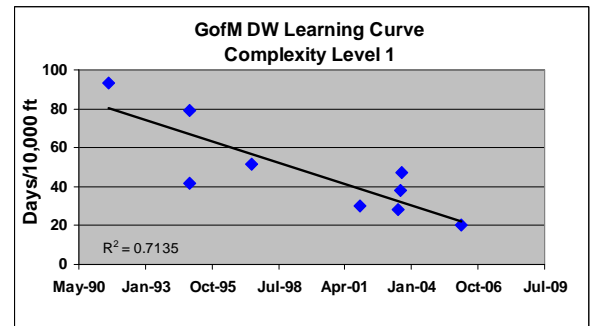


Fig: 2

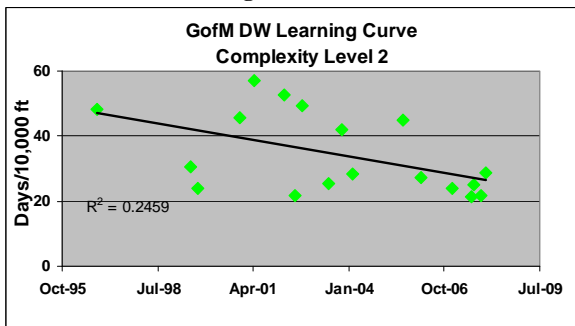


Fig. 3

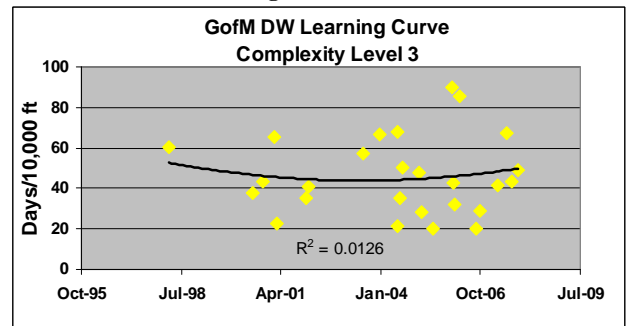


Fig. 4

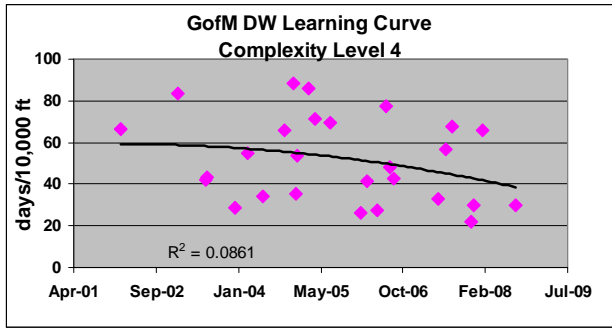


Fig. 5

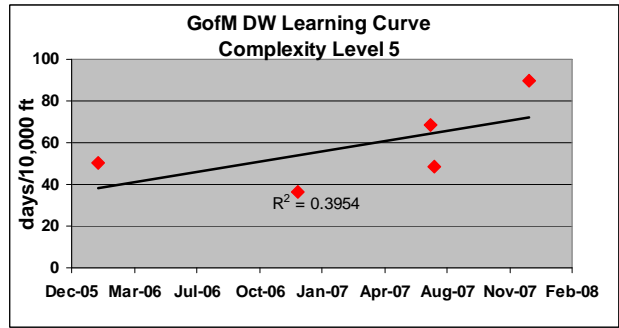
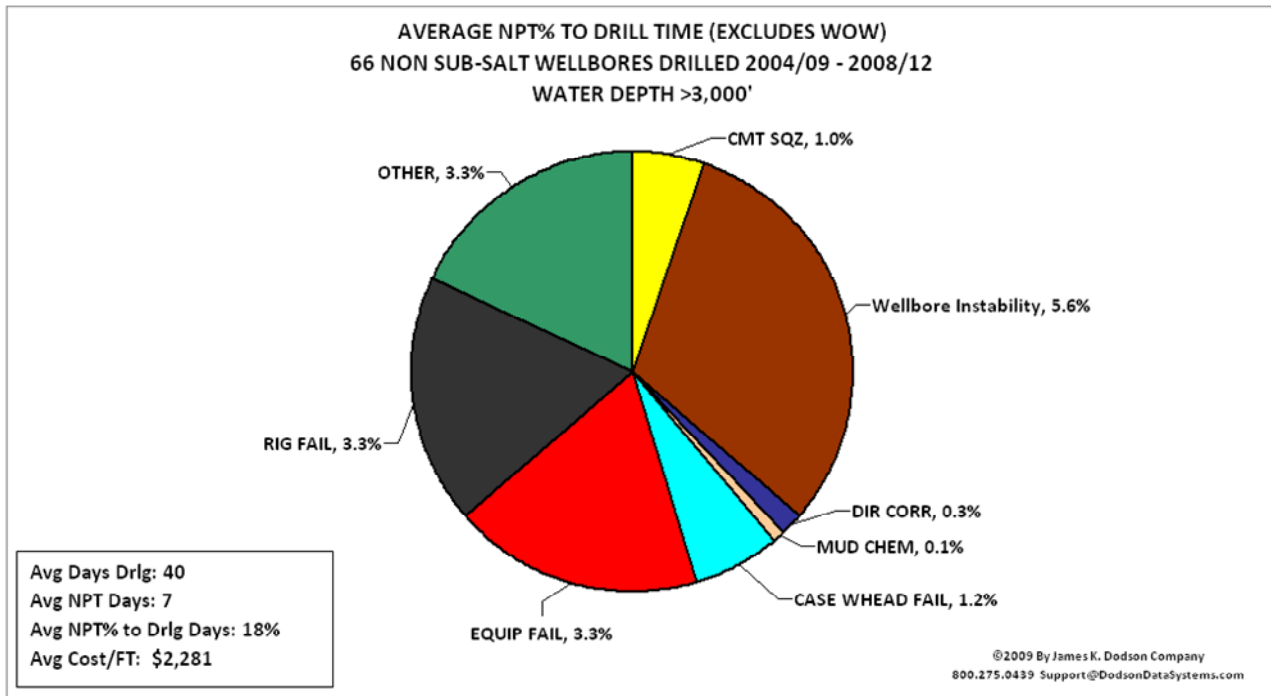


Fig. 6

Figs. 7 through 10 represent the metrics for non-weather related NPT. Wellbore instability issues in non-subsalt wells accounted for 5.6% of total well time (**Fig. 7**). This same metric doubles to 12.6% of total well time for subsalt wells (**Fig. 9**). Wellbore instability events account for over 31% of total NPT for non-subsalt wells, increasing to 41% for the same metrics for subsalt wells. In a well with a 20,000 ft MD, extrapolated losses equate to \$2,500,000US and approximately \$7,660,000US, respectfully. These metrics do not include wells that fail to meet multidisciplinary objectives or total well failures.



**Based on the above cost/ft, this relates to \$ 128/ft for Wellbore Instability.
 Based on a hypothetical 20,000' MD well: \$ 2,500,000/Well**

Fig. 7: Non-weather NPT% for non-subsalt wells, water depth >3,000 ft.

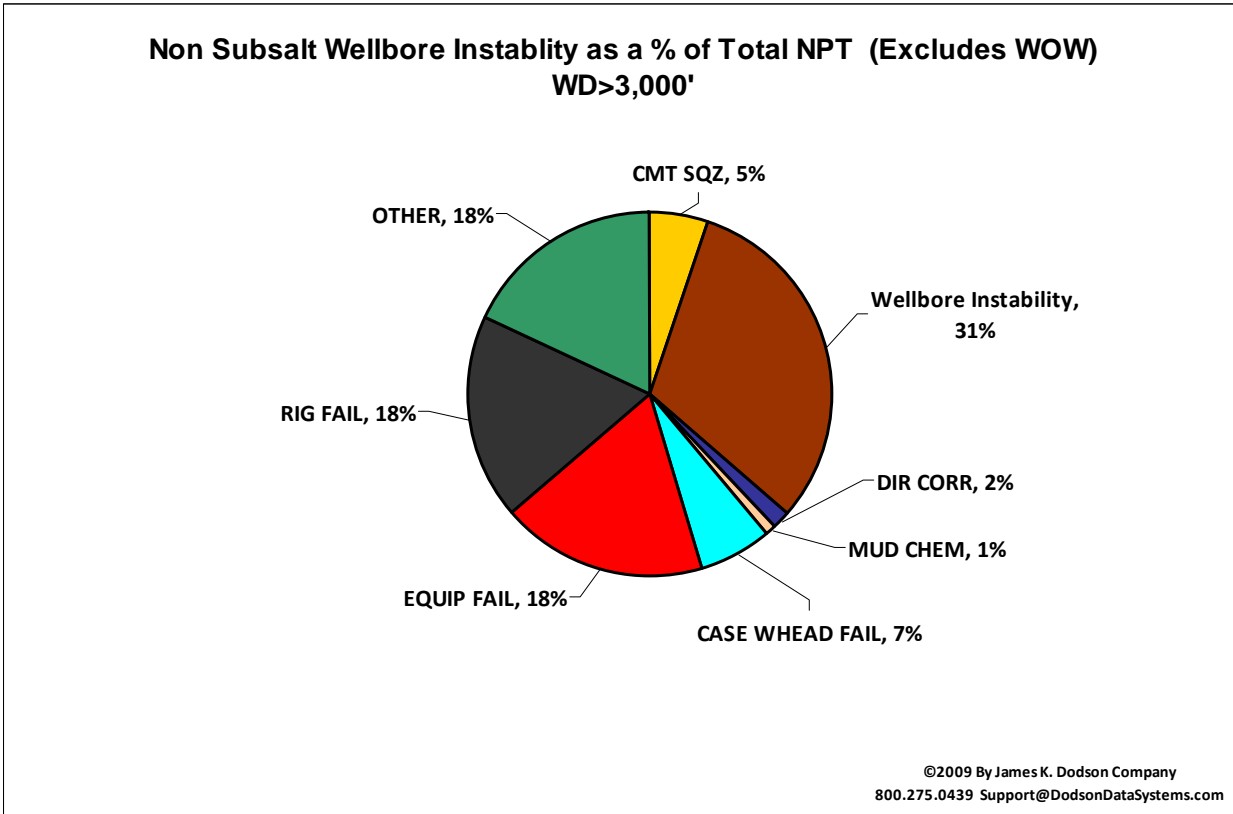
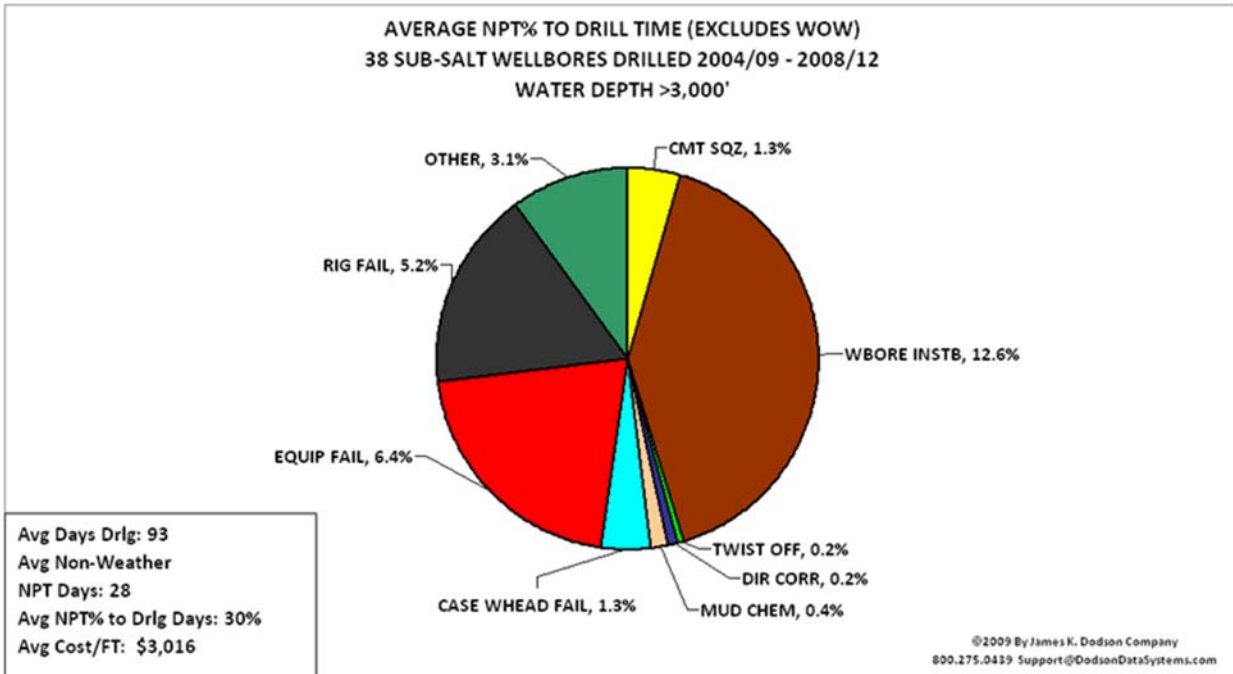


Fig. 8: Wellbore instability as a % of NPT for non-subsalt wells.



**Based on the above cost/ft, this relates to \$ 580/ft for Wellbore Instability.
 Based on a hypothetical 20,000' MD well: \$ 7,600,000,000/Well**

Fig. 9: Wellbore instability as a % of NPT for subsalt wells.

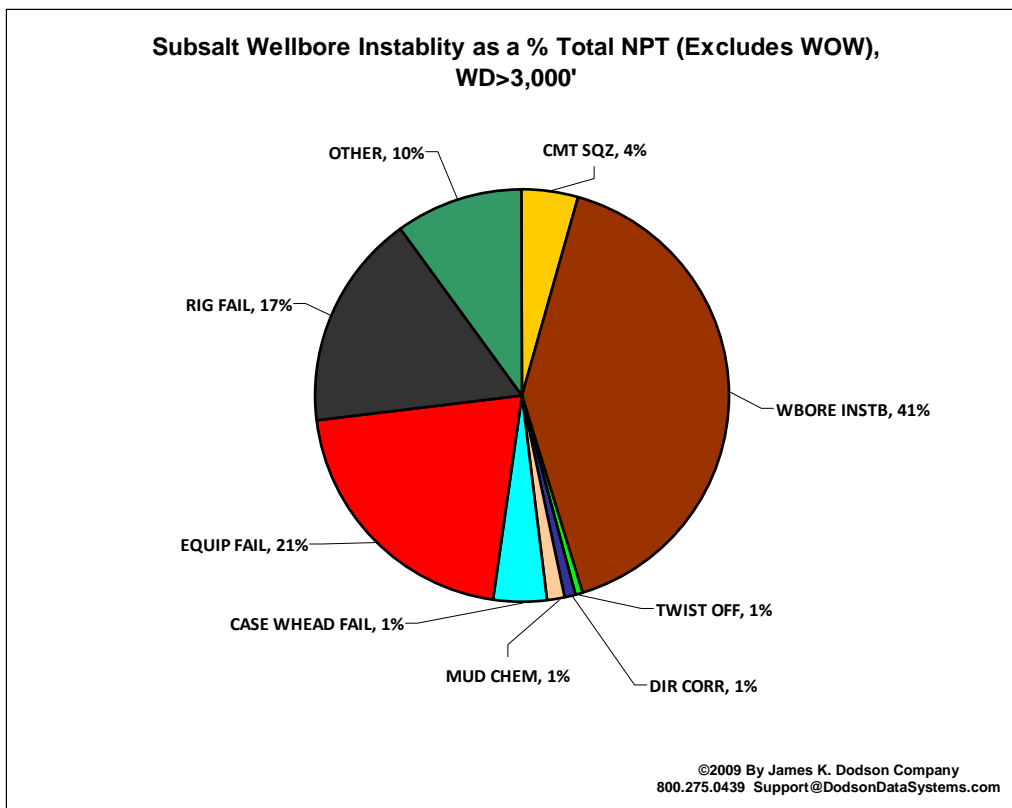


Fig. 10: Subsalt Wellbore Instability as a % of total non-weather NPT with Water Depth > 3,000ft.

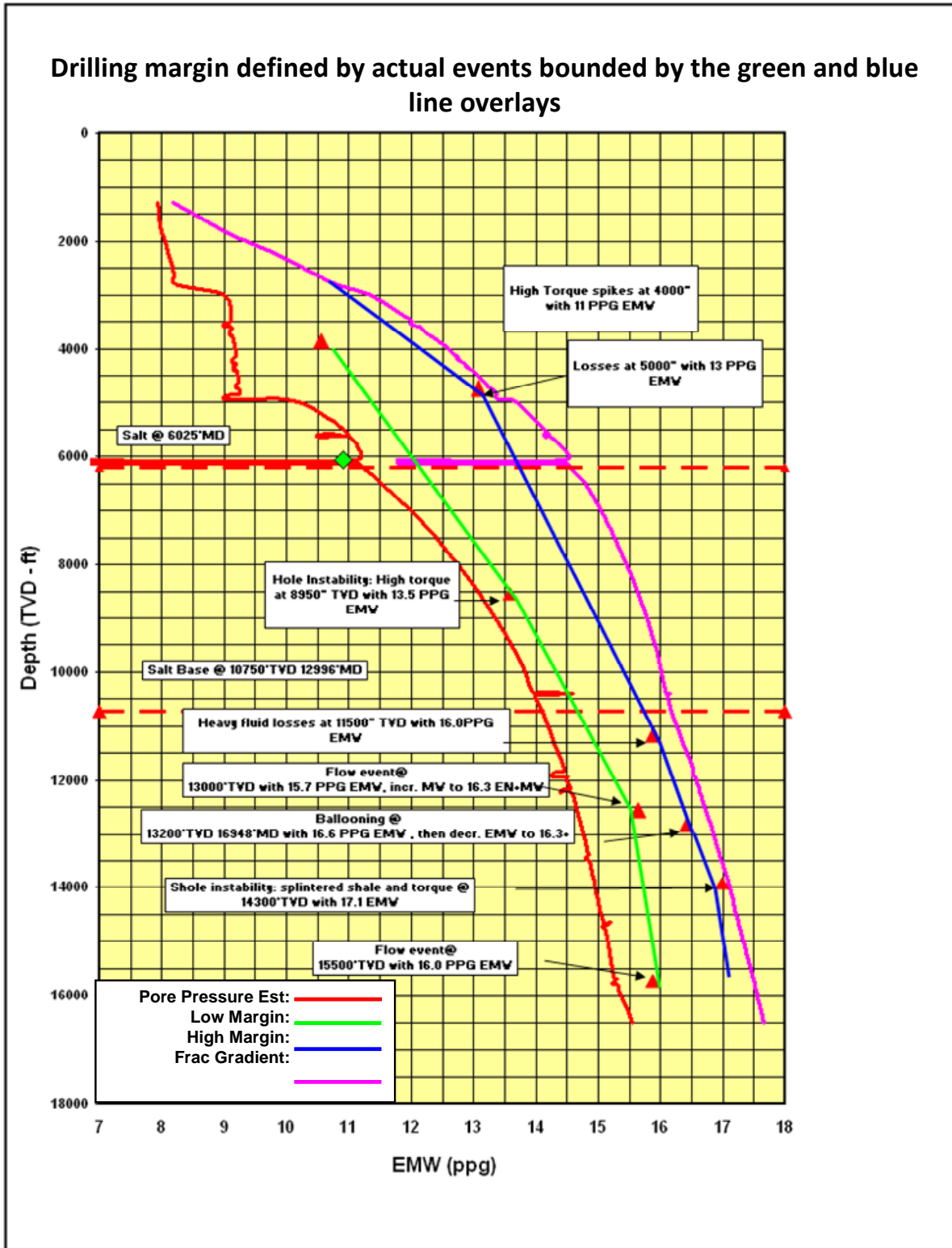


Fig. 11: Typical deepwater narrow margin PP/FG curve: margins defined by instability events.

Addressing best practices related to drilling hazards is crucial. Design issues and considerations should include enabling technologies such as DwC, CPD and SES with sustained learning a primary goal (Kotow and Pritchard 2009).

“Deep-shelf wellbores drilled deeper than 20,000 ft are a challenge that requires innovation, invention, and the will to use new deep-well technologies. Under conventional drilling practices, an ultra-deep well may require a 42-in. conductor at the mud line. The casing strings would telescope down in stages to a small diameter casing at the objective below 20,000 ft. This well design is a very expensive proposition in steel and drilling time. Newer technologies and approaches, such as expandable tubing and expendable monobore wells, exist to minimize this expense. Many technologies presented at recent

meetings show that cost-affordable deep drilling can be done. To overcome the cost and risk of deep-shelf drilling, operators must coalesce with the service industry as partners to push for cost-affordable deep-shelf drilling and completion technologies in a collaborative R&D effort” (Schmidt et al. 2004).

The price volatility of the industry demands that designs improve and that hazards are minimized for these very expensive wells. The industry must not be guilty of repeating the same process and hoping for a different result.

Drilling Hazards Management and Conventional Best Practices

Although not an exhaustive list of drilling hazards, the following discussion does represent a major portion of NPT in drilling operations and the root cause of the consequential compromise of multidisciplinary well objectives (Kotow and Pritchard 2009).

Best practices used while drilling is a fundamental principle of Drilling Hazards Management. Some drilling hazards can be induced by failure to recognize or misinterpreting the dynamics of the drilling margin. This margin represents the boundary between the lowest equivalent circulating density (ECD) necessary to ensure safe operations and wellbore integrity, and the highest ECD tolerable to avoid fluid losses or fracturing below the shoe of the prior casing string. The narrower the drilling margin, the more difficult it is to execute safe and efficient drilling operations. Narrow drilling margin operations are not limited to any particular environment. The band width can be influenced by stress in HPHT operations (Pritchard 2003), as a result of deepwater dynamics due to lack of sediment compaction, or even depletion in mature fields. The practices to execute and manage the hazards are virtually the same regardless of environment (Fig. 11).

In addition to some of the mitigating or enabling technologies that enhance best practices, the industry has other tools to help manage hazards, one of which is what can be referred to as “listening to the well” (Weatherford 2008). Listening to the well is simply recognizing, integrating, and correctly interpreting all drilling dynamics, WOB, RPM, ECD, and shale shaker cuttings, to assist in making the correct decision while executing drilling operations. The advent of real-time technologies facilitates the ability to make the correct decision and apply best practices to any operation (Drilling Hazard Management – WFT 2008). Table 2 depicts a summary of ECD applications and interpretations.

Indicators for Mud Weight (ECD) Too Low
Unexpected high ROP
Torque/Drag Increase
Cavings – Particularly "concave" or “splintered”
Flow rate increase
Shut in drilling pipe pressure + – Well control
Drilling Break gas failing to "fallout" after circulating
BHA drift (principles stress vectors)
Hole fill-up (sloughing or collapsing hole)
Indicators for Mud Weight (ECD) Too High
Unexpected low ROP.
High Bit Wear.
"Over wet" shales, lessen chemical inhibitive effectiveness and increases shale stress due to fluid penetration.
Creates unnecessary fluid losses, differential sticking, and risk of fracturing softer formations.
Increase opportunities for "Ballooning," possibly creating unsafe drilling conditions.
Other Hazard Indicators
“D”exponents: Changing drillability trends (analogue of mud weight, ROP, and WOB)
Pinched bits, elliptical hole (principle stress vectors)
Fluffy, wetted shales (Chemical instability)

Table 2: Results of ECD applications and practices.

Potential Hazards

Misinterpreting any of the previous dynamics can result in simple fluid losses to catastrophic failure. Singular interpretation of conditions from any of these dynamics can be counter productive to maintaining a safe and stable wellbore and result in actually inducing hazards.

Ballooning

“Ballooning” is a phenomenon and consequence associated with high ECD. Resultant flowback can often be confused with influx due to a pore pressure greater than mud balance. This interpretation is often further complicated by gas entrained in shale, common especially in mottled shale, with the operator “weighting up” to counter the shale gas, again, further complicating ballooning. Arbitrarily increasing mud weight in the presence of shale gas alone can result in fracturing the formation below or at the shoe. The consequence can be catastrophic (Swanson 1997).

Failure to recognize ballooning versus well control is a common mistake made in drilling operations. It is one of the leading causes of unnecessarily expending casing strings in narrow margin drilling operations.

Table 3 represents an actual example where high ECD resulted in ballooning and raising the mud weight resulted in fracturing the formation. The higher ECD further exacerbated correct wellbore instability conditions by increasing the cyclic bleed offs. Ultimately, the mud weight was increased to where fracturing occurred and massive and unsafe losses were sustained before regaining control of the well. The misinterpretation of ballooning required setting a liner before it’s time.

Condition	Actions/Conclusion
Prior Casing Depth: 3,465m.	The casing was set with 1.7 SG mud weight. Mud weight was arbitrarily increased in the shoe track to 1.9 SG before drilling ahead. ECD Management became difficult with frequent events of ballooning. Conducted frequent flow checks, no flow. All other drilling dynamics were normal: no torque, drag, with normal cuttings
Background gas increasing in shale.	Several incidents of weighting up occurred without conducting any flow checks. Gas alone is not a reason to increase mud weight. Since shale does not have transmissibility but does have porosity, entrained gas is common and cannot be “weighted-out”, especially in highly mottled shale. Entrained gas always arrives with the cuttings, no matter the mud weight.
Continued drilling in shale from 4055-4268m, with increasing background gas.	Circulate and condition with no fill. Closed BOP, no flow, no pressure, and control circulated through the choke. No torque spikes, no drag, no fill with normal cuttings. Increased mud weight to 2.0 SG while on choke.
Shut in drill pipe pressure, 340 psi, bled back with no further flow or pressure.	Closed BOP with 340 PSI. Opened. The well briefly had slight initial flow and then shut in with no pressure. Pened and was stable with no flow. Shut-in pressure was taken and not measurable. Circulate and condition and increase mud weight to 2.3 SG. Further increased mud weight to 2.45 SG with immediate and massive fluid losses. Ballooning induced fracturing after increasing the mud weight. Three days of circulating and conditioning back to 2.1 SG was necessary to stabilize the well.
Severe losses as a result of inordinate and arbitrarily high mud weight.	A decision to run liner once stable. The pore pressure/frac gradient curves were normal. Other than background and connection gas, which bled off, there was no reason to increase the mud weight initially (even at the shoe track). Conclusion: Managing ECD and recognizing ballooning as a consequence of high ECD could have resulted in drilling this section deeper, needlessly requiring a liner before planned. Ballooning and then fracturing the well created an unsafe condition with massive fluid losses. This condition could have resulted in well-bore collapse, or worse, a shallower formation influx from an underbalanced formation.

Table 3: Actual historical analysis (Pritchard 2003).

When ballooning is recognized, care must be taken to avoid unnecessarily weighting up. Bleeding back trapped pressure as a result of ballooning is critical.

Best Practice:

The best practice revolves around "well listening" and integrating all drilling dynamic factors to make the correct hazard management and avoidance decisions. Interpreting ballooning is crucial to narrow margin drilling operations and ensuring safe an efficient drilling operations.

Stuck Pipe

Stuck pipe is a drilling hazard that can be associated with ballooning and fluid losses. Generally, stuck pipe is avoidable if drilling margins are honored, with the exception of causes as follows:

Primary Causes:

- Differential sticking - most common
- Key seating and hole geometry
- Pack-off / bridging
- Reactive formations (swelling shale)

Secondary Causes:

- Coal sections
- Tar
- Undergauged hole and pseudo stresses.
- Permeable sections, high fluid loss
- Cuttings buildup
- Salt creep
- Collapsed casing
- Junk
- Green cement

Recognition and avoidance of stuck pipe requires some of the same “well listening’ techniques:

- Geometry or volume of shaker cuttings, trends in mud properties, or drilling parameters
- Out-of-balance mud weight or high ECD
- Hole caving
- Splintered cuttings
- Concave-shaped cuttings
- Sloughing shale, chemical shale wetting, and instability
- Tectonic or pseudo-induced stresses

Best Practice

The best practices to avoid stuck pipe are much the same as ballooning and fluids loss—recognizing the conditions within the drilling margins and events and reacting correctly (e.g. drilling hazard understanding). In addition, other factors such as BHA and drillstring configuration and the inhibitive characteristics of the formations being drilled should be considered.

The previously discussed drilling hazards are not meant to comprise an exhaustive list, however, through good drilling practices such as outlined, these hazards can be recognized, understood, managed, and either avoided or mitigated effectively.

Technology Applications to Mitigate Drilling Hazards

As previously stated, if the drilling hazard can’t be avoided completely, it needs to be successfully dealt with (Drilling Hazard Mitigation). The following sections of the paper discuss this process, elaborating on several applications of effective well construction technologies that can be utilized to mitigate various drilling hazards.

Maintaining ECD – A Managed Pressure Drilling Case Study

Managed Pressure Drilling (MPD) provides a method of determining and maintaining the ECD within prescribed limits imposed by the difference between the drilled formation’s pore pressure and the fracture pressure of the section being drilled. Most MPD techniques typically employ a rotating control device (RCD), which provides a seal between the drillstring and the annulus during the drilling process, providing for a closed pressurized fluid circulating system (**Fig.13**). The equivalent mud weight (EMW) at any time is thus the sum of the mud hydrostatic, the annular friction pressure drop, and the surface application of back pressure by way of a MPD choke on the return line. In this way with the use of pressure while drilling (PWD) techniques, the ECD can be accurately monitored for more precise control.

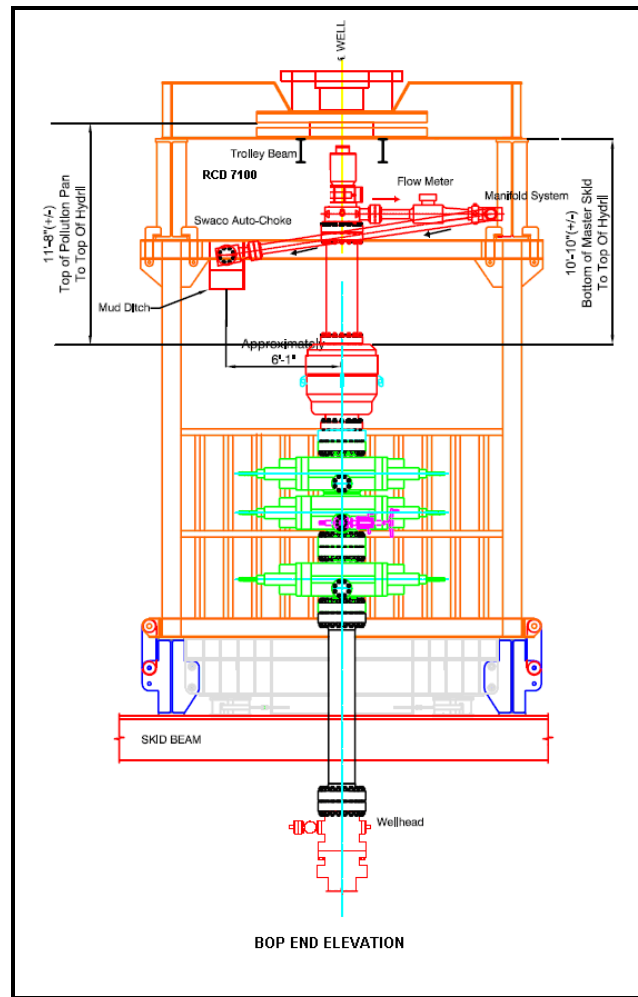


Fig. 13: RCD used to maintain ECDs.

The first ever application of MPD in the Gulf of Mexico occurred in 940 ft of water some 105 miles south of Galveston, Texas.

The platform was set in 1981 and 25 development wells were drilled from it. Subsequently in 2004, three wells were planned, one new well and two re-entry and sidetrack operations (Greve 2005). The earlier drilling and development program experienced several drilling hazards that needed to be address while planning this new campaign:

- Wellbore ballooning and lost circulation problems
- Recurring stuck pipe due to borehole collapse
- Sparse logging data due to the hole condition problems with frequent bridging occurring
- Hole cleaning due to gumbo shale being encountered frequently
- Difficult directional control that required frequent BHA changes
- Logistical and deck space problems because of the remote nature and size of the platform posed

Managing these drilling hazards successfully required taking into account the following aspects of the planned program:

- The mud weight window between pore pressure and lost circulation was extremely narrow – “continental slope in relatively deep water”.
- Losses and wellbore collapse were experienced in a similar three-well program on the nearby platform in 2003 and the mud weight window on this platform was expected to be less.
- With conventional drilling practices, the required static mud weight relative to pore pressure would result in lost circulation as soon as the pumps were turned on to circulating rate.
- A pre-drill wellbore instability study considered the high probability of borehole collapse due to its observance in previous drilling records.
- The slim hole geometry of the re-entry sidetracks and the use of environmentally friendly synthetic mud would lead to calculation of high ECD.
- The availability of PWD/LWD would provide confirmation of the required ECD control to be achieved.

After careful consideration of all these drilling hazards, MPD was decided as the method best suited to manage them. The MPD layout is shown in **Fig. 14**.

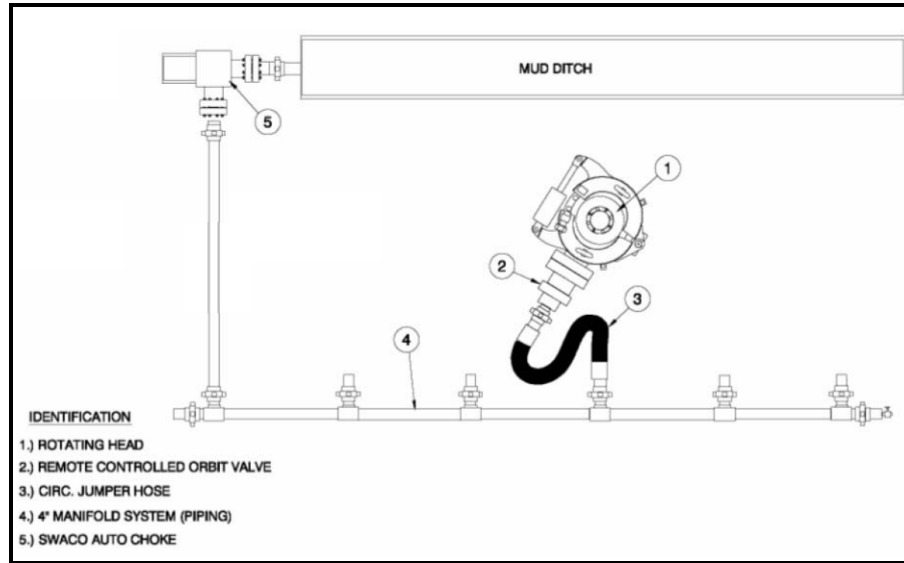


Fig. 14: MPD layout (Flowmeter not shown in schematic).

Successful implementation of MPD practices on the three-well program resulted in the following observations:

- MPD worked well without compromising the overall drilling rates
- Future application of the technique would be accurately budgeted.
- The maximum ECD managed throughout the campaign was 2.25ppg in one of the re-entry wells.
- Tripping in wells with large ECDs can easily induce wellbore instability and requires accurate modeling of tripping swab pressures to provide realistic limits on tripping speed.
- Select a mud weight so that ECD is inside the pore pressure to fracture gradient window. Accurate prediction of ECD is important.
- No HSSE incidents occurred in the three-well program.
- Control of the pumps and choke was manual throughout; automated control would be an improvement.

This initial use of MPD technology in a known environment proved to be very successful. The lessons learned provided a path to refining the method and enhancing its effectiveness in drilling hazard management (Greve 2005).

Addressing Wellbore Instability and Lost Circulation, in Fractured Formations – A Drilling-with-Liner (DwL) Case Study

The Banuwati field offshore South East Sumatra, Indonesia presented major challenges to both drilling and liner running operations because of the problematic Lower Baturaja limestone formation (**Fig. 15**). This formation is a carbonate reef structure known for severe lost circulation conditions. The well track intersected a NW-SE fault twice. This lower limestone formation overlays the productive Gita Sand. Successfully drilling and completing of wells to this pay zone require overcoming both wellbore instability and total lost circulation challenges in one hole section (Jianhua et al. 2009).

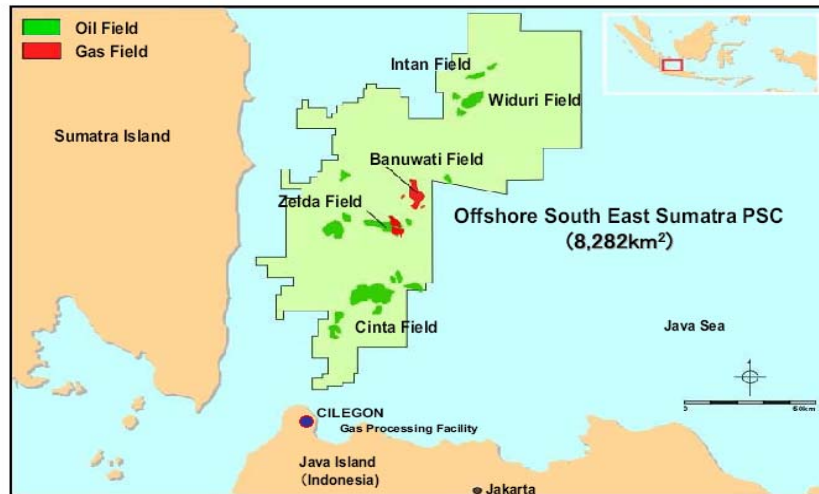


Fig. 15: Banuwati Field Map.

The operator had previously experienced severe losses with wellbore instability issues while drilling this formation which prevented setting the 7-in. drilling liner at the planned depth in well A-3. The liner had to be pulled out of the hole. This eventually led to abandoning the existing openhole section and sidetracking the well. Conventional drilling methods and attempts to deal with the hole problems resulted in extended well construction time and three sidetracking operations, incurring costly NPT. To successfully mitigate this troublesome zone, the operator decided another approach was needed and selected drilling-with-liner (DwL) technology as a solution for setting the planned 7-in. drilling liner through the loss interval.

Drilling-with-Liner technology was considered the most advantageous approach of achieving the desired result of setting the 7-in. liner at the target depth because of the following benefits:

- A history of minimizing or even eliminating lost circulation problems due in part to the existence of the “smear effect” (Fontenot et al. 2004), It is conjectured that this phenomenon is due to the proximity of the casing wall to the borehole that results in cuttings being smeared against the formation and creating an impermeable wall cake.
 - This proximity results in considerably higher annular velocities for a given circulation rate as compared to conventional drilling, leading to better hole cleaning while drilling—a necessity when drilling through unstable shale sections.
 - Minimal or no hole preparation is required as in regular drilling practices because the liner can be landed and cemented almost immediately on reaching target depth with minimal delay for circulation.
 - The rigidity of the liner being used as part of the drill string would lead to maintenance of both deviation and azimuth within the parameters of the existing 8 1/2-in. hole.

One of the most notable features of the DwL system is its compatibility with an innovative $7 \times 8 \frac{1}{2}$ -in. drillshoe—DS III. The DS III is a five-bladed PDC bit with features that allow it to be converted to a drillable casing shoe at TD to enable shoe-track drill-out with conventional drill bits—either PDC or roller cone (Fig. 16). The drillshoe performs as a PDC bit until TD is reached, at which time a ball is dropped into the liner running string and falls to the ball-funnel inside the bit, blocking the drilling nozzles from fluid flow. The casing string is then pressured up to approximately 2,000 psi, and shear pins are sheared, forcing the tool's inner piston downward. This action displaces the steel blades and PDC cutting structure into the casing-openhole annulus (Fig. 17). At the same time, cementing circulation ports are exposed. Fluid circulation is re-established through these cementing ports as the tool's inner sleeve slides down with a latching mechanism engaging at full stroke. The stroke of the tool is designed to fully displace the entire cutting structure to the annulus, which eventually is cemented in place. The center piston exposed is fully drillable with conventional roller-cone and PDC bits. A special bit or mill run is not required, thus eliminating a costly milling trip (Robinson et al. 2007).



Fig. 16: 7 × 8 1/2-in. DrillShoe III is a 5-bladed PDC bit with 13 mm cutters

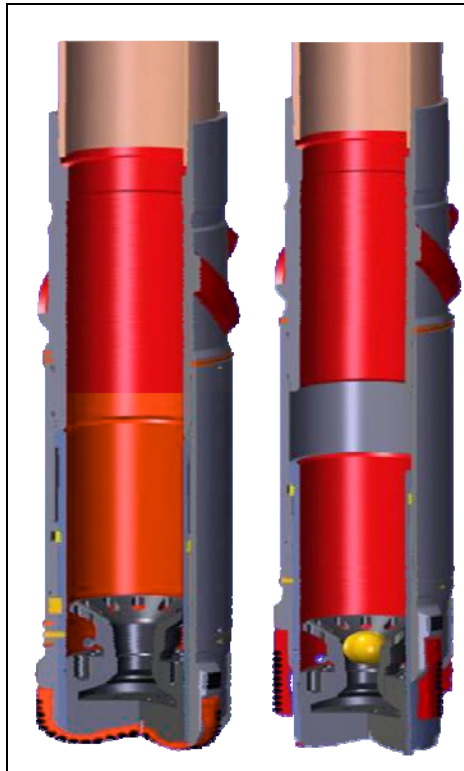


Fig. 17: DrillShoe III blade displacement process. Drill to TD (left), then drop ball (right), pressure up to shear pins, and displace blades to the annulus.

Not only was liner drilling operations successful but DwL exceeded expectations in combating the wellbore instability problems associated with lost circulation and previous drilling operations in the A-3 well. DwL provided a means of getting a liner to planned depth while mitigating the severe hole problems that conventional drilling techniques often encounter. This approach resulted in the following achievements:

- Successfully drilled an approximately 350 ft long 7-in. liner through a severe lost circulation zone enabling the liner shoe to be set at planned depth where previous conventional drilling attempts were unsuccessful.
- Despite severe fluid losses through the drillshoe, the annular fluid level could be managed by filling the annulus from surface.
- The drillshoe drill bit successfully drilled the required hole section.
- The drillshoe was successfully converted to a cementing shoe via a ball drop and pressure sequence.
- The liner was cemented in place within 5.5 hours of reaching TD with the liner hanger and packer set without incident.

- The use of the liner drilling system saved a minimum of three days of rig time compared against the AFE for conventional drilling, resulting in a savings of more than \$1 million US.
- Subsequent directional surveys indicated that the liner drilling process had enabled maintenance of inclination within 4° and azimuth to within 0.17° over the liner drilled section.
- The DS III was drilled out using the PDC bit planned for the next hole section (no dedicated mill run or special drill out bit was expected or required).

This case history illustrates the viability of use of the drilling with liner (DwL) technology to mitigating both the wellbore instability and lost circulation drilling challenges in this well and resulted in validating the following features, advantages, and benefits:

- DwL can enable setting the liner at planned depth through severe lost circulation and unstable wellbore intervals.
- The drillshoe (DS III) is a proven tool for DwL or drilling-with-casing (DwC), consistently drilling the required hole section and displacing PDC cutters to enable subsequent drillout with conventional bits.
- Liner drilling significantly reduces the fluid losses in the annulus when compared with conventional drilling, possibly due to the "smear effect" and/or the reduced annular clearance created by the liner and related liner tools.
- Liner drilling systems are proven to maintain high-angle tangential sections over hundreds of feet.

Maintaining the Basis of Design through Sub-Salt Rubble Zones – Monobore Solid Expandable System Application

Since first introduced, solid expandable liners have evolved to include a suite of expandable tools for both the open hole and cased hole that not only minimize hole reduction but eliminate it. One of the more significant advancements in expandable technology has been the monobore liner system. Monobore solid expandables installed in critical sections of wells prepare for, rather than react to, trouble zones.

A significant application consists of extending the critical 13-3/8 in./13-5/8 in. casing string with a monobore openhole liner. It has been determined that if a casing string that preserves hole size could be added below the conventional 13-3/8 in. string, many drilling challenges encountered down hole could be mitigated while maintaining optimum hole size for completion or evaluation.

One of the challenges with using large diameter solid expandable products has been the lack of external-pressure performance. Collapse is especially critical as it decreases as much as 50 percent when expanded. The most effective means of increasing the post-expanded collapse properties of cone-expanded tubulars is to increase the product's wall thickness. An 11-3/4 in. x 13-3/8 in. monobore openhole liner has been developed with a seamless casing wall almost twice as thick as any expandable currently available. This monobore liner system uses a flush-joint shoe, which has a slightly larger ID (~13.625 in.) than the 13-3/8 in. casing, and is run on the bottom of the conventional 13-3/8 in. casing string. This tieback shoe provides a receptacle for the 11-3/4 in., 71lb/ft expandable casing to be expanded into and still result in an expanded drift diameter of 12-1/4 in., the same as the previously run conventional 13-3/8 in. casing string. Once the 13-3/8 in. casing is run and the next hole section is drilled, the running sequence is similar to most conventional expandable openhole liners (**Fig. 18**).

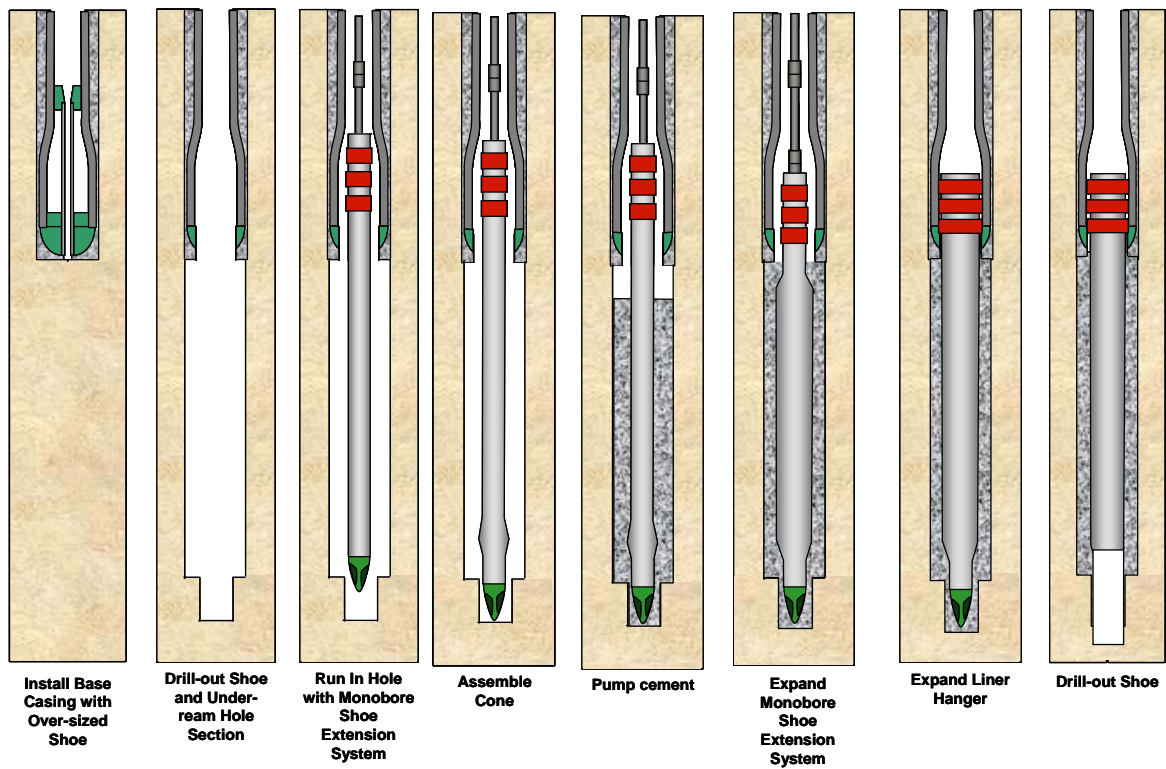


Fig. 18: Monobore installation running sequence.

Subsalt Rubble Zones in Deepwater Gulf of Mexico Wells

A GoM deepwater well where a rubble zone was encountered while drilling out of a salt formation resulted in the unexpected need to set a casing string (Cruz et al. 2007). An 11-7/8 in. high-collapse conventional liner (Fig. 19a) had to be set higher than planned to cover the ~1,000 ft rubble zone. Losing this point would require setting the 9-5/8 in. casing where the 11-7/8 in. was planned. Consequently, after encountering another trouble zone, the hole to reach TD would be 4-3/4 in. and result in the well’s potential completion size reduced by as much as 3-3/4 in. from originally planned (Fig.19b).

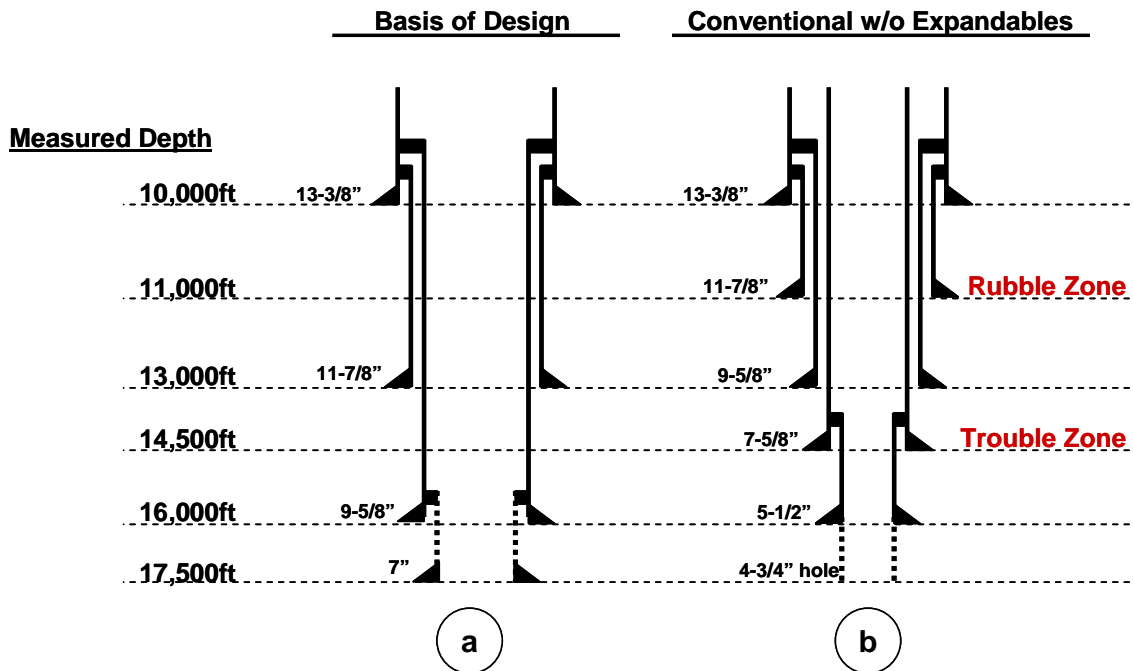


Fig. 19a: In the original casing design the 11-7/8 in. casing allowed for a 7-1/2 in. hole at TD. Fig. 19b: Potential reduction of hole at completion because of lost casing point.

To reach TD with a 7-1/2 in. hole, a 3,000 ft 9-5/8 in. x 11-3/4 in. conventional expandable liner was run below the conventional 11-7/8 in. liner. Because the expanded ID of the conventional expandable system was not large enough to accommodate running conventional 9-5/8 in. 53.5lb/ft casing and set across the subsequent hole section, a non-API 9-3/8 in. OD conventional liner was run. To get as close as possible back to the original well design, a 7-5/8 in. x 9-3/8 in. expandable liner was subsequently run that allowed a 7 in. flush joint liner to be run at TD (**Fig. 20a**). Hole size conservation (2-3/4 in.) assisted in the management of the ECD and increased the chance to properly evaluate a critical section of the well.

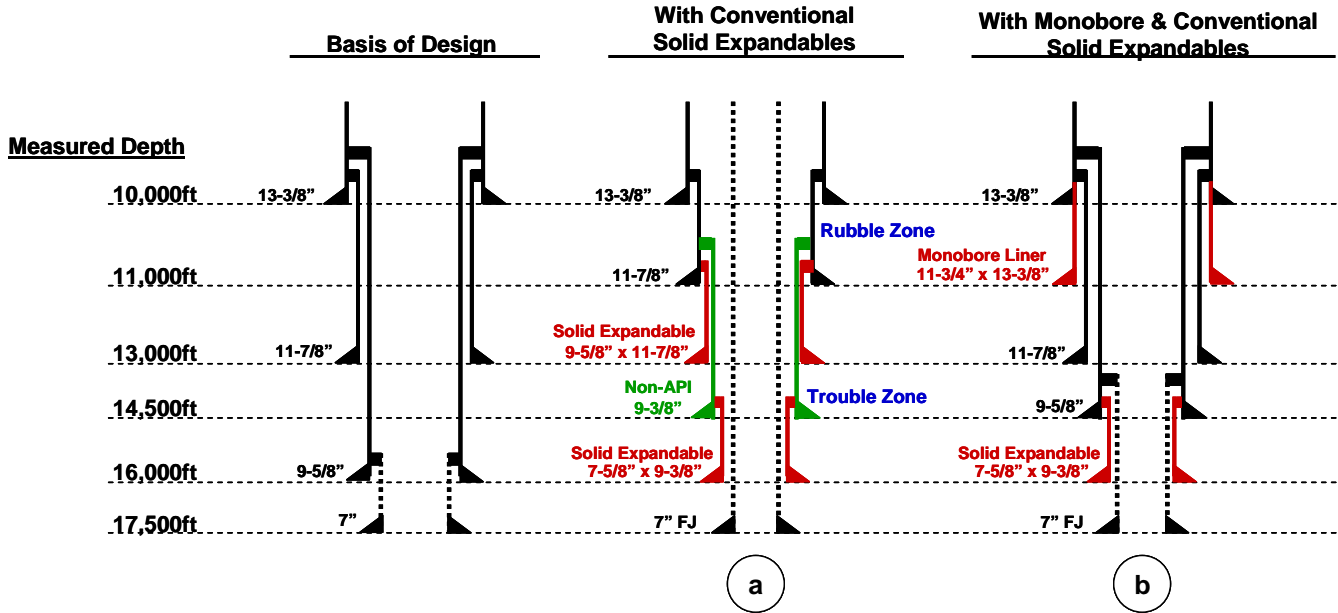


Fig. 20a: Getting back to the well design with solid expandable liner. **Fig. 20b:** Completion option using monobore openhole expandable liner.

These three liners covered the ~5,000-foot interval that had a 0.4 to 0.6 ppg pore pressure/fracture gradient window. Combining conventional solid expandable liners and non-API casing preserved ~60 percent more hole size compared to using only conventional tubulars.

Alternately, when the rubble zone was encountered under the salt, a ~1,000 ft 11-3/4 in. x 13-5/8 in. high-collapse monobore openhole expandable liner could have been run. Installation of this single monobore expandable liner has the ability to bring the well construction back to the original design and allow running the 11-7/8 in. conventional high-collapse liner at its originally planned depth. The subsequent well construction (**Fig. 20b**) could have been continued to reach the well’s TD with a 7 in. flush joint liner.

The shorter monobore expandable liner (~1,000 ft versus ~3,000 ft) doesn’t require the subsequent use of the non-conventional sized well construction equipment. Because the casing used in the 11-3/4 in. x 13-3/8 in. monobore system has a 0.582 wall, its collapse resistance is higher than conventional thin-wall solid expandable liners.

Conclusions

Drilling trouble zones has been a “way of life” for over a century as illustrated by a “drill-in and expand” concept patent issued in 1934 to mitigate sloughing formations, loss circulation challenges, etc., during well construction. Documentation describes that the learnings during the past 15 years have been inconsistent, if not minimal, to effectively address drilling through these trouble zones.

NPT associated with drilling trouble zones consumes from 10% to as much as 40% of well construction budgets if a comprehensive philosophy is not implemented when planning and drilling these wells. However, it has also been shown that these trouble zones can be effectively and efficiently drilled or even avoided if good drilling practices are considered, applied, and combined with proven drilling technologies, products, and processes.

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