Edelweiss Applied Science and Technology
ISSN: 2576-8484
Vol. 7, No. 2, 71-86
2023
Publisher: Learning Gate
DOI: 10.55214/25768484.v7i2.359

Analysis of a drilling mud-based system on the common problems related to coiled tubing application in slim-hole oil wells

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Abstract: Coil tubing is slim and looks like a long, continuous length of pipe made from carbon steel metal that is a lesion on spool that is 1 to 3.25 inches in diameter of 26,000 feet long. The main benefit of coil tubing in drilling operations over wireline jobs is the ability to pump chemicals through the coil and the ability to push it into the hole rather than relying on gravity. Inappropriate selection of the drilling mud is one of the contributing factors to hole problems. Different experiments were conducted to determine the mud rheology of multiple mud samples. Certain parameters, like the critical velocity, are calculated using a numerical approach for the coiled tubing applications. In addition, it is crucial to determine the pump pressure required to maintain a specific flow rate. It is noted that drilling operations become more efficient at lower plastic viscosities; however, plastic viscosity is reduced through dilution; hence, the rate of penetration is improved. Moreover, a higher yield point is capable of transporting the cuttings more effectively than a lower yield point. The critical velocity indicated the boundaries between the laminar and turbulent flow regimes. As the mud flow rate inside the tubing increased, the velocity increased, causing the shear stress at the tubing wall to increase.

Keywords: *Cerberus software, Coil tubing, Critical velocity, Drilling, Experiments, Flow rate, Hydra approach, Yield point.*

1. Introduction

The use of coiled tubing for drilling and intervention operations in slim-hole wells has seen an increase in the petroleum industry. Coiled tubing has several advantages over conventional drilling methods, including faster drilling rates, increased safety, and cost-effectiveness, yet the success of coiled tubing operations is significantly influenced by the performance of the drilling mud [1]. Oil and gas producers have faced a significant obstacle in the form of wet tree intervention in deep and extremely deep water. Utilizing a conventional Mobile Offshore Drilling Unit (MODU) or intervention vessel, typically a smaller MODU is currently the only practical intervention method, whether for a straightforward clean-up or resuming another producing interval. The intervention is only scheduled when the operation's financials are justified because this is a very expensive venture [2]. On top of the production trees, coil tubing pressure control equipment was attached to wells that had already been completed and sealed. A coil tubing tower was used to accommodate the drilling bottom hole assembly (BHA) and eliminate the risks associated with its deployment.

Coil tubing strings were made to reach target intervals with enough weight on bit (WOB), were suitable for sour conditions, and could withstand high pumping rates with low circulating pressures. A custom-fit closed-loop system addressed the dangers of handling hydrogen sulfide at the surface [3]. Several duties fall under the control of the drilling mud, including hole cleaning, lubricating, and cooling the bits, as well as maintaining the wellbore stability [4]. However, a small number of studies have shown that wellbore stability is a more complex phenomenon that is influenced not only by geomechanics but also strongly by drill-string vibrations' downhole forces and high mud flow rates; also, it was found that

History: Received: 3 July 2023; Revised: 12 September 2023; Accepted: 6 October 2023; Published: 15 November 2023
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some wells drilled with more mud weight have a more unstable wellbore than offset wells, which goes against the traditional theory that links wellbore stability to rock strength properties and stresses alone. Therefore, the purpose is to examine wellbore stability, considering both geomechanically and drilling parameters, to explain the typical wellbore enlargements that have been observed in two vertical wells drilled in the same location [5]. Analyzing the drilling mud used in coiled tubing operations is important to ensure efficient and productive drilling. In addition, the analysis of drilling mud should consider rheology, and the rheological properties of drilling mud determine its ability to perform certain tasks, such as the transportation of cuttings and wellbore stability; moreover, a range of rheological tests are available and have been used to evaluate the drilling mud properties, such as plastic viscosity, apparent viscosity, yield point, and gel strength. Furthermore, these tests will help spot potential issues like inadequate cutting transportation and wellbore instability, which may significantly impact how well-drilling operations are conducted [6].

In addition, chemical and physical properties such as the mud weight, pH, and filtration capacity should be examined to study the drilling mud. The mud density influences the wellbore's stability, loss of circulation and fracture formation [7]. Acidic mud may create erosion in the tubing and the borehole; therefore, alkaline mud is recommended and desirable, and the capability of filtration of drilling mud may negatively impact the hole cleaning process; consequently, it is preferred to evaluate the mentioned properties; moreover, determining the pump pressure for coiled tubing operations is essential because a pressure that is too high or too low, like extremes, may cause several issues during the operations; however, this will influence the drilling efficacy, stability of the wellbore, and formation conditions [8].

As shown in Figure 1, coiled tubing application or drilling in a slim hole well is used to replace the conventional rig, a platform, or the mobilization of a drilling rig when neither option is financially feasible. A small-diameter steel conduit that has been tightly wound around itself is known as coiled tubing. This technology has recently gained greater acceptance among operators because of its capacity to reduce overall costs and its increasing range of drilling applications.

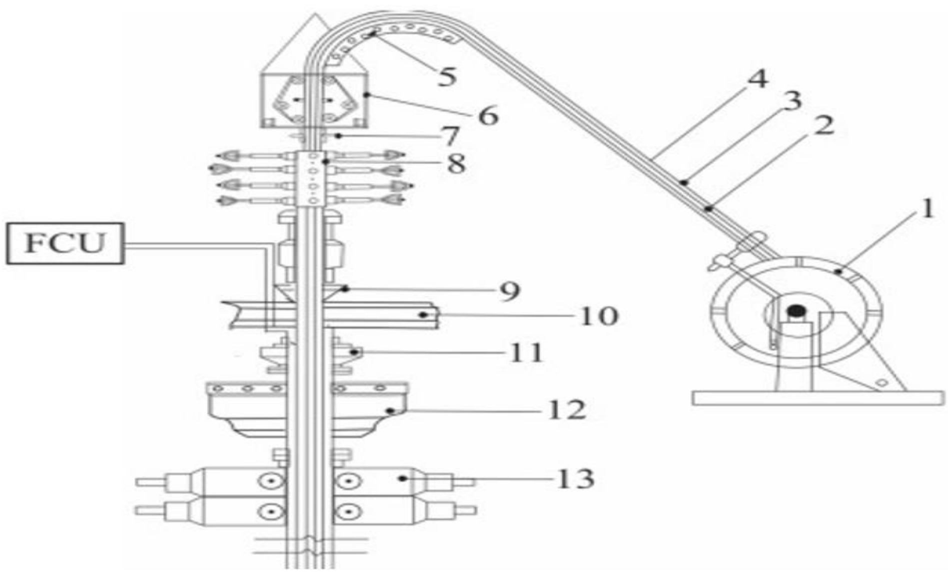

Figure 1.
Schematic view of coil tubing in a vertical well.

Note: Flow control unit (FCU).
1) Tubing reel 2) Inner tube 3) Outer tube 4) Coil tubing 5) Gooseneck 6) Injector head 7) Stripper 8) Blow out preventer stack 9) Slips 10) Rig floor 11) Rotating drill head 12) Hydrill 13) Stack.

Source: Shingala, et al. [10].

Coiled tubing, CT, is favored for extended- reach wells because of its ability to drill or deliver tools at high inclinations of the wellbores through, directional drilling. The range of tubing diameters spans from 0.75 to 45 inches, with a prevalence of 2 inches being the most frequently observed size. Its length may vary between 600 and 9,000 meters, or 2,000 and over 30,000 feet, and there is no need to make or break connections while drilling because the tubing is wound in a single continuous length and enables uninterrupted airflow when entering or leaving the orifice [9].

Coiled tubing has several advantages over conventional drilling and completion techniques, including a shorter rig time, lower costs, increased safety, and greater flexibility [11]. The coiled tubing technique is particularly useful in challenging environments such as extended-reach wells, horizontal wells, and deviated wells, where conventional drilling and completion methods may not be effective or practicable. The capacity to convey fluids and perform operations downhole through the continuous tubing is one of the fundamental principles of coiled tubing. The tubing is designed to bend and flex and is forced downhole, allowing it to reach deeper into the wellbore than conventional drilling techniques [6]. During drilling and production operations, a stable wellbore is always preferred. According to Sorgun, et al. [12] wellbore instability costs the petroleum industry more than $6 billion annually and is becoming more of a problem as the industry moves into more challenging formations, where most wellbore failures during drilling operations occur.

Abdulhadi [13] examined the hydraulics and flow characteristics of drilling muds in the annulus as well as the process of cutting transportation in a wellbore. In addition, fluid velocity has been observed to be the most influential variable in cutting transport. It is important to identify the mud velocity and critical velocity to determine its flow regime, which is either the mud flow in a laminar or turbulent flow regime. Furthermore, when the mud velocity is less than the critical velocity, it indicates that the mud is in laminar flow, and when the velocity exceeds the critical velocity, the mud is in turbulent flow; however, the drilling mud is unable to keep the cuttings suspended during the flow, and the cuttings are suspended and accumulated at the side of the wellbore wall, which may lead to hole cleaning issues. Akl [14] studied the effect of drilling mud rheology on hole-cleaning operations.

Furthermore, their studies found that the rheological properties of the drilling mud, such as yield point and plastic viscosity, did not affect the cutting transportation under a turbulent regime. In contrast, a higher yield value contributed to improved cuttings transport under the laminar flow regime. In the annulus, different flow patterns are formed based on several controlling factors. Figure 2 presents the flow pattern profile, yellow color represents the tubing, and the white color represents the space between tubing; and the wall of the wellbore. Unwanted stationary layers result from low flow rates of the drilling mud in the annular space. Therefore, high flow rates are necessary to improve cutting transport. High pump pressure can lead to a high flow pressure, but higher pump pressures can cause fractures and washouts in less-consolidated formations. The results indicated that the cutting transport is more effective at high mud viscosities because the cuttings are spread throughout the annular space, whereas when only water is used as a drilling fluid, the cutting tend to stick more to the bottom side of the annulus. It was concluded that hole-cleaning process is achieved with high viscosity and high flow rate. In a laminar flow regime, the rheological properties of mud, like the yield-point values, are more influential than in turbulent flow regime. The outcome of the real-field scenario is contingent upon the circumstances of the wellbore and equipment. Therefore, the main objective of this paper is to determine the optimal pump pressure using Cerberus software by considering different variables related to the tubing specifications and mud properties, as well as to examine the performance of the coiled tubing operations as a slim hole well to ensure effective drilling operations are achieved.

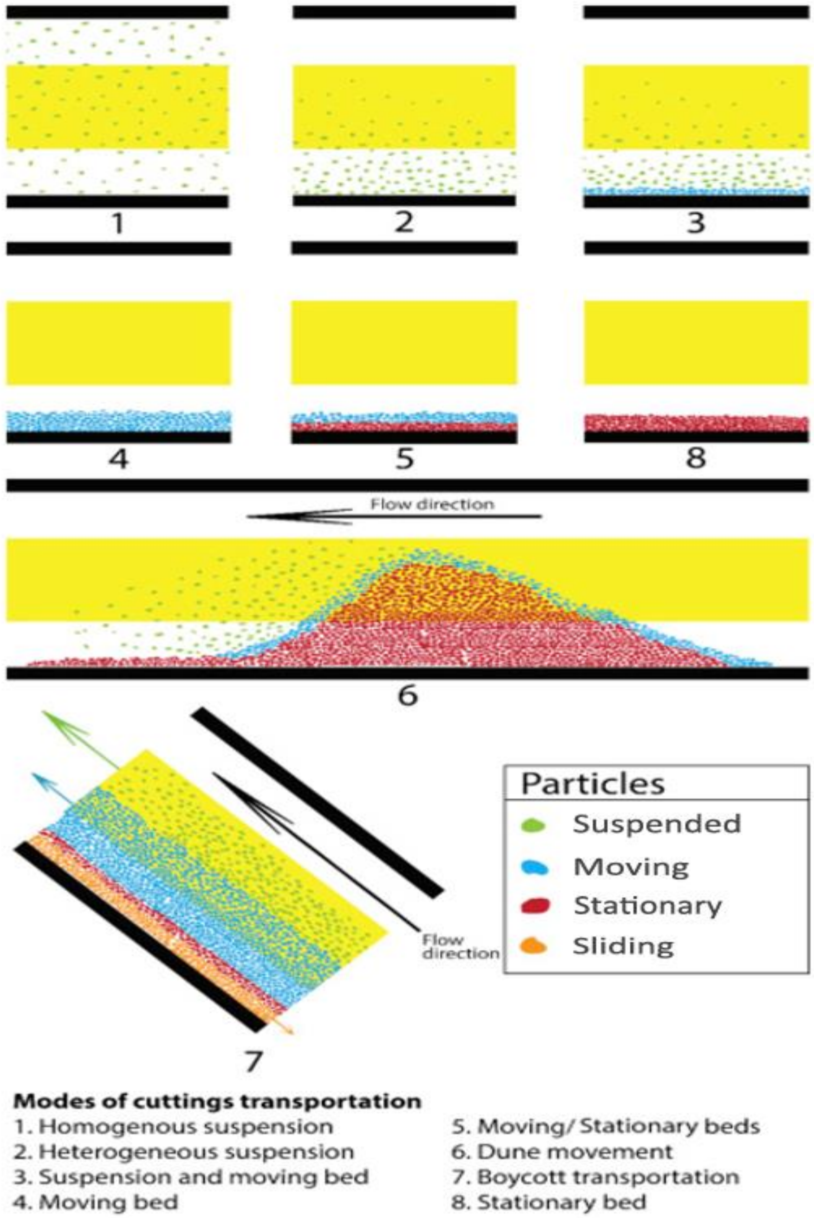

Figure 2.
Profile of flow patterns.
Source: Kamyab and Rasouli [15].

2. Experimental Study

2.1. Determination of Mud Weight

Using the Hamilton Beach Mixer in the laboratory, 12.09 grams of Bentonite were added to 350 milliliters of water and mixed for 5 minutes to create a proper mud system. To prevent the mud mixture from erupting from a sudden swirl, it was suggested that bentonite powder be added gently to water while it was being mixed; the mud balance was introduced to measure the mud weight. Figure 3a shows the mud balance. The calculated amount of Barite was added to the mud mixture and thoroughly mixed before the density was measured. Before and after the addition of barite, the density of the sediment was measured to be 9.2 pounds per gallon. Using the marsh funnel viscometer, as shown in Figure 3b, the viscosity was

Edelweiss Applied Science and Technology
ISSN: 2576-8484
Vol. 7, No. 2: 71-86, 2023
DOI: 10.55214/25768484.v7i2.359

measured, and the consistency of the mud was checked. In addition, the pH paper is submerged in the mixture to determine the pH value of the mud by analyzing the color generated when the pH paper is immersed in the mud to check whether it is acidic or alkaline.

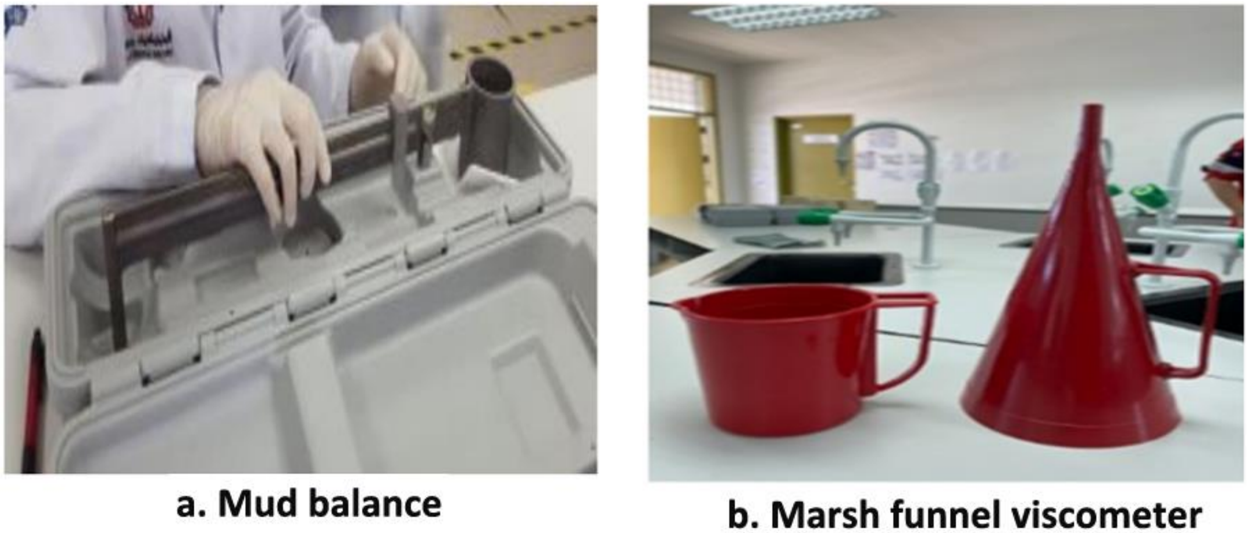

Figure 3 a & b.
Mud rheology tools.

2.2. Determination of Mud Rheology

Four mud systems were used in this study to determine the mud rheology of different mud types, as shown in Table 1. The mud systems were obtained after mixing 12 grams of Bentonite into 350 milliliters of water with additives of two grams of Mil Pac, 1.5 grams of Xan Pleed and 10 grams of Barium Sulfate, respectively. Each chemical additive has its own uses, as shown in Table 2. After the mud was created, it was thoroughly mixed and its weight was measured. A mud balance was introduced to determine the density of each mud system. This was done by adjusting the slider weight of the beam until the bubble in the vial was aligned with the line.

In addition, to determine the plastic, apparent viscosity, and yield point of the fluid, a Fann rotational viscometer, as shown in Figure 4a, was utilized; initially, the cup was filled with a desired drilling mud to the scribed line, and the two dots on the rotor sleeve were entirely submerged in the mixture. The rotation began at various revolution per minutes, Revolution per minute (RPMs) at 300 and 600; however, 100 and 200 existed, but there is no use of such rpms. When the rotor rotated between 300 and 600 rpm, as the dial speed, the readings were recorded once they reached a constant value.

Moreover, gel strength was measured using the same rotational viscometer and evaluated. Furthermore, the Fann Viscometer was adjusted to 3 RPM, and the readings were obtained after 10 seconds and 10 minutes. Using the dial reading obtained from each RPM, the rheological measurements, such as the plastic viscosity, yield point, and apparent viscosity, were calculated using Equations 1, 2 and 3.

$$\text{PV} = \text{Reading at 600 rpm} - \text{Reading at 300 rpm} \quad [1]$$

$$\text{Yield point, YP (Unit in lb/100ft}^2\text{)} = \text{Reading at 300 rpm} - \text{PV} \quad [2]$$

$$\text{Apparent viscosity (Unit in cp)} = \frac{Reading\ at\ 600\ rp}{2} \quad [3]$$

The Standard API filter press was used to measure the water loss, and the thickness of the mud cake was evaluated as the device appears in Figure 4b. Referring to the drilling fluids practical manual for a detailed step-by-step procedure to determine the water loss and the thickness of the mud filter cake. The

ISSN: 2576-8484
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device was set, and the data was recorded after 30 minutes. Data with an interval of 5 minutes was recorded by a supply of nitrogen gas pressure at 100 psi, which is a low-pressure experiment.

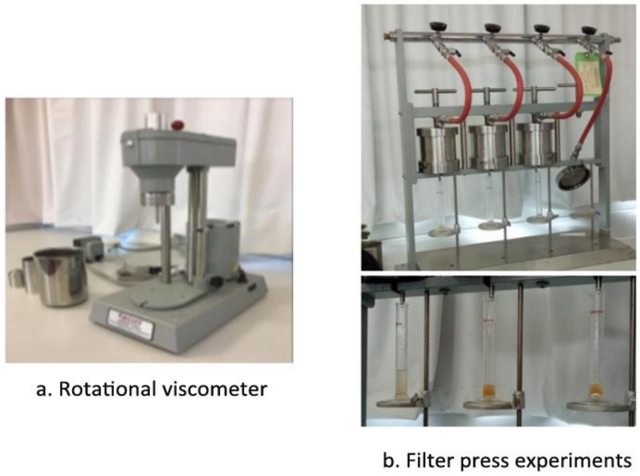

Figure 4 a & b.
Rotational viscometer and filter press experiments.

Table 1.
Mud components.

Components	Mud 1	Mud 2	Mud 3	Mud 4
Water	✓	✓	✓	✓
Bentonite	✓	✓	✓	✓
Barium sulphate	✓	✓	✓	✓
Mil pac	–	✓	–	✓
Xan pleed	–	–	✓	✓

Table 2.
Types of chemical additives for mud.

Chemical	Uses
Bentonite (Clay)	A basic component was added, which acts as a viscosifier to get a good filter cake.
Barite	To increase density
Mil pac	Filtration control agents improve filter cake by reducing permeability.
Xan pleed	To increase/Adjust the viscosity

2.3. Modeling Tools

A software called Cerberus is used in this study. Cerberus is treated as computer fluid dynamics or CFD has advanced features, including 3-dimensional visualization tools, machine learning algorithms, MLA, and optimization algorithms. Therefore, drilling parameters such as bit selection, drilling fluid properties, and well trajectory were adjusted for the operation. In addition, Cerberus software contains various features such as a reek-Trak, hydra, packer, completion analysis (PACA), Orpheus, velocity string and solids cleanout, as presented in Figure 5.

Cerberus Hydra wellbore hydraulic simulator model is used in this study to calculate the output pressure along the coiled tubing by using the drilling mud properties obtained from the laboratory's rheological test.

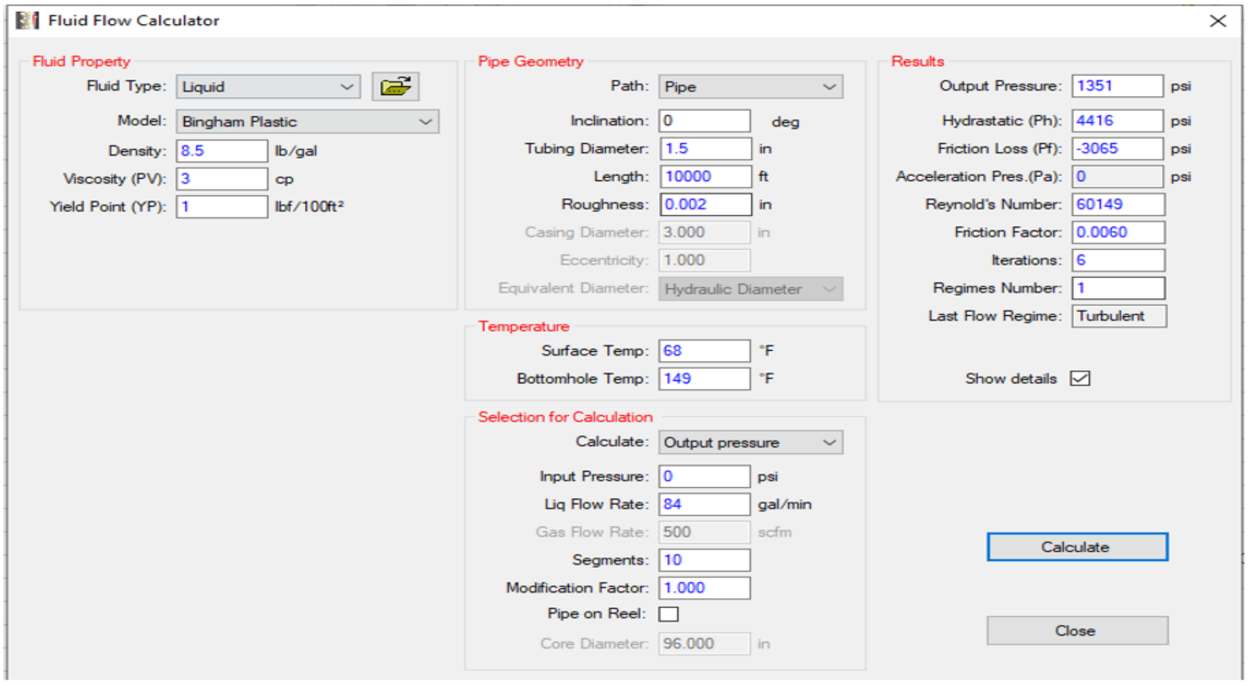

Figure 5.
Hydra fluid flow calculator.

3. Results and Discussion

All mud mixtures were measured using the mud balance, and the result was 1.02 g/cm³, 8.5 lbs./gal. The material balance was implemented to determine the quantity of barite required after obtaining the fluid densities, bentonite volume, and final mud density. To increase the fluid density to 9.2 pounds per gallon, material balance was used. To find the volume of barite, 40 grams of barite were added to the mud mixture to increase the mud weight to 9.2 pounds per gallon. Equation 4 presents the value of the mud density change after barite was added and functioned as a weighing agent.

$$V_1 W_1 + V_2 W_2 = V_f W_f \qquad [4]$$

Where, V1 = Volume of the first material to be mixed, W1 = Density of the first material, V2 = Volume of the second material, W2 = Density of the second material, VF = Total or sum of all volumes mixed, WF = Density of the total mixture. Proportional average of all Volumes mixed.

3.1. Mud Rheology Determination

Table 4 presents the mud properties measured. Ideal drilling mud is used during real drilling operations and should have a suitable pH and a proper mud weight, and this depends on factors like depth and formation type to be drilled. Acidic drilling mud is not advised as it may cause problems to the drilling equipment and formation damage, and that is the benefit of pH, and the range was between 7 and 10, indicating alkali. As shown in Figure 4a, rotational viscometer was utilized to obtain the values of yield point, plastic, and apparent viscosity of mud because they are significant in mud rheology. A fluid is placed in the cup, spanned at 300 and 600 RPM speeds. The higher the fluid resistance for rotation at a high RPM, the higher the viscosity value. This kind of evaluation is used to assess distinct types of mud to select the optimal drilling mud. Table 3 represents the results obtained from the rotational Viscometer with various mud types. The readings were used to calculate the other properties like plastic, apparent viscosity, and yield point of mud, and Table 3 also shows the results of the mud rheology samples.

Edelweiss Applied Science and Technology
ISSN: 2576-8484
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Table 3.
Mud properties.

Mud property	Mud 1	Mud 2	Mud 3	Mud 4
Mud weight (ppg)	8.5	8.4	8.7	8.6
pH	7	10	10	8
Temperature (°C)	20	20	20	20
RPM @ 300	4	22	8	10
RPM @ 600	7	36	12	18
Plastic-viscosity (cp)	3	14	4	8
Yield-point (lb/100ft^2)	1	8	4	2
Apparent viscosity (cp)	3.5	18	6	9

On the one hand, a mud that has a low plastic viscosity, the drilling operation becomes more efficient, which means that it is easier for the mud to flow out of the jet nozzles; hence, the rate of penetration and ROP are improved, and the results were compared with those of other researchers [16, 17] . On the other hand, plastic viscosity is reduced through dilution. A yield point, therefore, is a force to carry or lift the cuttings from the downhole through the annulus. A drilling mud with a higher yield point should be able to move cuttings more effectively than one with a lower yield point. Therefore, identifying mud rheology is vital for hole-cleaning process. In addition, the gel strength of mud is noteworthy characteristic. By measuring the gel strength at a low shear rate, the Rotational viscometer can determine the thixotropic property related to the suspension of the cuttings and other materials during the circulation process. Identifying the gel strength of the mud is important for maintaining wellbore stability and preventing issues like stuck pipes. Moreover, the gel strength of the drilling mud is typically measured at 3 RPM because it is within the range of the shear rates normally applied in the field. 3 RPM speed is regarded as a low shear rate, which is crucial because it enables the development and the measurement of the drilling mud's gel structure without excessive shear thinning.

To capture the gel's strength at the start of the measurement period, the initial gel strength data is recorded at 10 seconds. This measurement assesses the drilling mud's capacity to suspend rock cuttings and other materials throughout the drilling process. In determining the maximum gel strength that the mud may form over time, a 10-minute reading was recorded. This test evaluates the drilling mud's capacity to preserve the structural integrity and prevent the solids from settling. Table 4 shows the Rotational or Fann Viscometer gel strength readings using various mud systems. The drilling mud can suspend the rock cuttings while drilling. A higher gel strength may prevent the cutting buildup and effectively lower the risk of a stuck pipe. A lower gel strength value at 10 minutes indicates that the drilling mud may efficiently transport the cuttings out of the wellbore under static conditions, which may prevent formation damage and therefore increases the oil production.

Table 4.
Readings for gel strength.

Time	Mud 1	Mud 2	Mud 3	Mud 4
10 second	1	2	4	0.5
10 minutes	2	4	1.5	1.5

The Standard American Petroleum Institute, API Filter Press test is commonly used to calculate the drilling mud's fluid loss. A nitrogen gas pressure of 100 psi is applied to the drilling mud for 30 minutes. Before comparing each mud system's filter cakes (1, 2, 3 and 4), water loss was first recorded (in milliliters) when the gas valve was opened for 5, 10, 15, 20, 25 and 30 minutes. The results are recorded in Table 5.

Table 5.
Lost circulation using different mud systems.

Time (Minutes)	Mud 1 (ml)	Mud 2 (ml)	Mud 3 (ml)	Mud 4 (ml)
5	8.5	4	6	7
10	12.75	7	7	9
15	16	9	9	11
20	18.5	10	11	13
25	20.5	11	13	15
30	22	12	14	16

A high-water loss can cause formation damage, decreased drilling efficiency, and increased costs due to the need for more drilling mud. In addition, significant water loss may result in differential sticking, where the coil becomes stuck in the formation due to the pressure difference between the drilling mud and formation fluids.

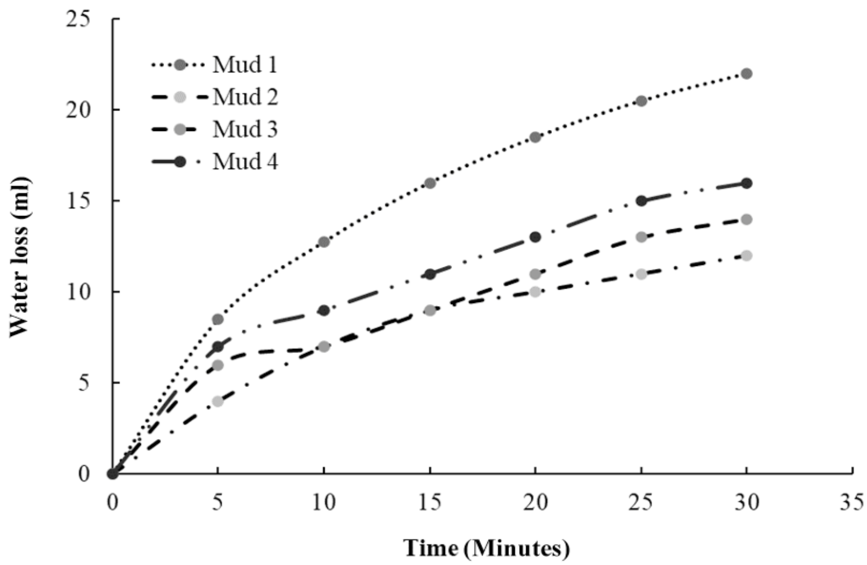

Figure 6.
Water loss against time.

Figure 6 shows that Mud 1 has the highest water loss, and Mud 2 has the lowest water loss over time. This proves that adding a chemical additive like Mil Pac decreases the water loss, which improves the filter cake. Lower water loss improves the filter cake quality. When the drilling mud is pumped into the wellbore, it forms a filter cake on the wellbore wall. This filter cake prevents drilling mud from escaping to the formation, leading to damage and poor hole cleaning. If the drilling mud has high water loss, it can result in a thick and poorly consolidated filter cake. In addition, this may lead to channeling or gaps in the filter cake; thus, it may allow drilling mud to penetrate the formation and reduce the effectiveness of the filter cake.

Furthermore, the formation may become contaminated with the drilling mud, leading to formation damage. Alternatively, when the drilling mud has lower water loss, it can result in a thin and well-consolidated filter cake. This may help maintain the wellbore stability, prevent the loss of drilling mud, and improve hole-cleaning efficiency.

3.2. Rheological Model

This is referred to as fluid rheology, and most of the oil and gas industry uses non-Newtonian fluid behaviour because the viscosity changes with the shear rate. For a Newtonian fluid behaviour where the viscosity is constant regardless of shear rate.

The rheology of mud is continuously measured and modified with additives to satisfy the requirements of the operation. There are three categories of models for non-Newtonian fluid behaviour, power law, Bingham plastic, and Herschel-Buckley models. Figure 7 shows the four different rheological models. To determine the type of rheological model for various mud systems, shear rate and shear stress are required. Fann Viscometer RPM can be converted to a shear rate. To calculate the shear rate in s^{-1} for a given RPM, Equation 5 is used to obtain the proper conversion factor.

$$Shear\ Rate = RPM\ \times 1.7 \qquad [5]$$

To calculate Shear Stress in dynes/cm^2, Equation 6 is used to obtain the shear stress.

$$Shear\ Stress = Dial\ Reading\ \times 5.11 \qquad [6]$$

The values of the dial readings for a certain RPM have been experimentally estimated and shown in Table 3. Table 6 displays the shear rate for 0, 300, and 600 RPM, as well as the shear stress for each mud at a given shear rate. These values are calculated using Equation 5 and 6.

Based on Table 6, as the shear rate increases, the shear stress also increases. Figure 5 represents the mud behaviour, which is non-Newtonian, because when the shear rate is zero, the shear rate is not zero; instead, it is the value of the yield point. All the curves of shear stress vs. shear rate are in a straight line, which indicates that the rheological model follows the Bingham plastic model.

Table 6.
Shear stress at a given shear rate.

Shear rate, s^{-1}	Mud 1, dynes/cm^2	Mud 2, dynes/cm^2	Mud 3, dynes/cm^2	Mud 4, dynes/cm^2
0	1	8	4	2
300	20.44	112.42	40.88	51.1
600	35.77	183.96	61.32	91.98

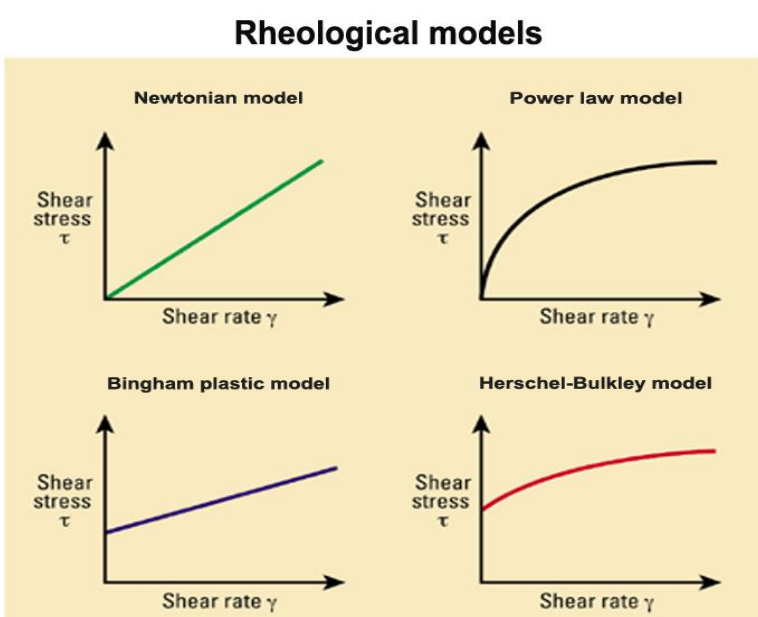

Figure 7.
Types of rheological model, Schlumberger energy glossary.

ISSN: 2576-8484
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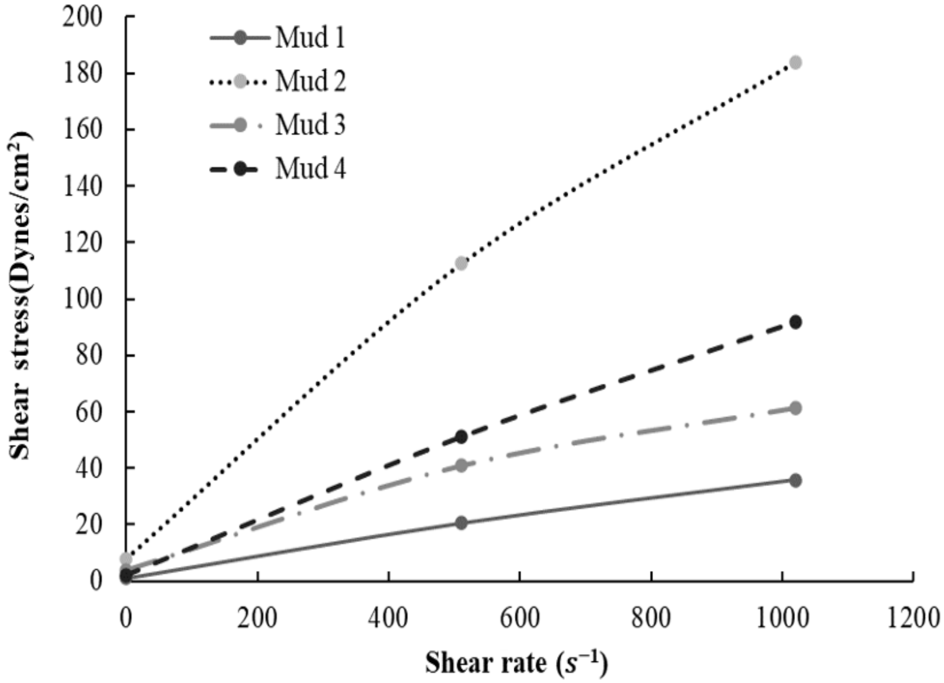

Figure 8.
Shear stress against shear rate.

3.3. Friction Pressure

Typically, the pressure drop at the surface equipment is calculated by equating it to an equivalent length of the drill pipe, which means the length of the coiled tubing. Table 7 represents varied sizes of the coiled tubing's outer diameter, the corresponding internal diameter, and the weight.

Table 7.
Coiled tubing in 3 7/8-inch well.

Coiled tubing specification		
Outer diameter (OD) (In.)	**Inner diameter (ID) (In.)**	**Weight (lb/ft)**
2.375	2.063	3.7
2	1.688	3.07
1.75	1.438	2.66
1.5	1.376	2.24

To determine the friction pressure along the tubing, it is necessary first to calculate the velocity of the drilling mud, its critical velocity, and the categories of flow that occurred at a particular flow rate. That is because there are two flow regimes: laminar and turbulent. every flow possesses a distinct set of equations that can be utilized to compute the friction pressure within the tubing. The average velocity and critical velocity are needed to determine the type of flow that occurs in the tubing. The critical velocity is the boundary between laminar and turbulent flow. When the velocity is less than the critical velocity, the flow is laminar, and when it is greater, the flow is turbulent [15]. Since drilling mud follows the Bingham plastic model, the equations for calculating average velocity, critical velocity and friction pressure were based on this model. For the calculations, coiled tubing with an outer diameter of 1.5 inches is used in this study, followed by an internal diameter of 1.376 inches. The length of the coiled tubing is

DOI: 10.55214/25768484.v7i2.359

10000 feet. Equation 7 is used to determine the average velocity of the mud based on a specific flow rate. The velocity values obtained for various flow rates of 84, 105, and 126 gal/min are 18.1 ft/sec, 22.6 ft/sec, and 27.2 ft/sec, respectively.

$$V = \frac{Q}{2.448\,(I.D^2)} \qquad [7]$$

The critical velocity is substantial to evaluate whether the flow is laminar or turbulent after obtaining the average velocity at a specific flow rate. To obtain the critical velocity for the mud, Equation 8 was used. Since four diverse types of mud were studied, each of which has different properties. Then four different values for four mud systems for the critical velocity were achieved as $V_c = 1.6\, ft/s$,$V_c = 4.94\, ft/s$, $V_c = 2.96\, ft/s$ and $V_c = 2.70\, ft/s$ respectively. Critical velocity at which laminar flow is converted to turbulent flow.

$$V_c = \frac{1.08PV + 1.08\sqrt{(PV)^2 + 12.34(I.D^2)(YP)(\rho)}}{\rho(I.D)} \qquad [8]$$

Based on the critical values for velocities obtained for each mud system at different flow rates of 84, 105 and 126, the average velocities exceed the critical velocities, which indicates a turbulent flow behaviour because of the small internal diameter of coiled tubing that caused the velocity to be high enough. Then the flow regime for each flow rate and friction pressure for the turbulent flow were calculated using the Bingham plastic model using Equation 9. The results of the calculated friction pressure are presented in Table 8. Figure 8 presents the flow rate on the x-axis and the friction pressure on the y-axis.

$$P_p = \frac{\rho^{0.75} V^{1.75} PV^{0.25} L}{1800\,(I.D)^{1.25}} \qquad [9]$$

Table 8.
Friction pressure at a given flow rate.

Q (Gal/Min)	Velocity, ft/Sec	Mud 1	Mud 2	Mud 3	Mud 4
		Friction pressure, psi	Friction pressure, psi	Friction pressure, psi	Friction pressure, psi
84	18.12	3887.79	5663.70	4251.22	5011.93
105	22.65	5745.08	8369.37	6282.11	7406.24
126	27.18	7904.29	11514.89	8643.17	10189.78

The pressure drop caused by the friction between the fluid and the tubing walls is known as friction pressure. As the flow rate of the mud in the tubing increases, the velocity increases, causing the shear stress at the tubing wall to increase. This increased frictional resistance and pressure. The increase in the friction pressure may increase the pressure gradient along the tubing, which may alter the flow characteristics of the mud. Figure 9 shows that as the flow rate in the tubing increases, the friction pressure along the tubing increases too.

Moreover, as friction pressure increases, the pressure drops across the length of the tubing increases, decreasing the flow rate. consequently, it is necessary to improve the pumping pressure in order to sustain a consistent flow rate.

This can result in issues, including decreased pumping system efficiency, increased apparatus wear, and an increased risk of pipe fatigue failure. Furthermore, increased frictional pressure may increase energy consumption and operational expenses.

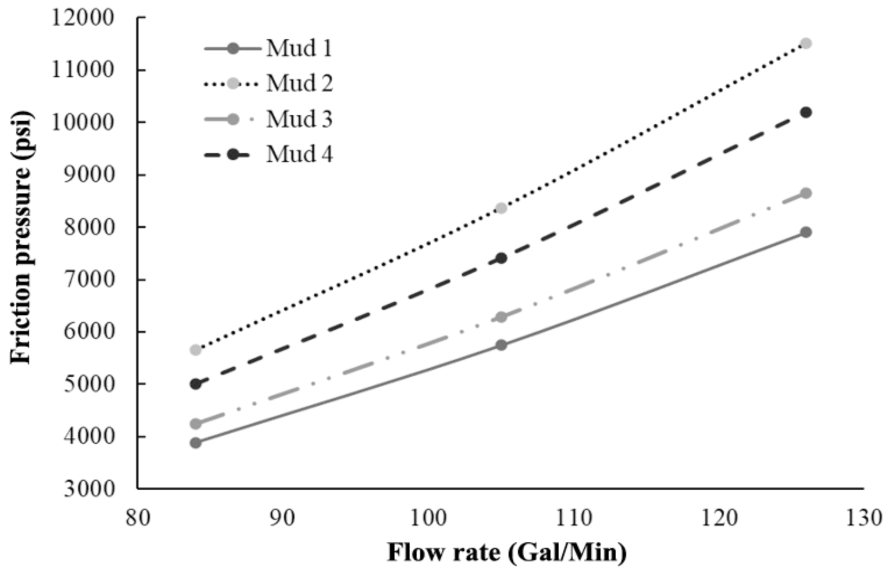

Figure 9.
Pressure loss in 1.5-inch O.D.

3.4. Output Pressure Determination

For safe and effective drilling operations, determining the input pressure or pumping pressure in coiled tubing is essential so that the tubing is not exposed to excessive pressure. It enables the appropriate mud weight and viscosity to be used during drilling operations. Using Cerberus modelling software, the output pressure in the coiled tubing was determined. The fluid flow calculator determines the input/output pressure inside the tubing. This software supports four model types: Newtonian, Bingham, Power Law, and Herschel Buckley. According to the collected data, four of the drilling muds fit the Bingham plastic model, and the properties of the mud, such as density, viscosity, and yield point, were determined from the rheological test. For pipe geometry, the tubing specifications, as shown in Table 9, are particularly usedS for coiled tubing. In this circumstance, for 10,000 feet of 1.5-inch coiled tubing, the surface temperature is 68 degrees Fahrenheit, and the bottom-hole temperature is 149 degrees Fahrenheit. To determine the output pressure inside the tubing, the input pressure is set to zero, assuming that no pump pressure is applied. When the output pressure is negative, the pump pressure required to maintain the flow rate is estimated. The calculated friction loss is slightly different from the Cerberus software results, as shown in Figure 7. This is because the results from the software depend on factors, for example, pipe roughness and inclination, whereas analytical analysis does not require these factors. Thus, errors are encountered in calculating the friction loss numerically, and the values should be rigorously evaluated for the tubing. Table 9 represents the data obtained based on the factors that influenced the output pressure.

Table 9.
Output pressure in the tubing.

Q (Gal/min)	Mud 1	Mud 3	Mud 4
	Output pressure, psi	**Output pressure, psi**	**Output pressure, psi**
84	1351	1278	895
95	549	439	-6
105	-259	-406	-907
115	-1141	-1327	-1887
126	-2198	-2429	-3054

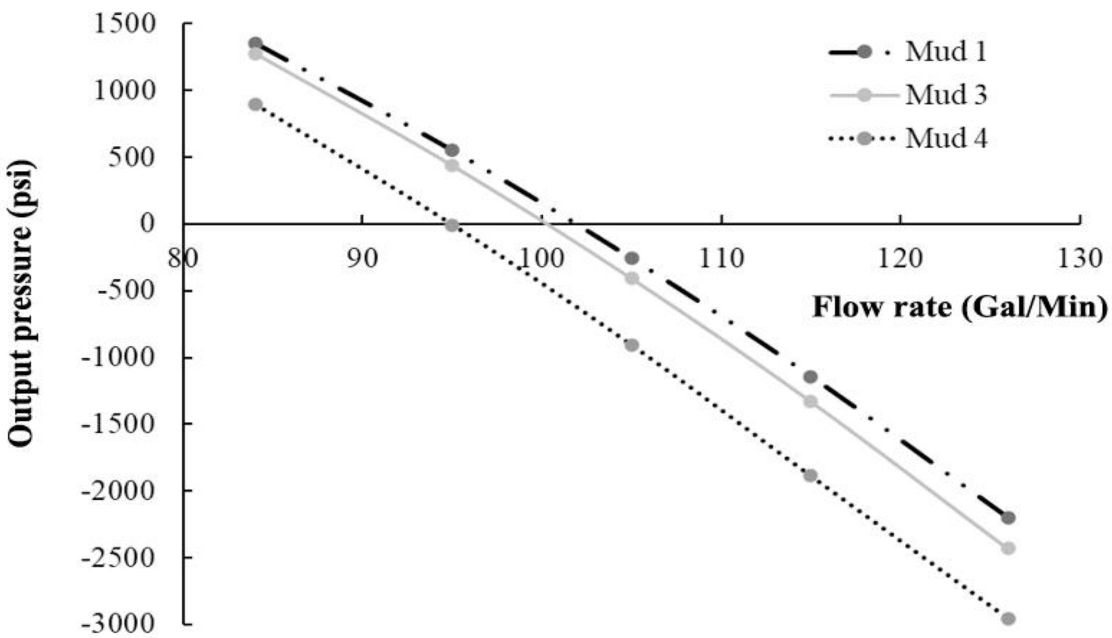

Figure 10.
Output pressure vs flow rate.

The Cerberus software does not support mud with a plastic viscosity greater than 10 cp; therefore, mud system 2 is not used because its plastic viscosity is 14 cp. Thus, only three mud systems named 1,3, and 4 were used and analyzed in Figure 10. The mud at a certain flow rate experienced a negative output pressure because the friction loss was greater than the hydrostatic pressure. Coiled tubing operations require pump pressure to produce the necessary force to move to mud through the coiled tubing and into the wellbore. The frictional pressure losses that happen when the fluid passes through the coiled tubing, the wellbore, and the formation are compensated using the pump pressure. Additionally, this applied pressure serves the purpose of compelling the mud to penetrate the formation while simultaneously eliminating the cuttings from the wellbore. According to Figure 10, mud 1 required pump pressure to sustain the flow rate of 102 gal/min and above. While mud system 3 maintains a flow rate of at least 100 gal/min, and mud system 4 maintains a flow rate of at least 94 Gal/min. As a result, pump pressure is required, which only applies to the internal of the tubing and does not account for friction losses at the bit and the annulus.

4. Conclusion

In conclusion, barite was used effectively to increase the density of drilling mud because it is essential for preventing formation kicks. nevertheless, an excessive increase in mud density can also result in the occurrence of formation fractures and lost circulation. Plastic viscosity significantly impacts the efficacy of drilling mud, with lower values observed in mud 1 and mud 3. indicating greater flow ability. As observed in the laboratory in Mud 2 and Mud 3, a high yield point improves the transportation of cuttings and the hole cleaning process. Gel strength is significant for maintaining wellbore stability and preventing it from getting stuck in coiled tubing applications. A higher gel strength at 10 seconds can help prevent cutting buildup and effectively lower the risk of a stuck pipe. A lower gel strength value at 10 minutes indicates that the drilling mud can efficiently transport the cuttings from the wellbore under a static condition, and based on the gel strength results, mud 3 is the best candidate. Mud 1 has the maximum water loss among the tested muds, while mud 2 has the lowest. Mud 1 requires the least pump pressure for the same flow rate inside the tube due to its lower friction pressure. Pump pressure that is too high may cause formation damage, wellbore instability, and equipment damage. Overall, the best drilling mud for coiled tubing applications in slim hole drilling in terms of rheological properties and friction pressure is mud 3. Therefore, it is essential to evaluate the properties of the drilling mud to increase the efficacy of coiled tubing operations and prevent any hole problems.

Nomenclature:

PV = Plastic Viscosity
YP = Yield Point
V_1 = Volume of Bentonite
W_1 = Density of Bentonite
V_2 = Volume of Barite
W_2 = Density of Barite
V_f = Final Volume of Mud Mixture
W_f = Final Density of Mud Mixture
O.D = Outer Diameter
ID = Internal Diameter
V = Velocity
Q = Flow Rate
V_c = Critical Velocity
P_p = Friction Pressure
ρ = Density of the mud
L = Length of the tube
RPM = Rotation per Minute

Funding:
This study received no specific financial support.

Institutional Review Board Statement:
Not applicable.

Transparency:
The authors confirm that the manuscript is an honest, accurate, and transparent account of the study; that no vital features of the study have been omitted; and that any discrepancies from the study as planned have been explained. This study followed all ethical practices during writing.

Competing Interests:
The authors declare that they have no competing interests.

Authors' Contributions:
All authors contributed equally to the conception and design of the study. All authors have read and agreed to the published version of the manuscript.

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