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EXPERIMENTAL INVESTIGATION OLEFIN-BASED INVERTER DRILLING FLUIDS ON HPHT CONDITIONS: APPARENT VISCOSITY IN DIFFERENT OIL/ WATER RATIOS

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Abstract. *Drilling fluids are essential in the oil and gas industry to help maintain wellbore stability, cool and lubricate the drill bit, and carry cuttings to the surface. In high-pressure, high-temperature (HPHT) conditions, these fluids face unique challenges due to the extreme environment they are subjected to. One of the main challenges of drilling fluids in HPHT conditions is maintaining their rheological properties, such as viscosity and yield strength. These properties are crucial for effectively carrying cuttings to the surface, and they can be impacted by the high temperatures and pressures present in HPHT wells. The objective of this work is to analyze the dependence of the oil-water ratio and density on the viscosity of drilling fluids with NaCl, as well as to fit the viscosity variation with shear rate, temperature, and pressure. Olefin-based drilling fluid with two different oil-water ratios (60/40 and 70/30) and three different densities (11.5 ppg, 10 ppg, and 8.5 ppg) were rheologically characterized. Steady-state flow curves were developed at temperatures of 4, 65, 93, 121 ºC and atmospheric pressures of 70, 270, and 550 bar. The experimental data were collected on a Mars 60 rheometer (Haake, Germany) coupled with a D600/250 pressure cell. The results showed that the shear stress decreases with increasing temperature and the oil-water ratio and improves with increasing pressure and density. The temperature variation from 4 to 121ºC decreased approximately 84% in the 60/40 fluid and 55% in the 70/30 with 8.5 ppg at the shear rate of 510.9* s^{-1}. *We can see that between lower oil-water ratios, better capacity has the drilling fluid in HPHT conditions. In the case of pressure, shear stress increases in both 60/40 and 70/30 fluids. On the other hand, increasing the density increases the shear stress, as expected. Increased from 12.8% (8.5 to 10 ppg) and 21.7% (8.5 to 11.5 ppg) in 60/40 fluid, and 30.0% (8.5 to 10 ppg) and 53.2% (8.5 to 11.5 ppg) in the 70/30, when comparing the values of shear stress at 4 ºC, atmospheric pressure, and 510.9*s^{-1}. *Then, the experimental viscosity data were fitted as a function of temperature, pressure, and shear rate.*

Keywords: *Drilling fluid, Apparent viscosity, Oil/water ratios, HPHT condition, offshore fields.*

1. INTRODUCTION

The growing global demand for oil and gas has led to a substantial increase in well drilling activities, especially in deep wells that operate under high-pressure and high-temperature (HPHT) conditions (Ibeh, C., 2007; Long, H., Chen et al., 2021; Patel, H.A.,2019). This surge in drilling activities presents significant challenges for the oil industry, necessitating the development and implementation of advanced technologies, improved drilling fluids, and an enhanced understanding of the factors that ensure safe and efficient operations. To address these challenges, numerous studies have been conducted to investigate the impact of HPHT conditions on the rheological properties of drilling fluids and other related issues (Gautam, S., et al. 2022; Palaoro et al. 2022; Quitian et al., 2022). The selection of appropriate drilling fluids is of paramount importance to prevent costly delays, wellbore instability, and environmental hazards (Fakoya, M.F., 2018; Greenaway, R., 2008; Hermoso, J., 2014a).

One type of non-aqueous drilling fluid that has garnered attention for its exceptional performance under HPHT conditions is olefin-based inverter drilling fluids. These fluids are formulated with olefin-based synthetic base oils, known for their remarkable thermal stability and resistance to degradation at high temperatures. Additionally, olefin-based fluids offer a broad operating temperature range, rendering them suitable for even the most extreme HPHT environments. The utilization of olefin-based inverter drilling fluids presents several advantages for drilling operations under HPHT conditions (Wang, H., et al., 2022). Firstly, these fluids exhibit outstanding lubrication properties, which reduce friction and minimize wear on drilling equipment, ultimately enhancing drilling efficiency and reducing downtime. Secondly, they maintain excellent thermal stability, preserving their rheological properties and performance even at elevated temperatures. This stability is critical for maintaining wellbore integrity and preventing issues such as fluid loss and wellbore collapse. Furthermore, olefin-based inverter drilling fluids enhance wellbore stability by minimizing differential sticking and reducing the risk of formation damage. These fluids have low invasion characteristics, preventing fluid invasion into the formation and minimizing the potential for wellbore instability. They also exhibit excellent shale inhibition properties, reducing the risk of shale swelling and sloughing (Howard A. Barnes, 2000).

The rheological properties of olefin-based inverter drilling fluids can be tailored to specific HPHT conditions by adjusting the concentration of additives, such as viscosifiers and rheology modifiers (Rodrigues, R.K., 2020). This flexibility allows for optimal fluid performance in a wide range of HPHT environments. While olefin-based inverter drilling fluids have shown promising results in HPHT conditions, ongoing research and development efforts are aimed at further enhancing their performance and addressing any existing limitations. These efforts focus on improving fluid stability, compatibility with other drilling fluid components, and optimizing the fluid formulation to suit specific well conditions. In this study, we examine the rheological behavior of olefin-based drilling fluids with varying densities and two different oil/water ratios under high-pressure and high-temperature (HPHT) conditions. The primary objective is to gain insights into shear stress variations during these conditions by employing a non-linear fit approach with strong physical significance. A key contribution of this research is to emphasize the importance of barite density variations in olefin-based drilling fluids in HPHT environments. Additionally, the data fitting process proves valuable in well planning procedures

2. MATERIALS AND METHODS

Olefin-based drilling fluid with two different oil-water ratios (60/40 and 70/30) and three different densities (11.5 ppg, 10 ppg, and 8.5 ppg) were rheologically characterized. The rheological characterization involved the development of steady-state flow curves at various temperatures and atmospheric pressures, as can be seen in Table 1.

Table 1. Description of Fluids and Measurement Conditions in Rheological Analyses.

Drilling fluid	Salt-based	Oil-water ratios	Barite Density [ppg]	Shear rate $[s^{-1}]$	Pressure [bar]	Temperature [ºC]
Oleofin-based drilling fluids	NaCl	60/40	11.5	510.9, 340.6, 170.3, 102.1, and 51.09	70, 270, and 550	4, 65, 93, and 121
			10			
			8.5			
		70/30	11.5			
			10			
			8.5			

The experimental data were collected using a Mars 60 rheometer (Haake, Germany) in conjunction with a D600/250 pressure cell. The flow curves were generated at temperatures of 4°C, 65°C, 93°C, and 121°C [Table 1], which cover a spectrum of operating conditions encountered in high-pressure and high-temperature (HPHT) drilling environments. The selected pressure levels for the experiments were 70 bar, 270 bar, and 550 bar, all relevant to HPHT conditions and conducive to a comprehensive analysis of the drilling fluid's rheological behavior under varying pressure regimes.

During the rheological characterization, controlled shear rates were applied to the drilling fluid samples using the rheometer. The resulting data recorded shear stress and shear rate, allowing us to establish the fluid's flow behavior at each temperature and pressure condition. The rheometer, equipped with a D600/250 pressure cell, provided the precision and control necessary for obtaining reliable data on the drilling fluid's behavior. Overall, this experimental setup and methodology facilitated the characterization of the olefin-based drilling fluid's rheological properties across a range of oil-water ratios, densities, temperatures, and atmospheric pressures commonly encountered in HPHT drilling operations.

With the aim of predicting rheological behavior, we applied these conditions to the data gathered from all measurements to derive the fitting parameters for the power law model, which establishes the relationship between shear stress and shear rate. Subsequently, we utilized models with physical significance to fit the consistency coefficient values as a function of pressure, as illustrated in Figure 1. Similarly, we established a factorial model that accounts for the effects of both pressure and temperature on the consistency coefficient by correlating the influence of temperature using the fitting parameters. We repeated the same process to determine the flow behavior index. To achieve this, we employed the Barus model and the Williams-Landel-Ferry (WLF) model, which are well-known for their physical significance (Chaudemanche et al., 2009; Fakoya and Ahmed, 2018; Fillers and Tschoegl, 1977; Hermoso et al., 2017b; Tschoegl et al., 2002; Williams, 1964), to fit the pressure and temperature dependencies of the consistency coefficient, respectively. The impact of pressure on the flow behavior index was evaluated using the power law model, while we used the Arrhenius equation to consider the effect of temperature. By employing these models and fitting techniques, we accurately characterized the rheological behave of the drilling fluid, accounting for the impacts of both pressure and temperature on both the consistency coefficient and the flow behavior index.

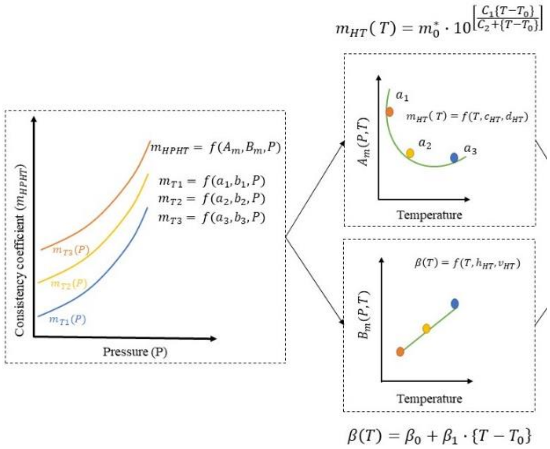

Figure 1. Graphical representations of the pressure and temperature fit process of the consistency coefficient with WLF model and Barus model.

3. RESULTS AND DISCUSSION

Oil-based and synthetic drilling fluids have long been integral to well drilling operations, especially when confronting high-temperature and high-pressure environments. However, the contemporary landscape of offshore well drilling presents a new set of challenges, marked by the prevalence of High-Pressure High-Temperature (HPHT) conditions and even more rigorous environmental constraints. In this context, understanding the rheological behavior of olefin-based drilling fluids at elevated temperatures and pressures becomes paramount for the formulation of novel drilling fluids that can effectively adapt to the specific conditions encountered in these challenging wellbores. The challenges extend further, as offshore drilling activities involve not only the HPHT conditions but also the considerable variability in subsea seabed temperatures. These seabed temperatures have been reported to plummet to a minimum of approximately 4°C, an astonishing contrast to the high-temperature conditions that exist just above them. Consequently, the formulation of drilling fluids tailored for offshore applications necessitates a comprehensive evaluation of several critical variables, which include barite density, the oil-to-water ratio, shear rate, temperature, and pressure. These variables play pivotal roles in the performance of drilling fluids and their ability to navigate the complexities of high-pressure, high-temperature, and subsea environments. Our study aimed to unravel the intricate interplay of these variables, particularly focusing on shear stress, a fundamental parameter that defines a drilling fluid's ability to perform effectively under such diverse conditions. To achieve this, we conducted extensive rheological experiments, capturing and analyzing the shear stress response in a systematic manner across the spectrum of these vital parameters.

In Figure 2, we illustrate the variations in shear rate concerning temperature, while systematically varying barite density for an oil-based drilling fluid with a 60/40 oil-to-water ratio. The findings reveal a consistent trend across all tested densities in Figure 2(a), (b), and (c) – the drilling fluid displayed shear-thinning behavior, characteristic of non-Newtonian fluids. Moreover, these fluids exhibited a dynamic yield stress, signifying that a minimal stress is required to initiate flow. However, due to the elevated temperatures involved in our experiments, we had to cap the shear rate at 50 s^{-1}, as measurements conducted at higher rates fell below the equipment's minimum torque threshold. It is evident from these experiments that elevated temperatures correlate with lower shear stress measurements, signifying a reduced capacity to withstand the operational stresses. Intriguingly, an increase in pressure could compensate for some of the shear stress losses attributed to high temperatures. This observation underscores the temperature effects as being more pronounced, while pressure, fueled by the compressibility of the oil component in the drilling fluid, emerges as a potent counterbalance to the capacity losses induced by elevated temperatures during drilling.

A closer examination of the drilling fluids at a uniform temperature of 4°C reveals significant insights. We observed a remarkable threefold surge in shear stress when comparing the shear rate at 510.9 s^{-1} and a pressure of 550 bar to conditions at 70 bar. Importantly, as we increased the barite density in the drilling fluid to 8.5, 10, and 11.5 ppg, we noted corresponding increases in shear stress, reaching values of 112.8, 159.3, and 223.7 [Pa], respectively. This information presents an invaluable perspective on the equipment's maximum capacity requirement for efficient operation within a specific wellbore scenario. On the other hand, when we investigated the fluid's behavior at high temperatures of 121°C, at the highest shear rate, we noted a substantial rise in shear stress from 18.15 to 46.9, further escalating to 70.54 [Pa] as the barite density was elevated under a pressure of 550 bar. In Figure 2(b), the data reveals that as temperature increases, the shear stress values diverge more significantly with increasing pressure. This divergence suggests a probable connection between pressure effects and the density of particulate matter in the fluid, particularly with regard to barite.

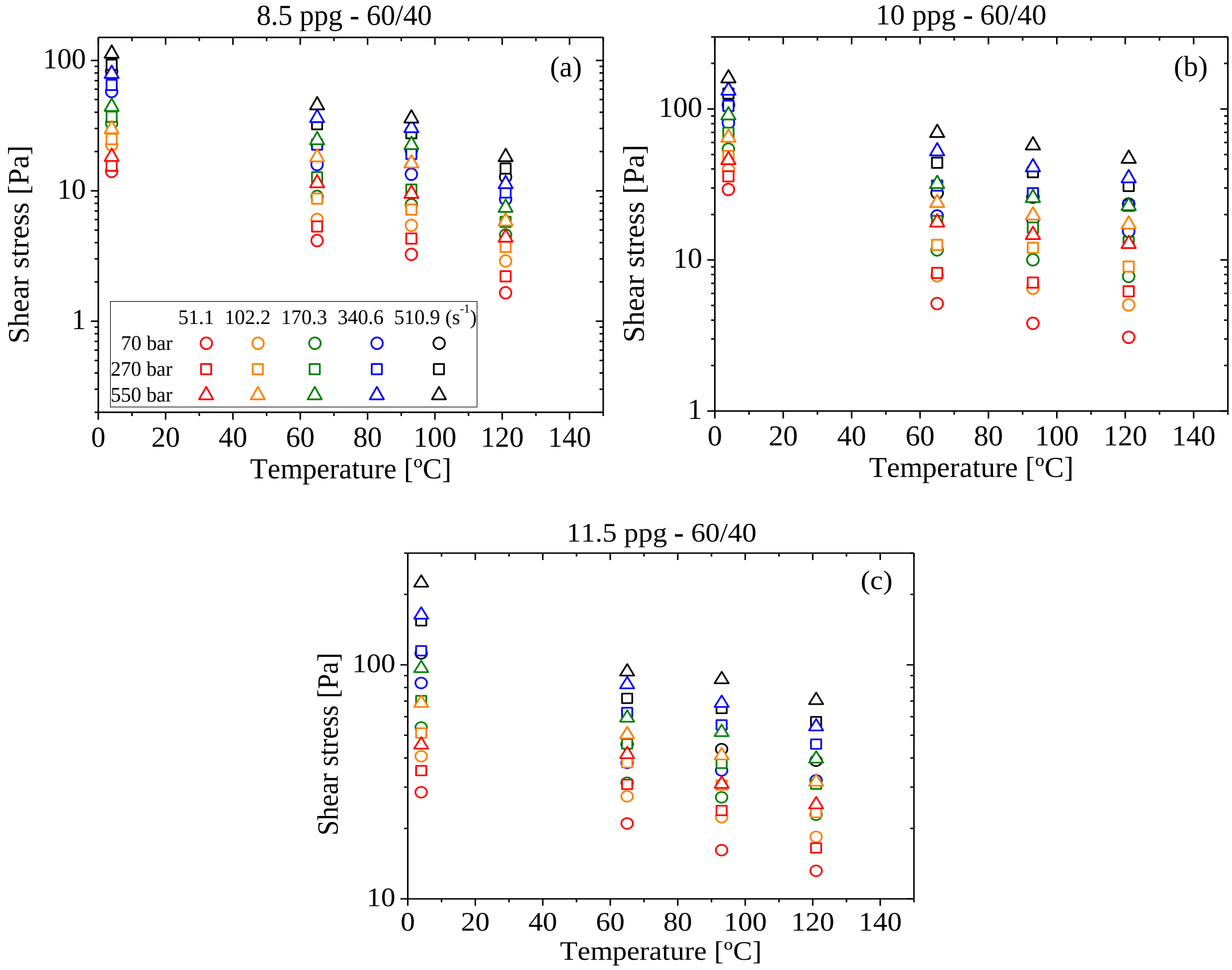

Figure 2. Shear stress as a function of temperature for three different pressures for an olefin-based drilling fluid with a 60/40 oil/water ratio and densities of (a) 8.5 ppg, (b) 10 ppg, and (c) 11.5 ppg.

Furthermore, our analysis extended to explore the behavior of oil-based drilling fluids with a different oil-to-water ratio of 70/30, signifying a higher proportion of oil within the fluid composition. Encouragingly, we found that the shear-thinning behavior, consistently observed in the drilling fluid with a 60/40 ratio, remained present in all tested samples, as vividly depicted in Figure 3. The temperature impact emerged as a highly pronounced factor, with pressure playing a crucial role in restoring shear stress and compensating for the losses incurred at high temperatures. For instance, at a temperature of 4°C, we identified lower shear stress values when comparing 550 bar to 70 bar at a shear rate of 510.9 s^{-1}

for the same densities (8.5, 10, and 11.5 ppg), registering values of 49.6, 87.16, and 104.58 [Pa]. This observation strongly implies that increasing the oil content within drilling fluids results in a diminished capacity to cope with subsea conditions, signifying a unique challenge for such formulations. An intriguing finding in the behavior of the 70/30 fluid at a density of 10 ppg, evident in Figure 3(b), was the increased spacing between measurements. Additionally, our exploration of shear stress at high temperatures of 121°C indicated that for a density of 8.5 ppg (Figure 3(a)), the value varied by a mere 1 [Pa]. However, for densities of 10 and 11.5 ppg, represented in Figure 3(b) and (c) within the 70/30 ratio fluid, we identified substantial reductions in values – 22.8 and 27.5 [Pa], marking reductions of 2 and 2.5 times, respectively.

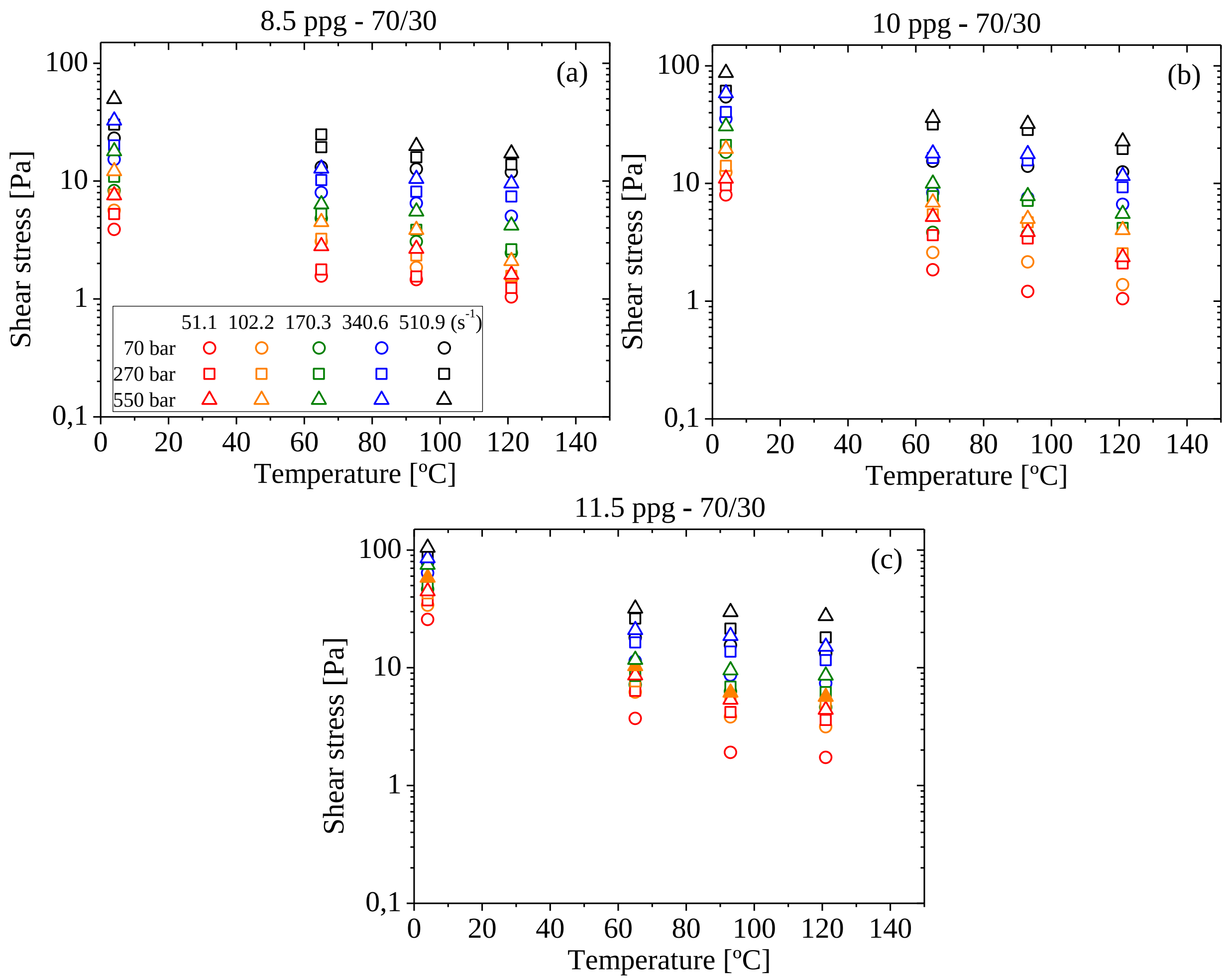

Figure 3. Shear stress as a function of temperature for three different pressures for an olefin-based drilling fluid with a 70/30 oil/water ratio and densities of (a) 8.5 ppg, (b) 10 ppg, and (c) 11.5 ppg.

To predict shear stress values across a spectrum of diverse conditions within the measurement range, we harnessed a sophisticated methodology developed and honed at the prestigious Center for Rheology and Non-Newtonian Fluid Research (CERNN). This methodology, a culmination of cutting-edge research and innovation of rheological behavior and anticipate shear stress responses under various conditions (Quitian et al., 2022). The core of this methodology revolves around fitting flow curves, an intricate task that allows us to model the behavior of drilling fluids with remarkable precision. Specifically, we employed a power-law model, a foundational framework that has been refined and enhanced over the years to capture the dynamic properties of non-Newtonian fluids. Within this model, two fundamental parameters come into play: the consistency coefficient (m) and the flow behavior index (n). These parameters act as the key to deciphering the complex relationships between temperature and pressure, two vital variables that define the behavior of drilling fluids under real-world conditions.

Intricately woven into our methodology are well-established physical models, each tailored to address distinct aspects of drilling fluid behavior. The WLF model, a revered framework in the field, comes into play, offering insight into the impact of temperature variations on shear stress. We drew upon the expertise of researchers (Fakoya and Ahmed, 2018; Fillers and Tschoegl, 1977; Hermoso et al., 2017b; Tschoegl et al., 2002; Williams, 1964), who have significantly advanced the understanding of this model. Likewise, the Barus model, another cornerstone in our methodology, takes center stage when grappling with the complexities of pressure's influence on shear stress. Studies about pressure effect (Chaudemanche et al., 2009; Hermoso et al., 2017b), have contributed to refining the Barus model, empowering it to provide a deep understanding of how pressure affects drilling fluid behavior.

To put our methodology to the test and ascertain its reliability, we conducted comprehensive rheological experiments, focusing on a specific scenario: a 60/40 oil-to-water ratio oil-based drilling fluid with a density of 8.5 ppg. This choice allowed us to meticulously examine the behavior of drilling fluids under varying pressures and temperatures. Figure 4, an illustrative representation of our findings, encapsulates the alignment between predicted and experimental shear stress data for this particular drilling fluid. This alignment, exemplified in Figure 4, stands as a testament to the robustness and precision of our predictive model, underscoring the methodology's accuracy. But we did not stop at the validation of our methodology for a single scenario. We extended our predictions to encompass a wide array of drilling fluids, each characterized by its unique combination of density and oil-to-water ratio. For instance, we explored drilling fluids with a different oil-to-water ratio, a 70/30 composition, which signifies a higher proportion of oil within the fluid. The results were nothing short of remarkable. The fits between our predictions and the experimental data displayed outstanding correlation coefficients (R^2), serving as concrete evidence of the model's versatility and its applicability to diverse fluid compositions and operating conditions. This near-perfect alignment held true for the majority of scenarios, affirming the methodology's reliability across a wide spectrum of conditions. However, as in any scientific endeavor, there are exceptions that prompt further investigation. In the case of drilling fluid with a density of 10 ppg within the 70/30 ratio, an anomaly emerged. The predicted shear stress values did not precisely mirror the experimental results. While this discrepancy could be attributed to measurement errors or unforeseen phenomena, it represents a fascinating avenue for future research and exploration.

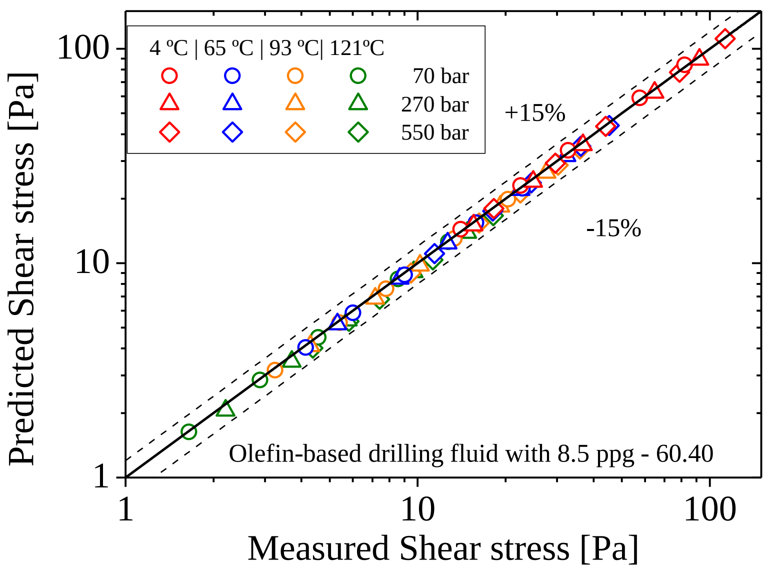

Fig. 4 Validation of shear stress value predictions for oil-based drilling fluid with 8.5 ppg, oil/water ratio of 60/40 under various pressure and temperature conditions

As a final layer of scrutiny, we subjected all the model fits to an exhaustive analysis using a single-factor statistical analysis of variance (ANOVA). This rigorous examination allowed us to assess variations in the data obtained from our rheological measurements. The outcome of this analysis revealed a high level of statistical significance, with a 95% confidence level between the measured and predicted values. This robust statistical confirmation further bolsters the methodology's accuracy and its capacity to consistently and reliably anticipate shear stress values across a wide array of conditions, making it a powerful tool for the formulation of drilling fluids tailored to meet the specific demands of challenging wellbore scenarios.

4. CONCLUSIONS

The current study highlights the critical role of drilling fluids in adapting to the demands of high-pressure, high-temperature (HPHT) offshore well drilling. Through extensive rheological experiments, we have unraveled the intricate interplay of variables such as temperature, pressure, shear rate, barite density, and oil-to-water ratio, with a particular focus on shear stress. The findings underscore the significance of these parameters, emphasizing the impact of elevated temperatures on shear stress, mitigated by increased pressure. Moreover, they reveal the challenges associated with higher oil content in drilling fluids. a novel methodology for assessing the impact of high pressures and temperatures on olefin-based drilling fluid. The proposed equation effectively captures the combined effects of temperature and pressure on the behavior of the drilling fluid. This equation holds immense potential for oilfield engineers as it enables the simulation of drilling fluid performance under high-pressure and high-temperature (HPHT) conditions, thereby facilitating the development of effective drilling strategies.

5. ACKNOWLEDGEMENTS

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