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Managed Pressure Drilling Enables Operator to Reduce Mud Weight Below Pore Pressure And Improve Hydraulics And Hole Cleaning In Far East Depleted Offshore Field

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Abstract

For some time now, drilling in the Bunga Kekwa field shared by Malaysia and Vietnam has been pinched by contracting pressure margins and increasing difficulty. Years of production have depleted the geo-pressures and squeezed the margin between stability and fracture to an unmanageable level. While still facing the need for high mud weight to control stability and high solids to control coal seam losses the operator now faces the conflicting need to reduce annular loading to avoid fracture losses.

Conventional efforts were made in the Bunga Kekwa field to improve hole cleaning and reduce the level of solids in the annulus by reducing flow rates, controlling drill rates, and back reaming before every connection. However, these were ineffective at preventing high equivalent circulating density (ECD) and lost circulation.

In turning to managed pressure drilling (MPD) for a solution the operator elected to use the Dynamic Annular Pressure Control (DAPC) system. Automated with an integrated controller and real-time hydraulics model the system operates a choke manifold and backpressure pump to manage the ECD within narrow windows and stabilize the bottom hole pressure during sudden changes.

The efforts made in the Bunga Kekwa field with the DAPC system paid off and allowed the operator to lower the mud weight by over 1 ppg, reduce the static mud weight below pore pressure, eliminate lost circulation solids, increase the flow rate by 27%, reduce the ECD, avoid losses, and reduce the amount of non-productive time spent back reaming.

Introduction

Located in the Gulf of Thailand, the Bunga Kekwa fields sit in a narrow stretch of water shared by Malaysia and Vietnam in block PM-3 of the Commercial Agreement Area. A map of the area and the location of the fields are shown in Figure 1. The block, operated by Talisman Malaysia Limited, is being developed from six wellhead platforms. Beginning in 2002 with the BK-A platform the initial drilling phase included 10 development wells. Subsequent to this, five additional platforms were installed and over 60 development wells drilled to date.

The targeted Middle and Lower Miocene reservoirs range in depth from 1,600 m to 3,000 m TVD. Stratigraphically, the Malay Basin is characterized by discrete shale, sand and coal sequences and normal to near-normal pressure regimes and temperature gradients.

Bunga Kekwa wells are typically drilled with build-and-hold trajectories at inclinations up to 70°, with open hole sections ranging from 1,000 to 2,500 m, pump rates above 1,000 gpm, and rotary speeds above 110 rpm.

In a majority of the BK-A wells Talisman has frequently encountered stuck pipe and drilling problems in the 12¼" sections related to the cuttings deposits and high flow rates. They often have to contend with significantly increased pressure caused by turbulent flow around the cuttings beds and tight spots through the cuttings beds on trips out of the well.

One of Talisman's primary drilling objectives in high angle wells is operational efficiency within the required safety margins, with identifiable cost savings. Achieving that objective meant optimizing drilling parameters and procedures for hole-cleaning efficiency, frictional-load control, and wellbore quality and stability.

Starting in 2003, after evaluating their experience on the BK-A wells and analyzing the objectives for the BK-C development, Talisman implemented general drilling guidelines to improve hole cleaning which included:

- Maximizing flow rate between 950 to 1050 gpm taking into account ECD control limitations
- Maximizing string rotation between 90 to 120 rpm to avoid solid particle sedimentation, taking into account motor bend and WOB
- Maintaining plastic viscosity and low-gravity solids as low as possible and minimizing mud weight (MW) at 10.2 ppg for wellbore stability
- Optimizing drill rate based on torque and drag (ROP often limited by LWD to 50-60 m/hr)

However, whenever hole cleaning problems occurred, Talisman would control drill until torque and drag returned to normal. Additionally, they would stop drilling, pull off bottom and circulate bottoms-up to clean the well, and if necessary run sweeps, make wiper trips, and back-ream three or four times before making a connection.

Improper hole cleaning was becoming very costly and time consuming. In an effort to improve it Talisman applied Managed Pressure Drilling (MPD) methods on two BK-C wells, BK-C VV and WW. The MPD system utilized on these two wells provided automated control of surface applied backpressure which enabled Talisman to significantly reduce the surface MW, control the ECD, increase flow rate, reduce back reaming time, and reduce flat time.

MPD Hydraulics Analyses

Hole cleaning was, and still is, a primary drilling issue in Talisman's deviated wells. Sections at angles 40 degrees or more are known to be zones with cuttings sedimentation and recirculation problems. Though hole cleaning is often thought to be a straightforward process, the main challenges in achieving it are reducing cuttings build-up and transporting solid particles to the surface.

However, these are complicated in the Malay Basin by the need to mitigate a number of other risks associated with:

- High ECD caused by the high MW required to maintain borehole instability
- Unstable and troublesome coal deposits found in most PM3 wells
- Lost circulation while drilling the narrow margins between wellbore stability pressure and fracture gradient
- Differential sticking due to high overbalance (>2,000 psi) in severely depleted gas sands

The pressure profile of an offset BK-C well drilled earlier in 2007, Figure 2, shows the reservoir pressure and overbalance in a number of depleted sands that are commonly encountered in the Malay Basin but which vary across the basin. Total losses occurred in this well in the H2 sand at 1794 m.

Using pressure data from this offset well several scenarios were analyzed to determine the optimum MPD solution for the two targeted BK-C wells.

The objectives of the analysis were to collate and review well data pertaining to BK-C VV and WW, determine the optimum hydraulics parameters, and evaluate the applicability of At Balance's Dynamic Annular Pressure Control system in drilling the 8-½" hole sections past the depleted H2, H3, and H4 sands.

Before performing the analysis, PWD data and mud reports were collected from the reference offset well and used to calibrate and create a theoretical model up to the point where total losses were observed. The basic parameters which were derived from the 8 ½" section drilled with a rotary steerable assembly are shown in the table below and a plot of the predicted ECD for the reference offset well is shown in Figure 3, calculated with the calibrated model.

Parameter	Value
Analysis Depth	1794 m
Density at 104°F	16.5 ppg OBM
Viscosity Law	Power Law
PV	32 cp
YP	18 lb/100 sqft
R6	10 deg
Flow Rate	750 gpm
ROP	60 m/hr
Rotary Speed	160 rpm

Once calibrated, several scenarios were modeled to determine the optimum MPD solution and mud parameters for the targeted wells. These scenarios included:

- BKC-VV Base Case @ 10.5 ppg static MW & proposed fluid properties
- BKC-VV MPD Case @ 9.0 ppg static MW with revised fluid properties
- BKC-VV Flow Sensitivities
- BKC-VV MW Sensitivities
- BKC-WW MW Sensitivities

BK-C VV Base Case

In the base case for the planned well BK-C VV the ECD was analyzed using the calibrated model and the following operating parameters:

Parameter	**Base Case**
Analysis Depth	2059 m TVD SS
Density at 104°F	10.5 ppg OBM
Viscosity Law	Power Law
PV	25 cp
YP	28 lb/100 ft^2
R6	15 deg
Flow Rate	600 gpm
ROP	60 m/hr
Rotary Speed	120 rpm

In the base case analysis, shown in Figure 4, there is an operating window of 351 psi between borehole stability (10.5 ppg) and the minimum fracture gradient (11.5 ppg) in the depleted H2 sand. However, with the maximum program mud weight of 10.5 ppg the calculated ECD is 12.82 ppg EMW (4503 psi) which is 0.92 ppg EMW greater than the minimum fracture gradient. Under these modeled conditions well VV is conventionally undrillable.

BK-C VV MPD Case

In the MPD case for well BK-C VV the ECD was analyzed using a significantly reduced static mud weight of 9.0 ppg in addition to the following operating parameters:

Parameter	MPD Case
Analysis Depth	2059m TVD SS
Density at 104°F	9.0 ppg OBM
Viscosity Law	Power Law
PV	18 cp
YP	15 lb/100 ft ^2
R6	12 deg
Flow Rate	600 gpm
ROP	60 m/hr
Rotary Speed	120 rpm

In the MPD case analysis, shown in Figure 5, there is still an operating window of 351 psi between borehole stability (10.5 ppg) and the minimum fracture gradient (11.5 ppg) in the depleted H2 sand. Now, with 9.0 ppg EMW the ECD is 10.59 ppg EMW (3720 psi) which is only marginally greater than borehole stability. In the event the PWD actually measured and ECD less than 10.5 ppg EMW, surface back pressure can be added to increase it. In this scenario, 558 psi of surface back pressure would be applied to maintain the ECD at 10.5 ppg during connections. No LCM, such as calcium carbonate and graphite, is required which would reduce the thickness of the filter cake.

BK-C VV Sensitivity Analyses

In the MPD case, the result of a flow rate sensitivity analysis showed that when flow was varied from 550 to 650 gpm, the ECD increased only marginally by 0.08 ppg EMW (~30 psi). This showed that it would be possible to improve hole cleaning by increasing the annular velocity.

The result of a MW sensitivity analysis showed that when the density was varied from 9.0 to 10.0 ppg, the operating window was largest, 298 psi, at the lower mud weight. At that level an additional 627 psi of back pressure would be required to achieve 10.65 ppg EMW during the connections for wellbore stability.

VV MW Analysis	9	9.4	9.6	9.8	10
ECD (ppg)	**10.65**	11.07	11.29	11.5	11.71
ECD (psi)	3741	3888	3966	4040	4113
Operating Window (psi)	**298**	151	73	-1	-74
Back Pressure (psi)	627	585	593	597	600
Surface ΔP 4" Pipe	~140	~140	~140	~140	~140

BK-C WW Sensitivity Analyses

Similar sensitivities analyses were performed for BK-C WW at a flow rate of 650 gpm. The MW sensitivity analysis showed that 9.4 ppg was the optimum MW for maintaining the borehole stability with an ECD of 10.63 ppg. Under those conditions the operating window was calculated to be ~276 psi and approximately 461 psi back pressure would be required during connections to hold the ECD of 10.63 ppg EMW.

The ECD values were dramatically different than those calculated for the BKC-VV well due to the planned lower inclination of the WW well.

WW MW Analysis	9	9.4	9.6	9.8	10
ECD (ppg)	10.21	**10.63**	10.84	11.04	11.25
ECD (psi)	3880	4036	4115	4191	4271
Operating Window (psi)	432	**276**	197	121	41
Back Pressure (psi)	453	461	465	465	468
Surface ΔP 4" Pipe	~140	~140	~140	~140	~140

The results of these analyses showed that both BKC-VV and BKC-WW would benefit from Managed Pressure Drilling with the Dynamic Annular Pressure Control system in the narrow operating margins.

Depth VS Time in Offset Well

Depth versus time data was taken from another offset well and plotted to show the non-productive effect that back reaming has had on drilling time. Figure 6 shows the non-productive impact that excessive back reaming can have on drill time. Over 80 connections were made while drilling the interval shown in this plot and on average each stand was back reamed 2 to 3 times, and sometimes more before the connection was made. This represents about 2 days worth of rig time and about $800k or more of cost.

That cost estimate does not include the additional rig time taken to clean the hole by circulating bottoms up or making short trips.

BK-C VV MPD Results

BK-C VV was the first planned well for MPD operations. This well was part of the development program that was planned for the recently installed Bunga Kekwa-C Annex platform. Engineered as a Single Horizontal Oil Producer (SHOP) its objective was the H – I Group of sands. The well plan, shown in Figure 7, called for drilling the 8 ½" hole section in two intervals.

In the H group of sands, Talisman estimated that the H2 in the VV well would be depleted between 1600 and 1800 psi which created a risk of differential sticking.

In addition, Talisman had to contend with unstable coal formations which had been troublesome in almost all PM3 development and exploration wells drilled to date. Possessing low compressive strength and being brittle make the coals easy to fracture and collapse when the horizontal stress is relieved at the bit. One of Talisman's primary drilling objectives was to maintain 10.2 ppg MW for coal stability in the 8 ½" hole section.

Yet another area of concern in the depleted H2 sand was the risk of lost circulation. In the offset reference well used as the basis for calibrating the hydraulics model, Talisman experienced losses when static overbalance reached approximately 2,000 psi with 10.2 ppg MW. Data from the Pressure While Drilling (PWD) tool indicated that the ECD was between 11.4 ppg to 11.9 ppg, equivalent to about 2,400 psi overbalance. Various attempts to cure the losses were unsuccessful and the loss zone had to be cased with 7" liner.

The upper interval of the 8 ½" hole was conventionally drilled as a tangent section at ~64 degrees from the casing shoe down to 1,697 m MD, approximately 300 m above the H-

2 sand. Drilling this section with 10.2 ppg EMW at flow rates between 550 – 600 gpm created a scenario that was statically above pore pressure and bore hole stability.

Managed pressure drilling was used in the lower interval from 1,697 m to section TD at 4,243 m in which the well angle was built from 64 to 90 degrees and direction turned 80 degrees in azimuth.

Prior to the start of MPD the 10.2 ppg mud that was used to drill the upper interval was changed over to 9.0 ppg static MW during which time the flow rate was staged up from 550 to 650 gpm. This created a drilling scenario that was statically above pore pressure but below bore hole stability.

While drilling the 8 ½" hole section in the VV well 55 connections were made during which the Dynamic Annular Pressure Control (DAPC) system maintained a pressure of 10.35 ppg EMW without any well incidents.

On average, the connection time from beginning of pump ramp down to the end of the pump ramp up cycle was 22.7 minutes which does not include the additional time to receive the directional survey and downlink to the rotary steerable tool. In start-up MPD operations it is not unusual for connections times initially to be longer than normal. This reflects the natural learning curve that rig crews follow as they become familiar with new MPD procedures. It also reflects a normal amount of shake out time during which the overall MPD system and communications are being optimized.

A brief statistical summary is listed below of MPD operations in the VV 8 ½" hole section. This operation provided an opportunity to compare ECD in the same size hole section with and without MPD.

BKC-VV MPD Job Info		
Start	2,657m MD	63.9° inc
End	4,243m MD	88° inc
Hole	8-1/2"	
Connections		55
Average Conn Time		22.7 min
Mud weight		9.0 ppg
Max ECD		11.0 ppg
Min ECD		10.0 ppg
Delta ECD		0.37 ppg
Average Delta ECD		0.19 ppg
Backpressure max		595 psi

Equivalent circulating density for the conventionally drilled 8 ½" hole section of VV well is plotted in Figure 8. It is a good illustration of the difficulties Talisman has faced in the Bunga Kekwa field with hole cleaning and ECD management. Equivalent circulating density varies from +/- 11.0 ppg EMW at the beginning of the upper interval to +/- 12.25 ppg EMW at the end.

By comparison, the significantly more stable ECD in the 8 ½" section drilled with pressure management, plotted in Figure 9, is maintained at or below 11 ppg EMW which represents significant improvement in hole cleaning.

It took a little more than fours days to drill the 1,586 m long, 8 ½" MPD interval. The depth vs. time plot for VV, plotted in Figure 10, shows that up to 30 minutes or more were spent back reaming each stand. That adds up to over 24 hours of non-drilling time for the 55 connections made in this MPD interval. In spite of the extra time taken to back ream, the rig still managed to drill 378 m/day which represents a 37% improvement in drilling performance compared to what was achieved on the offset well, plotted in Figure 6.

BK-C WW ST MPD Results

BK-C WW ST1 was also part of the same development program on Bunga Kekwa-C Annex platform. Engineered as a Single Oil Producer (SOP) its objective was the H – J Group of sands. The well plan, shown in Figure 11, called for drilling the well to 40° inclination and, like the VV well, drilling the 8 ½" hole section in two intervals.

As in the VV well, the 8 ½" hole section of the WW ST well was drilled in two intervals. The upper interval was conventionally drilled to 1,929 m MD, to within 300 m of the H-2 sand, with 10.2 ppg EMW at flow rates in the same range as before, 550 – 600 gpm. Also, as before, the static pressure scenario was above pore pressure and bore hole stability.

Upon reaching the target depth above the H2 sand, the mud was changed over to 9.0 ppg static in preparation for MPD operations. The table below presents a brief statistical summary of MPD operations in the 8 ½" hole section.

BKC-WW ST MPD Job Info		
Start	1,929m MD	39.8° inc
End	2,950m MD	39.8° inc
Hole	8-1/2"	
Connections		35
Average Conn Time		11.7 min
Mud weight		9.0 ppg
Max ECD		10.8 ppg
Min ECD		10.0 ppg
Delta ECD		0.34 ppg
Average Delta ECD		0.2 ppg
Backpressure max		572 psi

One of the objectives during MPD operations in BK-C WW ST was to reduce the connection times relative to VV. On average, connections on WW ST took 11.7 minutes compared to 22.7 minutes in the VV well. This represents a 50% increase in efficiency. The improvement was achieved by feeding Wits data directly into the DAPC system controller and bypassing the third party provider where the delay occurred. A example of a pressure transition plot from the WW ST well is shown in Figure 12. It highlights the time it took, on average, to ramp down and ramp up the pumps, as well as the in-slips time.

Figure 13 illustrates the ECD for the conventionally drilled 8 ½" hole section of WW ST. The ECD varies from 11.0 to over 12 ppg EMW through the interval and there are wide swings from stand to stand.

By comparison, the ECD in the 8 ½” MPD section, plotted in Figure 14, stays within a much smaller window in a much lower range, between 10 and 11 ppg EMW. On average, using MPD has helped reduce the magnitude of ECD by as much as 1 ppg below the level in the conventionally drilled section, which represents significant improvement in hole cleaning.

It took two days to drill the 1,050 m long, 8 ½” MPD interval. The depth vs. time plot for VV, plotted in Figure 15, now shows much less time spent back reaming each stand. On average, each stand was back reamed only once, taking less than 15 minutes per stand. That amounts to about 9 hours of non-drilling time for the 35 connections made in this MPD interval which represents a reduction in non-drilling time of 50% from the VV well. This efficiency improvement helped the rig drill 510 m per day which represents a 35% improvement in drilling performance compared to the VV well, and an 85% improvement over the offset well, plotted in Figure 6.

Figure 16 is a plot of the minimum and maximum pressure fluctuation on every connection during which pressure was controlled by the DAPC system. On average, the max to min pressure delta is on the order of +/- 0.1 ppg.

Dynamic Annular Pressure Control Description

The Dynamic Annular Pressure Control (DAPC) system incorporates a programmable controller integrated with a real-time hydraulics model and human machine interface to maintain a constant bottom hole pressure (BHP) at a programmed BHP set point while drilling, tripping, or making connections.

For the Bunga Kekwa wells the DAPC system was programmed to maintain constant BHP during connections and tripping. Backpressure was not applied while drilling as the planned flow rate provided adequate ECD for borehole stability.

The DAPC system utilized on BK-C consisted of three main pieces of equipment: a choke manifold, a backpressure pump, and an Integrated Pressure Manager (IPM) shown in Figure 17. Figure 18 shows a photo of the manifold and backpressure pump rigged up on the BK-C platform, next to the catwalk.

DAPC Choke Manifold

Under the control of the IPM the choke manifold makes continuous backpressure adjustments to maintain the BHP at the programmed set point. Precise BHP control is accomplished using continuous flow into the choke manifold from the backpressure pump while the rig pumps are off.

The choke manifold contained two primary 4” hydraulic choke legs and one 2” secondary hydraulic choke leg. Under normal operation only one primary choke is active, the other acts as backup. The backup 4” choke was programmed for static high-level pressure relief to protect the wellbore against over pressure events. All three chokes used on BK-C were mechanical, gear driven position chokes activated by a hydraulic power unit (HPU) mounted on the manifold. A redundant feature of the manifold allows the HPU to be powered from multiple sources in case of malfunction or failure. Primary power is supplied by an electric motor and secondary power by the rig air supply. In the unlikely event both fail, then manual power is available by recharging the designated accumulators while still maintaining the programmed BHP set point under automated control.

DAPC Backpressure Pump

Backpressure pump operation is under full control of the IPM. The pump provides a dedicated, on-demand supply of backpressure whenever the rig pump flow rate drops below a defined threshold.

A steady flow of mud into the choke manifold, when needed, gives the system the ability to actively stabilize the BHP during connections. By changing the set point in the IPM the BHP can be increased or decreased during a connection.

Integrated Pressure Manager

Measurement, monitoring, analysis, and control are all integrated into the third component of the DAPC system, the Integrated Pressure Manager (IPM). The IPM consists of a control computer, a programmable logic control system, a real-time hydraulics model, and data communications network. Together they provide the automated software control and data acquisition necessary to maintain constant BHP through the choke manifold. A human machine interface (HMI) provides the interface for a control system technician to configure and adjust the operation of the IPM and the entire system.

Accurate BHP control requires a steady stream of accurate data. The IPM relies on this stream of data to maintain its accurate control of the BHP throughout the drilling interval. Regularly updated drilling parameters and real-time data from the PWD tool are transmitted over a data communications network to the IPM. Of particular importance is the rig pump stroke counter, which is a crucial parameter for the operation of the DAPC system. The IPM uses the pump strokes as its primary indicator that the pumps are working, mud is flowing, and that there is annular friction in the wellbore.

As a contingency, in the event that all rig data being transmitted was severed the control system technician could manually enter the stroke rate. The hydraulics model runs continuously to provide the IPM with the necessary calculated data to maintain the set point. Using the model and the manually entered stroke rate, the IPM will still generate the required DAPC system configuration and continuously control the BHP.

Coriolis Flow Meter

Installed downstream of the choke manifold is a Coriolis, mass flow and density meter providing measurements of all flow going through the system. Figure 19 shows the flow meter rigged up on BK-C downstream of the manifold. Continuous flow out measurement is graphically compared with rig pump flow in to detect formation influx or downhole losses. The density measurement monitors gas levels in returns and provides quick detection of return mud density when weighting up or cutting back the mud system.

Conclusion

This was the first application of managed pressure drilling in the Gulf of Thailand purely for hole cleaning improvements.

Hydraulics analysis showed that the two Bunga Kekwa wells, BK-C VV and WW were not drillable with the planned hydraulics program due to the resulting high ECD caused by the high MW needed for wellbore stability. However, the analysis clearly showed they were drillable with Managed Pressure Drilling and significantly reduced mud weight (reduced up to 1.2 ppg). Actual drilling results proved out the accuracy of this analysis.

Managing constant bottom hole pressure with reduced mud weight and improved mud properties (lower plastic viscosity and yield point, etc) proved its ability to improve hole cleaning and drilling performance by:

- Reducing ECD
- Increasing flow rate
- Reducing back reaming
- Reducing drill time
- Mitigating risk of losses

Acknowledgements

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References

1. Mango, H., Elder, R., Boulet, J. and Monnet, A. "Maximizing drilling efficiency in Bunga-Kekwa's high-angle wells," *World Oil*, (January 2008, Vol. 229 No.1)

Figures

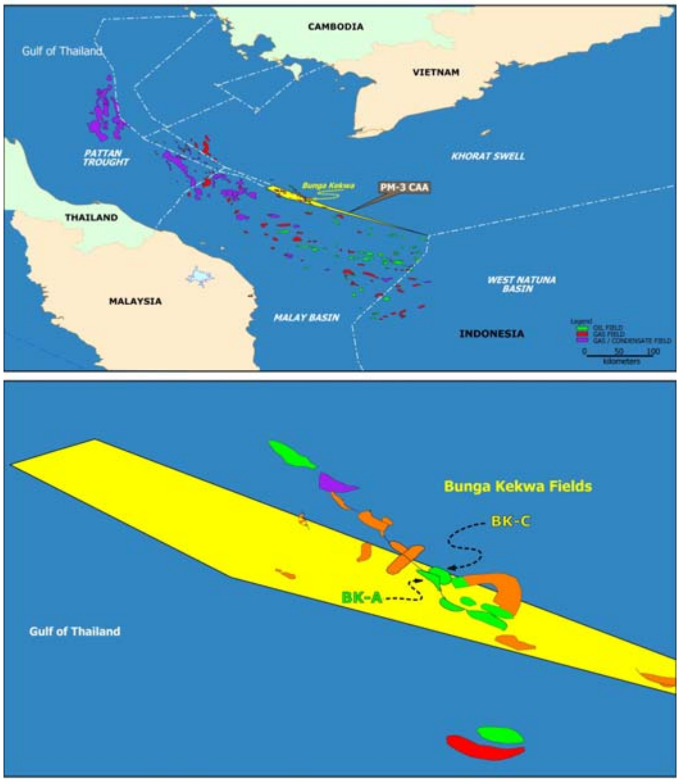

Figure 1. Location of Bunga Kekwa fields. The upper map shows the location of the PM-3 Commercial Agreement Area relative to Vietnam and Malaysia. The lower detail map pinpoints the location of the Bunga Kekwa fields in the PM3 CAA block.

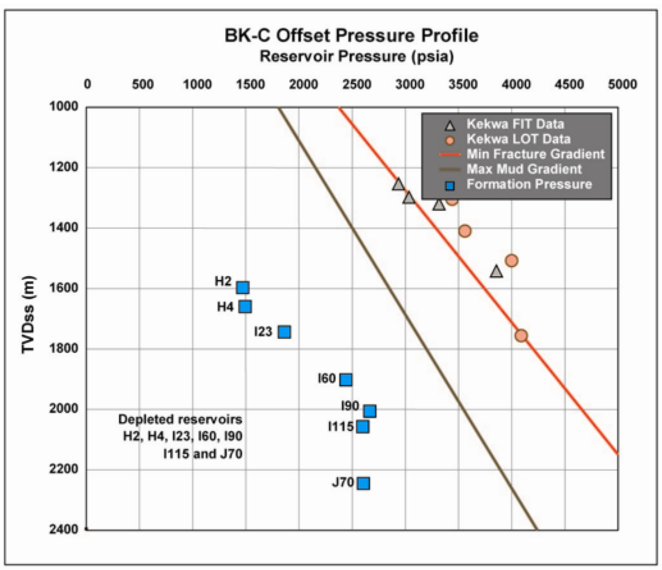

Figure 2. Pressure profile from BK-C reference offset well showing some of the depleted gas sands commonly encountered in the Malay Basin. Total losses occurred in this offset well in the H2 sand.

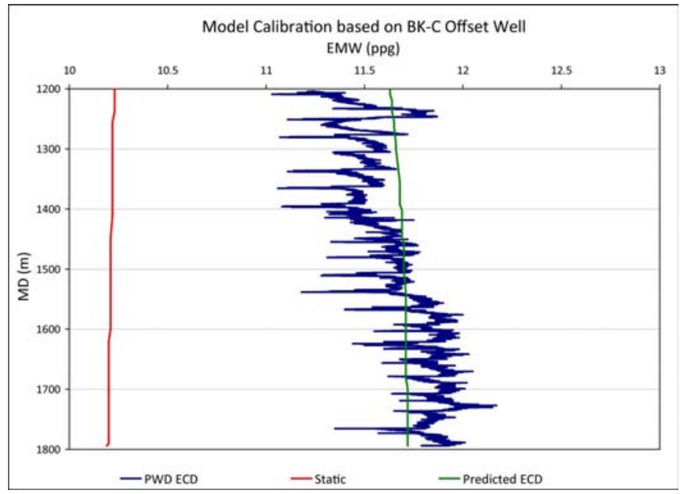

Figure 3. Predicted ECD (green line) for BK-C reference offset well calculated by hydraulics model after calibration.

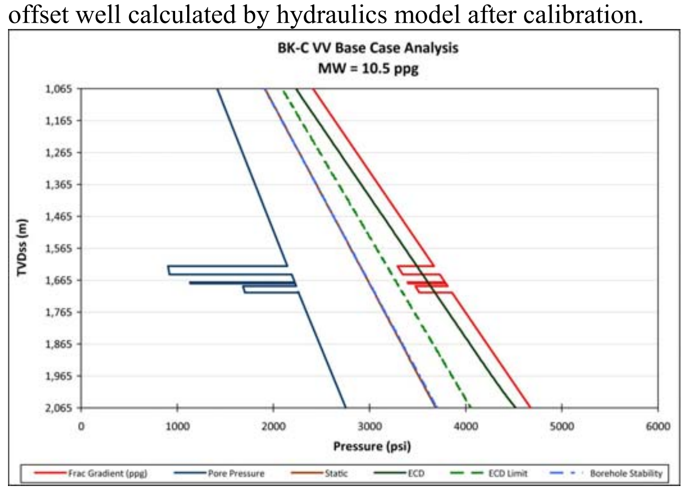

Figure 4. Results of the base case analysis for BK-C VV. The modeled ECD exceeds the fracture gradient in the H2 sand making VV undrillable with 10.5 ppg MW.

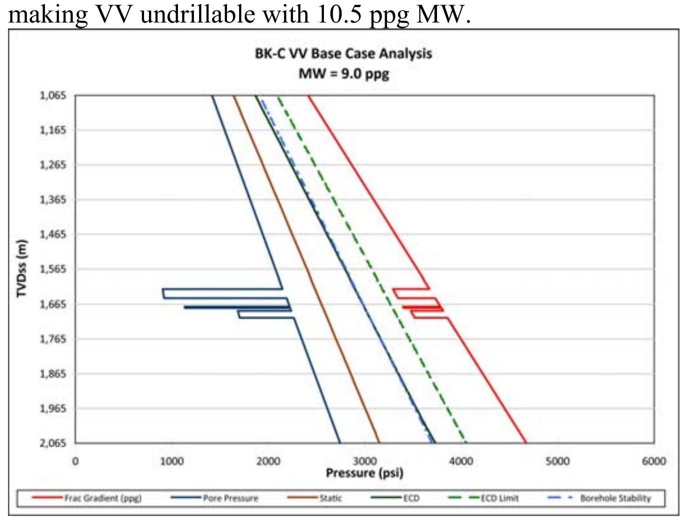

Figure 5. Results of the MPD case analysis for BK-C VV. The modeled ECD is only marginally greater than the wellbore stability making VV drillable with 9.0 ppg MW.

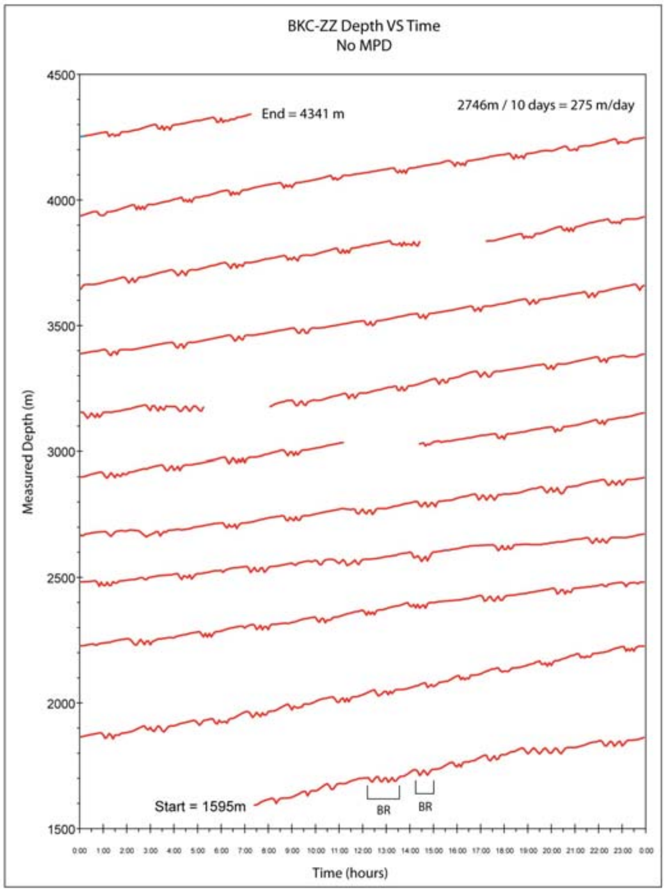

Figure 6. Depth versus time from an offset well showing the non-productive impact of back reaming Each stand is back reamed 2-3 times, sometimes more, adding 30-60 minutes of flat time which for 80 connections is about 2 days of NPT.

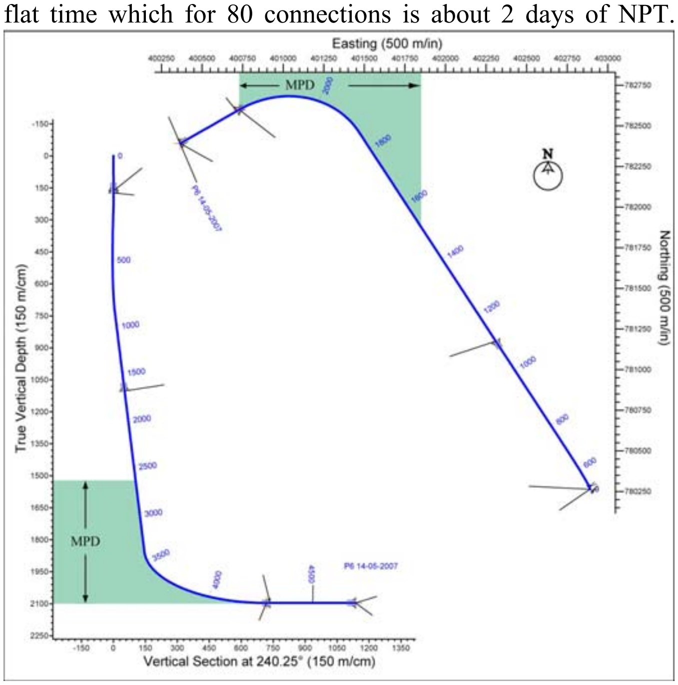

Figure 7. Well plot of BK-C VV showing the angle build and turn section drilled with MPD.

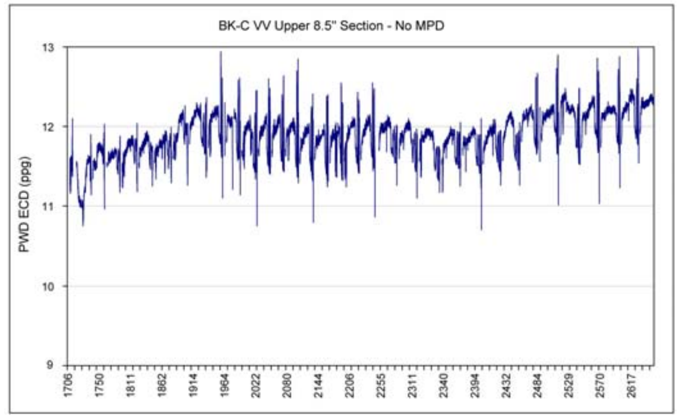

Figure 8. PWD plot in upper 8 ½" hole section of BK-C VV drilled without MPD, with 10.2 ppg static MW. ECD is unstable throughout and climbs from 11.25 to almost 12.5 ppg.

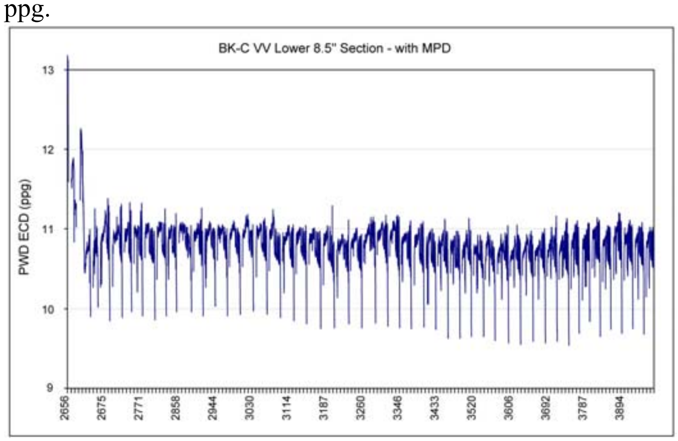

Figure 9. PWD plot in lower 8 ½" hole section of BK-C VV drilled with MPD and 9.0 ppg static MW. The ECD was kept at or below 11 ppg EMW for the entire section and unlike the upper section it was stable and constant throughout.

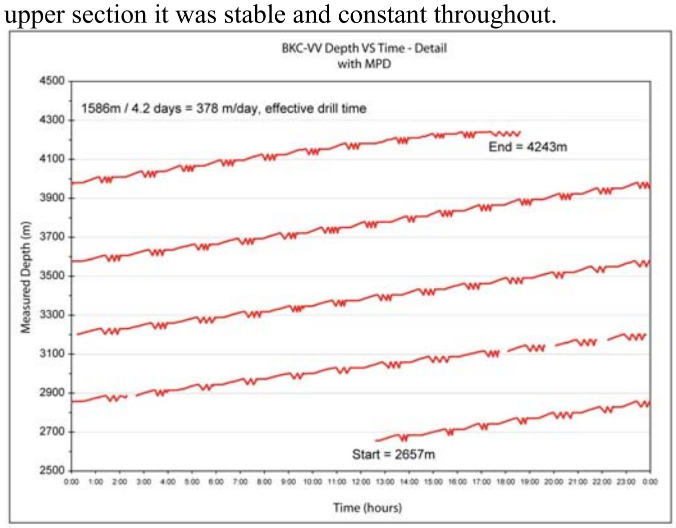

Figure 10. Plot of depth versus time from section of BK-C VV drilled with MPD. Even though the rig continued to back ream each stand 3 times before every connection drilling averaged 378 m/day compared to 275 m/day achieved in the offset well shown in Figure 6.

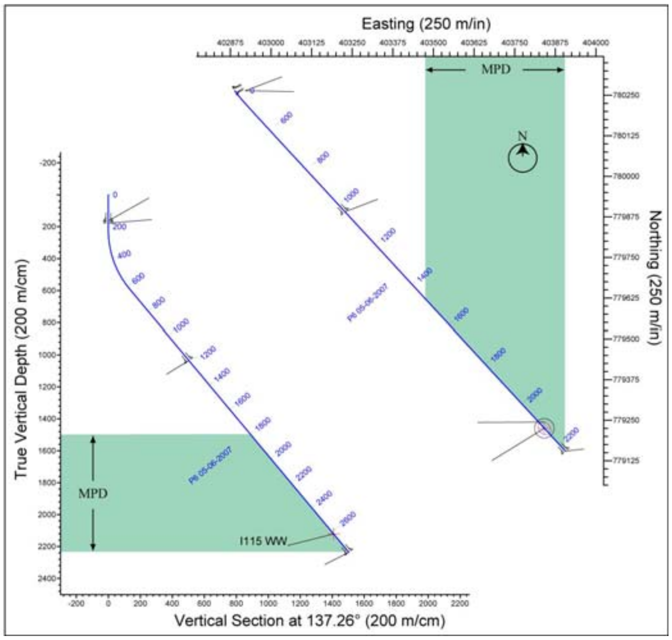

Figure 11. Well plot of BK-C WW showing the tangent section drilled with MPD.

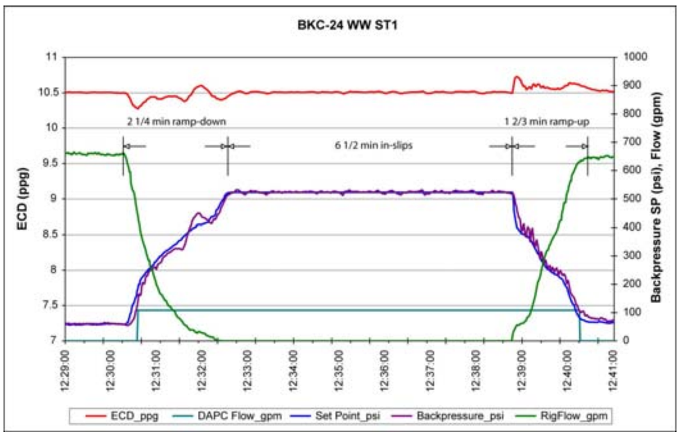

Figure 12. Plot of pressures during a connection made on BK-C WW ST. In this example, the pump-to-pump connection time is less than 10.5 minutes.

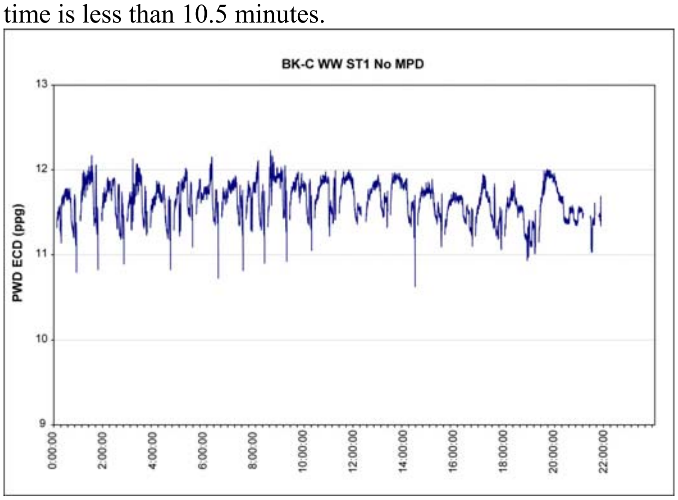

Figure 13. PWD plot in upper 8 ½" hole section of BK-C WW drilled without MPD, with 10.2 ppg static MW. ECD stays below 12 ppg EMW but varies almost 1 ppg over the interval.

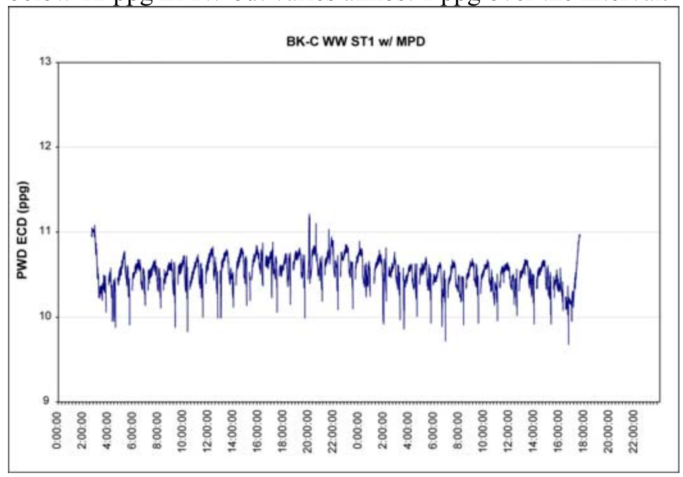

Figure 14. PWD plot in lower 8 ½" hole section of BK-C WW drilled with MPD and 9.0 ppg static MW. The ECD was kept well below 11 ppg EMW for the entire section and it was more stable than the upper section.

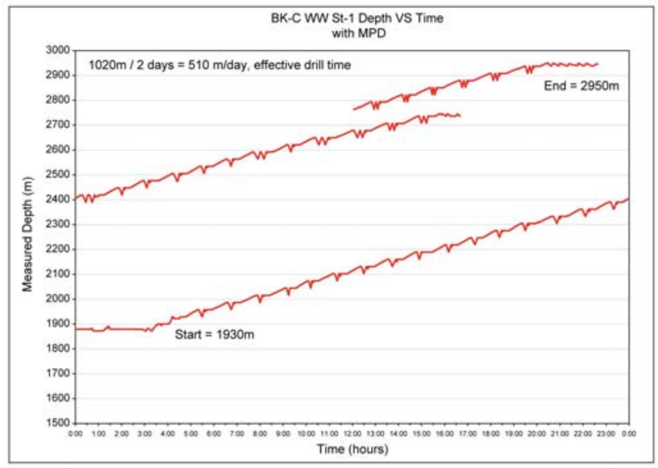

Figure 15. Depth vs. time from section of BK-C WW drilled with MPD. Back reaming was reduced significantly, 1-2 times per stand, and drilling averaged 510 m/day compared to 275 m/day in the offset well shown in Figure 6.

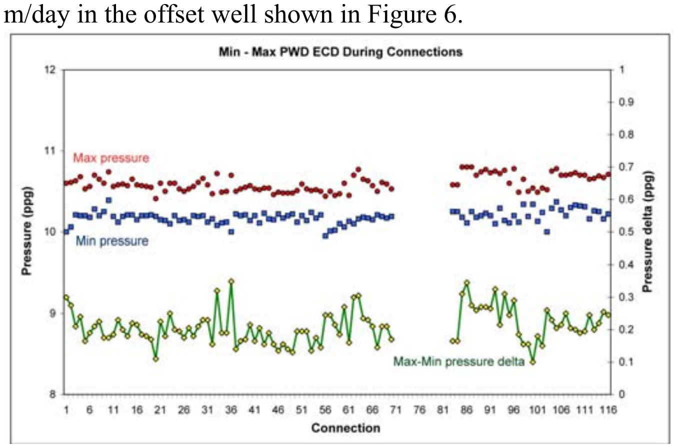

Figure 16. Plot of maximum and minimum pressure recorded on every connection made with MPD in three Bunga Kekwa wells.

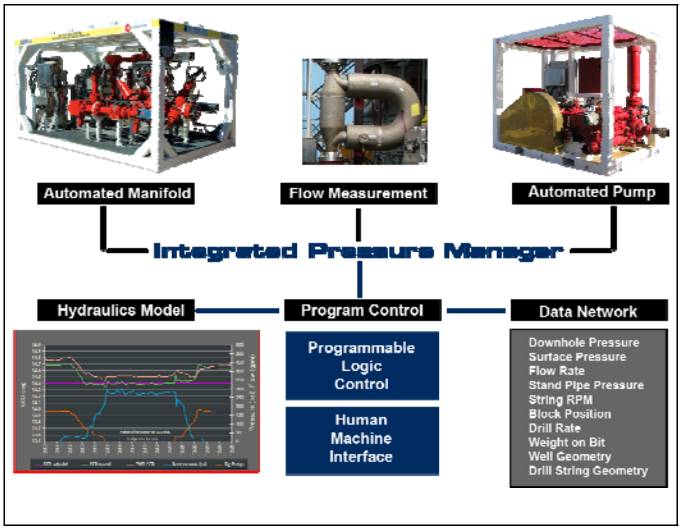

Figure 17. Schematic showing the main components of the DAPC system. The Integrated Pressure Manager consists of the programmable controller, the human machine interface, and the hydraulics mode. The IPM controls the choke manifold and the backpressure pump and monitors flow in and out for early kick detection.

Figure 18. The DAPC choke manifold and backpressure pump rigged up next to the catwalk on the Bunga Kekwa C platform.

Figure 19. Coriolis flow meter rigged up and connected to the discharge outlet of the choke manifold.

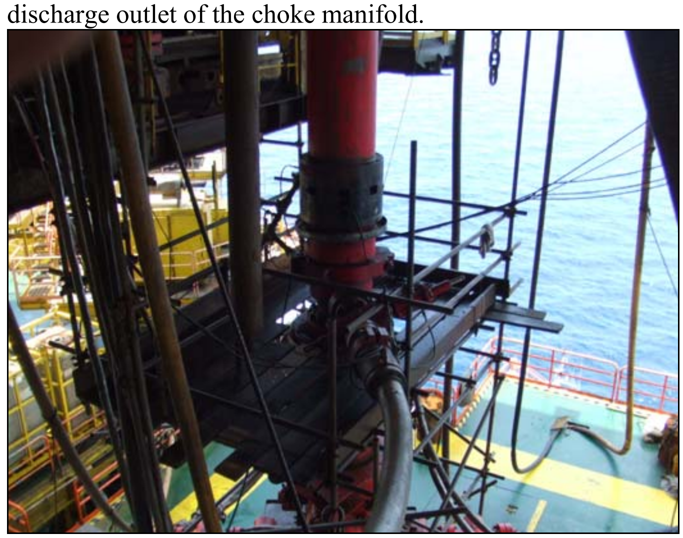

Figure 20. Picture showing the HOLD 2500 Rotating Control Device installed in the riser above the stack.