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DUAL GRADIENT DRILLING: A PILOT TEST OF DECANTER CENTRIFUGE FOR CAPM TECHNOLOGY

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Abstract

The article is about problem of drilling deepwater oil and gas wells that consists in complicating and increasing cost of their well design due to narrowing mud window at different depths. The authors analyse drilling technology developed and applied in practice of offshore drilling with a dual gradient drilling, which allows drilling significant intervals without overlapping an intermediate casing string. Based on analysis of these technologies and taking into account their disadvantages the authors proposed and tested a new drilling technology of dual gradient drilling with placement of all necessary innovative equipment on drilling platform.

Keywords:

Managed pressure drilling;
Deepwater drilling;
Offshore drilling;
Dual gradient drilling;
Riser;
Oil and gas exploration in sea.

Introduction

Mineral resources are increasingly exhausted thereby requiring more sophisticated solutions to increase efficiency of drilling and production technologies. The introduction of new technologies will enable efficient well drilling that was previously considered either abnormal or impossible in terms of view of trouble-free drilling [1,2].

Prospecting and appraisal deepwater and HTHP wells (high temperature and high pressure) with subsurface uncertainty due to such risks as mud loss, differential sticking of drill pipes, and gas, water and oil shows are striking examples thereof. Such problems may result in failure to achieve exploration targets, and even in loss of wells under application of traditional drilling methods.

Such data complicating drilling result in searching for new equipment and technologies to be implemented for reducing both risks and costs for the construction of complicated offshore wells. The Managed Pressure Drilling (MPD) technology in the «well-formation» system [3] enabling safe construction of a section within the narrow drill slot of safe pressures (range between formation pressure and loss start pressure) is one of the promising directions for solving this problem. It is achieved through the use of low-density mud, accurate annular back pressure control and current analytic algorithms enabling analyzing the well for losses / demonstration.

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The MPD technology for deepwater wells may be implemented as a dual gradient drilling system (hereinafter referred to as DGD). The Underbalanced and Managed Pressure Drilling Committee at the International Association of Drilling Contractors (IADC) has defined the dual gradient drilling as the special application of two pressure gradients in the wellbore and/or pipeline [3,4].

The application of DGD technology when making deepwater wells enables to significantly reduce the overburden on formations with a "narrow mud window", therewith having the necessary tools for reducing risks of oil, gas and water shows and mud loss. Such approach provides making longer drilling intervals in problem conditions. Various versions of DGD have been studied, with many of them having been failed or closed.

Proceeding from the above, the aim of this study is to theoretically analyze the DGD, and to consider the results of both laboratory and field tests of the key element of the DGD system, i.e. a centrifuge that is separating the mud to fractions of different densities for deepwater drilling.

An integrated approach was used for analyzing the obtained information, i.e. analysis of various DGD technologies and literature and electronic sources; laboratory and field tests.

Dual gradient drilling technology

Under conventional single-gradient drilling (hereinafter referred to as SGD) the bottom-hole pressure is made up of two components i.e.

hydrostatic pressure and pressure friction loss during the drilling mud annular flow movement from the bottom-hole to the wellhead. For better understanding we will not consider herein the influence of cuttings/ROP on the hydrostatic component of pressure, as well as RPM of topdrive, eccentricity of bottom-hole assembly (BHA), and flow properties upon pressure friction loss within the annular space. Under static conditions of the well the last component of the equation is zeroed and the bottom-hole pressure is reduced (fig.1):

Fig. 1. Bottom-hole pressure components during SGD and making connections

Due to the application of a set of additional equipment MPD there appear conditions of a closed circulation circuit (similar to circulation conditions with a closed blowout preventer (BOP) enabling to add an additional component to the equation i.e. surface backpressure (SBP) (fig. 2):

The backpressure is especially important in static conditions thereby enabling compensating for the absence of friction pressure loss in the annular space keeping the bottom-hole pressure unchanged. Such notions as equivalent circulating density (ECD) and equivalent static density (ESD) are used for better comparison of both hydrostatic head and flowing pressure in the well with mud density and the formation pressure gradients and fracture pressure (FP). ECD of the drilling mud is the equivalent of the flowing pressure in the well expressed as density (most often in g/cm3). In the absence of drilling mud circulation the notion of ESD is used i.e. the value of the mud density equivalent to the bottom-hole pressure in static conditions being more relevant in wells where MPD technology is applied.

Unlike conventional SGD or MPD the DGD [5] is applying two hydrostatic pressure gradients. For example, the seawater gradient (the top mud in table) from the sea surface to the seabed is used to control the well, while the mud gradient from the seabed to the bottom-hole is used for the wellbore stability and removing cuttings therefrom (fig. 3):

The drilling rig may be conventionally said to be located on the seabed, since the overlap of the water column is balanced by the seawater line gradient (fig. 4b). The DGD is to be noted to be already applied in drilling of pilot holes or upper sections of wells prior to installation of BOP.

The two fluids within the annulus may present more favorable wellbore pressure profile compared to conventional drilling. The DGD system is transforming the general pressure profile with depth compared to conventional drilling providing a larger drilling margin by shifting the pressure profile to the left.

Scientific and technological research of the dual gradient pressure drilling system

An industrial project for engineering the well drilling technology with dual gradient pressure drilling was launched in early 1996.The technology was intended to be used in ultradeep water conditions under high formation pressure and low fracture pressure gradient (such formation conditions are found in the Gulf of Mexico and in various parts of West Africa shelf). Without this technology, the drilling contractor could hardly be able to develop the identified resources in such conditions [8,9].

The leading western oil companies have invested hundreds of millions of dollars over a 15-year period (until 2011) in the research and development of DGD technology.

The world's first «Max Lift Drilling» dual gradient well was successfully made in September 2001 in the Green Canyon of the Gulf of Mexico of 277 m in depth. The initial enormous cost of the project has somehow undermined the Customers' enthusiasm for the continuation of the project. Current status of research and development in the field of DGD drilling is given in table below. Some companies are developing systems being supplementary ones to the research. The other companies have merged, while the third companies have been terminated as they originally were.

However, the DGD technology is one of the few methods available in the drilling industry for deep water drilling thereby providing positive results as compared to conventional drilling technology, such as: better well control in difficult conditions, less

Fig. 2. Bottom-hole pressure components during drilling with MPD

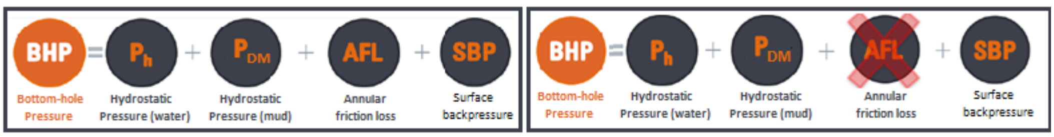

Fig. 3. Bottom-hole pressure components during drilling with DGD

Table

Dual gradient drilling systems analysis [12]

	PRE-BOP	POST-BOP				
DGD system	**Subsea pump (riserless)**	**Subsea pump with riser**		**Dilution**	**Controlled mud level**	
Technology name	**RMR™**	**Max Lift Drilling (previously SMD)**	**CMP****	**CAPM*****	**EC-Drill******	**EC-Drill+**
Technology promoting company	**Enhanced Drilling**	**Chevron/GE/ Pacific Drilling/ Enhanced Drilling**	**Enhanced Drilling**	**Transocean**	**Enhanced Drilling**	**Enhanced Drilling**
GENERAL						
Reducing the risk of shallow gas release, drilling with zero discharge of the top-hole sections and direction	Y	N	N	N	N	N
Ultra deepwater tight pressure margins	N/A	Y	Y	Y	Y	Y
Abnormal pressure	N/A	Y	Y	Y	Y	Y
Closed system with RCD?	N	Y	Y	Y	N	N
Reduces number of casing strings	Y	Y	Y	Y	N	Y
MECHANICAL						
Top fluid, static conditions	Seawater density	Seawater density	Seawater, OBM or inert gas	Diluted well fluid	Riser full/ atmospheric pressure	Inert gas atmospheric pressure
Top fluid, dynamic conditions	Seawater density	Seawater density	Inert gas or air	Diluted well fluid	Inert gas or air	Inert gas or air
Base fluid	Higher than conventional density mud	Higher than conventional density mud	Conventional or higher than conventional density mud	Higher than conventional density mud	Conventional mud density	Higher than conventional density mud
Pump location	Near seabed	In-line above LMRP	Near seabed / midriser	N/A	Suspended or riser fixed 365 m below sea level	Suspended or midriser fixed
Pump type	Centrifugal	Positive displacement	Centrifugal	Centrifugal	Centrifugal	Centrifugal / PD
Fluid kick point	Wellhead	Near seabed	Riser/choke line	Riser (booster line)	Riser	Riser
Power source	Electrical	Surface seawater pump	Electrical	Surface mud pumps	Electrical	Electrical
Pump electric power	Case dependent	~ 100 HP	Case dependent	N/A	Case dependent	Case dependent
Riser modification	N/A	Mud return and seawater power lines	One Modified Riser Joint Modified Choke Line	Upper Riser Flow Control Equipment	One Modified Riser Joint	Two Modified Riser Joints + Riser annular (gas handler)
Surface mud treatment	Standard	Standard	Standard	Centrifuges	Standard	Standard
RCD location	Casing head (if used)	Near seabed	None	Upper Riser Flow Control Equipment	None	None
Downhole valve in BHA?	N (optional)	Y (optional)	Y (optional)	Y (optional)	Y (optional)	Y (optional)
Max water depth	1524m	3000m	1524m / all	3000m	All	All
Max flow rate of drilling pump at max. WD	4542 l/min	6813 l/min	6056 l/min	Light - weight mud: 11356 l/min Heavy - weight mud: 5678 l/min	6056 l/min	6056 l/min
Max mud density	1677 kg/m^3	2216 kg/m^3	Depth dependent	Heavy - weight mud: 1437 – 2216 kg/m^3 Light - weight mud: 1078 – 1677 kg/m^3	2216 kg/m^3	2216 kg/m^3
Min water depth	30m	900m	900m	0 – 900m	90m	180m
OPERATIONAL						
Variable interface level	N	Y	Y	N	Y	Y
Variable top fluid density	N	N	N	Y	N	N
Cuttings size limit	50.8 mm	N	50.8 mm	N	50.8 mm	50.8 mm

table continued

WELL CONTROL						
Specialized well control equipment required?	N	Y	Y	N	N	Y
Is full riser margin pressure restorable?	N/A	Y	Y	N	N	Y (case dependent)
Well control method (driller's, bullhead and engineer's)	N/A	All	All	All	All	All
Kick detection method	Pump speed / power	Pump speed under circulations, flow in static condition, if not	Pump speed/ power and/or flow meter control system with delta flow measurement	Closed system, secure software and Coriolis flowmeters	Volume control (including riser level) and ccurate outlet flow	Volume control (including riser level) and accurate outlet flow
Direct measurement SIDPP	N/A	Y, multiple methods	N	Y, multiple methods	Y	N
Use of choke/kill lines for well control	N/A	Y	N	Y (Drillers method) N (Modified Methods)	Y	Y (part way)
Well control fluids via pump	N/A	Y	Y	N/A	N	Liquids only
How high gas fraction is pumped	N/A	Lower pump rate	10% (free gas) maximum	N/A	Not affected in WC events	Not affected in WC events
Estimated smallest detectable inflow	< 0.318 m^3	< 0.318 m^3	< 0.318 m^3	1 bbl	< 0.159 m^3	< 0.318 m^3
Max pump flow at well killing	N/A	> 1589 l/min	Case dependent	Method dependent	N/A	Case dependent
Max circulation rate limitation	N/A	Gas handling	Gas handling	Friction losses/ Gas handling	Depends on procedure	Depends on procedure
TECHNOLOGY AVAILABILITY						
DGD operations and WC procedures fully developed?	Y	Y	Y	Y	Y	Y
DGD operations and WC procedures training program fully developed?	Y	Y	Y	Y	Y	Y
Number of specialists trained by 2013?	>20	~300	<10	<10	<20	<10
Highest level of equipment testing: (none/component in shop/flow loop/field test components/field test system/well drilled/ multiple wells drilled)	200 well drilled	1 well drilled	Pump type to be specified	Dilution principle – flow loop test Upper riser package – Dry Run on DEN & similar package in use (MPD application from a DP Drill ship) Flow Stop Valve – Flow loop and open water tested	3 DW wells drilled	SS choke to be specified
Estimated first test system deployment date	2004	Sep-01	2013 (failed)	2014 (failed)	Done in 2012	2014
Estimated first commercial deployment date	Acting	2013 (project closed)	2015 (project closed?)	2014 (Abandoned)	Acting	2015 (Abandoned?)
TRAINING PROGRAM						
Basic operations	5 days (basic + RMR specific)	8 days	3 days introduction specific, 2 days specific and 3 days simulator course	days	RMR training + 6 days specific course	5 days general + specific courses
Advanced well control	N/A	5 days. Written and simulator testing	Case specific. Written and simulator testing	Case specific	None	3-5 days. Case specific.

table continued

Compliance with regulatory / industry standards	Active	IADC Accreditation received for Basic DGD Operations and Advanced Well Control Subsea option of WellCAP. Certificate to be required	None	Training meetings with BSEE	Training meetings with BSEE	Training meetings with BSEE
International standards for equipment certification	Norsok Z-015 / DNV	ABS / DNV	DNV-OS-E101 Drilling facility	DNV DVR for equipment installation to be checked depending on (ABS / DNV)	DNV-OS-E101 Drilling facility	DNV-OS-E101 Drilling facility
Peer review	Regulatory - approved by the 3rd party	Regulatory - approved by the 3rd party	HAZID / HAZOP and DNV operators	Blade Energy Services accepted	DNV as per DNV-RP-A203 Qualification of new technology and HAZID / HAZOP	Y

* *Riserless mud return system*
** *Controlled Mud Pressure system*
*** *Continuous Annular Pressure Management*
**** *EC-Drill® is a Controlled Mud Level (CML) system*

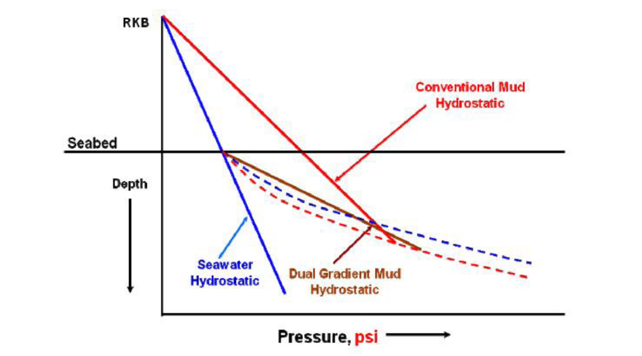

Fig.4. Graphical comparison between (a) SGD and (b) DGD: (a) red solid line; (b) blue solid line till «Seabed» line further being changed to brown solid line

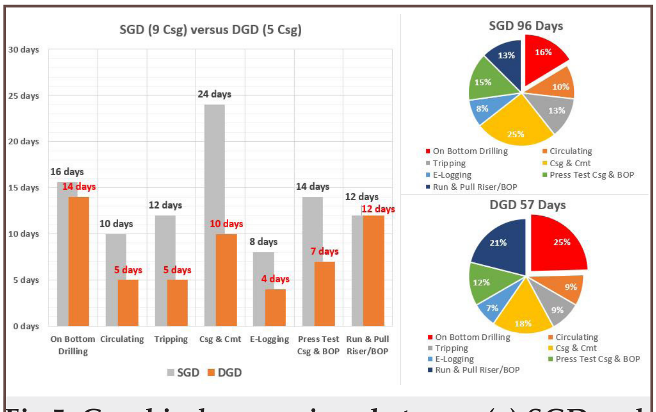

Fig.5. Graphical comparison between (a) SGD and (b) DGD

casing strings, more possibilities in well completion (larger tubing diameters may be applied) and reduced drilling costs [4-7].

The potential economic effect of applying the DGD system is indicated in figure 5 taking deep water well in the Black Sea as an example. Therewith the one day cost of a deep-water well construction (including all materials and services) under the conventional method is approximately USD 1 mln. It will take 57 days to construct the well (instead of 96 days under the conventional method), if the DGD system is applied, with the economic effect being estimated about USD 39 mln.The greatest effect is due to the cost savings for casing, cement, drilling mud and time for RIH/POOH operations.

Dual Gradient Pressure Drilling Technology at CAPM

According to the analysis given in table the «Continuous Annular Pressure Management (CAPM)» System is considered to be one of the most promising and underanalyzed methods of the DGD [11,12].

The principle of CAPM system operation is shown in figure 6: low density drilling fluid (light-weight drilling mud) is pumped into the annular space through the kill lines, where over the lower riser package it is mixed with the heavy-weight drilling mud flowing up from the bottom-hole to the surface. A diluted mud is thereby made inside the riser. The diluted mud on the surface (either platform or ship) is passing through the treatment system to the centrifuge being separated again to light- and heavy-weight drilling mud. As a result, the bottom-hole pressure is formed as the sum of the hydrostatic pressure of the heavy drilling mud column and the diluted mud.

The main elements of the CAPM systems are the **Rotating Control Device (RCD)** and the **Bearing Packing Unit (BPU)** to be installed below the telescoping joint between the riser and the tensioner, preventing the exit of the drilling mud from the well and directing the circulation thereof along the closed DGD loop, therewith enabling BHA rotating, RIH/POOH and drilling. The drilling mud is then flowing to the DGD choke valves, where the required backpressure is generated.

The API CAPM choke manifold is a combination of valves and chokes enabling the diluted mud going out from the well and controlling the annular pressure.

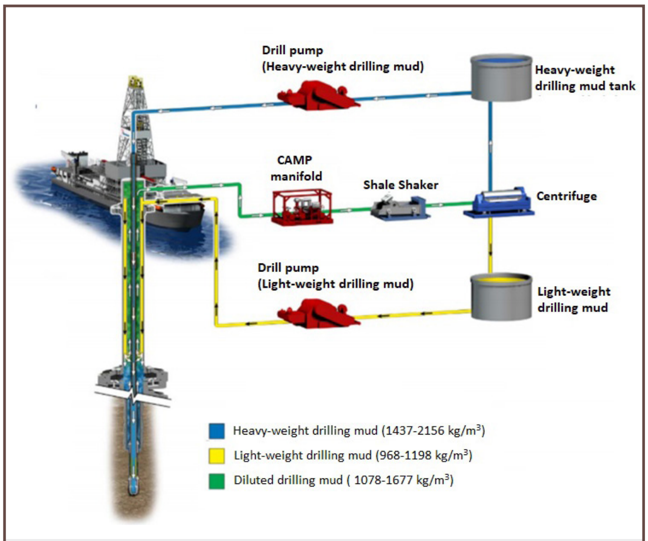

Fig. 6. The «Continuous Annular Pressure Management» system

Programmable logic controller (PLC) is a system for collecting and processing data from DGD instrumentation and mudlogging, as well as a system for remote automatic control of Integrated mud cleaner hydraulics. It is the link between the human-machine interface and the entire DGD equipment.

Human Machine Interface (HMI) is software enabling to control the DGD equipment by sending commands to the PLC. An individual well analysis model is preliminarily developed and loaded inside the HMI for applying the automatic pressure control. Based on the current drilling values, the system is specifying the required backpressure value at the current moment and is sending a command to the PLC to move the choke. The HMI has built-in early detection function of fluid kick / fluid loss thereby enabling real-time monitoring of the well condition.

The Coriolis flowmeter is a device for measuring the values of the drilling mud flow by the principle of accurate measurement of the Coriolis effect. The flowmeter is equipped with an electronic measuring device connected via a signal cable to the workstation. The software compares the drilling mud flow at the outlet with the flow at the inlet of the well thereby determining either the loss or manifestation.

The backpressure pump is making the mud flow on the surface in the DGD piping system. The backpressure pump, like a vacuum cleaner, enables making more accurate control of the annular pressure during the connection process, preventing sudden pressure fluctuations when the mud pump is starting, and performing RIH/POOH operations preventing surge and swab, controlling the well for the loss or manifestation. The pump may be started remotely, forcibly or automatically depending on the operation. To protect the pump against various impurities found in the drilling fluid a coarse filter is to be installed in the pump suction line.

Fig.7. 14” DE-1000 Derrick decanter centrifuge

The CAPM centrifuge is a decanter centrifuge with bowl diameters of 20 inches and more, with the ability to pump mud at 2200 l/min separating the diluted mud into light- and heavy-weight mud. Six centrifuges (including a reserve one) with a total capacity of 11,000 l/min are required for the non-stop operation of the CAMP system on a drilling vessel.

The FlowStop downhole valve not only stops the flow of drilling mud from the annular space (AS) to the drill string (DS) but from the drill string to the annular space either, when the mud pumps are stopping the drilling mud circulation in the FlowStop DS-AS system. This downhole valve is installed above the bit and is pre-set for a certain design opening pressure by changing the spring characteristics. According to this calculation, two factors influence the opening pressure calculation of the FlowStop – water depth and density of drilling mud [13,14].

CAPM centrifuge making and testing

The CAPM centrifuge for drilling mud separation is unique that at the time of the CAPM system development (patent of 2001) there was no documentary evidence in the world of applying such centrifuges. There was also neither literature nor technical books on this process. We had to start from scratch therefore tests 1, 2 and 3 were critical in determining the type and size of the centrifuge to suit the CAPM unit performance.

Centrifuges in drilling are used for cleaning drilling mud from cuttings, as well as for regenerating drilling mud heaver (ex. barite). Until recently, sedimentation scroll centrifuge with a rotor diameter of 320 ... 500 mm were usually applied [1]. But there was no centrifuge for separating the drilling mud into two new fluids with the required densities. We also needed to know what centrifugal force is required and for what period and whether the centrifugal forces (hereinafter G) in a centrifuge may destabilize the emulsion in the drilling mud.

Test No.1 was made in September 2002 at Derrick Equipment Services in North Houston. We have tested and validated the concept of separating 100% 9.5 ppg SOBM at high speeds (>180 GPM) applying a 14” DE-1000 Derrick decanter centrifuge.

Main results of Test No.1:

1. Diluted 9.5 ppg SOBM mud may be separated into 7.3 ppg light-weight mud and heavy-weight mud (12 ppg to 18ppg) depending on the centrifuge setting.
2. The drilling mud property (viscosity) remained

the same during the separation and mixing process.

3. According to the test a small centrifugal force (< 700G) is enough to separate the drilling mud.

4. The polymers or drilling mud used in the process retained the properties thereof during many circulation cycles.

5. One of the flow rate limitations was due to the centrifuge engineering constraints. To put it differently, if the main drive had more power (horsepower), the unit could handle over 250 gpm.

6. We may conclude that the process of separating the drilling mud to parts of different density is possible and is a repeatable process.

7. To increase the flow rate to > 400 GPM per unit, a larger inner diameter of the centrifuge bowl > 20 inches is required.

Test No.2 was made in August 2003 at CTI facilities in West Houston. We have tested and validated the concept for separating a synthetic oil-based mud (SOB) containing 20% brine (WNF 80/20). Maximum flow rate of the mud through the rig was 160 GPM if a Sharples 3400 14" centrifuge identical to the DE1000 Derrick rig is applied. We also found that the power consumption for separating the drilling mud is 0.25HP/GPM at 10.5ppg.

Main results of Test No.2:

1. Under the test results it was concluded that the inner diameter of the centrifuge bowl should be over 20 inches while the rotor length should 2½ times exceed the diameter thereof to provide 500 GPM of mud flow into the centrifuge.

2. The main drive should have at least 0.25 HP/GPM for a centrifuge flow rate of 500 GPM.

3. Diluted 10.5 ppg 80/20 OWR/SOB mud may be separated into 8.5 ppg light-weight mud and 12 ppg to 18ppg heavy-weight mud, depending on the centrifuge setting.

4. According to the test a small centrifugal force (G <700G) is enough to separate the viscous fluid from barite in SOB mud.

5. The properties or drilling mud used in the process remained the same in the course of separation and mixing.

6. We may conclude that 100% SOBM and SOB with 80/20 WNF were identically separated with the only difference that the 80/20 OWR light-weight mud was 1 ppg more as compared to 100% OBM, i.e. 100% OBM contained about 7.5 ppg light-weight mud, while 80/20 OWR contained about 8.5 ppg (including 20% brine).

A modified Sharples P-5000 centrifuge was developed and made under finance of Transocean Company for making Test No.3 in June 2006 at CTI's West Houston office. We have successfully tested high mud flow rates up to 500 GPM in the modified centrifuge, and have made tests for separating two types of drilling mud: 80/20 OWR / SOBM and 100%

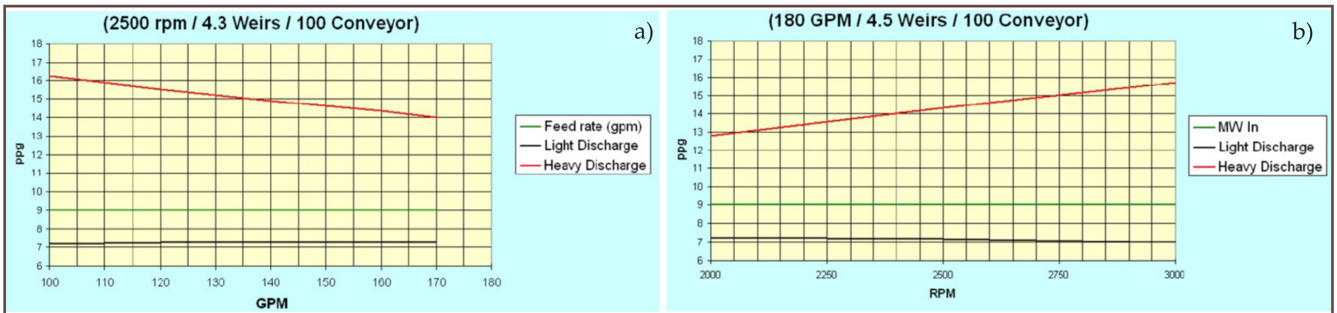

Fig.8. Results of Test No.1 of DE-1000 Derrick centrifuge
a) Reduced mud weight by increasing flow rate from 100 gpm to 170 gpm (from 16 to 14 ppg)
b) Change in the weighted drilling mud density at the outlet of the centrifuge due to an increase in centrifugal force G thereof

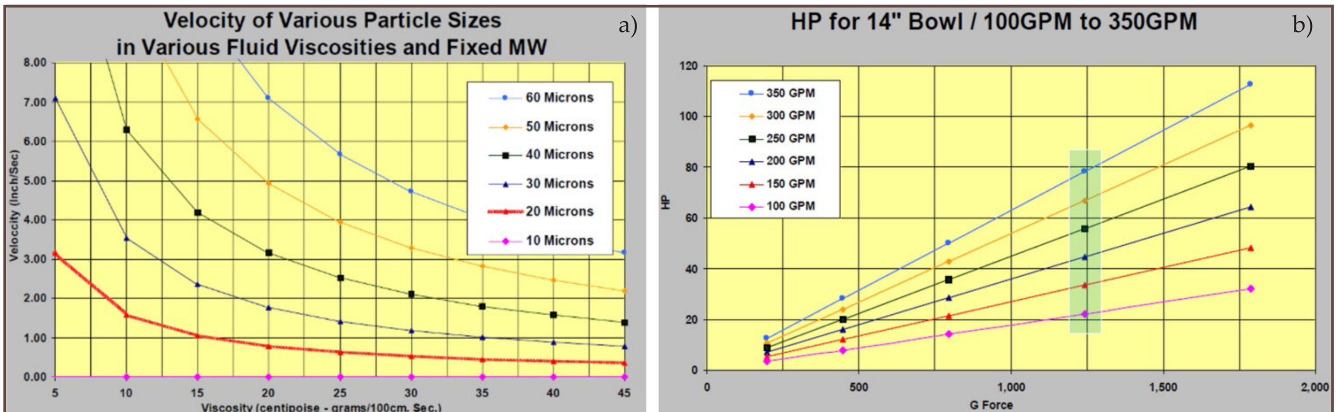

Fig.9. Results of Test No.2 of Sharples 3400 Centrifuge
a) The various size particles velocity at different viscosities of the mud and fixed weight of the drilling mud; b) The required horsepower for a 14-inch centrifuge at various centrifugal force values

Fig.10. The Modified Sharples P-5000 decanter centrifuge

WBM.

The modified Sharples P-5000 decanter centrifuge was taken for making this test for the following reasons:

- Sharples P-5000 was considered to be the most suitable decanter centrifuge for the mud separation process, basically due to internal configuration and performance thereof.
- Prior tested Sharples P-3400 decanter block (14" bowl size) has demonstrated very good results in the high speed separation process.
- Drilling mud was separated by Sharples P-3400 as expected.
- Scaling up the unit as recommended by Sharples will increase the capacity thereof by a factor of 10 (P-3400) to 22 (P-5000).
- The more is the centrifuge power (0.25 HP / GPM), the more is the capacity of the unit > 500 GPM.

Main results of Test No.3:

1. The larger centrifuge with outer bowl diameter (25" vs 14") with more main drive power (150 HP) specially modified for making this test was confirmed to really meet our calculations and exceed our expectations in the mud flow rate over 500 gpm.
2. The results of separating the tested drilling fluids themselves coincide with the results of our two previous tests. Moreover, the water-based drilling mud was separated in the same way as with SOBM but its light phase of the mud was heavier as expected (all water-bases + additives).
3. Also, this separation process required a little more power mainly due to the greater weight of the drilling mud itself (0.32 HP/GPM, on average) (11ppg).
4. Separation of WBM mud gave the same results as with SOBM mud.
5. The properties of the drilling mud remained the same in the course of separation and mixing.
6. During the extended test for separation this process was confirmed to generate internal heat (as expected) as all the energy required to separate the drilling mud is converted into friction generating the heat in its turn.
7. The separation process could be repeated for both SOBM and WBM without any changes or requirements for adding chemicals to the drilling mud for maintaining the specified properties thereof.

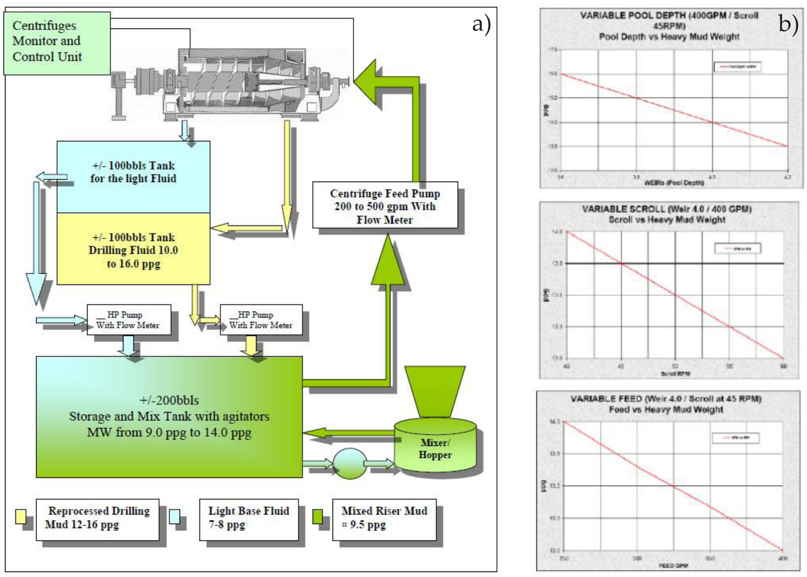

Fig.11. Results of Test No.2 of Sharples 3400 Centrifuge a) Block diagram of the CAPM centrifuge test; b) Graph parameters of the modified Sharples P-5000 centrifuge (density of drilling mud vs depth of the basin, screw rotation speed, flow through the central pipe)

Conclusion

• The DGD opens up new fields for technological possibilities in making deep-water wells with "narrow mud window". Reducing the cost of well construction by up to 40% due to the application of this technology may result in increase of financing for geological exploration.

• The leading Western oil companies have invested up to USD 100 million over a 15-year period in research and development of DGD technology but currently all these developments still have to be applied. Some companies continue to develop DGD systems, being supplementary ones to the original inventions (see table). Nowadays some drilling vessels are technically equipped for making DGD, e.g. 6-7 mud pumps for 510 atm are installed in the Pacific Santa Ana, Pacific Khamsin and Pacific Sharav offshore drills.

• One of the most promising and underanalyzed methods of the DGD is the CAPM "Continuous Annular Pressure Management" System, with all the components thereof being tested in the field, except for centrifuges enabling to separate the diluted drilling mud into light-weight and heavy-weight drilling mud.

• According to the centrifuge test results the diluted drilling mud (all types) may be separated into light mud at 7.3 ppg and heavy mud (12 ppg to 18 ppg) depending on the centrifuge setting and with no changing of other mud properties.

• Test No.3 results confirmed that the larger centrifuge with outer bowl diameter (25" vs 14") with more main drive power (150 HP) may increase the flow rate of drilling mud through the centrifuge to 500 gpm.

• The next step in implementing the CAPM DGD technology is field testing of Flottweg Z6E-3/451 decanter centrifuges (bowl diameter 24", length 72") capable of pumping 11 ppg mud at 500 gallons per a minute.

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Бурение с двойным градиентом: экспериментальные исследования декантерной центрифуги для технологии САРМ

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Реферат

Статья посвящена проблеме бурения глубоководных нефтегазовых скважин, заключающейся в усложнении и удорожании их конструкций из-за сужения диапазона выбора плотности бурового раствора на разных глубинах.

Авторы анализируют разрабатываемые и применяемые в практике морского бурения технологии бурения с двойным градиентом давления, позволяющие бурить значительные интервалы без перекрытия промежуточной обсадной колонной.

На основании анализа данных технологий и с учетом их недостатков авторами предложена новая технология бурения с двойным градиентом давления с размещением всего необходимого инновационного оборудования на буровой платформе.

Ключевые слова: бурение с контролем давления; глубоководное бурение; морское бурение; бурение с двойным градиентом; райзер; морская геологоразведка.

İkiqat qradient ilə qazma: CAPM texnologiyası üçün dekanter sentrifuqanın eksperimentləri üzrə tədqiqatlar

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Xülasə

Məqalə dərin sulu neft-qaz quyularının qazılması zaman müxtəlif dərinliklər üçün qazma məhlulunun sıxlığının seçilməsi diapozonunun daralması səbəbindən onların konstruksiyasının mürəkkəbləşməsi və bahalaşmasından ibarət probleminə həsr olunmuşdur. Müəlliflər, dəniz qazma təcrübəsində işlənilən və tətbiq edilən aralıq qoruyucu kəmərdən istifadə etmədən geniş intervalların qazılmasına imkan verər ikiqat təzyiq qradienti ilə qazma texnologiyalarının təhlilini verir. Məqalədə müəlliflər bu texnologiyaların təhlili əsasında və onların çatışmazlıqlarını nəzərə alaraq qazma platformasında bütün zəruri innovasiya avadanlığının yerləşdirilməsi ilə ikiqat təzyiq qradienti ilə yeni qazma texnologiyası təklif edilir.

Açar sözlər: təzyiqin nəzarəti ilə qazma; dərin sulu sahələrdə qazma; dəniz qazma işləri; ikiqat qradient ilə qazma; rayzer, dəniz şəraitində geoloji kəşfiyyat.