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The Design of High Performance Drill-In Fluids with a View to Maximizing Production and Minimizing Cost

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Abstract

This paper summarizes the design, selection and application of a novel reservoir drilling fluid in a North Sea field development. The oil-based fluid uses the micronized barite technology, based on treated colloidal weight material, to allow improved drilling hydraulics in a well with a narrow mud weight window and minimum invasion in a high-permeability reservoir containing reactive, inter-bedded shales. Five horizontal producers have been drilled and completed with sand screens with significant improvement in drilling performance compared with offset wells. Initial testing shows the wells may be capable of producing above expectations.

Results demonstrate the benefits of running a low-viscosity fluid to reduce the equivalent circulating density (ECD) and the cleanup times prior to running sand screens. The benefits of torque, drag and friction reductions on the drilling performance and screen running are also shown. Return permeability testing carried out before drilling highlighted the importance of bridging agents for controlling fluid invasion and minimizing formation damage. The paper discusses how bridging agent selection was managed on the rig to ensure reservoir protection without compromising flow rates or blinding screens.

The experience and lessons learned from this campaign demonstrate that this technology combined with good planning can play a key role in improving drilling and production performance.

Introduction

The Dumbarton field is located in Blocks 15/20a and 15/20b of the UK sector of the North Sea, between Tiffany and MacCulloch. The Dumbarton field (previously named “Donan”) was discovered in 1987 and developed in the early 1990’s. It produced approximately 15.3 mmstb oil between 1992 and 1997. Production ceased in 1997 with a final water cut of 71%. The field was acquired by Kerr-McGee and partners in 2002 and subsequently by Maersk Oil, who assumed operatorship in November, 2005.

The Dumbarton reservoir is located at a depth of 6,380–6,460 ft true vertical depth subsea (TVDSS) in the Palaeocene Lower Balmoral Sands. The oil is of good quality, 39° API and is under-saturated with an Oil-to-Gas Ratio (OGR) of 315. Reservoir sections are typically 4,000 ft long with 30-70% inter-bedded shale (Andrew and Lista formations). A typical casing scheme and lithology are given in **Fig. 1**. Redevelopment involved a tieback to an FPSO. Five horizontal oil-producer wells and one water-injection well were to be drilled with the Noble *Ton van Langeveld* semi-submersible drilling rig. The drilling campaign commenced in January 2006 and the final well was completed in July 2006.

Previous Problems and Challenges

On previous North Sea projects, the Maersk drilling team had used a variety of reservoir drilling fluids including sized salt, sized carbonate and oil-based mud (OBM). A smart, risk-taking approach, using an ongoing evaluation of new technologies, is employed.

Oil-based muds were used in 12¼-in. sections since the early 1990s. However, due to the anticipated risk of formation damage and sand-screen plugging, water-based fluids were preferred for drilling the reservoir, followed by water-based completion fluids and breakers. This entailed typically one day of rig time for brine displacements and wellbore cleanups.

The design and placement of the breaker proved critical to success; management of losses when pulling the washpipe proved difficult. In addition, the sized salt fluids suffered from a weight limitation and from salt crystallization at surface.

On Dumbarton, wellbore stability studies indicated that mud weights in the range 11.8 to 12.4 lb/gal would be required. This would add significant cost to water-based reservoir fluids due to incorporation of sodium bromide. In addition, the Dumbarton wells required sand screens to be run in up to 5,000 ft of openhole through a mixed sand/mudstone lithology. Concerns about wellbore stability, torque and drag when running the screens, the effects of drill solids on formation damage, and completion efficiency were all important drivers for alternative solutions.

Previous Experience with OBM in the Reservoir

Prior to 2002, the drilling team had had concerns about using OBM in the reservoir section, specifically with respect to formation damage and screen plugging. However, for the Tullich field development (2002), this was reviewed and OBM was selected for both 12¼- and 8½-in. sections with consequent cost and logistical savings.

Four wells were drilled with mud weights of 11.3 lb/gal in the 12¼-in. sections and 10.4 to 10.8 lb/gal in the 8½-in. sections. These wells were deemed successful but several completion issues were noted. The original plan was to use expandable sand screens, but these were withdrawn by the manufacturer and premium screens had to be used. There was concern that when the formation collapsed around the screen, the resultant mixture of formation and filtercake solids would cause plugging. To alleviate the consequences should this occur, the plan was to displace the well to low-solids OBM at TD prior to running the sand screens.

Mixing problems and contamination issues meant that the low-solids fluid did not meet viscosity specifications and failed the Production Screen Test, *i.e.,* could potentially plug the sand screens. Due to changes in the drilling plans, no lost rig time was incurred and the mud was used after reconditioning. Nevertheless, this incident highlighted the problems of mixing bulk fluids onshore to very tight specifications and time constraints. Consequently the team reverted to water-based, sized-carbonate fluids for the subsequent Gryphon wells, drilled in 2004.

Planning for Dumbarton

The experiences summarized above together with the additional challenges of the Dumbarton wells (higher mud weights, narrow ECD drilling window, longer reservoir sections with thick claystone interbeds) required a different approach. The initial design review suggested that novel oil-based fluids weighted with micronized barite would provide additional benefits in terms of ECD reduction and reduced risk of screen plugging.

Treated, Micronized Barite Technology

The treated, micronized barite technology involves using specially treated, micron-sized barite with a typical particle size distribution of 0-5 µm, with the mean below 2 µm. The material is supplied as a liquid concentrate, typically at 19.2 lb/gal in base oil. Previous applications of this technology are described by Oakley[1] and Fimreite, *et al*.[2]

A major advantage of this approach is that barite sag is effectively eliminated and drilling fluids can be formulated with much lower viscosity, hence reducing ECDs. Other noted benefits are reduced torque and drag, even compared to standard OBM, together with reductions in waste and dilution rates consequent on improved solids-control efficiency, using finer shaker screens. The colloidal particle size should also reduce the risks of plugging the sand screens. The main concern was that it could also lead to higher invasion and consequently formation damage.

Laboratory Testing

The intra-reservoir shales were analyzed for cation exchange capacity (CEC), mineralogy (by XRD and infra-red) and for dispersion tendency (by Slake durability). Reservoir core samples were tested for return permeability to different fluids. Thin section analysis was conducted with an optical microscope to look at the rock fabric and pore sizes.

Test results on the shale samples are given in **Table 1** and **Table 2** for CEC and Slake durability, respectively. The CEC was measured using a cobalt dye technique.[3] The results are consistent with mineralogical analysis, which showed total clay contents of 67-79%, with the <2 µm fraction dominated by expandable illite/smectite (70-90%). Slake durability test involves placing sized (2- to 4-mm) pieces of shale in a rotating cage exposed to various brines and determining weight loss after 2 hr. The effect of glycol and polyether diamine (PEDA) stabilizers was also evaluated. The results indicate that the shale has high-to-very-high reactivity but appears to be non-dispersible in the brines tested. However, Slake durability results can be misleading and depend on sample quality and preparation method.

Thin section analysis (**Fig. 2**), showed a sandstone with high porosity (~30%), containing angular to sub-angular quartz grains with 10-15% feldspar, 15% clay and 5% other minerals. The grain sizes varied from 50-250 µm and the pore sizes from 50-100 µm, although a significant number of "oversize" pores were present, mainly 150-200 µm but up to 400 µm in one instance. The porosity values were subsequently confirmed by helium porosimetry as being in the range 31-35%.

Return permeability test results are summarized in **Tables 3-5.** The initial and second sets were conducted by the fluids supplier. The cores were vacuum saturated with 10% NaCl brine. Initial and return permeability measurements were made with mineral oil at 175°F. Exposure to mud was for 4 hr under dynamic conditions at 175°F and 500-psi overbalance pressure. The cores were judged to be too fragile to allow testing at 1,000 psi as planned. Pore pressure was set to 500 psi and net confining stress was 250 psi.

The initial set (**Table 4**) compared various sized carbonate water-based fluids against OBM with treated, micronized barite. The first set of data suggested that poor bridging was occurring on some tests. Accordingly in the second set of tests, involving the sized carbonate/NaCl/KCl/NaBr fluid and OBM with treated micronized barite, the bridging content was increased. The PEDA inhibitor was added to the water-based fluid as optical microscopy had indicated significant clay content. These fluids gave improved results, with the oil-based fluid clearly out-performing water-based fluid.

The sized calcium carbonate bridging package chosen for the oil-based fluid was very coarse, with D_{10}, D_{50} and D_{90} of 2.3, 58 and 228 microns, respectively. This would cause significant problems in the field with maintaining the particle size distribution. Accordingly in the final set of tests, conducted by a third party lab, a further comparison was made between this coarse bridging package and a medium bridging package with D_{10}, D_{50} and D_{90} of 1.6, 37 and 133 microns, respectively. Results are given in **Table 5** and confirmed again that the coarser bridging package gave better results. Exposure to mud was for 48 hr under dynamic conditions at 175°F and 1,000-psi overbalance pressure. This test also included a displacement fluid with finer carbonate and insertion of a 230-

micron premium screen.

Mercury porosimetry tests indicated median pore throat diameters of 20-24 microns with maximum diameters 28-32 micron, which is not consistent with the thin section analysis. The mercury porosimetry technique is not best suited for characterizing the largest pores due to the low injection pressures required; in this case more credibility was placed on the thin section results as the return permeability tests indicated better performance from coarser calcium carbonate.

Risk Assessment and Success Criteria

Following successful completion of the lab work, the decision was taken to use the oil-based, treated micronized barite fluid (TMBF) to drill the five production wells. A sized carbonate water-based fluid was selected for the water injector well, where the reservoir interval was much shorter, with consequently reduced risk to the completion. The TMBF was also selected for the 12¼-in. intermediate sections, as staying with a single oil mud was advantageous from both cost and logistical standpoints.

Since this would be the first UK application of this technology in a mainstream drilling application, a detailed risk assessment was prepared. The key issues were thought to be communication and training, logistics, hole cleaning and maintenance of the coarse bridging package in the reservoir section. Communication and training was addressed by assigning a technical specialist to the rig for the first hole sections, partly to assist the mud engineers in handling and treating the concentrate, partly to answer any questions from the offshore drilling team and to follow the implementation of the new technology. The mud engineer provided a checklist for the rig floor and shaker house and emphasized the importance of avoiding contamination. Mud engineer training was also conducted prior to the job starting.

The main logistical concerns were the ability of the supply boat and the rig to handle and store the heavy liquid concentrate. This was validated. Hole cleaning concerns were addressed by software simulations, which showed good hole cleaning in the 12¼-in. sections at the expected flow rates of 900-1,100 gal/min, with ROP of 100-140 ft/hr.

Maintenance of the bridging package was addressed by measuring the HTHP fluid loss on sized aloxide discs. Originally 190-micron discs were proposed but this would have entailed the use of coarse shakers and heavy maintenance additions to maintain the coarse calcium carbonate solids in the system. Accordingly, a compromise was reached with a revised bridging package intermediate between the coarse and medium sizes. This would allow the medium carbonates to be supplied in bulk, with smaller additions of the coarser carbonate (supplied in sacks) to replenish losses at the shakers. Bridging would be controlled by measuring spurt loss on a 90-micron disc.

The various success criteria proposed are given in **Table 6.** Performance against these targets will be assessed later.

Drilling Performance – 12¼-in. Sections

The plan was to use the TMBF for all 12¼-in. hole sections; however, after the first two, the decision was made to change to regular OBM. This decision was based primarily on loss circulation encountered in the Grid Sands and when running and cementing the 9⅝-in. liner. Reverting to regular OBM prompted the remaining 12¼-in. sections to be batch drilled, saving rig time and logistics.

The losses in the Grid Sands probably occurred as a result of invasion of whole mud as the bridging package in this hole section was not designed for this highly permeable formation (thought to be >10 Darcy). Evidence for invasion can be seen in the ARC resistivity curves, supported by high bit resistivity measured by the GVR tool, suggesting that the micronized barite fluid was being flushed ahead of the bit.

Unusual wear was seen on the valve seats of the mud pumps. This was investigated by comparative abrasion tests. These were carried out using the API method measuring weight loss of a mixer head immersed in the test fluids. Results (**Fig. 3**) show that the TMBF was ***less*** abrasive than regular OBM, although the fluids tested did not contain real drilled solids. The wear was later proved to be caused by pitting-type corrosion following prolonged exposure to seawater while batch drilling the 36- and 17½-in. hole sections.

Generally, during the 12¼-in. sections, the drilling team traditionally maximizes ROP, which in some cases can reach instantaneous rates of 400 ft/hr. It was felt that the low viscosity TMBF did not permit optimum hole cleaning under these conditions. This was evidenced by occasional packoffs and by a delay of typically 4-5 min in the cuttings reaching the shakers when circulation was started after a connection. This compares to typically less than a minute with regular OBM. The wells also took slightly longer to clean up at TD, requiring circulating five times "bottoms up" before pulling out to run casing compared to an average of four times "bottoms up" with regular OBM on the subsequent wells. The 6-rpm dial reading was run at 4-5 for the micronized barite system, giving typical PV/YP of 17/11. In contrast, the conventional OBM was run with typical 6-rpm dial reading of 12 and PV/YP of 27/20.

After setting the 9⅝-in. liner, the first well was suspended for 31 days with the TMBF and a trash cap while the rig moved on to other wells. Subsequent ROV inspections showed no break-out of the oil mud, confirming the expectations of good, long-term suspension properties.

The losses while running the 9⅝-in. liner could have been induced due to the small clearance between the liner hanger (OD 12.20 in.) and the 13⅜-in. casing (ID 12.347 in.). This resulted in a flow-area of only 2.8 in.^{2} and dimensions susceptible to plugging with the larger shale cuttings.

Although standpipe pressures were lower on the two sections drilled with the TMBF, there was no indication of significant ECD benefits compared to the subsequent sections drilled with regular OBM. However, drilling torque with the TMBF was generally lower over the significant parts of the wellbore and showed less variation.

Drilling Performance – 8½-in. sections

The application of the treated micronized barite fluid was validated on the 8½-in. sections and completions. Drilling fluid properties and drilling data are summarized in **Table 7**. A number of challenges were accomplished successfully:

• Acceptable hole cleaning, with no evidence of cuttings slippage (as with 12¼-in. sections).

• ECD management successful on all wells, allowing optimized ROP without exceeding the ECD limit.

• Gained confidence to lower mud weight from 12.0 to 11.6 lb/gal while still maintaining mechanical wellbore stability.

• Development of a technique for drilling through geological faults.

• Reduced time to condition mud over 270/325-mesh screens, 500 ft before TD.

• Achieved mud-cost saving compared to water-based sized-carbonate fluids.

The D1/D1z and D4/D4z wells proved challenging as it became necessary to sidetrack because of incurable losses and non-economic sands, respectively. On these wells, changes to the BHA design were made to mitigate increasingly severe stick-slip, and excessive wear on drill pipe hard bands was observed. The wear is believed to be partially caused by stick-slip and forward whirl in abrasive sands. This gave rise to further concerns that the TMBF might offer less protection than standard OBM to abrasion against the sandstone face. A further series of abrasion tests were conducted, which again disproved this.

Differential sticking was evident, especially on the D4/D4z sections. However the drilling team was reluctant to reduce the mud weight further as this would have necessitated pumping out of hole to avoid swab.

Mud Weight and ECD Management (8½-in. Section)

The mud weight was lowered from 12.0 to 11.6 lb/gal over the course of the five wells. Planned and actual ECD's are summarized in **Table 8**. On no occasions were the ECD limits exceeded.

The ROP was controlled at 100-200 ft/hr in the sands but was pushed to 400 ft/hr in shale. Instantaneous rates of 460 ft/hr were achieved without exiting the ECD window. It should be noted that the ROP's are affected by other factors, primarily controlled drilling in reservoir sands to meet data acquisition requirements.

Management of Bridging Material

The medium calcium carbonate was supplied in bulk and added at 40-lb/bbl rate for drilling the reservoir sands. The coarse material was supplied in sacks and added at 5-lb/bbl rate with maintenance additions of 4-8 sacks/hr to replace losses on the shakers. The addition rate was increased during periods of high ROP and results were checked by measuring the spurt loss on a 90-micron aloxide disc, with typical values of 8 mL and total loss (30-min) of 10 mL. The shakers were dressed with 175/210 mesh during drilling. Mud weight was maintained by operation of the centrifuge and by addition of base oil premix. If coarse bridging agents had not been required, use of 325- and even 400-mesh screens would have been possible due to the small size of the weight material, with consequent reduction in dilution and maintenance.

Drilling through Geological Faults

Losses were encountered when penetrating faults in the D3 and D1 wells. On the D3 section, the losses stopped after 404 bbl had been lost. On the D1 well, an instantaneous loss of 652 bbl occurred; the higher losses possibly caused by the fault being more or less parallel to the wellbore. Subsequently "ballooning" occurred with some mud lost when pumping and being returned when shutting down the pumps and pulling out of hole. This led to LCM material coming back and sticking around the BHA, which almost resulted in stuck pipe.

After sidetracking D1 to D1z, a technique was developed to minimize losses in faults. Prior to encountering an anticipated fault, time is spent circulating to reduce the ECD by removing the low-gravity solids. The fault is approached with reduced flow rate and reduced ROP and with an increased concentration of bridging agent (50 lb/bbl). The centrifuge is switched off 100 ft before, and all fluid transfers postponed until after passing the prognosed fault by 100 ft. This approach was successful and faults on D4/D4z and D2z were drilled with minimal losses.

Hole Cleaning

The difficulty of cleaning up the horizontal section was always recognized, and swab-surge limits were strictly observed. "Bottom-ups" was circulated in a stepwise mode only in shale sections to prevent washouts in the sands. Where required, reaming was done by running in hole with two singles and pulling one single out. Following hole cleaning concerns on the two 12¼-in. sections, the 6-rpm dial reading was run at 8 for the first reservoir section but then reduced to 4-5 for the remainder to help with ECD control. The flow regime in the openhole was turbulent at the flow rates used (580-700 gal/min, **Table 7**).

Mud Handling and HSE

No problems were encountered in transferring the heavy concentrate to the rig, although it had already been noted that only one of the two supply boats had the required pump capacity. Mud agitators could only be run intermittently in the concentrate because of motor limitations, but pit cleaning at the end of the campaign proved much easier with the TMBF as there was no barite settlement. The mud proved easier to prepare than conventional OBM and there was no dust hazard from powdered barite.

The centrifuge was used extensively in the 8½-in. sections; initially some stall outs occurred. This was solved by reducing the feed rate. A reduction in shaker screen usage was also observed.

Running Sand Screens

Various combinations of shaker-screen mesh and flow rates were tried to reduce conditioning time before running the sand screens. Significant time savings were realized, but the time taken was longer than anticipated from the start of the project. This was probably caused by cuttings continually washing out from the openhole section.

On the D3 well, TD was not known in advance, which meant that mud conditioning could not be started until TD was reached. On this well, 400-mesh screens were installed too soon, necessitating low flow rate. It was recognized that the 270/325-mesh screen combination gave the best results. The team also acknowledged the advantage and time-saving of starting to screen up some 500 ft prior to reaching TD (when this could be anticipated).

The Hook Load when running the sand screens on D2z is given in **Fig. 4**. Friction factors of 0.25 and 0.30 were applied for modeling the casing and openhole sections, respectively. The actual slack-off drag was lower than predicted, indicating that the assumed friction factors were conservative. The modeling was updated during the operation, resulting in less HWDP added to the drillstring with consequent reductions in rig time. Some differential sticking was observed on D4z, probably caused by sections of blank pipe included between the screens. Despite this, all sand screens were successfully run to bottom, with washpipe only used on one well, with consequent time savings.

Performance against Success Criteria

The agreed criteria for comparing performance against success are summarized in **Table 6**.

The ECD Management criteria set limits of how much the ECD could be above the mud weight for a given flow rate and instantaneous ROP. For example, at the 12¼-in. section TD, approximately 5,000 ft from the 13⅜-in. shoe, the ECD should not exceed the mud weight by >0.5 lb/gal. This requirement was fulfilled for both 12¼- and 8½-in. sections. The average ECD in the 8½-in. section was 0.4 lb/gal lower than traditionally seen for conventional OBM.

The requirements on drilling maintenance and dilution rate were not met because of the difficulty in maintaining the coarse bridging solids in the reservoir section. A high dilution rate was needed to maintain the mud weight; this was achieved by extensive use of the centrifuge and by adding base oil.

The drilling torque requirement in the 12¼-in. section was met, but valid comparisons against WBM when running screens was judged impractical. Typically, friction factors used in modeling OBM are 20% lower than for WBM.

Once the optimum combination of screen size and flow rate had been worked out, substantial time savings were made in conditioning the mud before running screens. The average on the last three wells was 9 hr and the average on all wells was 11 hr, compared to typically 23.9 hr on the Tullich wells.

The ROP targets were jeopardized by teething problems with a novel rotary steerable system, which affected both 12¼-in. sections drilled with the TMBF. These achieved average ROP of 105 and 185 ft/hr, respectively. Subsequent 12¼-in. sections with regular OBM achieved averages of 85, 114 and 134 ft/hr. With hindsight, the target of 200 ft/hr was probably unrealistic. In the 8½-in. sections, the requirements for geological data acquisition from a certain depth played a role in slowing down the average ROP achieved.

Average running speed for the first two 9⅝-in. liner jobs was 292 ft/hr with the TMBF compared to 275 ft/hr for the last three with conventional OBM and 214 ft/hr on three offset wells in the same block.

The economics of the TMBF system in the 8½-in. section were beneficial with mud cost/ft about half that of water-based fluids on offset wells. The higher mud weights required on Dumbarton would have exaggerated this difference further had WBM been used. Despite two unplanned geological sidetracks, the project cost was on budget. Drilling performance, based on Maersk Oil drilling metrics, was 30% better compared to previous U.K. wells in 2005.

Successful well tests indicated that the sand screens did in no case plug up and that the TMBF could be regarded as non-damaging to the reservoir formation with the customized bridging package used.

Conclusions

The oil-based fluid, using treated, micronized barite, met most of the success criteria that were set and proved economical in the reservoir section in terms of both mud cost/foot and rig-time savings. The following benefits were realized.

- ECD limits were never exceeded on both 12¼- and 8½-in. sections despite high instantaneous ROP's.
- Lower friction factors and higher running speeds were demonstrated when running 9⅝-in. liner.
- All sand screens were successfully run to bottom, with lower friction factors demonstrated.
- No barite sag was observed and there was no mud-related down time.
- No wellbore stability issues were encountered, enabling slight mud weight reductions in later wells.
- There were no HSE or logistical/handling issues.
- Significant savings in rig time required to condition mud prior to running sand screens were realized (but less than targeted).
- Drilling techniques for traversing faults were successfully modified to reduce mud losses.

Issues that arose and targets that were not met include the following.

- Unexpected losses in high-permeability sands in the 12¼-in. section and when running the 9⅝-in. liner.
- The benefit of running one mud in both the 12¼- and 8½-in. sections was not achieved, primarily as a result of the losses.
- Maintenance of the coarse bridging package proved difficult with knock-on effects on solids-control efficiency, dilution rates and mud costs.
- Hole cleaning efficiency proved slightly less effective in the 12¼-in. hole at high instantaneous ROP, requiring slightly longer circulation time before

tripping.

- Mud pump and drillpipe wear occurred on several sections; these were subsequently accepted as not being mud related by the Operator.

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Nomenclature

ARC = *Array Resistivity Compensated*
BHA = *Bottomhole Assembly*
CEC = *Cation Exchange Capacity (meq/100 g)*
ECD = *Equivalent Circulating Density (lb/gal)*
FPSO = *Floating Production Storage and Offloading Vessel*
GVR = *GeoVISION Resistivity*
Mmstb = *Million standard barrels*
OBM = *Oil-Based Mud*
PV = *Plastic Viscosity (cP)*
ROP = *Rate of Penetration (ft/hr)*
TMBF =*Treated, Micronized Barite Fluid*
XRD = *X-Ray Diffraction*
YP = *Yield Point (lb/100 sq ft)*

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Table 1 – Cation Exchange Capacity of Intra-Reservoir Shales

Sample	Depth (m)	CEC (meq/100g)	Reactivity
BP 15/20a - 4	1952.7	49.5	Very High
S4 15/20a - 4	1975.3	28.5	High

Table 2 – Slake Durability Results – Intra-Reservoir Shales

Fluid	pH	Recovery
11.5ppg CaCl2/CaBr2	9.4	84.10%
As above + 3% Glycol	9.3	96.60%
As above + 2% PEDA	8.9	102.20%
11.5ppg Na/K formate	9.4	100.40%
As above + 3% Glycol	9.2	102.50%
As above + 2% PEDA	10.8	100.70%
11.5ppg NaCl/NaBr/KCl	7.8	90.60%
As above + 3% Glycol	6	96.80%
As above + 2% PEDA	10.2	99.90%
Base Oil	N/A	99.20%
Base Oil + 0.3% emulsifiers	N/A	80.10%

Table 3 – Initial Return Permeability Results

Core # (15/20A-9)	Drilling Fluid System	Initial Perm (md)	Vol filtrate (mL)	Spurt loss (mL)	Return Perm (md)	Return Perm (%)	Breakthrough Pressure (psi)
Core 25	Sized Carbonate WBM	1611	3.27	0.95	750.7	46.6	8.3
Core 27	Sized Carbonate WBM	1466	6.67	1.7	503.9	34.4	15.4
Core 32	Sized Carbonate WBM	1057	3.15	1.4	791.5	74.9	2.7
Core 33	OBM (Micronised barite)	954	2.48	1.85	103.7	10.9	13
Core 30	OBM (Micronised barite)	1657	1.81	0.9	1110.2	67	1.6

Table 4 – Second Return Permeability Results

Core # (15/20A-9)	Drilling Fluid System	Initial Perm (md)	Vol filtrate (mL)	Spurt loss (mL)	Return Perm (md)	Return Perm (%)	Breakthrough Pressure (psi)
Core 24	Sized Carbonate WBM (NaCl/KCl/NaBr)	1446	3.08	1.2	761	52.6	8.8
Core 26	OBM (Micronised barite) + Extra CaCO3	1593	1.47	0.8	1300	81.6	0.8

Table 5 – Third-Party Return Permeability Test Results

Core # (15/20A-9)	Drilling Fluid System	Initial Perm (md)	Vol filtrate (mL)	Spurt loss (mL)	Return Perm (md)	Return Perm (%)	Flow rate at 1psi (mL/min)
Core 9	OBM (Micronised barite) Medium Bridging	1907	2.19	1.4	1423	74.6	1.1
Core 7	OBM (Micronised barite) Coarse Bridging	1708	2.62	2.1	1524	89.2	1.28
Core 8	OBM UltraFine Barite Coarse Bridging	1454	5.01	3	992	68.2	0.38

Table 6 – Success Criteria
Plan vs. Actual

No.	Criteria	Description	Met
1	ECD Management	<0.1ppg/1000ft 12¼-in.hole @1000gpm/200 ft/hr <0.1ppg/1000ft 8½-in.hole @ 500gpm/150ft/hr	Y Y
2	Dilution Rate	<= 0.10 bbl/ft in 2¼-in.hole <=0.12 bbl/ft in 8½-in.hole	N N
3	Torque and Drag	>10% reduction vs OBM in 12¼-in.hole >30% reduction vs WBM in 8½-in.hole	Y -
4	Mud Conditioning	>2 hr/2 circulations/4 "bottoms up"	N
5	ROP	>200ft./hr in 12¼-in.hole >100ft/hr in 8½-in.hole	N N
6	Sag	No mud weight variations due to barite sag	Y
7	NPT	Zero NPT due to mud	Y
8	HSE	No unsafe incidents, compliance issues or spills	Y
9	Time Saving	Average running speeds increased for 9⅝-in. liner Time saving from having one fluid	Y Y

Table 7 – Drilling Fluid and Drilling Data Summary

Well Name	D5	D3	D1/D1z	D4/D4z	D2z
Reservoir Footage	2860	6614	2586/5500	4875/3928	5026
Mud weight (ppg)	12	11.8	11.8	11.6	11.6
6 rpm (dial)	8	5	5	5	4
YP (lb/100 sq.ft.)	15	12	11	10	8
Gels (10sec/10-min)	8/12	6/8	7/9	7/9	5/8
Electrical Stability (V)	850	680	680	585	560
HTHP FL (200^0F/500psi)	2	1.4	1.4	1.3	2
Circulating time on fine screens prior to TD (hr)	9	0	2	4	2
Circulating time on fine screens at TD to pass PST (hr)	9	19	6	11	10
Flow rate (gpm)	640	580/350	700	690	650-680
Screen mesh used	270/325	270/325/400	270/325	270/325	270/325
Average interval ROP* (ft/hr)	50	73	105	140	79

*includes controlled drilling for data acquisition purposes
The oil/water ratio was maintained around 75/25 and the water phase salinity at 180-200g/L chloride. The hole angle was 90 degrees in all cases.

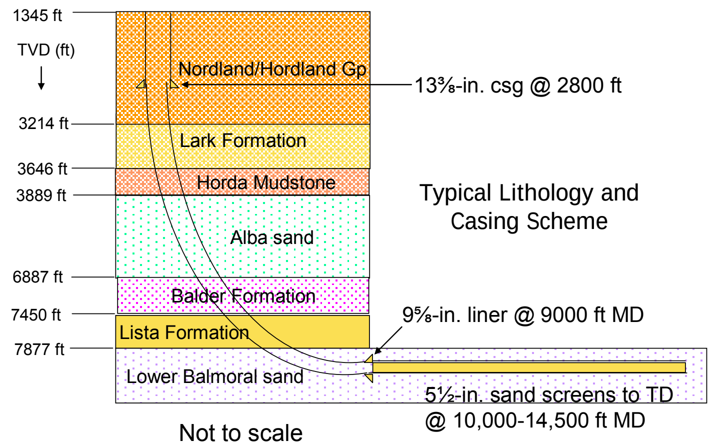

Fig. 1 – Typical lithology and casing scheme for Dumbarton wells.

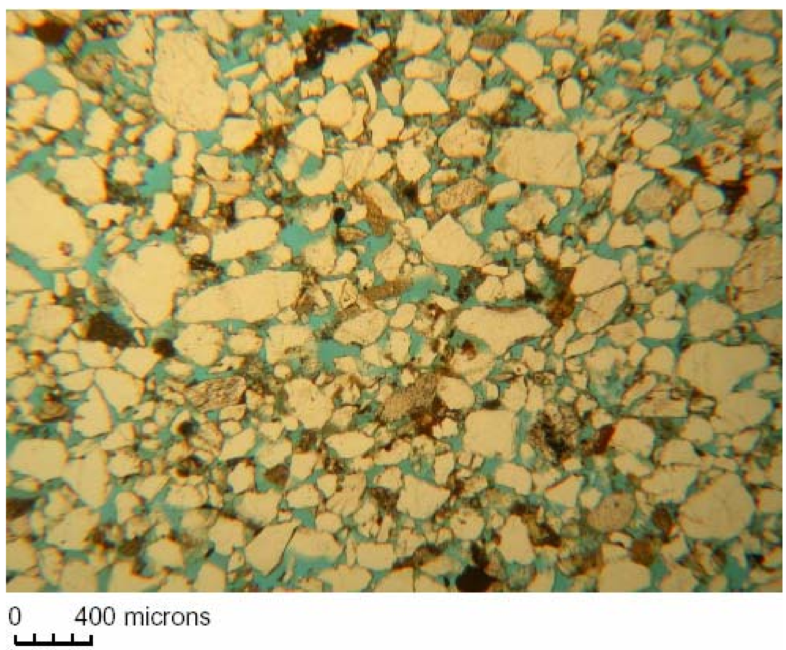

Fig. 2 – Thin section analysis.

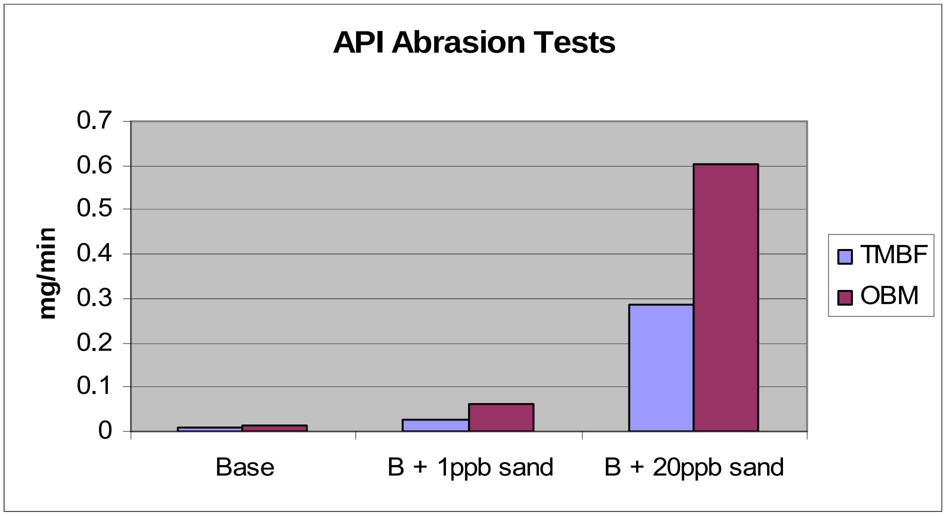

Fig. 3 – API abrasion tests comparing treated micronized barite fluid (TMBF) with normal oil-based mud (OBM).

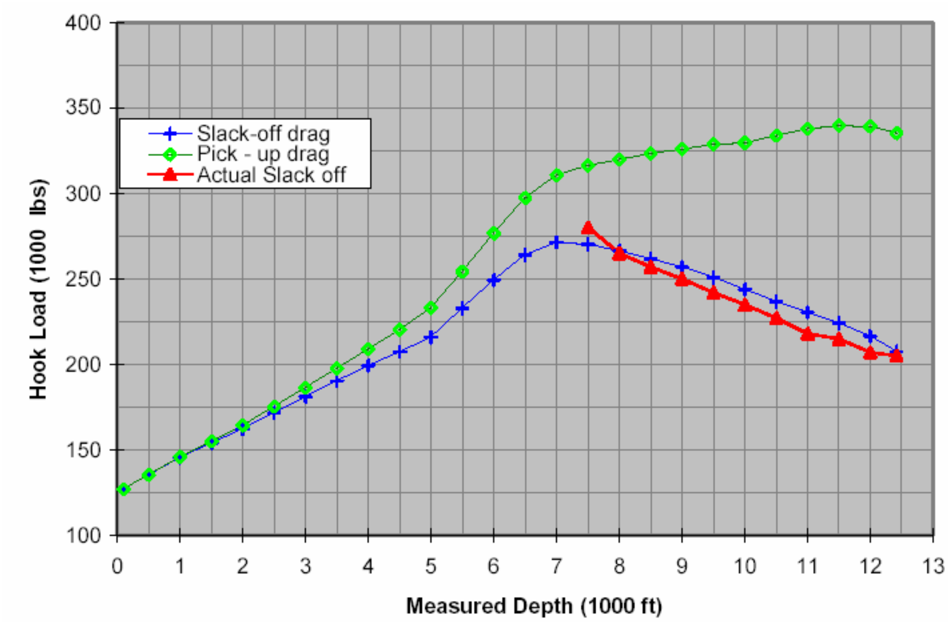

Fig. 4 – Theoretical vs. actual drag during screen running on D2z. The screens were run to 12,418 ft.