Development and Field Results of a Unique Drilling Fluid Designed for Heavy Oil Sands Drilling

Leonard V. Baltoiu, Flori Baltoiu and Brent Warren,
Q'Max Solutions Inc., Calgary, Canada

Abstract:

Drilling Heavy Oil Sands are traditionally fraught with many technical challenges. Stability of the wellbore, accretion of the tar on drill string and solids control equipment, torque-drag considerations, extreme temperature conditions, as well as the disposal of oily solids are just some of the challenges that need to be met.

This paper describes the development and large project field success of a new drilling fluid designed to meet these challenges. The water-based fluid is based upon two guiding principles, the ability to incorporate the bitumen into the mud itself, and the capability to later break the bitumen from the mud system. Incorporation of the bitumen into the Heavy Oil Sands Mud (HOSM) is via a direct emulsification and results in zero accretion, virtually oil-free sand from the solids control equipment, fast drilling rates and good hole stability.

Data from a 156 well (78 pair) horizontal Steam Assisted Gravity Drainage (SAGD) heavy oil program in Northeastern Alberta shows the robustness and effectiveness of the system. The new oil in water direct emulsion system drilled on average 1000 meter average horizontal wells in 6.1 days per (Injector/Producer) well pair. Lost time due to wellbore instability or accretion problems was virtually eliminated. Total project costs were 20% under budget, and the entire 156 wells were finished 5 months ahead of the drilling curve.

Introduction:

There are a number of challenges that operators face when drilling into the poorly consolidated McMurray tar sands in Alberta.[1] This 1-6 Darcy formation is composed of loose, well-sorted white sand and a bitumen matrix (up to 23% v/v). In poorer quality reservoirs, significant shale sections may be encountered within the tar sands themselves. A number of drilling challenges have been identified, including:

a. If mud temperature is not controlled, borehole stability may become an issue as the tar sand formation bitumen matrix melts away. This effect will depend upon the sand and bitumen quality, as well as the drilling fluid chosen. Such problems when they occur are typically alleviated by using mud coolers that maintain drilling fluid temperatures below the formation collapse temperature. This requirement may vary depending upon the bitumen composition/gravity.
b. Tar sand accretion is invariably the most difficult and persistent problem while drilling SAGD wells. Ribbons of tar sands adhere to the surface and subsurface equipment, thereby greatly reducing the performance of this equipment. Elevated torque and drag encountered while drilling and RIH with casing/liner, MWD and mud motors coated in sticky tar, shaker screens blinding, centrifuge's performance reduced due to tar plugging, drilling rig and mud tanks coated in tar sands are only a few problems generated by tar sands accretion.
c. Accretion also leads to large volumes of drilling fluid being used. This in turn creates an environmental issue as seen in excessive disposal and clean-up costs.
d. Foaming of the drilling fluids is also a common problem observed in a number of drilling fluids used for tar sand drilling. Once the foaming has started, it is often difficult to handle unless physical changes to the rig and fluid flow systems are undertaken. The use of defoamers typically leads to environmental challenges in fluid disposal.
e. Lubricity issues tend to run in unison with the accretion problem. Once accretion is handled, the torque and drag is reduced.
f. Although often thought of being of minor importance, formation impairment is an issue in drilling tar sands. Dirty sands with significant amounts of dispersable or swellable clays are prone to damage. In addition, formation of *in-situ* emulsions within the sand reservoir has also occurred.

g. Severe shaker screen wear from the coarse solids has also been a significant cost item.

Drilling fluids, in the 1990's and early part of 2000's were designed to reduce or alleviate tar sand accretion. These water based drilling fluids were polymeric based with additives such as potassium salts (KCl or K_2SO_4) or D'Limonene (orange oil extract) to inhibit tar accretion. There effectiveness was, at best, only partially achieved as accretion was still an issue, wellbore instability occurred and disposal costs were high.

In order to alleviate and eliminate these problems, an innovative approach to tar sands drilling fluids was developed. Approximately 280 lab tests and two field applications later, a new and fresh-water based drilling fluid, HOSM, has been developed. This paper describes the properties of a system to remove tar from the sand, the simple ability to strip the tar from the mud system and an environmental plan to handle the wastes. Details of the field success of HOSM in northeastern Alberta are discussed fully in terms of fluid design, fluid handling and economic success of the Commercial drilling phase.

Heavy Oil Sands Mud (HOSM) Development

The guiding principle in the development of HMOS was atypical, given how drilling fluids were previously used in tar sands. Rather than trying to prevent accretion by preventing any solubilization of bitumen into the mud system itself, HOSM acts by cleaning the bitumen completely off of the sand and "loosely emulsifying" the oil into the drilling fluid. At the end of the well/section, the oil is then stripped and drilling fluid either reused or simply disposed of.

The primary step in the bitumen solubilization step was to find an efficient cleaning product that worked quickly and efficiently, was of low toxicity and had minimal environmental impact. Following a selection process of 58 products, a cleaner was chosen that removed 96% and 98% w/w of bitumen from a tar sand core at 5% and 10% v/v concentrations of cleaner, respectively.

The HOSM proved to be very resilient with regards to tar cleaning ability, mud rheology control, filtration control and emulsion stability. Table 1 shows the effect of contaminants on the basic direct emulsion system. As expected with a polymer based fluid which contains no bentonite, the effects of lime, elevated pH and salt are minimal on the basic rheological properities. Gypsum addition resulted in a decrease of plastic viscosity and yield point. Increasing the solids content gave an expected increase in plastic viscosity, while the yield point and gel strengths remained stable.

No foam was generated through mixing the fluid or by any of the contaminants. Previously used salt-based fluids were typically very foamy in the presence of any amount of tar sand.

HOSM System with 5% v/v Tar Sand	600	300	200	100	6	3	PV (mPa.s)	YP (Pa)	GS 10" (Pa)	GS 10' (Pa)	API-FL (mL)
Blank	*64*	*47*	*39*	*28*	*8*	*6*	*17*	*15.0*	*3.0*	*3.5*	*10.0*
+ 5 kg/m^3 Gypsum	48	35	29	20	5	4	13	11.0	2.5	2.5	9.5
+ 1 kg/m^3 Lime	64	47	39	28	8	6	17	15.0	3.0	3.5	10.0
+ Caustic for pH=12.0	62	46	38	28	7	5	16	15.0	3.0	3.0	10.0
+ 20 kg/m^3 Salt	49	35	29	21	5	4	14	10.5	2.0	2.5	8.0
+ 6 % Tar Sand (LGS)	72	52	42	31	9	6	20	16.0	3.0	3.5	6.0

Table 1 – Effect of typical drilling contaminants on fluid properties of HOSM

While cleaning the tar from the sand is a critical step, the cleaning of the drilling fluid at the end of the well is equally important. A huge environmental and cost efficiency benefit is possible if the fluid can be stripped of the oil/bitumen under static conditions, and the fluid can then either be reused or cheaply disposed of. The idea behind HOSM was to break it into basic components of oil, water and solids, and then these components disposed of safely and cheaply and without impacting the environment.

Fourteen emulsion breakers were tested with various results. The best performance was produced by an environmentally friendly breaker, designated here as Breaker. The oilsands Breaker works by modifying fluid's rheology to the point where oil and solids are released from the external water phase.

Under static conditions gravitational segregation takes place over a number of days, allowing oil migration to surface solids migration to bottom and leaving clear water in between. Figure 1 below shows the effect of the Breaker on the rheology of the HOSM, in which 5% w/w tar sands has been incorporated. As the yield point falls over time, the separation into the distinct phases begins.

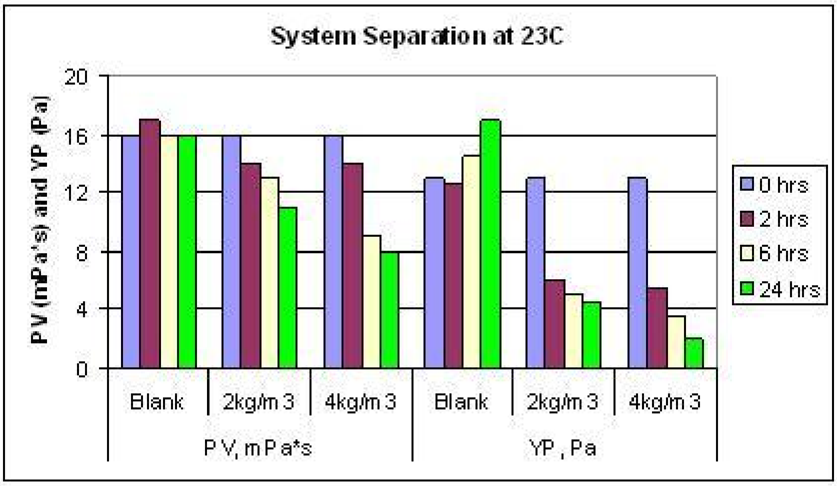

Figure 1 – Effect on Plastic Viscosity and Yield Point on room temperature HOSM fluid containing increasing amounts of oil-sands Breaker.

Oil Sands Steam Assisted Gravity Drainage (SAGD) Project

The Oil Sands property covers approximately 52,000 acres and is located about 45 km southeast of Ft. McMurray in northeastern Alberta (Figure 2). The entire property contains heavy oil of varying viscosities and is located at various depths from 200 to 450 meters. The shallow McMurray oil bearing sands are generally mined (< 100 m), while those at greater depth are typically produced through Steam Assisted Gravity Drainage (SAGD).

Discussion that follows will primarily focus on the 156 wells (78 well pairs) which make up the SAGD project and the influence of the drilling fluid selection on the positive results seen in the project itself.

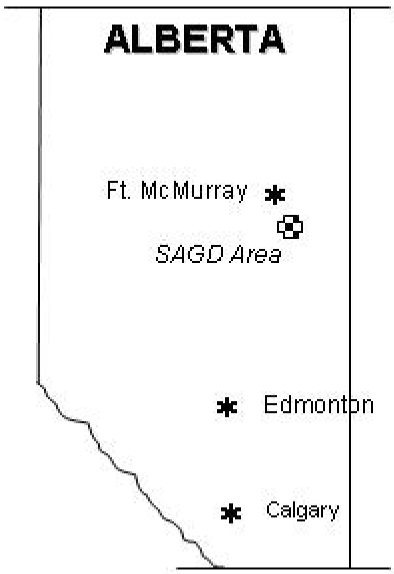

Figure 2 –SAGD Field situated 350 km N.E. of Edmonton, Alberta.

Twinned upper and lower horizontal well pairs are the keys to SAGD production, with the upper well being the steam injector. The lower producer well collects the hot, lower viscosity oil. The well pairs are often drilled from a central pad area, thereby allowing several well pairs from a single pad.

Drilling Problems:

The SAGD wells typically encounter the following problems during the drilling phase:

- Mud rings and sticky gumbo from below the surface casing shoe to approximately 250 meters depth within the Grand Rapids and Clearwater formations
- Running horizontal liner to TD is often difficult due to the shallow vertical depth and long horizontal reaches
- Instability of semi-consolidated oil sands is common if fluid type is not inhibitive, or if wellbore temperature rises above 26^{o}C
- Accretion of the oil onto drilling tubulars, solids control equipment and tanks leads to equipment failures and downtime
- Disposal of oil-contaminated solids and oil-contaminated drilling fluids is costly
- Dump and dilute mud system in order to maintain drilling fluid properties. Oil content within drilling fluid can affect rheology and filtration control, high solids contents also required dumping of whole mud
- Mud foaming

Commercial Project SAGD Results

To economize the use of materials and to increase time efficiencies, the wells were batch drilled from nine pad locations. Surface holes were drilled all at one time, then the build sections and finally the horizontal producers/injectors. The horizontal displacement was typically 950-1000 meters at a true vertical depth of approximately 250 meters.

The time for the Commercial Project was slated for 20 months – starting August 2004 with completion in March 2006. In order to drill all 78 well pairs in this time frame, it was estimated that each well would take 9.3 days to drill using three drilling rigs.

The drilling portion of the project was a success – both technically and financially. The 78 pairs were drilled, five months ahead of schedule ending November of 2005. Only the wells drilled from Pad #4, drilled under a lake, presented any difficulty (in terms of some lost circulation), yet no time was lost on this pad. In the other sets of wells from the various pads, NO significant lost time was observed. The wellbores were drilled quickly and without lost time due to hole instability, reaming, running casing and liners to their TD, etc..

Figure 3 shows the average time per well for the commercial SAGD project was 5.9 days for the producer and 6.35 days for the injector, an improvement of ~120 % over the previously drilled six well pilot project.

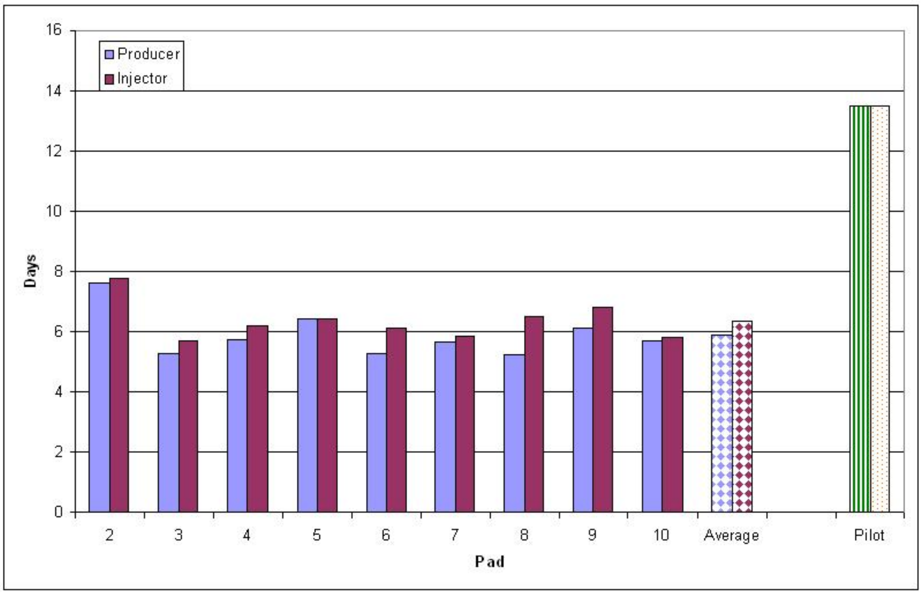

Figure 3: Commercial SAGD Project. Average days drilled for the producer and injector per pad. Included are the average days data for the Commercial Project and the Pilot Project.

Performance of Heavy Oil Sands Mud

The HOSM showed good technical performance in maintaining a stable wellbore, allowing casing and liners to be run to the planned depth, without getting stuck or losing any down-hole tools.

Figure 4 shows the drilling fluid and related costs (service and mud stripping) for each of the pads and compares those to the costs for the pilot wells. Not surprisingly, the only real outlier in the commercial SAGD project is from Pad #4, where some lost circulation difficulty was encountered. The two averages on the far right represent the average drilling fluid cost for the commercial work, one for all of the pads and the other less the costs on Pad #4. In either case, the actual drilling fluids cost was 25-28% of the costs spent on the pilot project.

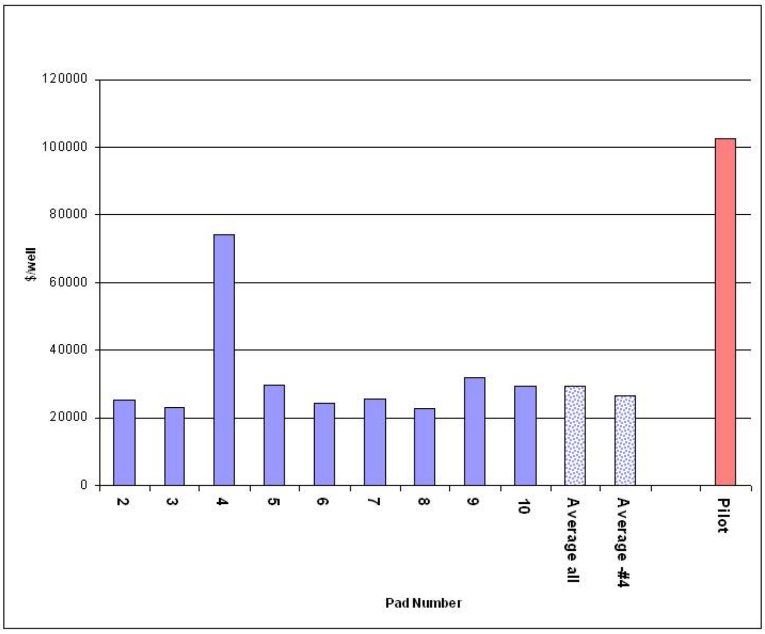

Figure 4. Commercial SAGD Project. Drilling fluid costs per well pair for both the Pilot Project and the Commercial SAGD pads. The average of the commercial project, with and without Pad #4 are included on the far right side of the individual Pad data.

Secondary Drilling Fluid Related Benefits with HOSM

The HOSM performed much better than the salt based systems used previously. The bitumen from the tar sand appeared to separate out from the sand over the shale shakers, but without adhering to those same shakers. The tar typically ran over the end of the shakers in long ribbons and without sand entrapment. Running finer shaker screens enhanced the process of tar and sand removal from the McMurray sand. Shaker screen sizes in the build section were commonly reduced to 210/175/175/145 and 210/210/180/145 over the sets of shakers (previous screens were a mixture of 60 to 120 mesh). As a result of the finer mesh shakers, the drilling fluid density was maintained at 1070 kg/m^3. Shaker screen life also increased up to 9 fold using the HOSM fluid. Cost savings were also realized as the use of drilling fluid coolers were eliminated for the producers, without impacting borehole stability. A cooler was still for contingency purposes in the used larger diameter injector holes.

During the drilling of the horizontal sections, the HOSM typically had densities controlled between 1050 to 1070 kg/m^3. The same shaker screen specifications that were run in the build section were continued throughout the horizontal drilling process. Accretion was not observed in the HOSM as a large majority of the tar flowed over the shaker screens. The concentration of Bitumen Cleaner needed to eliminate any accretion, and to insure that the tar was primarily lost on the screen over-flow, ranged from 6-9% v/v.

A disposal pilot test was conducted on site. The project consisted of solids sampling and then washing of these solids in fresh water and allowing the solids to settle. After removal of the water and oil, the solids were retested for oil content. The results are as follows:

- Centrifuge underflow solids met the criteria for a 3:1 mix-bury-cover ratio
- Solids obtained from the stripping of HOSM met the criteria as described above
- Solids from the scalping shakers were very high in oil content – a washing and settling regime was not attempted

Conclusions and Recommendations

1. Laboratory development of a unique tar/oil dissolving fluid was accomplished. The key components to the process are the oil-sands cleaner while actively drilling and the oil-sands breaker to separate the HOSM into three separate phases.
2. HOSM provides a viable method of drilling tar sands and heavy oil containing sands.
3. The fluid prevents accretion of the tar/oil onto drilling strings, casing, and any surface equipment. A minimum concentration of >5% v/v oil-sands cleaner is needed while actively drilling.
4. The SAGD commercial project was both a technical and financial drilling success. Significant savings (20%) were realized over the life of the 156 well project. Completion of the drilling phase was accelerated by 5 months, or a 20% reduction in originally estimated time curve.
5. Performance of the HOSM at the SAGD project was excellent, with very little drilling fluid related issues and good fluid performance. No accretion, foaming, wellbore instability or stuck pipe issues occurred.
6. In order to minimize volumes and to encourage water reuse, efficiencies into the flocculated weater drilling process needs to occur.
7. Future R & D must continue to determine the necessity of mud cooling with respect to the various Bitumen compositions/gravity.

Reference

1. Carrigy, M.A., “Geology of the McMurray Formation, Part 3, General Geology of the McMurray Area”, Research Council of Alberta, Memoir 1, 1959.