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## AADE 2009NTCE-04-04: PRACTICAL ASPECTS AND VALUE OF AUTOMATED MPD IN HPHT WELLS

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### Abstract

More often than not, high pressure and high temperature reservoirs are found in geological settings that carry inherently greater risk to drilling. Uncertain pressures, complex lithology, indeterminate flow-back, and the potential for high pressure well control are just some of the risks that drilling faces on an everyday basis. Decision making processes designed to mitigate those risks can carry significant non-productive time and cost.

Emerging automated Managed Pressure Drilling services offers a solution to mitigate some of the critical risks associated with HPHT drilling and thereby reduce drilling costs. As a solution, automated MPD provides specialized technology to control drilling pressure but it also provides specialized procedures for HAZID/HAZOP contingencies, equipment integration, training, and drilling operations.

This paper will describe:

- MPD equipment and rig compatibility
- MPD training requirements
- MPD value propositions for HPHT

Case history data will be used as much as possible to illustrate those topics and as they relate to the planning for and implementation of MPD in HPHT wells.

### Introduction

There is no one set of standards accepted by the oil industry as a whole that is used to define a high pressure high temperature well.

In the UK an HPHT well is defined by the Department of Trade and Industry as one in which the undisturbed bottom hole temperature is greater than 300° F and the maximum anticipated pore pressure of any porous formation to be drilled exceeds 0.8 psi/ft.

It is different in Norway where the Norwegian Petroleum Directorate defines an HPHT well as one that has an expected shut in wellhead pressure greater than or equal to 690bar (10,000psi) and a temperature in excess of 150° C (302° F).

And, one way in which the US Minerals Management Service defines an HPHT well is as one that requires well control equipment with either a pressure rating greater than 15,000 pounds per square inch gauge (psig) or a temperature rating greater than 350° F.

No matter how it is defined, the key to a successful HPHT well begins with proper planning and well construction and a single-minded focus on assuring pressure and well control integrity.

Maintaining pressure and well integrity in an HPHT well is complicated by the fact that the operating pressure margin is typically much smaller than a conventional well and, as in many HPHT projects there is insufficient offset control. That means drilling has to be ready for the

sudden appearance of permeable sequences abnormally pressured to higher than anticipated levels in an already narrow margin.

The use of multiple prediction and detection methods can help reduce some of the uncertainty related to pressure but not to flow back which if misinterpreted in an HPHT well with a narrow margin can have severe consequences.

Flow back refers to the volume of mud that was in dynamic flow but which returns to surface tanks when the pumps are turned off. Even a slight loss when the pumps are on coupled with an equivalent volume of mud flowing back into the surface system when the pumps are turned off or slowed down can be an early sign of wellbore breathing.

Fingerprinting flow back volume before drilling out of casing and immediately after drilling through the shoe establishes a base line profile for stable flow back. Tracking and comparing subsequent flow back volume to the base line provides an important means to help identify wellbore breathing and distinguish it from an actual kick.

The principal objective of fingerprinting is to identify influx by comparing real-time data to previously recorded data. However, accurate interpretation requires constant or at the very least consistent parameters, e.g. mud properties, observation time etc.

In an HPHT well with a narrow margin and an uncertain pore pressure profile an ill timed increase in mud weight in response to an incorrect interpretation of flow back will only worsen wellbore breathing and worse still lead to a severe well control event.

In consideration of the above discussion, the benefit of using an automated MPD system is in its ability to maintain constant bottom hole pressure (BHP) through dynamic and static drilling. Constant BHP can mitigate and even eliminate the conditions that cause wellbore breathing. That does not eliminate the need for proper flow back fingerprinting. Indeed, fingerprinting provides the necessary data to monitor the effectiveness of MPD procedures.

### MPD Equipment and Rig Compatibility

The MPD data, training, and procedures presented in this paper pertain to the Dynamic Annular Pressure Control\* (DAPC\*) system. The DAPC system is an automated system designed to maintain constant BHP, provide pressure relief, and detect kicks. It has been extensively described in other published papers so only a brief description will be provided as it applies to HPHT.

There are five essential modules that comprise the DAPC system which work together in a self-regulated way to control drilling pressure without human intervention.

Those five essential modules are:

- Programmable logic control (PLC)
- Real-time hydraulics model
- Human machine interface (HMI)
- Choke manifold
- Back pressure pump

In addition, the system also includes:

- A Coriolis flow meter
- An automated pressure relief choke
- Remote operating links
- Flow piping and control valves

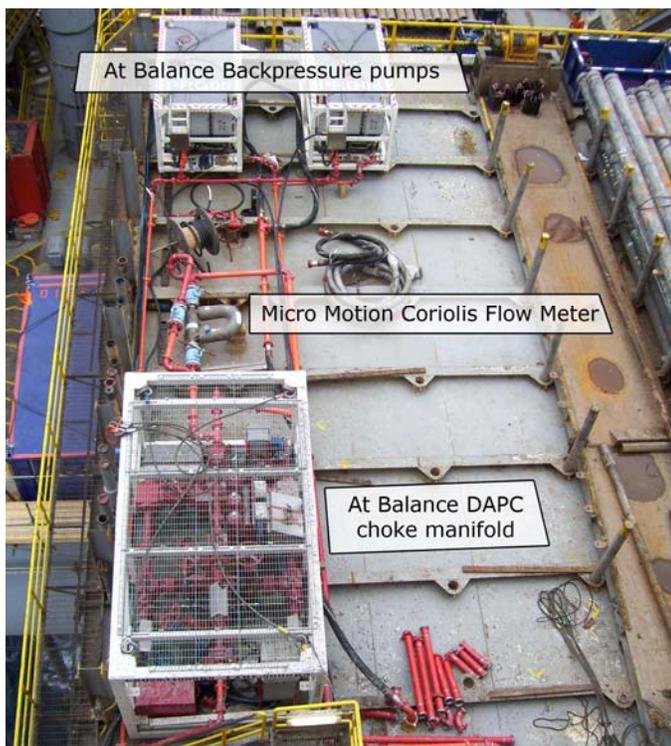


Figure 1 – photo of the DAPC system rigged up on a jack-up drilling an HPHT in the UK Central North Sea.

Figure 1 shows a photo of an offshore DAPC system rigged up on a North Sea jack-up drilling an HPHT well. This manifold contains three chokes, a PLC, and a hydraulic power unit (HPU). It is connected to the Coriolis flow meter through the low pressure discharge line. For this HPHT application two redundant back pressure pumps were installed for contingency purposes. Not shown are the hydraulics model and HMI which were installed in a safe area office elsewhere on the rig.

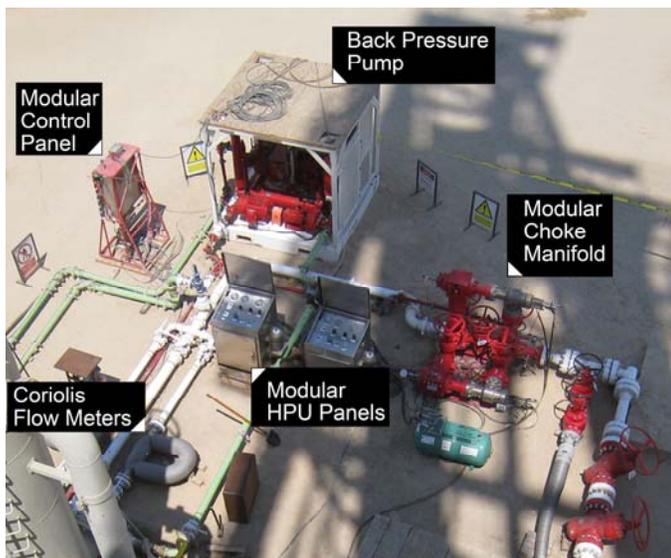


Figure 2 – photo of the modular DAPC system rigged up on a land rig in Libya drilling an HPHT well.

The DAPC system pictured in figure 2 is a modular design consisting of separate but connected manifold, HPU, and PLC components. This HPHT application called for redundant Coriolis meters and HPU panels for contingency purposes. The modular manifold contains two 2 redundant pressure balance chokes for active pressure control.

Every automated MPD project starts with a rig-site survey to identify and describe where and how the system will be installed and connected to the existing rig equipment. As the MPD supervisor surveys the rig he

makes notes of and reports the necessary rig modifications that have to be made.

Typical rig modifications might include the following mods:

- Changes to the wellhead stack to accommodate a rotating control device (RCD) below the drill floor
- Changes to the rig flow line to enable or facilitate connection to the DAPC flow in and out lines
- Changes and extensions to the MGS inlet pipe work
- Flow trough modifications to enable connection of a PRV line from the DAPC pump and choke
- Trip tank modifications to supply fluid to the DAPC back pressure pumps
- If trip tank charge pumps have to be run continuously during MPD operations additional work may be required to install a recirculation line to prevent damage to the charge pump
- An MPD installation might require existing hydraulic or manual valves to be removed depending on their function and placement in the surface circulation system

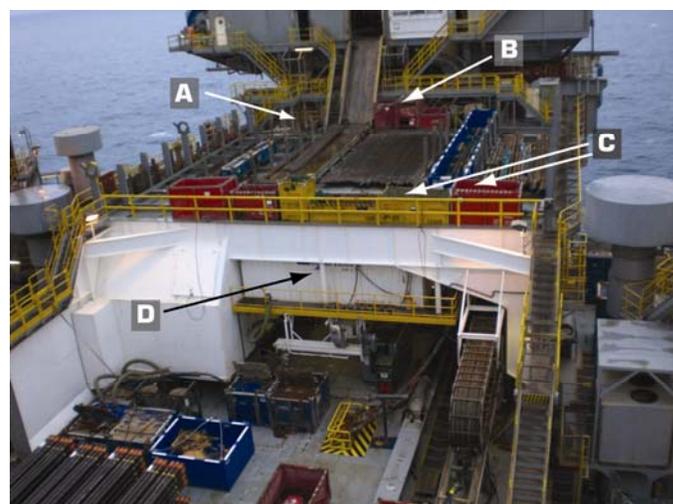


Figure 3 – photo from a typical rig-site survey indicating the preferred equipment locations each of which can require a different readiness or modification task

In figure 3 the arrow labeled as A indicates the proposed spot for the remote electrical junction box to supply power to the DAPC system; B indicates the preferred location for the DAPC choke manifold, back pressure pump and flow meter due its proximity to the to shaker box; C indicates a possible location for the spares container and control cabin if safe are room is unavailable elsewhere on the rig, D indicates the location of the mud logging unit which could possibly house the DAPC control equipment.

### MPD Training Requirements

Training procedures involve classroom workshops, hands on rig-site orientation, and simulated scenarios on the rig prior to the start of MPD operations. Those various training components are structured to reach all key drilling and rig personnel in a timely manner. Classroom sessions are held in a location convenient to the operator's facilities and scheduled around crew shift changes.

Training for MPD HPHT is normally conducted in three stages. The first stage involves a short classroom based orientation program. During orientation personnel are introduced to key MPD concepts and equipment, general applications for MPD, and system details. It also includes a general review of the contingency plans that come out of the HAZOP workshops.

The second stage involves comprehensive classroom instruction for key personnel directly involved with MPD operations on the rig or in the office. It includes instruction in operational and contingency

procedures, a review of the critical hazards and their importance to HSE, and HPHT MPD drilling and well control techniques. It is during this stage that the crew learns about the specific objectives of the well, the expected operating parameters, the reason and justification for MPD in HPHT, the nature of the narrow margin for kick tolerance, the avoidance of ballooning.

The third stage of training is performed on the rig for each crew prior to the start of MPD operations. It is the most practical hands-on session of the training program and the most important.

Stage three includes practical hands-on training on the RCD, element change out procedures, and pipe running practices through it. In stage three the driller is instructed in his MPD responsibilities and given hands-on practice in various scenarios. At the end of this training stage the crew is taken on a walk-through of the entire MPD system during with particular emphasis on installation and interconnection.

When the MPD operation is about to start, time is normally allocated during the first trip into the well to functionally test the system. That also happens to be the best time to practice contingency plan actions and give key rig personnel actual hands on practice in certain critical operational procedures.

Every project will be different and so will that the training objectives. During the planning stage the project management team from both the service and operating company work together to develop a detailed training schedule for each group involved in the MPD operation.

**Value Propositions**

Over time, and depending on the quality of the borehole seal, mud circulation can cause the BHP and formation pore pressure to converge in the volume of rock near the wellbore interface. As those pressures converge, the pore pressure near the wellbore will become higher than the static mud weight.

At the same time, cyclical fluctuations in the BHP can cause cyclical pressure charging and relaxation in both permeable and impermeable layers. The most severe fluctuations can occur with high equivalent circulating pressure (ECD) and repeated pump cycles and with high surge and swab pressures when the pipe is repeatedly run in and out of the hole too fast. As the excessive pressure is forced into a formation it will remain trapped until the confining pressure is released.

Under such dynamic pressure conditions wellbore breathing and instability are almost unavoidable.

An HPHT drilling plan must include a mix of conventional and unconventional practices. A misinterpretation of a loss or a gain from wellbore breathing as lost circulation or a kick can lead to a misapplication of the conventional practice that calls the mud weight to be decreased or increased.

That scenario can be avoided by using an automated MPD system to maintain a constant BHP through dynamic and static drilling phases. In an HPHT well, tight control of the BHP minimizes the fluctuations that cause wellbore breathing and instability.

An example of the type of non-productive time incidents that can occur in an HPHT project is shown in figure 4. The 12 1/4" sections of these wells have to go through a high pressure salt dome that contains over and under pressured sands. As the chart shows, the offset wells suffered kicks from one and losses in the other and over all a large amount of non-productive time (NPT).

In addition, the resultant contamination caused by the salt water kicks was so great that drilling was forced to completely replace the oil base mud system in some of the offset wells up to 3 times.

After a close analysis of the offset wells, the automated DAPC system was identified as a possible solution to mitigate the risks encountered in the 12-1/4" section. The challenge for MPD was to prevent salt water kicks and contamination of the oil base mud. Ultimately, the challenge was to preserve the integrity of the OBM and avoid the cost of losing it due to contamination.

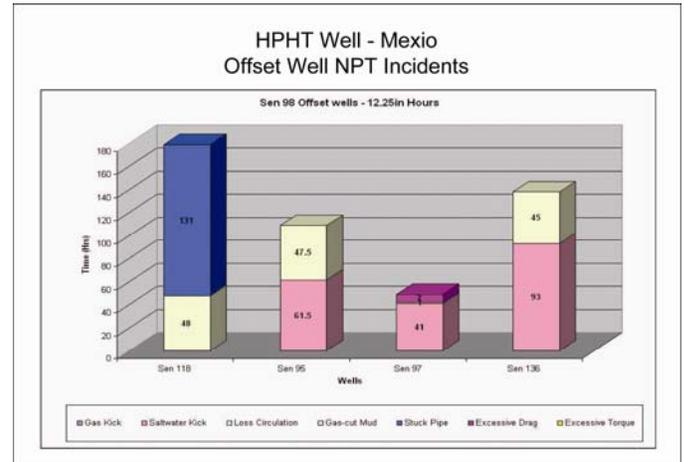


Figure 4 – fingerprint plot of flow back recorded by the DAPC system prior to the start of MPD operations.

Figure 5 is a plot of pressure data recorded with the DAPC system in an HPHT well drilled in Mexico. The DAPC system was used to maintain constant BHP during connections and to detect and suppress flow back due to wellbore breathing. The plot is a fingerprint of the flow back that was occurring in the well prior to the start of MPD operations. It also shows the dynamic losses that were occurring when the pumps were brought up to the drilling flow rate.

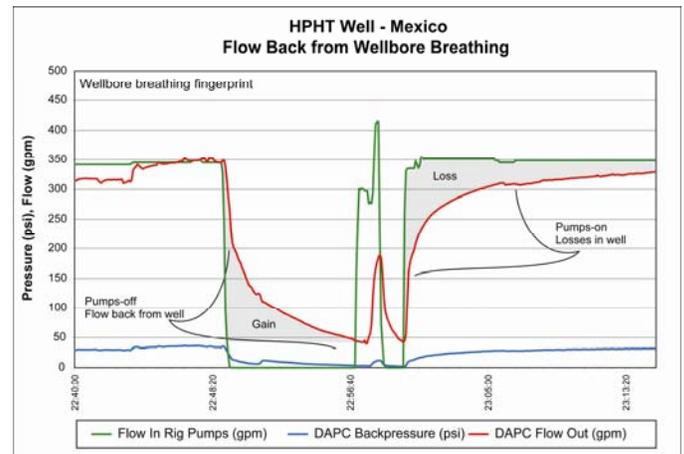


Figure 5 – fingerprint plot of flow back recorded by the DAPC system prior to the start of MPD operations.

Figure 6 is a plot of pressure data recorded during the 2nd connection with the DAPC system in an HPHT well drilled in Mexico. It shows that flow back and dynamic losses were still occurring in the well.

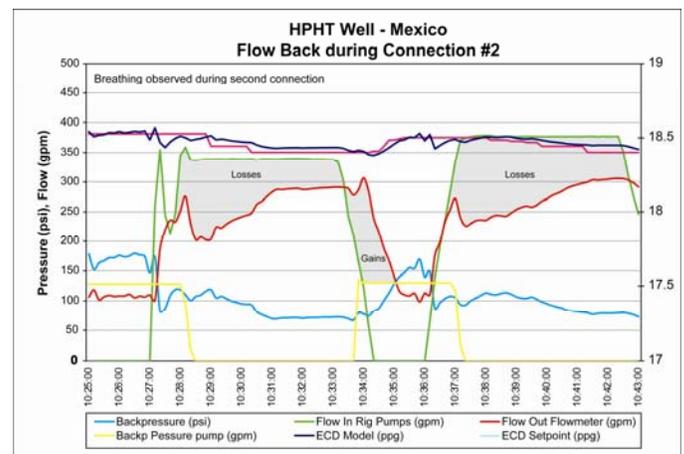


Figure 6 – plot of flow back recorded by the DAPC system during the second MPD connection.

Figure 7 is another plot of pressure data that was recorded with the DAPC system during the 5<sup>th</sup> connection in the same HPHT well in Mexico. Now there is no evidence of either flow back or dynamic losses indicating that the well has reached equilibrium with the constant BHP.

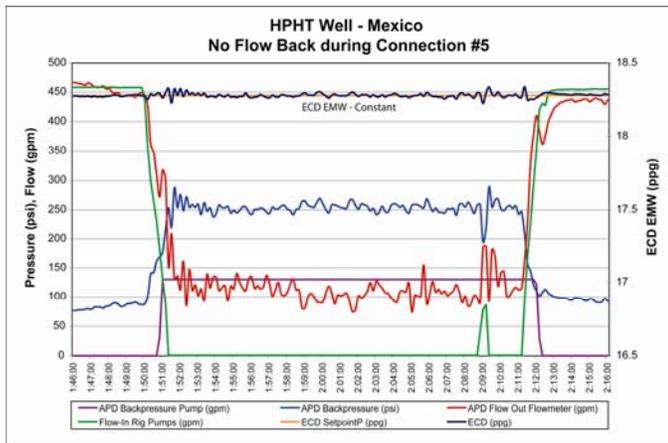


Figure 7 – plot of flow back recorded by the DAPC system during the fifth MPD connection showing no evidence of flow back.

Figure 8 is a plot of pressure data recorded during a flow check in the same HPHT well drilled in Mexico. At the start of the flow test the DAPC system was holding 250 psi of back pressure. The system was programmed to slow decrease the backpressure to 10 psi with the back pressure pump on to control flow. At that point the back pressure pump was turned off, the choke manifold was closed, and the shut-in pressure increased to a maximum of 200 psi. After maximum shut-in pressure was reached the choke was opened and the well started to flow. During the test the rig recorded a gain of 3 m3. The flow was killed by turning on the back pressure pump and applying 20 psi of back pressure.

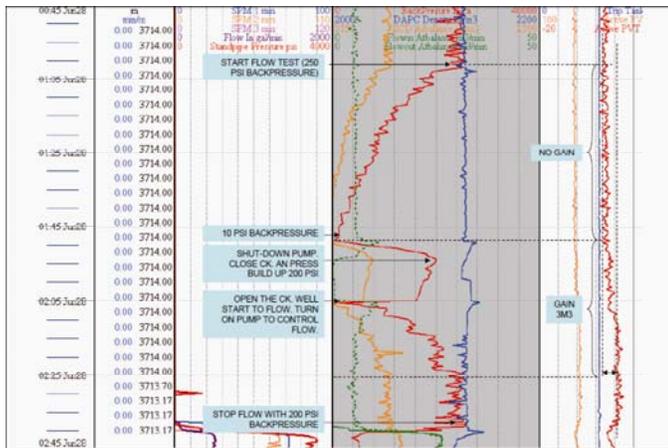


Figure 8 – plot of pressure data recorded during static flow check through the DAPC system.

The pressure log in figure 9 illustrates the very narrow margin that existed in the Mexico HPHT field. Just a 20 psi increase in back pressure was enough to induce mud losses.

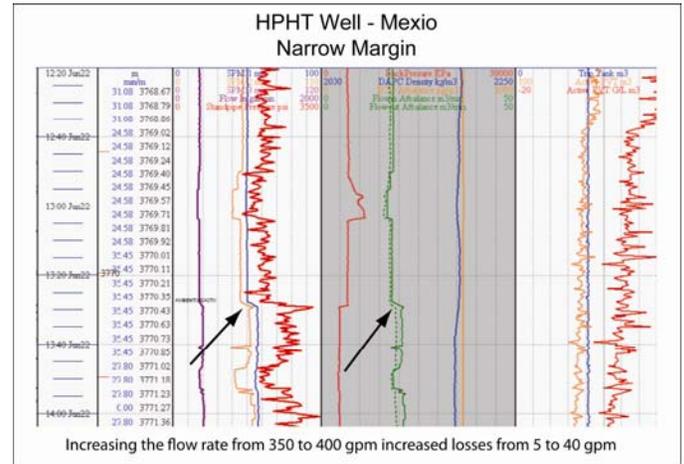


Figure 9 – plot of pressure through the drilled 12-1/4” section highlighting the very narrow margin in this well

The use of an automated MPD system in the Mexico HPHT well allowed drilling to avoid previously unavoidable major operational events such as influxes, losses, stuck pipe and salt water contamination of the OBM. In addition, by helping to detect micro influxes it gave tangible added value to the challenging narrow window in the 12-1/4” hole section. The operator was able to drill 938 meters of salt in only 11 days which was significantly faster than the field average of 30 days.

A final point about the potential value that automated MPD can deliver in HPHT is illustrated in Figure 10. That drawing lays out a simplified drilling tree used to identify flow back due to wellbore breathing. It details the conventionally accepted steps that are recommended to distinguish flow back due to breathing from an actual kick as well as the mitigating actions to counter it.

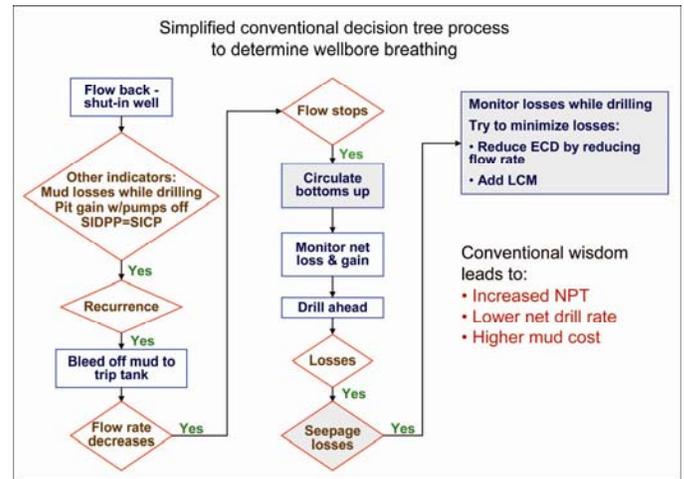


Figure 10 – a conventional decision tree used to drill an HPHT well

One of the action steps outlined in figure 10 is to take the time to circulate bottoms after each flow back. Also, if after drilling ahead losses continue it further recommends reducing the ECD by reducing the flow rate while adding LCM.

These conventionally prudent actions however naturally take time away from drilling which unavoidably increases drilling cost.

However, it has already been shown that automated MPD can eliminate the gains and losses due to wellbore breathing which would eliminate some of the NPT that are part and parcel of conventional drilling practices.

## References

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