HORIZONTAL WELL DRILL-IN FLUIDS

Nediljka GAURINA-MEDIMUREC

Faculty of Mining, Geology and Petroleum Engineering, University of Zagreb, Pierottijeva 6, HR-10000 Zagreb, Croatia

Key-words: Horizontal wells, Drilling, Fluids

Main objective of horizontal drilling is to place a drain-hole for a long distance within the pay zone to enhance productivity or injectivity. In drilling horizontal wells, more serious problems appear than in drilling vertical wells. These problems are: poor hole cleaning, excessive torque and drag, hole filling, pipe sticking, wellbore instability, loss of circulation, formation damage, poor cement job, and difficulties at logging jobs. From that reason, successful drilling and production of horizontal well depends largely on the fluid used during drilling and completion phases.

Several new fluids, that fulfill some or all of required properties (hole cleaning, good suspension, good lubrication, and relative low formation damage), are presented in this paper.

Introduction

Many of today's smaller and more marginal hydrocarbon accumulations can only be developed economically by horizontal wells. Under these delicate and stringent conditions attention must be focused on maximizing production from spudding of the first well. Formation damage minimization and skin awareness are now concepts familiar to all those present on a drilling rig and critical role in these processes (Byrd and Zamora, 1988; Ezzat, 1993; Dearing and Ali, 1996). High angle and horizontal hole drilling are difficult to achieve, but the present state-of-the-art technology is sufficiently well developed that they can now be performed with a satisfactory degree of confidence. Selected drilling fluids for horizontal drilling should satisfy the same basic functions which are common to all drilling muds and they have to provide excellent reservoir protection.

Major drilling problems such as poor hole cleaning, excessive torque or drag, wellbore instability, stuck of drill string, loss of circulation, subsurface pressure control, poor cementing jobs, difficulties associated with running electric logs and formation damage can result if the drilling fluid is poorly designed or executed (Byrd and Zamora, 1988). The reason for the growing importance of drill-in fluids is the expanding number of horizontal wells being drilled. In these wells, producing formations have a greater tendency to be damaged by the drilling process than those in vertical wells (Dearing and Ali, 1996).

Geological criteria relevant to the reservoir section is now the main driver for the selection of the drill-in fluid. As the number of horizontal, and now multi-later, wells continues to grow, so the use of drill-in fluids is growing as well. The way by which we consider drilling of boreholes is changing. The drilling phase of a well can be finished just above the reservoir and any penetration of potential hydrocarbon zones can be considered as part of the completion process. Traditional drilling fluids are designed from a safety and efficiency point of view, primarily with the overburden lithologies in mind. These fluids often are not best suited to maximizing productivity and minimizing damage in the reservoir lithologies.

A new generation of fluids, collectively known as drill-in fluids, has been developed to overcome these limitations (Jachnik, 1995; Dearing and Ali, 1996).

Horizontal drilling problems

A combination of a very high angle well path and a poor quality of reservoir may require a more complex drilling fluid specification compared to that used when drilling a conventional directional well, not only because of the increase in angle, but above all because poor quality reservoirs do not tolerate any further degradation and in order to avoid expensive and/or problematic stimulating treatments. Thus before considering hole-cleaning technique it should be pointed out that as we expect more from horizontal wells than from vertical wells, additional precautions have to be taken to (Byrd and Zamora, 1998; Ezzat, 1993; Dearing and Ali, 1996):

- ensure bore hole stability (in unconsolidated formations),
- hole cleaning,
- avoid damage to reservoir characteristics,
- avoid incompatibility between reservoir formation and fluid used,
- provide lubricity to decrease torque and drag, and hence, the possibility of sticking of drill string and casing.
Prevention of formation damage

In horizontal wells, fluid is typically in contact with the reservoir for a much longer period than in vertical or lower angle wells. Formation damage tends to be more significant in horizontal wells for a number of reasons (Dearing and Ali, 1996). Among the reasons are:

- Drilling fluid is in much longer contact with the payzone.
- Most horizontal wells are completed open hole without casing and perforation. Shallow fluid invasion may result in skin damage which can reduce production.
- Long, exposed payzones can result in difficulty obtaining uniform drawdowns to clean up damage.
- Flow mechanisms in horizontal wells differ from those in vertical wells, as do the horizontal and vertical permeabilities of most formations (these differences result in greater productivity impairments in horizontal wells exposed to equivalent damage).

Lubricity

In the horizontal and highly deviated sections of a horizontal well, the torque and drag are usually large enough to cause an unacceptable loss of power, and differential sticking was particularly liable to occur (Byrd and Zamora, 1988; Hemphill and Larsen, 1993). To solve this problem crude oil or certain lubricating agents should be used. The selected mud should be good enough to avoid sticking of the drilling string effectively in the horizontal well drilling.

Choice of drill-in fluid type

In order to design the best suitable drill-in fluids for horizontal wells, drilling problems generally encountered in each field should be studied and laboratory tests planned and conducted. Laboratory tests include:

- Study the reservoir rock and fluids characteristics.
- Select the most suitable and economical fluid formulations.
- Examine the effective pore size distribution and morphology of each reservoir rock.
- Run flow tests on core samples taken from each reservoir to determine the residual damage caused by several candidate fluids.
- Geological testing of reservoir samples in the drilling fluids (SEM, X-ray diffraction, petrography and mineralogy, and physical and chemical compatibility testing).

Standard tests such as fluid density, rheology, filtration, solid analysis and chemistry should be also performed because the drill-in fluid must act as a drilling fluid, often in quite demanding conditions in long horizontal wells.

Drill-in fluids are specialized systems designed to minimize formation damage or be used as packer fluids after completion operations. The impact of these systems to the productive formation must be capable of being reversed with remedial treatments such as acidizing and oxidation or through completion techniques and production operations. Systems consist of fluids which range from clear brines to polymer fluids (weighted with high-molecular-weight polymers are utilized to either encapsulate drill solids to prevent dispersion and coat shales for inhibition, or for increasing viscosity and reducing fluid loss. Various types of polymers, including acrylamide, cellulose and natural gum-based products.
Frequently, inhibiting salts such as KCl or NaCl are used to provide greater shale stability. These systems normally contain a minimum amount of bentonite and may be sensitive to divalent cations such as calcium and magnesium.

Most polymers have temperature limits below 150 °C, but under certain conditions may be used in wells with appreciably higher BTs. The polymer-based fluid is shear thinning, providing good hole cleaning properties which can be adjusted, as needed, to meet specific wellbore requirements. The systems polymer blend can be utilized effectively in both low density and high density brines to achieve desired rheological properties. Because it contains polymers, the system is naturally lubricious. Additionally, the filter cakes polymer coating imparts surface lubricity – minimizing torque and drag. This feature is especially critical in horizontal wells.

Different polymer fluids have been applied during drilling horizontal wells in France, Canada, Texas, Alaska, China, etc. (Zamora et al., 1993; Yan and Zong, 1995; Dearing and Ali, 1996) Polymer systems (NEW DRILL/KCl, PERFFLOW DIF) have been applied during drilling horizontal wells in Croatia as well.

**Oil-based systems**

Oil based systems (Invert emulsion muds, Oil-based muds) are used for a variety of applications where fluid stability and inhibition are necessary such as high-temperature wells, deep holes, and where sticking and hole stabilization is a problem (Hempill and Larsen, 1995). All oil systems require higher additional gelling agent for viscosity. Specialized oil-based mud additives include: emulsifier and wetting agents (commonly fatty acids and amine derivatives), high-molecular-weight soaps, surfactants, amine treated organic materials, organo clays and lime for alkalinity. Oil-based muds are more expensive than water-based ones and they are difficult to dispose of in an environmentally satisfactory manner. In fact, when oil-based mud has not been the fluid used for drilling neighboring vertical wells, this mud type should never been chosen for drilling horizontal wells.

The main reason for this is that when properly designed (choice of salt and concentration) and when enhanced with specific additives (lubricants, asphalts, diesel or mineral oil), low solid brine water-base fluid has successfully competed with oil-base fluid.

**Synthetic-based systems**

Synthetic fluids are designed to mirror performance of oil-based muds, without the environmental hazards (Dearing and Ali, 1996). Primary types of synthetic fluids are esters, ethers, poly alpha olefins. They are environmentally friendly, can be discharged offshore and are non-sheeting and biodegradable. The non-aqueous PAO (polyalphaolefin) system has been used on several wells in the Gulf of Mexico to drill problematic formations previously drilled with either inhibitive water-based or oil-based fluids (Park et al., 1993). Benefits in hole stability, cuttings integrity, lubrication, and gauge wellbores, all leading to increased penetration rates and subsequent reduction in drilling days, can be seen.

**Glycol system**

Glycols are compounds containing two hydroxyl groups attached to separate carbon atoms in an aliphatic chain. Although there are a few exceptions nearly all glycols consist solely of carbon, hydrogen and oxygen. Simple glycols are those in which both hydroxyl groups are attached to an otherwise unsubstituted hydrocarbon chain as represented by the general formula, \( C_nH_{2n}(OH)_2 \). The more complex glycols are given the name polyglycols and are distinguished by intervening ether linkages in the hydrocarbon chain (Jachnik, 1995).

Two common simple glycols are ethylene glycol and propylene glycol. Ethylene and propylene oxide are often the building blocks of the more complex polyglycols used as drilling fluid additives. The end result is a big range of products with varying molecular weights and characteristics used in water based drill-in and specialized coring fluids. Glycols have been used in horizontal wells in the North Sea.

Typical features of a glycol based drill-in fluid are (Jachnik, 1995):

- high lubricity, approaching that of an oil based mud,
- minimal invasion,
- improved inhibition and
- good environmental characteristics (low toxicity and vapor pressure and biodegradability).

**Formate system**

Formates are exotic salts, essentially being formic acid, HCOOH, with metal cations, K, Na, Mg and Cs. The density of the fluid is determined by which cation is used. Sized salt, NaCl, particles act as bridging solids and formate systems are barite free (Dearing and Ali, 1996). Very thin filter cakes are produced and the solid free nature of the fluids reduces equivalent circulating densities. This is particularly important in slimhole wells where problems can arise due to barite centrifuging out of the fluid on the internal section of the drill pipes as a consequence of high rotary speeds. The lower downhole pressures generated benefit all reservoirs. Formates have been used in horizontal wells in the North Sea (Ramsey and Shipp, 1996).

Advantages of the formate salts are:

- they can provide high-density brines that are non-hazardous and appear to be compatible with oilfield hardware,
- they are environmentally responsible and readily biodegradable,
- as powerful anti-oxidants, they can protect viscosifiers and fluid-loss polymers against thermal degradation up to temperature of at least 150 °C,
- they are compatible with formation waters containing sulphates and carbonates.

**Sized calcium carbonate system**

Sized calcium carbonate drill-in fluids originated as completion fluids and are now being used in the drilling of reservoir sections. Very pure metamorphic calcium carbonate with a carefully selected particle size distribution is used. The particle size mix has been carefully selected to effectively bridge the pore throat openings in formations with permeabilities ranging from a few millidarcies to more than 10 darcies (Dearing and Ali, 1996).

The concentration of bridging solids is carefully engineered to ensure optimum system performance. Solid concentration, as well as the particle size distribution, can be modified to fit particular reservoir applications. This bridging agent, combined with polymer viscosifiers and filtration control agents, forms a thin filter cake at the surface of the exposed formation. The filter cake forms quickly on the exposed surface of the wellbore to provide instantaneous leak-off control. This feature of these systems protects producing formations from dam-
age by limiting fluid loss, fine solid migration, clay swelling, and solid invasion. The polymer coating allows the calcium carbonate particles to «break» apart for easy removal when the well is produced. These particles will even flow back through a 40-60 gravel pack without requiring special clean-up procedures to dissolve the particles (Dearing and Ali, 1996).

**Mixed-metal hydroxide**

Improved understanding of rheological properties and increased control of filtration characteristics has expanded the applications of mixed metal hydroxide (MMH) fluids, or more specifically, magnesium aluminum hydroxides (Sparling and Williamson, 1991). MMH fluid is a blend of complex chemical fundamentally different from conventional muds. There are two unique additives to the MMH system: a mixed metal hydroxide of aluminum and magnesium and an organic fluid loss reducer developed specifically for the system (Fraser and Enriquez, 1992). MMH fluids have unique rheological and pore bridging characteristics resulting from the interaction of the synthetic mixed metal hydroxide (highly-charged cationic MMH crystals) with bentonite (smectite clay). The MMH fluid shows unusual physical properties, behaving like elastic solid when at rest or when under conditions of minimal mechanical displacement. This pseudo solid can be transformed into an extremely low viscosity fluid through application of displacement energy. The MMH fluids have low PVs, and extremely high values for YPs, gels, and low shear rate rheology, and good potential as non-damaging fluids in a variety of formations. They have been used in Australia, North and South America, UK, Indonesia, etc. (Fraser et al., 1994).

**Conclusion**

If actual horizontal drilling techniques appear to have been perfected nowadays in more or less favorable environment, it should nevertheless be taken in mind that numerous difficulties may arise and that a well-designed drill-in fluid will often solve such problems as:

- poor borehole stability, unconsolidated sands, swelling, fractures due to tectonic stress, shale sloughing, etc.,
- hole cleaning difficulties, incorrect appreciation of actual hole diameter and thus of mud velocity, difficult evacuation of cuttings according to angle, and possible build-up on the underside of well bore,
- annulus pressure instability in a constant pressure reservoir,
- formation damage, etc.

**REFERENCES**


Received: 1997-10-07
Accepted: 1998-07-07