Effect of Nanoparticles on the Modifications of Drilling Fluids Properties: A Review of Recent Advances

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Abstract

Production from unconventional hydrocarbon resources, such as shale gas, shale oil, deepwater and arctic reservoirs requires advanced drilling and extraction technologies. Furthermore, minimizing the environmental footprints associated with oil recovery processes are critical. Nanotechnology has been shown promising solutions to overcome such issues in oil and gas industry. Many studies have been conducted to analyse the enhancement of drilling fluids through the use of nanotechnology. In these studies modification of rheological, filtration, and heat transfer properties and friction reduction associated with drilling fluids have been investigated. They also showed that nanoparticles can improve fluid thermal stability, provide better lubricity, hole cleaning and wellbore stability, and mitigate hydrates formation within the fluid circulation system. This manuscript aims to analyse the outcomes of these studies and improvements that were observed for the application of nanoparticles in drilling fluids. This review provides the investigators with a detailed overview and comparison of the recent advancements in the field of drilling fluids and nanotechnology.

Keywords

Drilling Fluids, Nanoparticles, Rheological Properties, Filtration, Friction Reduction

Introduction

Use of nanotechnology in oil and gas industry has been improved rapidly over last decades. Adding nanoparticles (NPs), because of their very ultrafine size (<100 nm) and high surface area to volume ratio, allow engineers to modify the drilling fluids rheology by changing the composition, type, or size distribution of nanoparticles that suit desired drilling conditions without using other expensive additives (Abdo and Haneef 2012). In recent years, numerous studies have been reported on the application of nanoparticles as additives in drilling fluids formulation (Abdo and Haneef 2012, Amanullah et al. 2011, Sharma et al. 2012, Srivatsa and Ziaja 2012, Mao et al. 2015(a), 2015(b), Taraghikhah et al. 2015, Hassani et al. 2016, Shakib

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et al. 2016). The benefits include improvement of fluids rheological properties, reductions in filtration loss and friction coefficient, increase of the rate of heat transfer, shale stability improvement, and inhibition of gas hydrate formation. A summary of research studies to date is presented in Table 1 to 5 of this manuscript. Detailed review of the studies with profound outcomes are presented in the following section based on the modification of the drilling fluids property through addition of nanoparticles.

Modification of Rheological Properties

The rheology of drilling fluids should exhibit shear thinning characteristics to have less resistance at high shear rates. At low shear rates, (for instance when mud circulation is being stopped) the viscosity should be high enough to prevent transported cuttings from falling back downhole in the wellbore based on Stokes' Law. Apparent viscosity (AV); which is defined as the ratio of stress to rate of strain of liquid, plastic viscosity (PV); the resistance to flow of fluid, yield point (YP); the minimum shear stress required in order to move the fluid, and gel strength at 10 seconds and 10 minutes to measure the fluid capability to act like a gel and suspend cuttings and weighting materials when circulation is ceased, are the rheological properties investigated in this study. One of the common models for the rheology of drilling fluid is the Herschel-Buckley model (Eq 1),

$$\tau = \tau_0 + K\gamma^n \tag{1}$$

where τ is the shear stress (lb/100 ft^2), τ_0 is the yield point (lb/100 ft^2), K is the consistency index, γ is the shear rate (s^{-1}), and n is the flow behaviour index (dimensionless) that needs to be less than 1 for shear thinning fluids.

Nanoparticles can enhance the rheological properties of drilling fluids using various mechanisms which mostly depend on continuous phase of drilling fluids and nanoparticle characteristics. Silica nanoparticles can typically enhance the apparent viscosity of water as the continuous phase of drilling fluids (Mao et al. 2015 (a), 2015 (b), Sharma et al. 2012, Taraghikhah et al. 2015) or displacing fluids in enhanced oil recovery processes (Chegenizadeh et al. 2016, Rafati et al. 2016). It has been well established that the viscosity of nanofluids is much higher than the viscosity of conventional dispersions at the same volume concentration of dispersed particles. As viscosity is defined as internal friction between two layers of a fluid under shear stress, once nanoparticles are dispersed in the fluid there is a possibility of increasing friction between layers of the fluid, which results in an increase in viscosity of nanofluid (Sundar et al. 2013, Sharma et al. 2016). This enhancement in viscosity of nanofluids can be estimated through homogeneous solid–fluid interaction models. The available theoretical formulas for the estimation of viscosity of nanofluids have been developed initially from the Einstein model (Einstein, 1906), which is based on the assumption that the fluid contains suspensions of spherical shapes. However, his model was developed based on the simple assumptions and only worked at low concentrations of small nanoparticles. Later, modified models by other investigators have been introduced (Batchelor 1977, Brinkman 1952, Godson et al. 2010, Nguyen et al. 2007, Rea et al. 2009) that could be used for larger nanoparticles at higher concentrations, pressure and temperature. In addition, it has been found that the effective viscosity of nanofluids depends not only on the concentration of nanoparticles, but also on their sizes. This results have been confirmed through both molecular dynamics simulations of hard-sphere potential (Rudyak et al. 2008, Rudyak et al. 2009) and experimental studies (Rudyak et al. 2013, Timofeeva et al. 2010). It should be noted that in designing drilling fluids, different additives can be used to increase the rheological properties into an acceptable and desirable range required for hole cleaning, lubricating and cooling downhole equipment among others. However, these properties may not exceed beyond specific levels, inappropriate increase of properties may have negative effects during fluid circulation in the wellbore such as excessive frictions and weight that impose higher capacity pumps, and sand/cutting removal issues. Therefore, the aim of using nanoparticles is to attain desirable properties with lower cost and improved efficiencies.

Silica nanoparticles can also improve the rheological stability of emulsion based and invert emulsion based drilling fluids as they have a large free energy of adsorption and can attach to the oil-water interface depending on their degree of hydrophobicity (Agarwal et al. 2011, Ghosn et al. 2017). Metal NPs can also improve the rheological stability of drilling fluids due to their high thermal conductivities that can dissipate heat efficiently because of Brownian motion. Therefore, fluid is less affected by the temperature increase and keeps its liquid form, rather than degrading into a solid form. Results from several studies demonstrated that nanofluids have higher thermal conductivities compared to base fluids (Liu et al. 2005; Ding et al. 2006; Aybar et al. 2015). Different investigations on thermal conductivity of nanofluids showed enhancements from 12.4% to 80% can be obtained with carbon nanotubes dispersions in different fluids (Smith et al., 2017). Table 1 lists most of the recent studies on modification of rheological properties of drilling fluids by addition of nanoparticles.

Amanullah et al. (2011) investigated the effect of nanomaterials on several WBFs. They used a number of commercial nanomaterials to overcome challenges associated with conventional drilling fluids. Fluids were prepared with concentration of 0.14 wt% NPs and compared with a base sample. Their results showed no significant changes to the viscosity profile, however superior gelling properties were observed.

Agarwal et al. in 2011 used clay and silica nanoparticles to stabilise invert emulsion drilling fluids at HTHP conditions. They found that nanoclay and nanosilica can individually or as a mixture stabilise the invert emulsion drilling fluids. They also indicated that the rheological properties of invert emulsion drilling fluids are functions of nanoparticle's wettability (hydrophobicity). Their results showed addition of barite reduces yield stress but it can be regained by increasing the concentration of silica nanoparticles. They also found that stable invert emulsion drilling fluids can be obtained using organically modified nanoclay and hydrophobic nanosilica. Their analysis of gel strength showed that relatively hydrophilic/ hydrophobic nanosilica particles that are dispersed in water, and nanoclay particles that are dispersed in oil phase have significant effect on gel strength capacity.

Sharma et al. (2012) was the first to test a silica based NPs with an average particles diameter of 20 nm as an additive to drilling fluids. They analysed the effects of silica on rheological properties, and found that gel strength and YP were significantly decreased at concentration of 1wt%, while there was a slight decrease at concentration of 3 wt%. Srivatsa et al. (2012) also showed that the addition of silica increased the drilling fluid viscosity, with one sample achieving 30% increase in viscosity compared to the base drilling fluid. This is consistent with the recent work of Mao et al. 2015(b) who also concluded that addition of NPs into drilling fluids cause an increase in viscosity. Taraghikhah et al. (2015) demonstrated similar results for the use of silica with concentrations up to 1 wt%, and Hassani et al. (2016) tested silica NPs, and a hybrid NPs consisting of carbon nanotubes and silica. Hassani and his co-workers showed that both types of NPs can increase the effective viscosity of the drilling fluids significantly, with silica NPs showed a superior behaviour compared to the hybrid NPs. Salih et al. (2016) found that the properties of WBFs containing nanosilica are comparable to the higher performance and stability associated with OBFs. Needaa et al. (2016) tested sepiolite NPs, which contains silica, and showed that there was an increase in PV and YP when compared to a base drilling fluid sample. It can therefore be concluded that enhanced drilling fluid rheologies are common trends amongst WBFs with the addition of silica NPs.

Abdo et al. (2013), tested a WBF with a low concentration of Palygorskite (Pal) with particle size between 10-20 nm. The samples with low concentrations of Pal displayed significant improvement in rheological properties including a 200% increase in gelling characteristics. And it was noted that all the fluids displayed shear thinning properties.

Abdou et al. (2013) tested bentonite with particle size between 4-9 nm, as an additive to WBFs and compared the results with API bentonite properties and a sample with local bentonite not at nanosize. The overall rheological properties such as AV, PV and YP decreased due to the addition of bentonite with nanosize diameter, as the solid content of the fluid was decreased.

Table 1 Summary of the recent studies evaluating the application of nanoparticles on modification of rheological properties of drilling fluids

Author	**Types of NPs**	**Base Fluid**	**Modified Properties**	**Experimental Conditions**	**Summary of Results**
Abdo et al (2013)	Palygorskite	Water	- Plastic viscosity - Yield point - Gel strength	HPHT at 100-392°F and 100-16,000 psi	5.9 gr of nano-palygorskite with 10-20 nm diameter in WBFs showed a reduction of fluid rheological properties under HPHT (100-392ºF and 100-16,000 psi) conditions.
Abdo et al (a) (2014)	Nanocomposite of ZnO, montmorillonite and palygorskite	Water	- Plastic viscosity - Yield point	HPHT at 109-370 °F and 150-18,500 psi	Nanocomposite of ZnO, montmorillonite and palygorskite was used in water-based fluid system. 2.3wt% of the nanocomposite with 5-50 nm diameter resulted in more stable rheological properties under HPHT (109-370ºF and 150-18,500 psi) conditions.
Abdo et al (b) (2014)	Attapulgite	Water	- Plastic viscosity - Yield point	Ambient	2.0 wt % of attapulgite nanoparticles with 10-25 nm diameter in WBFs increased the rheological properties at ambient condition
Abdo et al (2016)	Sepiolite	Water	- Plastic viscosity - Yield point - Gel strength	HPHT at 77-365 °F and pressure up to 2,500 psi	4.0 wt% of nano-sepiolite with 30-90 nm diameter in WBFs resulted in more stable rheological properties under various HPHT (77-365ºF and pressure up to 2,500 psi) conditions.
Agarwal et al. (2011)	Clay and silica	Oil	- Plastic viscosity - Yield stress (gel strength)	HPHT at 437 °F and 500 psi	2.0 wt% of nanoclay individually, or mixed with 1 wt% nanosilica can improve the viscosity and gel strength of invert emulsion drilling fluids.
Amanullah et al. (2011)	Not specified	Water	- Plastic viscosity - Yield point - Gel strength	LPLT	0.14wt% of nanoparticles in water-based drilling fluids showed superior gelling properties under LPLT condition
Anoop et al. (2014)	SiO_2	Oil	Plastic viscosity	HPHT at 77-284°F and pressure up to 6,000 psi	2.0 vol% of nanosilica (SiO_2) with 20 nm diameter in OBFs increased plastic viscosity at ambient condition and maintained stable rheological profile under HPHT (77-284ºF and pressure up to 6,000 psi) conditions.
Ghanbari et al. (2016)	SiO_2	Water	- Plastic viscosity - Yield point	LPLT	0.5 wt% of silica nanoparticles (SiO_2) with 10 nm diameter in WBFs increased plastic viscosity and yield point under LPLT condition.

Hassani et al. (2016)	1. $SiO2$ 2. Carbon nanotubes 3. ZnO	Water	- Thermal conductivity - Plastic viscosity - Yield point	Temperature: 104 °F	Type of NPs: SiO_2, Carbon nanotubes, and ZnO. 2.0wt% of each nanoparticle in WBFs increases rheological properties significantly, however the highest improvement was obtained from silica NPs.
Jain et al (2015)	1. Composite of polyacrylamide and nanoclay 2. Composite of polyacrylamide-grafted-polyethylene glycol and SiO_2 nanoparticles	Water	- Plastic viscosity - Yield point - Gel strength	High temperature up to 203°F	The studies evaluated the application of (1) composite of polyacrylamide and nanoclay and (2) composite of polyacrylamide-grafted-polyethylene glycol and SiO_2 nanoparticles. 0.7wt% of each composite with 20-30 nm particle diameter improved fluid rheological properties. The drilling fluid had also showed a stable rheological profile at 203°F.
Li et al. (2015)	Cellulose nanoparticles	Water	- Plastic viscosity - Yield point - Gel strength	Temperature range from 20 to 176°F	0.5wt% of cellulose nanoparticles with 6 nm width and 228 nm length in WBFs increased rheological properties at elevated temperature range from 68 to 176°F
Mahmoud et al. (2016)	1. Fe_2O_3 2. SiO_2	Water	- Plastic viscosity - Yield point	HPHT	Ferric oxide (Fe_2O_3) and silica (SiO_2) NPs were used in water-based system. 0.5wt% of ferric oxide improved fluid rheological properties while silica at the same concentration that showed the opposite effects on rheology. Fluid with ferric oxide also exhibited more stable rheological properties under HPHT conditions.
Mao et al. (a,b) (2015)	SiO_2	Water	- Plastic viscosity - Yield point	LPLT and high temperature (392, 410, 428, 446°F)	1.0wt% of silica nanoparticles (SiO_2) in WBFs improved plastic viscosity and yield point under LPLT condition. The formulation also showed stable profiles at high temperature conditions. (392, 410, 428, 446°F)
Nasser (2013)	Nanographite	Oil	- Viscosity	LPLT	Nanographite with 40 nm diameter in OBFs increased fluid viscosity at LPLT condition.
Needaa et al. (2016)	Sepiolite	Water	- Plastic viscosity - Yield point	LPLT and HPHT (122-356°F and 500-6,000 psi)	1.4wt% of sepiolite NPs in WBFs exhibited stable rheological profiles under LPLT and various HPHT (122-356°F and 500-6,000 psi) conditions.
Sadeghalvaad et al. (2015)	TiO_2	Water	- Plastic viscosity - Yield point	LPLT	1 – 14 gr of the titanium oxide (TiO_2) NPs were added to the water-based fluid formulation. Results indicated improvement in plastic viscosity and yield point under LPLT condition.
Salih et al. (2016)	SiO_2	Water	- Plastic viscosity - Yield point - Gel strength	LPLT and HPHT at 199°F and 1,000 psi	0.3wt% of silica nanoparticles with 5.7 nm diameter in WBFs decreased the overall rheological properties under LPLT and HPHT (199°F and 1,000 psi) conditions.
Song et al. (2016)	Cellulose nanoparticles	Water	- Plastic viscosity - Yield point - Gel strength	LPLT	3.5wt% of celluloses nanoparticles with 8.2 nm width and 321 nm length in WBFs increased rheological properties under LPLT condition.
Srivatsa et al. (2012)	SiO_2	Water	- Viscosity	LPLT	10wt% of silica nanoparticles (SiO_2) in water-based fluids improved viscosity under LPLT condition

Taraghikhah et al. (2015)	SiO_2	Water	- Plastic viscosity - Yield point - Gel strength	High temperature at 250ºF	1.0wt% of silica nanoparticles (SiO_2) improved the overall rheological properties of WBFs both at LPLT and HPHT condition (250ºF).
Wagle et al. (2015)	Not specified	Oil	- Plastic viscosity - Yield point - Gel strength - Barite sag factor	High temperature at 250 and 302°F	Oil-based fluids (OBFs) containing nanoparticles exhibited stable rheological profiles under HPHT (250 and 302ºF) conditions and maintained barite sag to a lower level.

Kosynkin et al. (2011) were the first who tested carbon-based NPs (graphene oxide) as a filtration additive in water-based drilling fluids at concentrations as low as 0.2 wt% with xanthan gum. Their experimental results showed that a combination of large-flake and powdered graphene oxide in a ratio of 3:1 can provide the best filtration results, having an average fluid loss of 6.1 mL over 30 min and leaving a filter cake of about 20 µm thick. This was promising compared to a standard suspension of clays and polymers that are used in the oil industry which showed an average fluid loss of 7.2 mL and a filter cake of 280 µm thick.

Later in 2013, Nasser et al. also tested the rheological properties of carbon-based NPs (graphite) in WBFs. They showed for NPs with the size of 40 nm, the drilling fluid viscosity was increased, and as temperature and shear rate increase, the viscosity decreases. In 2014, Ismail et al. examined the use of multi-walled carbon nanotubes (MWCNT) in drilling fluids. They found that adding low concentrations of MWCNT with the size of 30 nm, at normal temperature made no significant difference in the rheological properties compared to the base sample. However, in ester-based drilling fluids, gel strength and emulsion stability slightly were increased with addition of MWCNT. Later, Taha et al. (2015) examined the use of carbon-based NPs graphene in WBFs, and similarly their observations showed improved rheological properties of drilling fluids.

Madkour et al. (2016) tested the use of MWCNT based biodegradable composites in oil based drilling fluids, and showed a significant increase (in some cases up to double) in AV, PV and YP as well as gel strengths over the commercial viscosifier that is used as a comparison, and found that the fluid followed the Herschel-Buckley model. Overall, carbon based NPs have been demonstrated to be effective rheological modifiers at HPHT (High Pressure, High Temperature) conditions, and provide stable drilling fluids (Liu et al. 2005, Ding et al. 2006, Farbod et al. 2015). Mahto et al. (2013) is, so far, the only study have tested the rheological properties of WBFs with the addition of fly ash NPs. Fly ash is small dark flecks and is composed of silica, alumina, magnetite and other components, and is produced from the burning of powdered coal. Fly ash is currently the world's fifth largest raw material resource, with India producing up to 130 Mt of fly ash per year. Fly ash NPs with the size between 1-100 nm, were added in concentrations of 1, 2 and 3 wt% and resulted in a stable rheology without any major changes in AV, PV, YP or gel strengths.

Sadeghalvaad et al. (2015) tested a mixture of TiO_2/polyacrylamide NPs with size between 10-15 nm and observed increases in rheological properties. Jain et al. (2015) used polyacrylamide-grafted-polyethylene glycol/silica nanocomposites, and their results showed an increase in rheological properties for NPs with the size between 20-30 nm, with increasing concentration from 0.3 to 1.1 wt% as shown in Figure 1.

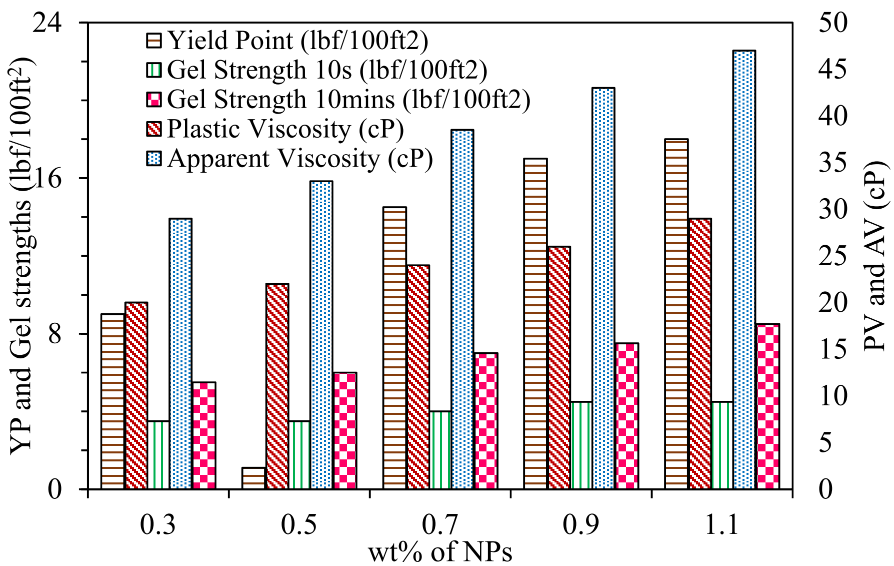

Figure 1: Improved rheological characteristics of WBF with increasing concentration of NPs, Jain et al. (2015) *(adopted)*

Transition metal NPs have been tested extensively in WBFs by several investigators (William et al. 2014and Barry et al. 2015). William et al. (2014) explored the effects of CuO and ZnO nanoparticles as additives with the size less than 50 nm, on the rheological properties of drilling fluids at different concentrations (0.1, 0.3, 0.5 and 1.0 wt%). The results showed that shear rates become thinner and more stable as the concentration increases, and fluid behaviour fits the Herschel-Buckley model well with viscosity only being a function of shear rate rather than pressure and temperature. Barry et al. (2015) tested iron based NPs (size of 3 and 30 nm) which their results showed all the samples with NPs concentration of 0.5 wt% exhibit shear thinning characteristic that follow Herschel-Buckley model.

Gerogiorgis et al. (2015) also used iron NPs (less than 50 nm in diameter) with concentrations up to 3 wt%. Their results showed that the fluid followed the enhanced multivariate Herschel-

Buckley model which outperformed the bi-parametric Bingham plastic, power law and Casson models demonstrating the rheological properties are temperature and concentration dependant.

Reilly et al. (2016) used iron oxide (Fe_3O_4) NPs with concentrations up to 3.0 wt% to develop the first principle model to describe the rheology of fluid as a function of shear rate, NP volume fraction, and temperature. The study proposed a bivariate and trivariate model for shear stress and apparent viscosity which is a more in-depth model than the Herschel-Buckley model. Hassani et al. (2016) used zinc to improve rheological properties of drilling fluids. One of the samples displayed 150% increase in PV and around 100% increase in AV and YP compared to the base mud and displayed shear thinning characteristic that follows the Herschel-Buckley model. Aftab et al. (2016) also tested a zinc based nano-composites which showed that, at high temperatures, rheological properties had a slight increase which is the common trend with the addition of transition metal based NPs to WBFs.

Cellulose, a natural biodegradable substance was first introduced by Li et al. (2015). They found that varying cellulose nanocrystals (CNC) concentration from 0-6.0 wt% made a large difference in viscosity and shear rate as shown in Figure 2. Song et al. (2016), stated that cellulose NPs (CNP) including CNC and cellulose nanofibers (CNF), can be used as eco-friendly additives for WBFs. The concentration range used in their study was from 0.05 wt% to 0.4 wt% for both CNC and CNF, while bentonite concentration reduced to 0.0 wt% at CNP concentration of 0.4 wt%. At concentration of 0.05 wt%, the rheological properties showed slight increases compared to the base sample, however, they were decreased as the concentration of CNP was increased while the concentration of bentonite was decreased. Analysis of the rheological properties showed that the Herschel-Buckley model provides a good characterisation of the samples. At 0.0 wt% bentonite AV, PV and YP were reduced by 85%, 82% and 92%, respectively for CNC.

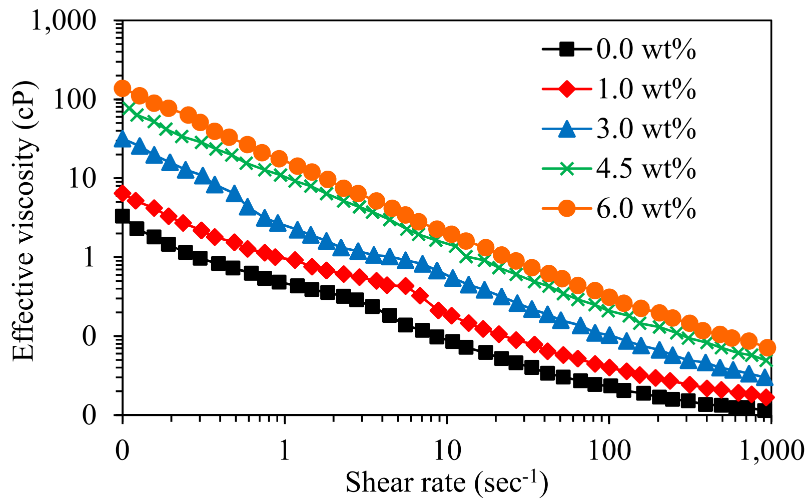

Figure 2 Viscosity versus shear rate for varying concentrations of CNC, Li et al. (2016) (*adopted*)

Reduction of Filtration Loss

There have been many studies on the effect of nanoparticles on filtration control during drilling operations. Amanullah et al. (2011) showed that the addition of commercial NPs into their sample resulted in no spurt loss, indicating a non-damaging fluid system that protects the nearby formations. The drilling fluid produced a very thin, well dispersed and tight mud cake. One of the first studies on the effect of silica based NPs on filtration control was conducted by Javeri et al. (2011). They reported reductions in filtrate volume up to 34% using silica NPs with the size ranging from 40 to 130 nm at the concentration of 3 wt%. Similarly, Cai et al. (2012) used silica NPs to decrease water invasion, at the concentration of 10 wt%, which returned reductions of 58-99% in the shale permeability to water for bentonite muds, and 46-88% for low solid content muds. They also proposed the ideal size of particles can be in the range of 7-15 nm. Table 2 lists some of the recent studies on the reduction of filtration loss by nanoparticles.

Table 2 Summary of the recent studies indicating reduction of filtration loss of drilling fluids by nanoparticles

Author	**Types of NPs**	**Base Fluid**	**Modified Properties**	**Experimental Conditions**	**Summary of Results**
Abdo et al. (2012)	Material called ATR	Water	- API fluid loss - Filter cake thickness	Material called ATR	Nanoparticles called ATR were used in water-based fluid system. The results show a decrease API fluid loss and filter cake thickness.
Abdo et al. (2013)	Palygorskite	Water	- API fluid loss - Filter cake thickness	HPHT at 100-392°F and 100-16,000 psi	The study observed palygorskite NPs in WBFs and showed a decreased in spurt loss and fluid loss by 30% at 30 minutes under API conditions.
Abdo et al. (2016)	Sepiolite	Water	- API fluid loss - Filter cake thickness - HPHT fluid loss	HPHT at 77-365°F and pressure up to 2,500 psi	4.0wt% of nano-sepiolite with 30-90 nm diameter in WBFs showed reduction of filtration loss under HPHT (77-365ºF and pressure up to 2,500 psi) conditions.

Aftab et al. (2016)	ZnO	Water	- API fluid loss - HPHT fluid loss - Filter cake thickness	LPLT and HPHT (150 and 250°F)	1.0 gr of zinc oxide (ZnO) NPs in WBFs reduced filtrate loss under HPHT (150 and 250ºF) conditions.
Akhtarmanesh et al. (2013)	SiO_2	Water	- Fluid Loss -Shale inhibition	-	30wt% of silica nanoparticles with 35 nm diameter in WBfs showed a reduction of fluid filtrate observed through the pore plugging test.
Barry et al. (2015)	Fe_2O_3	Water	- API fluid loss - HPHT fluid loss	LPLT and HPHT	The results showed an increase in fluid loss with the addition of ferric oxide (Fe_2O_3) NPs at LTLP conditions.
Cai et al. (2012)	SiO_2	Water	- API fluid loss - Shale inhibition	LPLT	10wt% of silica (SiO_2) NPs in WBFs reduced filtrate invasion and improved the ability of plugging and sealing micro-pores and micro-fracks of the shale formations.
Contreras et al. (2014)	1. Iron 2. Calcium	Oil	- API fluid loss - HPHT fluid loss - Filter cake thickness	LPLT and HPHT	The study tested iron and calcium NPs at concentrations 0.0, 0.5, 1.0 and 2.5 wt% along with lost circulation material (LCM), graphite at 0.5 and 2.0 wt% in OBF. At LPLT, samples with iron based NPs showed higher reduction of filtration loss than samples with calcium based NPs. It also concluded that LCM works better with iron based NPs but not with calcium at HPHT conditions.
Halali et al. (2016)	Carbon nanotubes	Water	- API fluid loss - HPHT fluid loss - Shale inhibition	LPLT and HPHT (248, 302, 347, 392°F)	0.8wt% of carbon nanotubes in WBFs reduced filtration loss under HPHT (248, 302, 347, 392°F) conditions.
Li et al. (2015)	Cellulose nanoparticles	Water	- API fluid loss - Filter cake thickness	Temperature range from 20 to 176°F	0.5wt% of cellulose nanoparticles with 6 nm width and 228 nm length in WBFs reduced fluid loss under elevated temperature conditions, range from 20 to 80ºC.
Liu et al. (2015)	1. Latex particles 2. Aluminium complexes	Water	- Shale inhibition - API fluid loss - HPHT fluid loss	LPLT and HPHT	The study tested spherical latex particles with size distribution 80-345 nm with aluminium complexes in WBfs and concluded they had excellent plugging abilities with API filtrate reducing by 44%
Liu et al. (2016)	SiO_2	Water	- API fluid loss - Shale inhibition - Hydrate inhibition	Low temperature 21 to 43°F)	2.0wt% of silica (SiO_2) NPs in WBFs reduced filtration loss at low temperature (21 to 43ºF) conditions.
Madkour et al (2016)	1. Graphene 2. Carbon nanotubes	Oil	- HPHT fluid loss	HPHT (59-199°F)	The study tested graphene and multi-walled carbon nanotube (MWCNT) NPs at concentration of 0.5 wt% in an OBFs and showed reduction in filtration loss under HPHT at 302°F and 500 psi.
Mahmoud et al. (2016)	1. Fe_2O_3 2. SiO_2	Water	- HPHT fluid loss - Filter cake thickness - Filter cake permeability	HPHT	0.5wt% of ferric oxide (Fe_2O_3) NPs in WBFs showed minor fluid loss under HPHT conditions compared to silica (SiO_2) NPs which showed an increase of fluid loss as due to an increase in porosity and permeability of the filter cake.
Mahto et al. (2013)	Fly ash	Water	- API fluid loss - Filter cake thickness	LPLT	Experiments using fly ash NPs in WBFs achieved a 30% reduction in filtration loss and about a similar proportion amount again in filter cake thickness. Increasing the concentration of the NPs and the size of the fly ash also decreases filtrate significantly
Mao et al. (a,b) (2015)	SiO_2	Water	- API fluid loss	LPLT and high temperature (392, 410, 428, 446°F)	1.0wt% of silica (SiO_2) NPs in WBFs considerably reduced API fluid loss over 80% improved plastic viscosity and yield point while considerably reduced fluid loss.
Nasser et al. (2013)	Nanographite	Oil	- API fluid loss	LPLT	The study tested 40 nm graphite NPs and showed mud filtrate reduction by 50% under LPLT condition.
Sadeghalvaad et al. (2015)	TiO_2	Water	- API fluid loss - Filter cake thickness	LPLT	The experiment tested on titanium oxide (TiO_2) NPs in WBFs and resulted in the reduction of filtration loss and filter cake thickness by 64%.

Salih et al. (2016)	SiO_2	Water	- API fluid loss - Filter cake thickness	LPLT and HPHT at 199ºF and 1,000 psi	Silica (SiO_2) NPs at 0.7 wt% in WBFs gave the lowest mud cake thickness (1 mm) and found that filtration reduced as the concentration increased.
Song et al. (2016)	Cellulose nanoparticles	Water	- API fluid loss - Filter cake thickness	LPLT	3.5wt% of celluloses NPs with 8.2 nm width and 321 nm length in WBFs reduced filtration loss at LPLT condition.
Taha et al. (2015)	Graphene	Water	- API fluid loss - Coefficient of friction - Shale inhibition	LPLT and high temperature (120 and 351°F)	The study tested 1, 2, 3, 4 and 5 wt% of graphene NPs in a 10 ppg WBF and resulted in reduced API fluid loss of up to 30%.
William et al. (2014)	1. CuO 2. ZnO	Water	- API fluid loss - Filter cake thickness	LPLT and HPHT (T: 158, 194, 230°F; P: 1,450 psi)	CuO and ZnO NPs were used in the experiments. Both WBF samples have NPs less than 50 nm at concentration of 0.1, 0.3 and 0.5 wt%. The results showed that fluid loss and filter cake thickness decreased significantly under LPLT and HPHT (T: 158, 194, 230 ºF; P: 1,450 psi) conditions. Overall, at the same concentration ZnO NPs showed a better result
Yusof et al. (2015)	SiO_2	Syntheti c	- HPHT fluid loss - Filter cake thickness	HPHT (275, 351, 450°F)	40wt% of silica (SiO_2) NPs with 10-20 nm diameter in synthetic-based fluids (SBFs) showed significant reduction of fluid loss and filter cake thickness under HPHT (275, 351, 450ºF) conditions.
Zakaria et al. (2012)	Not specified	Oil	- API fluid loss - Filter cake thickness	LPLT	0.74wt% of NPs with 20-40 nm diameter in OBFs reduced filtration loss up to70% under LPLT condition.
Zhang et al. (2015)	Not specified	Oil	- Shale inhibition - API fluid loss - HPHT fluid loss - Filter cake thickness	LPLT and HPHT (194°F)	2.0wt% of NPs in OBFs effectively significantly reduced fluid loss and filter cake thickness under HPHT condition at 194ºF.

Srivatsa et al. (2012) also reported up to 50% reduction in filtration loss by using silica NPs in a surfactant based mud. Sharma et al. (2012) observed that invasion into shale is reduced by 10 to 100 times when using silica NPs with the size of 20 nm. Mao et al. (2015(b)) also tested a silica based nanocomposite with 12 nm silica NPs and achieved an API fluid loss reduction of over 80%. Meanwhile, Needaa et al. (2016) found using sepiolite NPs can give 15% reduction in filtrate volume. Research by Salih et al. (2016) showed that using silica NPs at concentration of 0.7 wt% gave the lowest mud cake thickness (1 mm) and found that filtration was reduced as the concentration was increased.

Mahmoud et al. (2016), however, showed that as the concentration of silica NPs increases, an increase in porosity and permeability of the filter cake can be observed due to an increase in agglomeration. Thus, the general trend for using silica based NPs is that it can reduce filtration loss efficiently. Mahto et al. (2013) used fly ash NPs in their experiments and achieved 30% reduction in filtration loss and about a similar proportion amount again in filter cake thickness.

Bentonite and barite are typically used as a viscosifier and weighting agent respectively in drilling fluids. Abdou et al. (2013), reported that the use of bentonite with particle size between

4-9 nm increases filtration loss compared to the micro-sized bentonite particles. This could be due to using NPs at a high concentration where the drilling fluid does not have a large particle size distribution, which could affect its plugging abilities or the particles being so small that they just flow through filter cake. Akhtarmanesh et al. (2016) used mechanically and chemically prepared barite NPs with average size of 1205 nm and 744 nm, respectively. The sample with chemically prepared NPs had 60% greater maximum sealing pressure during the particle plugging test than the base mud, and mechanically prepared sample had 90% greater maximum sealing pressure than the chemically prepared sample. The mechanically prepared NPs had a much larger particle size distribution which causes fluid to form a better, more compact filter cake, hence much higher maximum sealing pressure is tolerable. Cedola et al. (2016), while testing the use of barite, determined there is also an increase in fracture sealing capabilities with mechanically over chemically prepared NPs, where mechanically prepared NPs increased the fracture reopening pressure by 13%.

Nasser et al. (2013) was the first to test a carbon-based NPs for their filtration properties. They tested 40 nm graphite NPs which the reported mud filtrate volume has been reduced by 50%. Ismail et al. (2014) concluded that the addition of MWCNT NPs into commercially available fluid loss additives gives a good mixture for preventing fluid loss. Taha et al. (2015) investigated graphene NPs for its application to improve drilling fluids performance. Graphene was tested at concentrations of 1, 2, 3, 4 and 5 wt% for a mud with density of 10 lb/gal, and returned an API fluid loss decrease up to 30%. Similar observation was reported by Abdo et al. (2013), when testing the mineral Pal NPs in WBFs, and found a spurt loss and fluid loss decrease by 30% at 30 minutes under API conditions.

The transitional metal NPs feature commonly in testing for API fluid loss. Ponmani et al. (2016) conducted the some tests on the use of copper and zinc based NPs in drilling fluids. Both samples had NPs less than 50 nm at concentration of 0.1, 0.3 and 0.5 wt% and the results were compared with micro sized particles. The results are shown in Figure 3, where it shows a significant decrease in filtration with any addition of NPs. Mahmoud et al. (2016) also showed an iron based NPs can have a significant reduction in filtrate volume by 43% for the sample with NPs concentration of 0.5 wt%.

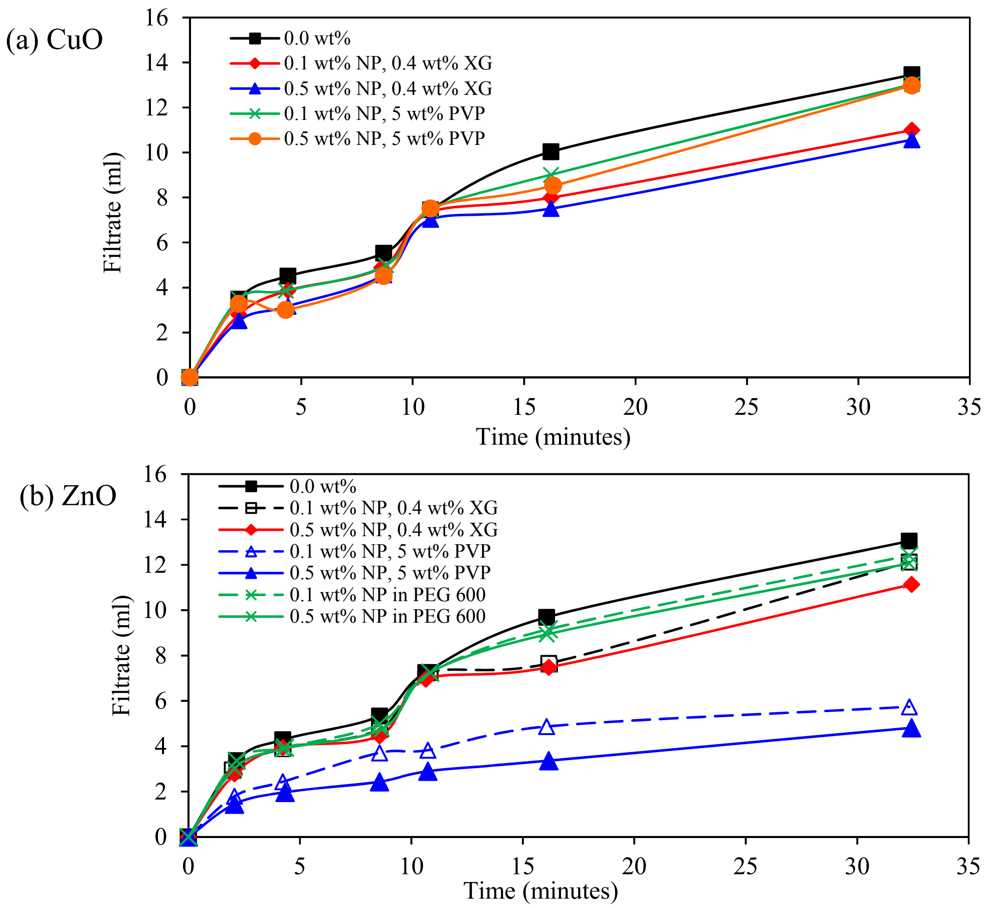

Figure 3 Fluid loss durig a period of 30 minutes for WBF and nano-enhanced WBF. (a) CuO; (b) ZnO, Ponmani et al. (2016) (*adopted*)

Polymer NPs have also been tested as fluid loss control additives to WBFs. Sadeghalvaad et al. (2015) performed tests on polyacrylamide/TiO_2 NPs and showed that filtrate volume and filter cake thickness both reduced by 64%. Jain et al. (2015) also investigated a polyacrylamide/silica NPs drilling fluid and achived API fluid loss reduction of 14% at particle concentration of 1.1 wt%. Liu et al. (2015) tested spherical latex particles with size distribution between 80-345 nm with aluminium complexes, and concluded they had excellent plugging capabilities with a reduction in API filtrate volume by 44%.

Li et al. (2015), used CNC NPs, and observed that changing the concentration have minimal change in filtration properties, however, Song et al. (2016) observed that filtrate volume increased at higher concentrations of NPs. Zoveidavianpoor et al. (2016) discussed the use of tapioca starch as NPs additive in WBFs. The NPs were tested with concentrations up to 2.5 wt% and three different sizes of 7 μm, 64 μm and 920 nm. 920 nm sample achieved a fluid loss reduction between 61% - 67.5% over the tested concentration range, and similar values for mud cake thickness indicated the improved filtration properties.

Zakaria et al. (2012) examined the use of NPs in OBFs and the focus was on reducing fluid loss at LPLT conditions. NPs were prepared ex-situ and in-situ with the size between 1-30 nm, and they were compared with commercial NPs with particle size between 20-40 nm. Commercial NPs reduced fluid loss by 66.7%, however, the in-house prepared ex-situ and in-situ decreased it by 68% and 77%, respectively at 30 mins, with the in-situ having zero spurt loss. Thickness of the filter cake however, did increase by 23% and 13% for ex-situ and in-situ prepared NPs, respectively.

Contreras et al. (2014) tested iron (NP1) and calcium (NP2) based NPs at concentrations of 0.0, 0.5, 1.0 and 2.5 wt% along with lost circulation material (LCM), graphite at 0.5 and 2.0 wt% in OBFs. The rheology of the samples did not change significantly with the addition of NPs and LCM up to 120 °F. At NPNT (Normal Pressure, Normal Temperature; 14.7 psi and 73° F), filtration reduced 100% for the sample with 2.0 wt% graphite and 1.0 wt% iron based NPs. The maximum reduction in filtrate volume for calcium based NPs was 45% with 2.0 wt% graphite and 0.5 wt% NPs. In summary NP1 showed a better performance at higher concentrations of graphite at HPHT conditions, whereas NP2 performed better at lower concentrations. Figure 4 shows that LCM works better with iron based NPs but not with calcium at HPHT conditions. Iron based NPs with LCM could achieve filtration reduction over 75%.

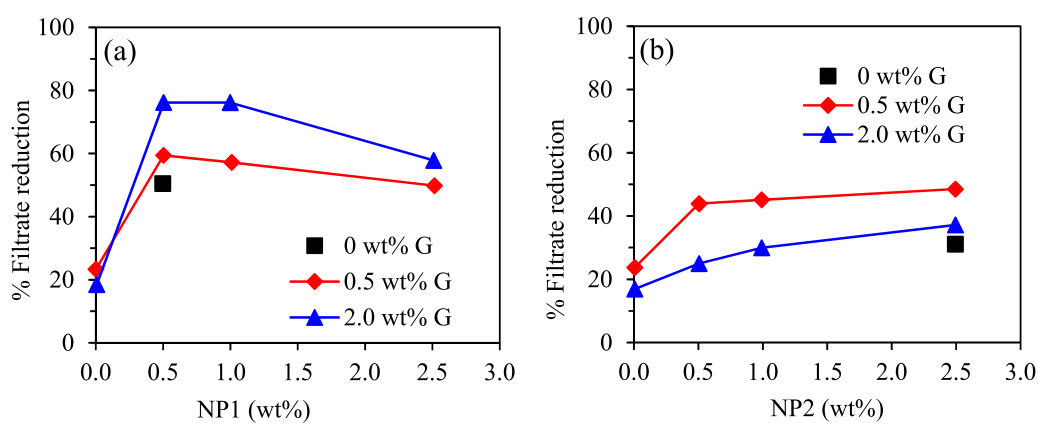

Figure 4 Percentage of reduction in mud filtrate at 30min under HPHT for (a) NP1 (the single square represents the blend only containing NP1 at 0.5wt%) and (b) NP2 (the single square represents the blend only containing NP2 at 2.5wt%), Contreras et al. (2014) (*adopted*)

Madkour et al. (2016), tested graphene and MWCNT NPs at the concentration of 0.5 wt% in an OBF for HPHT conditions of 300°F and 500 psi. The rheological properties and HPHT filtration loss are shown in Figure 5. All rheological properties were increased with the addition of MWCNT and graphene NPs. All samples showed stable rheology at elevated temperatures and followed the Herschel-Buckley model.

Improvement of the Rate of Heat Transfer

Drilling fluid characteristics under HPHT conditions are important as fluids need to be stable at elevated temperatures and provide the rheological and filtration properties as required for the well. The rate of heat transfer of the drilling fluid is also critical in maintaining a stable fluid to prevent the overheating of drill string components. Ideally the drilling fluid should display low deterioration, high stability, consistent rheology and filtration loss, and a high rate of heat transfer. Table 3 presents recent studies reporting the improvements in heat transfer properties of drilling fluids.

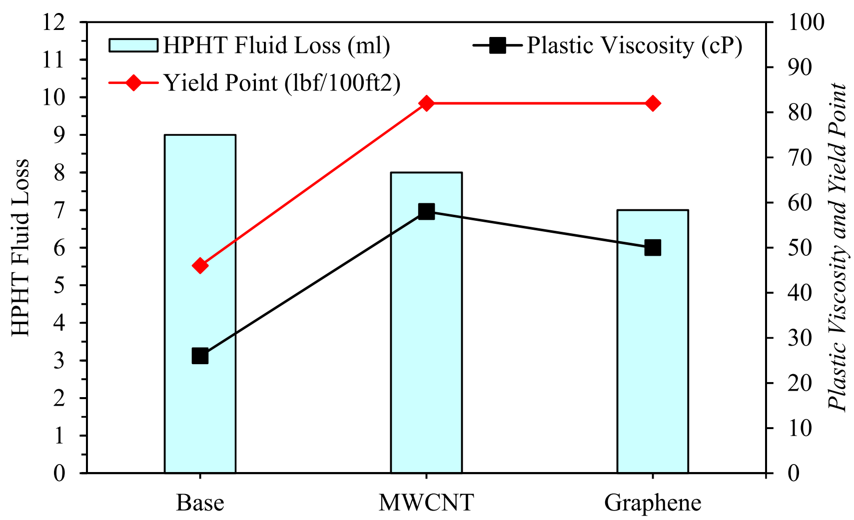

Figure 5 Rheological properties and HPHT filter loss for the base sample, sample with MWCNT and sample with graphene NPs, Madkour et al. (2016) (*adopted*)

Table 3 Summary of the recent studies evaluating the application of nanoparticles to improve heat transfer properties of drilling fluids

Author	**Types of NPs**	**Base Fluid**	**Experimental Conditions**	**Summary of Results**
Srivatsa et al. (2012)	SiO_2	Water	LPLT	Silica based NPs were mixed with surfactant in WBF system. The results showed that, at 392°F and 1000 psi, surfactant stability was better when mixed with silica NPs compared to samples without NPs.
Abdo et al (2013)	Palygorskite	Water	HPHT at 100-392°F and 100-16,000 psi	The results on palygorskite NPs showed that the WBF had perfect stability at temperatures up to 392°F and pressure up to 16,000 psi
William et al. (2014)	1. CuO 2. ZnO	Water	LPLT and HPHT (T: 158, 194, 230°F; P: 1,450 psi)	WBF samples of copper and zinc based NPs showed an increase of up to 53% and 23% in thermal conductivity respectively, with copper having a larger increase in thermal conductivity. The results also showed that using particles at nano level provides superior thermal conductivity than using the particles at micro

Barry et al. (2015)	Fe_2O_3	Water	LPLT and HPHT	The study tested the filtration and filter cakes at HPHT conditions, 1015 psi and 392 °F, of WBFs. Iron based NPs performed better at HPHT than they did at ambient condition and decreased the filtration.
Fazelabdolabadi (2015)	Carbon nanotubes	Water based and oil based	LPLT	1.0 vol% of carbon nanotubes with 15 nm diameter and 20 nm length in WBFs increased thermal conductivity of drilling fluids
Hassani et al. (2016)	1. SiO_2 2. Carbon nanotubes 3. ZnO	Water	Temperature: 40ºC	Some WBF samples were prepared, each containing silica (SiO_2), carbon nanotubes (CNT), and zinc oxide (ZnO) NPs. The results showed a 16.9% improvement in thermal conductivity at 2 wt% of sample containing silica NPs. CNT additive on WBF had a 12% increase in thermal conductivity at 2 wt% which is less than the results of silica and zinc at the same concentration, 16.9% and 22%, respectively
Needaa et al. (2016)	Sepiolite	Water	LPLT and HPHT (122-356ºF and 500-6,000 psi)	The study reported WBF samples containing 1.4 wt% of sepiolite NPs which successfully stabilised the rheological properties up to pressures as high as 6000 psi and temperatures up to 356 °F
Mahmoud et al. (2016)	1. Fe_2O_3 2. SiO_2	Water	HPHT	The results showed that aging silica (SiO_2)-containing WBF to 350 °F and 500 psi had a negative effect and gave a severe gel strength loss of the fluid. When testing iron oxide (Fe_2O_3) NPs the results displayed that fluid viscosity and yield stress stabilised with the addition of iron NPs at high temperatures up to 200 °F and minor changes to the fluids rheological properties when aged at 350°F for 16 hours. Improvement in filtration properties were also obtained at HPHT condition. The optimum concentration was 0.5 wt%.
Halali et al. (2016)	Carbon nanotubes	Water	LPLT and HPHT (248, 302, 347, 392°F)	CNT NPs were used in WBFs in concentrations up to 0.8 wt% at temperatures 248, 302, 347, and 392°F. The results indicated that thermal conductivity was enhance by up to 12 %.)
Aftab et al. (2016)	ZnO	Water	LPLT and HPHT (149 and 250°F)	Zinc oxide (ZnO) NPs were used in WBF at HPHT (65 and 121ºC) conditions for the fluids filtration properties. Filtration reduced slightly at 121 °C, 500 psi, as the concentration of zinc increased from 0 g up to 1 g in a sample of 350 cc of drilling fluid from about 13.5 ml to around 10.5 ml.
Krishnan et al. (2016)	Boron	Water	HPHT	The study tested boron NPs in WBFs and showed that, at HPHT (302 °F and 500 psi) condition, the samples could withstand higher temperatures and prevent early breakdown of the polymers in the WBF. A field trial indicated that 2 wt% concentration could go up to 349 °F with no noticeable degradation of the fluid system

Silica based NPs were tested at HPHT conditions by Srivatsa et al. (2012). Silica has a thermal stability up to 250°F which makes it an ideal additive for drilling fluids. Srivatsa and his co-workers presented their results at HPHT conditions with and without silica NPs, and showed that the surfactant that was used for surfactant/polymer based drilling fluids was not stable at 392 °F and 1,000 psi, however, it was stable when blended with NPs. Mao et al. (2015(b)) used silica based nanocomposite and observed the reduced HPHT filtration loss by 69% after aging at 802 °F for 16 hours, which showed that the fluid is stable with little or no degradation. Hassani et al. (2016) also reported 16.9% improvement in thermal conductivity of WBFS through addition of silica NPs with the concentration of 2 wt%. Results obtained by Mahmoud et al. (2016), however, indicated that aging silica at 350°F and 500 psi had a negative effect and resulted in a severe gel strength loss of the fluid. Needaa et al. (2016) reported using sepiolite NPs can stabilise the rheology of the WBFs up to pressures as high as 6000 psi and temperatures up to 356 °F.

One of the first studies to test transition metal based NPs at HPHT conditions in WBFs was conducted by William et al. (2014). They tested samples of copper and zinc based NPs and showed up to 53% and 23% increase in thermal conductivities of the muds respectively. Ponmani et al. (2016) reported similar observations for both copper and zinc NPs. Their experiments also showed how using particles at nanometre level provides superior thermal conductivity than using particles at micrometre level as shown by the Figure 6.

Barry et al. (2015) tested the filtration loss and filter cake at HPHT conditions; 1015 psi and 392 °F. Iron based NPs performed better at HPHT conditions compared to ambient conditions with a decrease in filtration volume. Aftab et al. (2016) also tested zinc based NPs in WBFs at HPHT conditions for the fluid filtration properties. Filtration loss slightly reduced from about 13.5 ml to 10.5 ml at 250 °F and 500 psi as the concentration of zinc was increased from 0 to 1 g in a sample of 350 cm^3 of drilling fluid. Mahmoud et al. (2016) displayed that the fluid viscosity and yield stress were stabilised with the addition of iron NPs at high temperatures up to 200 °F and minor changes in rheological properties when aged at 350 °F for 16 hours. They also found that filtration loss was improved at HPHT conditions with the addition of iron NPs where the optimum concentration (the lowest filtrate volume) was 0.5 wt% as shown in Figure 7.

Ismail et al. (2016) examined the addition of carbon based NPs into a WBF at HPHT conditions. They monitored the rheology and fluid loss behaviour of MWCNT at elevated temperatures up to 250 °F, and found that the increase in temperature reduced PV and gel strength of the sample. However, the conditions did not show a significant difference to filteration loss. Taha et al. (2015) observed an enhancement at the lower end rheology (in the range of 200%) without affecting PV and YP by using graphene NPs in WBFs with concentrations up to 5 wt% and temperatures up to 350 °F. Halali et al. (2016) performed experiments on CNT NPs with concentrations up to 0.8 wt% at temperatures of 248, 302, 347, and 392 °F. They found that viscosity could be increased especially at low shear rates, similar to Taha et al.'s (2015) observations. Fluid loss reduction occurred by over 93.3% and thermal conductivity was also enhanced by 12 %. Another study by Hassani et al. (2016) on CNT additive in WBFs showed 12% increase in thermal conductivity at the concentration of 2 wt%, which is less than the reported values for silica and zinc at the same concentration, 16.9% and 22%, respectively.

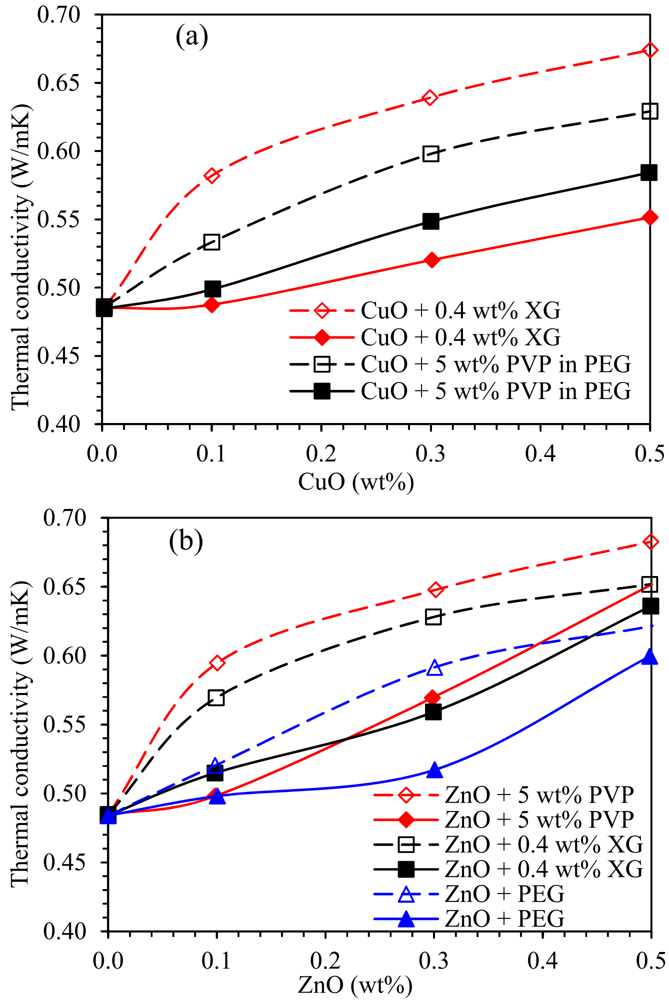

Figure 6 Variation of thermal conductivity of nano-enhanced WBF (unfilled symbols) and micro-enhanced WBF (filled symbols) (a) CuO-based; (b) Zn0-based, Ponmani et al. (2016) (*adopted*)

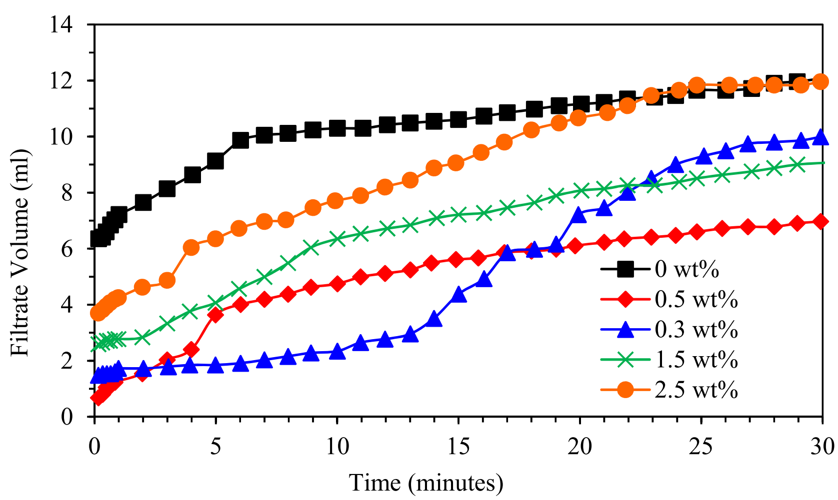

Figure 7 Filtrate volume plotted against square root of time for drilling fluids having different concentration of ferric oxide NPs at 300 psi and 250 °F, Mahmoud et al. (2016) (*adopted*)

Other NPs tested at HPHT conditions are Pal, cellulose and boron. Abdo et al. (2013) used Pal NPs and found that WBFs showed perfect stability at temperatures up to 392 °F. Song et al. (2016), tested the use of cellulose NPs in drilling fluids, and noticed there was a decrease in filtrate volume with increasing concentrations of NPs at HPHT conditions; 199°F and 1000 psi, and CNF produced the least fluid loss. Meanwhile, Krishnan et al. (2016) focused on boron NPs, and analysed fluid loss and stability at temperatures up to 302 °F and the pressure of 500 psi. They found that the drilling fluid properties at HPHT conditions could withstand higher temperatures and prevent early breakdown of the polymers in the WBFs. In a field trial at Myanmar, the boron NPs were used with the concentration of 2 wt% in downhole temperature conditions as high as 349 °F, and there was no noticeable degradation of the fluid system. A recent study by Chai et al. (2016) also confirmed that the use of MWCNT NPs in OBFs could increase the thermal conductivity of the fluid at higher concentrations.

Friction Reduction

Friction reduction becomes increasingly important during drilling of long deviated wells. WBFs tend to have a coefficient of friction (COF) greater than 0.1 and OBFs tend to be less than 0.1. The drilling fluid ideally should have the lowest possible COF to reduce wear on the drilling string. This might also reduce wear on the previous casing, which is important as if it wears, the tri-axial burst / bi-axial collapse limit changes. Wears on casing are dangerous as it can lead to a failure to withstand high circulating pressure especially when a kick occurs. Table 4 summarises recent studies on friction reduction in drilling operations through addition of nanoparticles in drilling fluids.

Table 4 Summary of the recent studies evaluating the application of nanoparticles to reduce friction during drilling operations

Author	**Types of NPs**	**Based Fluid**	**Experimental Conditions**	**Summary of Results**
Aftab et al. (2016)	ZnO	Water	LPLT and HPHT (149 and 250°F)	1.0 gr of zinc oxide (ZnO) NPs in WBFs slightly increased fluid rheological properties and reduced filtrate loss and friction coefficient under HPHT conditions.
Javeri et al. (2011)	Graphene	Water	LPLT and high temperature (120 and 351°F)	3.0wt% of silica NPs in WBFs successfully reduced loss circulation and differential sticking problems resulted from friction reduction LPLT
Mao et al. (a,b) (2015)	SiO_2	Water	LPLT and high temperature (392, 410, 428, 446ºF)	0.5 wt% of silica (SiO_2) NPs in WBFs reduced the friction coefficient as high as 93.4%.
Srivatsa et al. (2012)	SiO_2	Water	LPLT	The study concluded that silica (SiO_2) NPs in a surfactant based fluid benefits horizontal and directional drilling resulted from the low solid content and the ability to form a thin, impermeable filter cake that can reduced friction between the drilstring and the borehole surface.

Taha et al. (2015)	Graphene	Water	LPLT and high temperature (120 and 351°F)	5.0wt% of nano-graphene containing lubricant improved lubricity of the drilling fluids. It also showed a torque reduction of 80% at 199ºC conditions and as high as 50% at 351ºF.
Taraghikhah et al. (2015)	SiO_2	Water	High temperature at 250ºF	1.0wt% of silica (SiO_2) NPs in WBFs reduced friction coefficient significantly from 0.37 to 0.11, and showed mud cake friction factor reduction as the concentration of silica NPs increase

A study performed by Javeri et al. (2010) on the application of silica NPs in drilling fluids, suggests the use of NPs would be promising to mitigate loss circulation and differential sticking problems due to a decrease in friction. Later, Sharma et al. (2012) tested silica NPs, and determined that the fluid is ideal for drilling long lateral sections due to reduced friction of the fluid. Srivatsa et al. (2012) concluded that silica NPs in a surfactant based fluid benefits horizontal and directional drilling operations due to the formation of a thin, impermeable filter cake, reduced friction and low solid content. Mao et al. (2015(b)) conducted experiments on drilling fluids with addition of 0.5 wt% silica NPs, and concluded it is possible to successfully reduce the lubricating coefficient as high as 93.4% as shown in Figure 8. Similarly, Taraghikhah et al. (2015) indicated that mud cake friction factor reduces as the concentration of silica NPs increases.

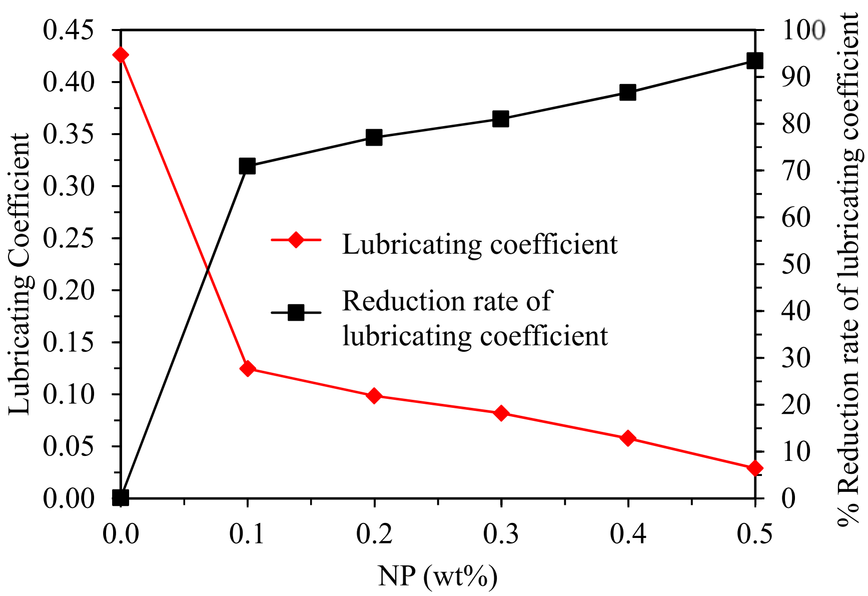

Figure 8 The effects of extreme pressure lubricating coefficient of water based drilling fluid by silica based NP concentration Mao et al. (2015(b)) (adopted)

Other NPs tested to help lubricity and, reduce torque and drag are Pal, graphene and boron. Abdo et al. (2013) reported a 34% reduction in torque with one sample of drilling fluid containing 7.4 wt% Pal NPs. Taha and Lee (2015) used a sample with 5 wt% of graphene NPs, and they achieved 80% reduction in torque at 200 ºF condition, and as high as 50% reduction in torque at 350 ºF. At a field trial, the mud with graphene NPs with the concentration of 3 wt%, increased the rate of penetration (ROP) by 3 times and was stable at high temperatures up to 349 °F. In this field trial, COF was reduced from 0.21 to 0.08 which is in the similar range as synthetic based muds, and torque was reduced by 44% and the equivalent circulating density (ECD) was noted to be stable. Photos of the drill bits used at field trial (shown in Figure 9) indicates the use of NPs can increase the life of the drill bit by 75%. Krishnan et al. (2016) reported very similar results to Taha & Lee. (2015), while using boron NPs instead of graphene NPs at the field trial in Myanmar. It can be justified that the high surface to volume ratio along with good lubricating properties of the nano-sized particles compared to that of the bulk materials, and the interaction between the particles with hydrophobic/hydrophilic properties with the drilling tools is the main factor for reducing the friction factor at the drilling bit.

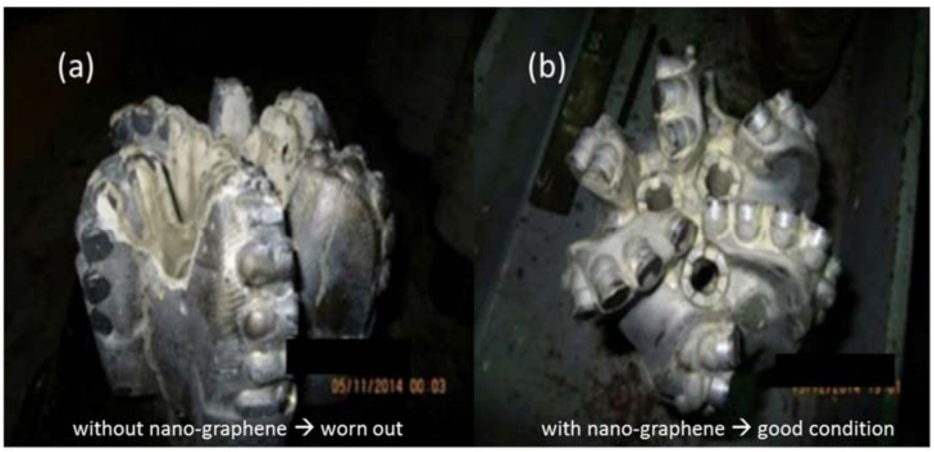

Figure 9 Drill bit conditions after being pulled out of hole: (a) without the graphene enhanced lubricant the bit was worn out with lots of solids sticking to it, and (b) with the graphene enhanced lubricant the bit was in good condition and cleared from any solids, Taha & Lee. (2015) (*adopted*)

Shale Inhibition and Wellbore Stability Improvement

The complex chemical and physical variations in shale formations can cause many challenging conditions such as sloughing, swelling and abnormally pressured formations. To counteract these issues, it is important that the drilling fluid acts as a shale inhibitor which in turn provides wellbore stability due to lower fluid invasion into the shale formation with less reactive fluid filtrate. Table 5 lists recent studies reporting increase of wellbore stability in shale formations with the use of nanoparticles in drilling fluids. In most of these studies, due to the formation of a very low permeable mud cake on the wellbore, which acts as a barrier between drilling fluids and shale formation, there would be no serious reaction between drilling fluid and shale rocks, and therefore no wellbore stability issues.

Table 5 Summary of the recent studies evaluating the application of nanoparticles to improve heat transfer rate properties of drilling fluids

Author	Types of NPs	Base Fluid	Experimental Conditions	Summary of Results
Aftab et al. (2016)	ZnO	Water	LPLT and HPHT (149 and 250°F)	1.0 gr of zinc oxide (ZnO) NPs in WBF slightly increased fluid rheological properties and reduced filtrate loss under HPHT conditions. The fluid formulation was also able to prevent swelling of shale minerals.
Akhtarmanesh et al. (2013)	SiO_2	Water	Not specified	30wt% of silica NPs with 35 nm diameter in WBFs showed an inhibitive behaviour towards shale minerals indicated from the reduction of mud filtrate observed through the pore plugging test.
Cai et al. (2012)	SiO_2	Water	LPLT	10wt% of silica NPs in WBFs reduced filtrate invasion and improve the ability of plugging and sealing micro-pores and micro-fracks of the shale formations.
Jain et al (2015)	1. Composite of polyacrylamide and nanoclay 2. Composite of polyacrylamide-grafted-polyethylene glycol and SiO_2 nanoparticles	Water	High temperature up to 203°F	The study tested composite of polyacrylamide-grafted-polyethylene glycol and silica nanoparticles. 0.7wt% of the composite with 20-30 nm diameter in WBF showed a stable rheological profile at 203°F and exhibit a high inhibition towards clay minerals which can prevent swelling of shale formations during drilling process.
Liu et al. (2015)	1.Latex particles 2.Aluminium complexes	Water	LPLT and HPHT	The study suggested that novel latex and aluminium complexes with 80 – 345 nm diameter for WBFs is a potential shale stabilizers that can reduce pressure transmission and improved membrane efficiency to have superior shale stability due to bridging and sealing micro and nano scale pore throats.
Østergaard et al. (2000)	SiO_2	Water	Not specified	The study used water based drilling fluid enhanced by silica NPs to improve inhibition of shale materials as compared to a synthetic based mud which is commonly used for when wellbore stability is of importance. Testing 3.0 wt% of silica produced a permeability reduction greater than the water based mud without silica of 20.1% showing its ability at plugging and sealing micro-pores and micro-fracks.
Taraghikhah et al. (2015)	SiO_2	Water	High temperature at 121°C	Study on silica NPs in WBFs to improve shale inhibition found that the optimum concentration is 1.0 wt% compared with other shale inhibitors by preventing the shale from swelling.
Zhang et al. (2015)	Not specified	Oil	LPLT and HPHT (194°F)	2.0wt% of NPs in OBFs effectively improved shale stability by plugging and sealing micro-pores and micro-fracks. Significant reduction was also obtained on fluid loss and filter cake thickness under HPHT condition.

Riley et al. (2012) evaluated the use of silica nanomaterials in a WBF to improve inhibition of shale materials and compared it with a synthetic based mud which is commonly used for wellbore stability concerns in shale formations. Sample with 3.0 wt% of silica produced a permeability reduction of 20.1% greater than the base sample without silica, showing its ability at plugging and sealing micro-pores and micro-fractures.

Akhtarmanesh et al. (2013) found that to reduce permeability and fluid invasion the minimum colloidal silica NPs concentration needs to be 10 wt%, and a better plugging performance was noted with the 35 nm sized NPs as compared to the 50 nm NPs. Similarly, Taraghikhah et al. (2015) tested silica NPs in WBFs to improve shale inhibition with the concentration of 1.0 wt% and compared the results with a WBF containing shale inhibitors. Figure 10 shows that even with the shale inhibitor in the advanced polymer drilling fluid, swelling still can occur whereas the nano-drilling fluid prevents the shale formation from swelling and successfully acts as a shale inhibitor.

Liu et al. (2015) conducted a test using novel latex and aluminium complexes with 80–345 nm diameter, as a potential shale stabilizers. They found that superior shale stability was due to the reduced pressure transmission and improved membrane efficiency which come from bridging and sealing micro and nano scale pore throats.

Zhang et al. (2015) reported that testing nanoparticles in an oil based mud had a similar effect as testing in a water based mud and helped to improve shale stability by plugging micro-pores and micro-fracks. A field test was also conducted using the NP-based OBF and it was found that while being run for 30 days, the mud still showed good comprehensive performance and the borehole instability was improved significantly with problems such as hole collapse and stuck pipe not being encountered.

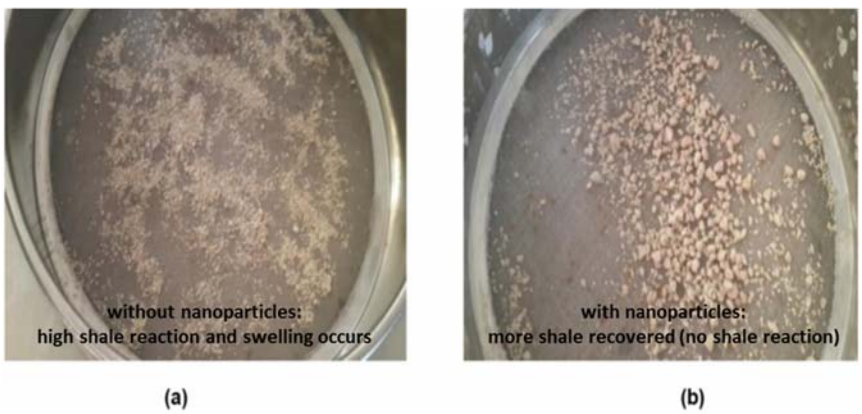

Figure 10 (a) Shale recovery after subjected to advanced polymer and (b) after exposed to the nano-drilling fluid Taraghikhah et al. (2015) (*adopted*)

Hydrates Inhibition

One of the main challenges in deepwater drilling operations is the formation of gas hydrate in the drilling fluid circulation system. Hydrates are formed by water molecules that are stabilised by the presence of other molecules, commonly gas molecules, and create complex, three-dimensional crystal structures. Formation of hydrates, especially in water-based drilling fluids, eliminate water from the fluids and eventually alter the fluid properties. Hydrates depositions can cause an increase in fluid weight that can be dangerous in narrow pressure window margin during deepwater drilling operations. Furthermore, combination of cold seabed conditions and high hydrostatic pressure is a favourable environment for hydrates to precipitate in the fluid circulation system, and become accumulated near the conductor pipe, blowout preventers, and even inside the choke and kill lines. Common method to tackle hydrate formation during drilling operations is by adding chemicals, such as methanol, glycols, salts, polymers, and often combinations of those chemicals to suppress hydrate formation temperature to a lower level.

Very little research has been conducted into hydrate inhibition. Liu et al. (2016) studied the effect of nanoparticles in drilling fluid to mitigate hydrates formation during drilling operation. They used silica nanoparticles with the concentration of 2 wt% in a seawater-based drilling fluid. They measured rheological and filtration properties along with the potential of hydrate formation in water based drilling fluids at 2611 psi and 39 °F. They compared a nano based drilling fluid with sea water and customised water based drilling fluid called Aqua-ColTMS.

Their results showed that their proposed nanosilica based drilling fluid had an optimal density, good low-temperature rheology, and an acceptable filtrate volume.

Their results also indicated that no crystal hydrate was formed during the experiment at temperatures as low as 39ºF and pressures up to 2611 psi, simulating the seabed conditions of the South China Sea regardless of whether the drilling fluid was circulated or not during 20 hours-long experiment. However there is no clear conclusion why the addition of silica NPs prevented hydrate forming. It might be due to high heat capacity of silica nanoparticles which can change the conditions of hydrate formation. They also suggested that the use of silica NPs can reduce the cost by 15-20% compared to the use of conventional drilling fluids for drilling operations in the region. To date, this is the only study reported the application of nanoparticles to mitigate hydrate formation in drilling fluids and more investigations need to be performed in order to draw a clear conclusion about the effectiveness of nanoparticles on hydrate formation.

On the other hand, the effect of nanoparticles on hydrate formation has been well studied in the gas storage and transportation area (Liu et al. 2017, Najibi et al. 2015, Pahlavanzadeh et al. 2016, Yu et al. 2017), Zhou et al. 2014). However, most of previous studies confirmed that combination of metal nanoparticles with anionic surfactants such as SDS (sodium dodecyl sulfate) can promote hydrate formation. Najibi et al. (2015) investigated the application of surfactant and copper oxide nanoparticles on promotion of hydrate formation for gas storage and transportation at temperatures of 34.7 and 38.3 °F and pressures of 725 and 870 psi. Their results showed that adding copper oxide (CuO) nanoparticles enhances the rate and amount of gas consumption, and the mole percent of water to hydrate conversion. They also found that gas hydrate improvement is proportional to the concentration of nanoparticle. Their results also showed that adding CuO nanoparticles decreases the induction time with no considerable effect on the final gas storage capacity. In another study, Pahlavanzadeh et al. (2016) studied the kinetic of methane hydrate formation in the presence of copper nanoparticles dispersed in the cetyl trimethyl ammonium bromide (CTAB) and SDS surfactant solutions at temperature and pressure of 35.6 °F and 798 psi, respectively. Their experimental results showed that copper nanoparticles and CTAB solutions reduce the induction time of methane hydrate formation, but CTAB seems to be more effective in this regard. They concluded that the most effective solution to promote hydrate formation is water-based copper nanoparticles with high concentrations of 0.0157 M and 0.157 M.

Recently, Liu et al. (2017) investigated the effect of iron oxide nanoparticles dispersed in sodium dodecyl sulfate (SDS) solution, on natural gas hydrate formation. They found that SDS coated iron oxide nanoparticles with a size of 20 nm can also promote methane hydrate formation up to two times more than the case with no nanoparticles. They also found that smaller particles result in a faster hydrate formation rate. In general it can be concluded that metal nanoparticles boost the formation of gas hydrates during gas storage and transportation, while opposite behaviour was observed for their mixtures in drilling fluids as hydrate inhibitors (Liu et al. 2016).

Conclusions

Reports of the most recent studies on the application of nanoparticles in drilling fluids have been covered in this manuscript. The application of nanoparticles in drilling fluids, induces exceptional performance by having the potential to mitigate and reduce the problems might encounter during drilling operations. Conclusions on the roles of nanoparticles in modifying the drilling fluids characteristics may be drawn as follows:

- Overall, studies on the addition of NPs showed a general improvement in rheological properties while fluids can retain shear thinning characteristic that follow the Herschel-Buckley model. However, NPs should not be used as a substitute for bentonite/barite as they may reduce the rheological properties of the mud significantly.
- The filtration loss and filter cake properties generally show improvements through using NPs. It has been observed that there would be a reduction in filtrate volume for API tests by over 60%. Filter cakes have also been noted to be thinner and much more compact, leading to a reduction in porosity and permeability.

- Heat transfer properties have been improved significantly through addition of NPs. With the use of NPs, thermal conductivity increases over 50% for some cases, and filtration loss decreases with increasing NPs concentration for nearly all studies. Rheology and thermal stability remaining consistent at HPHT conditions which make the use of drilling fluids feasible at HPHT and ultra-deep formations.
- The addition of NPs has shown to improve friction reduction in drilling fluids making even WBFs to have nearly as low COF as OBFs. This is due to the decrease in solid content of mud as the NPs are so small they can act like fluid.
- Nanoparticles have also been able to improve wellbore stability especially when drilling through shale formations. The very small particles contained in the drilling fluids are able to plug and seal micro, and nano scale pores and fractures, avoiding excessive filtrates to penetrate into the formations.
- Until today there have been very limited studies on application of nanoparticles to mitigate gas hydrates formation in drilling operations. It was shown that the presence of silica nanoparticles promotes the dissolution of gas in the drilling fluid preventing crystal hydrates to form. However, mechanisms on how the nanoparticles supress hydrates formation have not been discussed further.

Recommendations

Most of the studies have touched almost all the main parts of the technical aspects in drilling operation. However, more extensive analysis and observations are required for further research include:

1. Key mechanisms of particles interactions to understand physical interaction or chemical reaction between nanoparticles and the common additives present in drilling fluids.
2. Use of a more complex, optimised fluid formulation including oil based fluids with added NPs and evaluate the properties, as most of the previous studies focused on water based drilling fluids.
3. Evaluate the effect of extreme pressure and temperature conditions to the performance of drilling fluids, for example under ultra HPHT environment or in extreme cold seabed condition during deepwater drilling.
4. Further investigation particularly to mitigate gas hydrates formation in the circulation system.

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Abbreviations

API	=	American Petroleum Institute
AV	=	Apparent viscosity, *centipoise (cP)* or *mPa.s*
CNC	=	Cellulose nanocrystals
CNF	=	Cellulose nanofibers
CNP	=	Cellulose nanoparticles
COF	=	Coefficient of friction, *dimensionless*
ECD	=	Equivalent circulating density
EOR	=	Enhance oil recovery
HPHT	=	High pressure and high temperature
LCM	=	Lost circulation material
LPLT	=	Low pressure and low temperature, means that a measurement performed at ambient temperature and under 100 psi differential pressure which also, refers to API Filter Press standard condition
MWCNT	=	Multi-walled carbon nanotubes
NPs	=	Nanoparticles
OBFs, OBDFs, OBMs	=	Oil-based fluids, oil-based drilling fluids or oil-based muds are drilling fluids whose liquid phase is mixture of oil and water
Pal	=	Palygorskite, or attapulgite, is a type of clay mineral
PV	=	Plastic viscosity, *centipoise (cP)* or *mPa.s*
ROP	=	Rate of penetration
WBFs, WBDFs, WBMs	=	Water-based fluids, water-based drilling fluids or water-based muds are drilling fluids in which water is the external or continuous phase
YP	=	Yield point, $lbf/100ft^2$ or *Pa*

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