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RESEARCH ARTICLE

EFFECT OF TEMPERATURE AND EXTENDED STATIC TIME ON RHEOLOGICAL PROPERTIES OF DRILLING FLUIDS

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ABSTRACT

The drilling industry has faced a lot of problems due to the poor conditioning of drilling fluids at bottom-hole conditions thus, drilling fluid properties change owing to an elevated temperature and also the properties deteriorate under static conditions hence, affecting drilling operations. However, these problems may lead to non-productive time (NPT) thereby, increasing the cost of operation and it may lead to a kick or blow-out. Attention must be given to a proper selection of drilling fluid as well as effective performance of the rheological properties. To make up for this gap, effect of rheological properties behaviour of pseudo-oil and water based drilling fluids were investigated at different temperatures and static time. Test results indicated high viscosity readings, yield point and gel strength of the pseudo-oil and water based drilling fluids decreased significantly with increasing temperatures of 800F, 1200F, 1500F and 1900F respectively whereas the parameters increased at a given temperature with an increase in extended static time. Conversely, there was a clear reduction in plastic viscosities with an increase in extended static time for every temperature that was considered. Models were developed for different shear rate for both the water base mud and the oil based mud, the goodness of fit for the water and pseudo-oil base mud. It was observed that the water base mud model for all shear rate gave better R2 and Adjusted R2 value, this indicates that the water based model will give a better result when used for prediction than the pseudo-oil base model. From the results obtained, no doubt, having good understanding of the rheological behaviour of a drilling fluid at down-hole conditions and static time will mitigatea lot of drilling problems if the optimum values of these rheological properties are monitored and maintained in drilling operations.

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INTRODUCTION

Rheological properties of drilling fluid must be considered for an oil or gas well to be successfully drilled, especially in deeper reservoirs therefore, it is important the drilling fluid is kept in desirable conditions. Increasing temperature and pressure are among the utmost substantial factor that can extremely influence and changed rheological properties of drilling fluid; and it is obvious that significant numbers of oil and gas lie within the deep formations. Under reservoir condition temperature and pressure increase with increasing depth and therefore production of oil or gas involve several challenges to petroleum engineers in term of drilling, completion, and production. Among them is the changing of the rheological properties of drilling fluid therefore, understanding the rheological properties of the drilling fluids under higher temperatures and pressures is vital for petroleum engineers. More than 85 percent of the oil and gas industry is involved in higher temperature and higher pressure assets in some capacity and some 60 % of these are expecting to put in place as HTHP program within the next few years (Loth WD, 1998). Amani *et al* (2012) observed that rheological properties of selected oil and water based fluids were influenced when subjected to high temperature and pressure conditions, thus these changes might have an undesirable influence on the drilling fluid's functions. Understanding the influence of these two factors is crucial for the purpose of designing acceptable drilling fluids that can function properly in such an environment. The experimental study of Annis (1997) discovered that there is a change in rheological properties at a temperature up to 300°F, bentonite clay flocculates leading to high yield point, high fviscosities at low shear rates, high gel strength and permanent thickening of the mud. Awele (2014) emphasized that in drilling operation aging should not be ruled out when handling bottom-hole conditions

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thus, it helps to investigate the properties of drilling fluid at bottom-hole conditions. The concept of aging is important in simulating the properties of drilling mud at bottom-hole conditions as the properties at the surface do not depict the bottom-hole conditions. Makinde *et al*., 2011 simply defined aging as a process whereby drilling fluids previously subjected to a period of shear are allowed to more fully develop their rheological and filtration properties. Aging is done under conditions which vary from static to dynamic and from ambient to highly elevated temperatures. The industry has faced a lot of problems due to the poor conditioning of drilling muds. At bottom-hole conditions, properties of drilling mud change owing to an elevated temperature, pressure and aging, and these may cause problems in drilling a successful well, especially deep wells. Without knowing the right and efficient aging of drilling mud, properties of the mud may diminish, affecting drilling operations.

However, Makinde *et al* (2011) disclosed that the viscosity of most muds is decreased on heating, but the interesting thing is that the degree of flocculation is also increased on heating. There will be a greater tendency to seal off formations at high temperatures than at low temperatures with regard to the effect of temperature on viscosity and yield point. Therefore, it is imperative to have an understanding of the behavior of drilling fluids under elevated temperatures in relation to it being subjected to extended static time because of the prevalent challenges associated with drilling operations. Laboratory investigation done by Mohammed (1990) on high temperature (490^{0}F) and aging time of 30days on water-base mud properties using the HTHP viscometer, baroid roller oven(dynamic aging) and distilled water as the continuous phase discovered a decrease in viscosity, yield point and gel strength with an increase in temperature for all values of aging time.

Table 1. Result of Water-based Mud Rheology @ 80^{o}F (29^{0}C)

RPM	0	0.5 hr	1hr	3hrs	5hrs	8hrs	24hrs
Ɵ600	70	79	81	86	92	93	102
Ɵ300	50	57	59	72	87	89	97
Ɵ200	42	46	48	60	70	72	83
Ɵ100	31	34	37	43	60	63	71
Ɵ6	11	12	14	17	24	25	56
Ɵ3	5	4	4	6	10	11	21
PV (cP)	20	22	22	14	5	4	5
YP (lb/100ft^2)	30	35	37	58	82	85	92
10secs(lbf/100ft^2)	10	11	11	13	10	11	22
10 mins(lbf/100ft^2)	14	20	21	24	28	28	32
Density (ppg)	9.0						

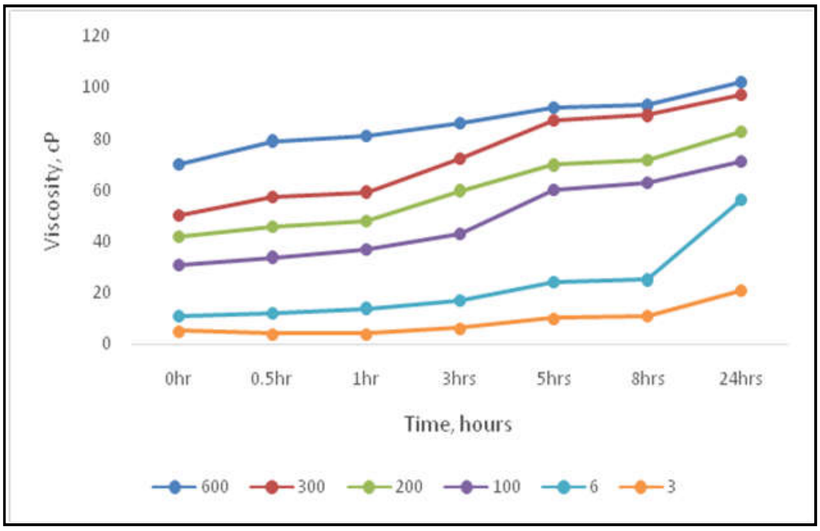

Figure 1. Water-based Mud Rheology @ 80^{o}F (29^{0}C)

These problems may lead to non-productive time (NPT) thereby increasing the cost of operation and also may be lead to a kick or blow-out. A good example of the poor monitoring of the downhole condition of drilling mud may lead to filtration loss and differential sticking. Also, certain conditions especially those prevalent in harsh downhole environments can lower the competence of drilling muds by effecting changes in muds properties like rheology. The fluids are mixed or sheared for the number of times appropriate to achieve a homogenous mixture and are then set aside to “age”. Exner (2011) stated that yield point and viscosity of mud variation with respect to temperature has not been very clear by the data available. Both appear to decrease slightly with increasing temperature up to 200^{0}F thus, very little information has been published regarding the effects of temperature on the viscosity of drilling mud.

Experimental

This research was aimed at investigating the effects of temperature and extended static time on rheological properties of oil and water based fluids. The experiment was therefore designed to capture these conditions as are often encountered in Niger Delta wellbore. To achieve the above aim, the experiment was done in accordance with the American Petroleum Institute (API).The pseudo oil based fluid (POBF) is an emulsion of water droplets in base oil enriched with weight material as well as salts, clay, $Ca(OH)_2$ emulsifier, and fluid loss material, thus, the ratio of the pseudo-oil to water was 75/25. The water based fluid (WBF) was enriched with weight material as well as inhibited, clay and fluid loss materials.

Fluid Characterization

The continuous phase was stirred in the Hamilton Beach Model HMD200, thereafter, samples were weighed and added within the interval of 5minutes to an obtained homogenous mixture. The mixer motor was turned on and maintained at (4000±200 rpm) according to API RP10-2B procedure (API Edition, 2009). Rheological properties were obtained at zero time, then left to rest for 0.5hours, 1hour, 3hours, 5hours, 8hours and 24hours respectively, rheological properties were obtained on each of the time interval at temperature range of (80 to 190°F).

RESULTS

Rheological measurements of the pseudo oil based fluid and water based fluid were at test temperature range of (80 to 190°F). The apparatus used for the test is a concentric cylinder device (Couette Flow) commonly used in the oilfield (Fann VG 35A) (API RP 13B- 2016).

The apparatus used for the test is a concentric cylinder device (Couette Flow) commonly used in the oilfield (Fann VG 35A)(API RP 13B- 2016).

Table 2. Result of Water-based Mud Rheology @120°F (49°C)

RPM	0hr	0.5hr	1hr	3hrs	5hrs	8hrs	24hrs
ϴ600	67	72	74	82	86	89	98
ϴ300	50	53	55	69	75	77	92
ϴ200	42	44	46	54	55	57	87
ϴ100	30	32	35	40	45	45	70
ϴ6	11	11	12	15	20	21	49
ϴ3	5	4	3	6	12	12	15
PV (cP)	17	19	19	13	11	12	6
YP (lb/100ft^2)	33	34	36	56	64	65	86
10 secs(lbf/100ft^2)	6	10	12	12	10	10	16
10 mins(lbf/100ft^2)	13	17	18	22	22	22	26
Density (ppg)	9.0						

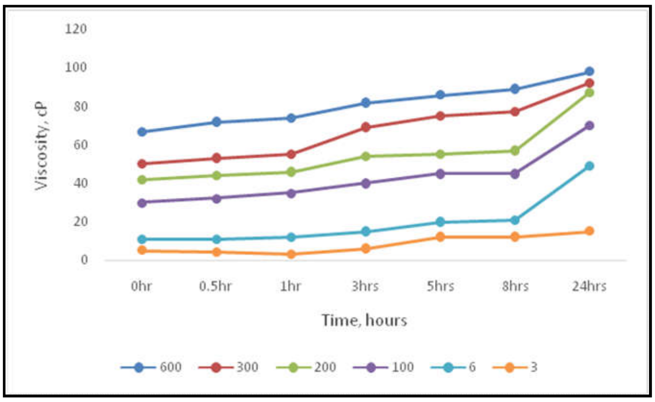

Figure 2. Water-based Mud Rheology @ 120°F (49°C)

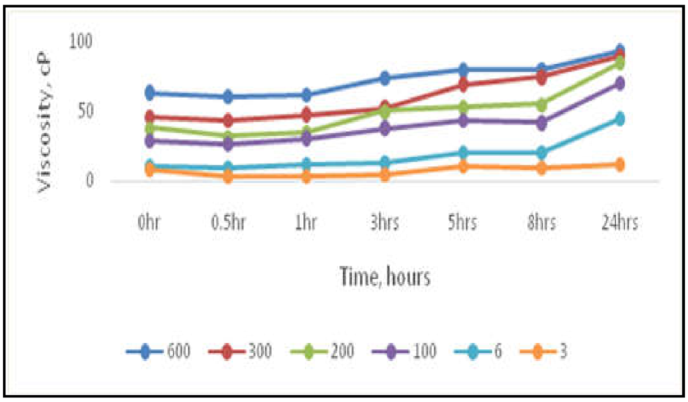

Figure 3: Water-based Mud Rheology @ 150°F (66°C)

Table 3. Result of Water-based Mud Rheology @150°F (66°C)

RPM	0hr	0.5hr	1hr	3hrs	5hrs	8hrs	24hrs
ϴ600	64	61	62	74	80	81	94
ϴ300	46	44	48	53	70	75	90
ϴ200	38	32	35	50	53	55	85
ϴ100	29	27	31	38	44	42	70
ϴ6	10	9	11	13	20	20	45
ϴ3	8	3	3	4	11	10	12
PV (cP)	18	17	14	21	10	6	4
YP (lb/100ft^2)	28	27	34	32	60	69	86
10 secs(lbf/100ft^2)	6	9	10	11	8	9	12
10 mins(lbf/100ft^2)	8	14	18	20	18	20	22

Table 4. Result of Water-based Mud Rheology @ 190°F (88°C)

RPM	0hr	0.5hr	1hr	3hrs	5hrs	8hrs	24hrs
ϴ600	52	51	57	61	65	67	87
ϴ300	37	36	43	50	62	64	74
ϴ200	30	28	32	46	45	49	61
ϴ100	21	19	28	36	39	41	36
ϴ6	5	4	10	12	18	20	21
ϴ3	4	3	3	3	7	10	10
PV (cP)	15	15	14	11	3	3	10
YP (lb/100ft^2)	22	21	29	39	59	61	64
10 secs(lbf/100ft^2)	6	5	9	9	8	9	10
10 mins(lbf/100ft^2)	8	11	15	16	15	19	20
Density (ppg)	9.0						

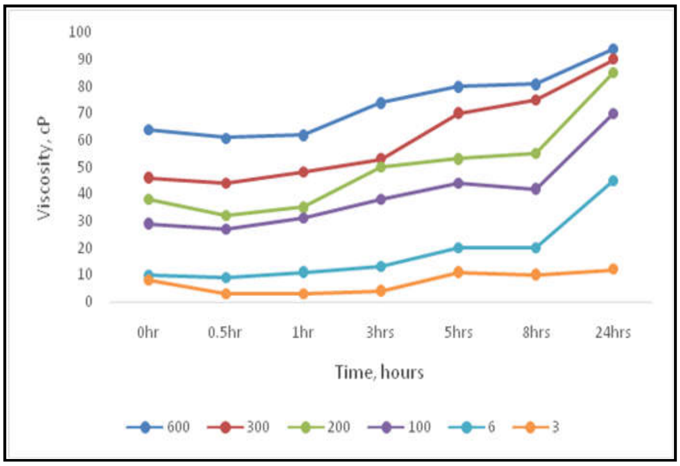

Figure 4. Water-based Mud Rheology @ 190°F (88°C)

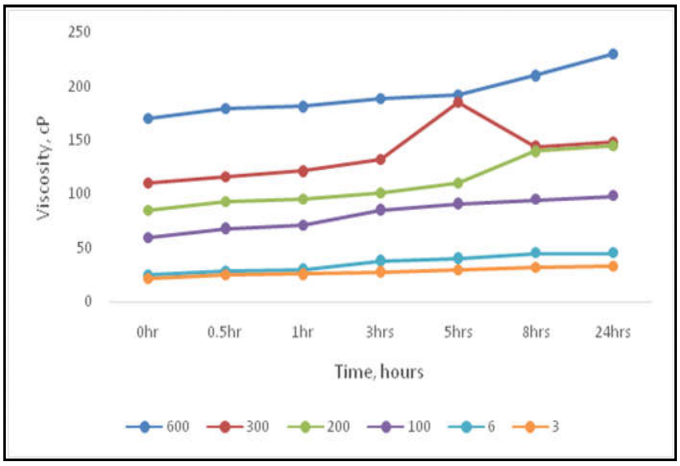

Figure 5. Pseudo-oil based Mud Rheology @ 80°F (29°C)

Table 5. Result of Pseudo-oil based Mud Rheology @ 80°F (29°C)

RPM	0hr	0.5hr	1hr	3hrs	5hrs	8hrs	24hrs
ϴ600	170	179	181	188	192	210	230
ϴ300	110	116	121	132	185	144	148
ϴ200	85	93	95	101	110	140	145
ϴ100	60	68	71	85	91	95	98
ϴ6	25	28	30	38	40	45	45
ϴ3	22	25	26	28	30	32	33
PV (cP)	60	63	60	56	7	66	132
YP (lb/100ft^2)	50	53	61	76	178	78	16
10 secs(lbf/100ft^2)	28	25	28	28	31	35	37
10 mins(lbf/100ft^2)	30	31	31	33	36	42	45
Density (ppg)	9.0						

Table 6. Result of Pseudo-oil based Mud Rheology @ 120°F (49°C)

RPM	0hr	0.5hr	1hr	3hrs	5hrs	8hrs	24hrs
ϴ600	165	169	`176	186	`189	206	208
ϴ300	105	110	117	130	180	137	140
ϴ200	82	86	92	98	100	110	113
ϴ100	59	62	67	84	90	78	79
ϴ6	25	25	26	36	40	38	41
ϴ3	22	22	23	26	30	30	31
PV (cP)	60	59	59	56	9	69	68
YP (lb/100ft^2)	45	51	58	74	171	68	72
10 secs(lbf/100ft^2)	26	23	25	26	30	32	32
10 mins(lbf/100ft^2)	29	29	30	30	33	43	43
Density (ppg)	9.0						

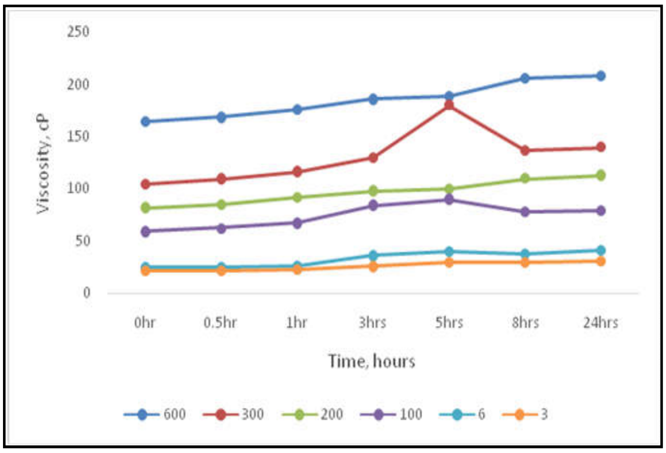

Figure 6. Pseudo-oil based Mud Rheology @ 120°F (49°C)

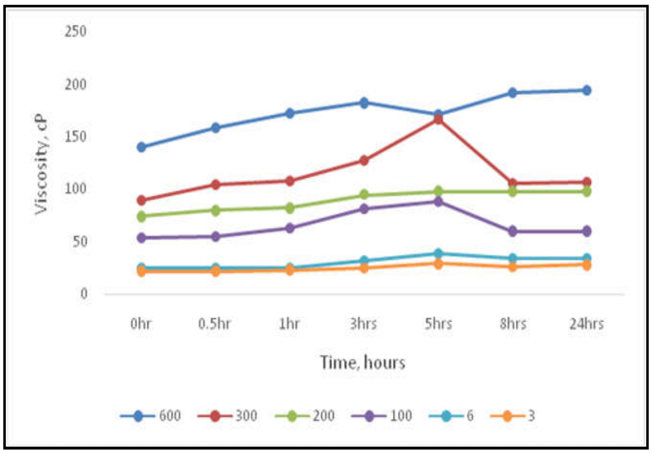

Figure 7. Pseudo-oil based Mud Rheology @ 150°F (66°C)

Table 7. Result of Pseudo-oil based Mud Rheology @ 150°F (66°C)

RPM	0hr	0.5hr	1hr	3hrs	5hrs	8hrs	24hrs
ϴ600	140	158	172	182	171	192	194
ϴ300	90	105	108	128	167	106	107
ϴ200	74	80	82	95	98	98	98
ϴ100	54	55	63	81	88	60	60
ϴ6	25	25	25	32	39	34	34
ϴ3	22	22	23	25	29	26	28
PV (cP)	50	53	64	54	4	87	87
YP ($lb/100ft^2$)	40	52	44	74	163	19	20
10 secs($lbf/100ft^2$)	26	21	25	25	25	26	25
10 mins($lbf/100ft^2$)	27	22	30	28	31	31	36
Density (ppg)	9.0						

Table 8. Result of Pseudo-oil based Mud Rheology @ 190°F (88°C)

RPM	0	0.5hr	1hr	3hrs	5hrs	8hrs	24hrs
ϴ600	110	114	120	170	166	172	176
ϴ300	73	75	85	121	161	104	107
ϴ200	60	61	71	91	92	95	96
ϴ100	43	45	55	76	81	55	56
ϴ6	20	20	21	28	33	38	38
ϴ3	17	18	20	22	26	21	22
PV (cP)	37	39	35	49	5	68	69
YP ($lb/100ft^2$)	36	36	50	72	156	36	38
10 secs($lbf/100ft^2$)	17	17	21	23	21	20	28
10 mins($lbf/100ft^2$)	20	21	24	25	31	25	30
Density (ppg)	9.0						

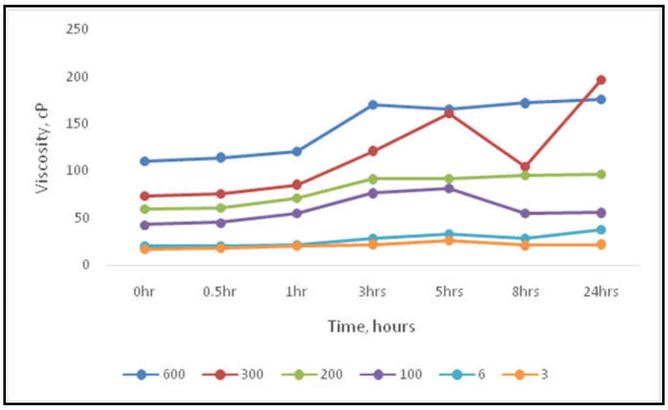

Figure 8. Pseudo-oil based Mud Rheology @ 190°F (88°C)

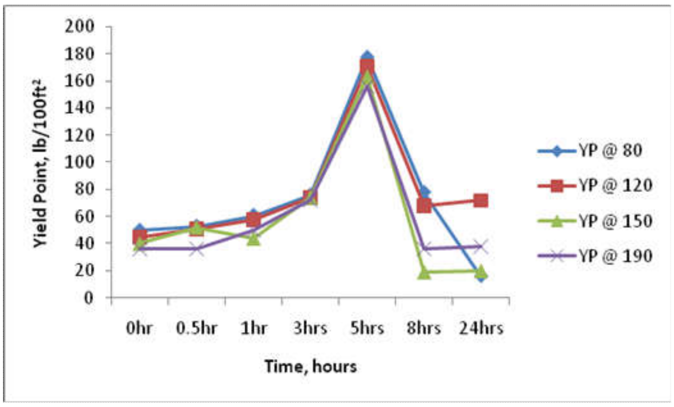

Figure 9. Yield Point as a function of time @ different temperature (°F)

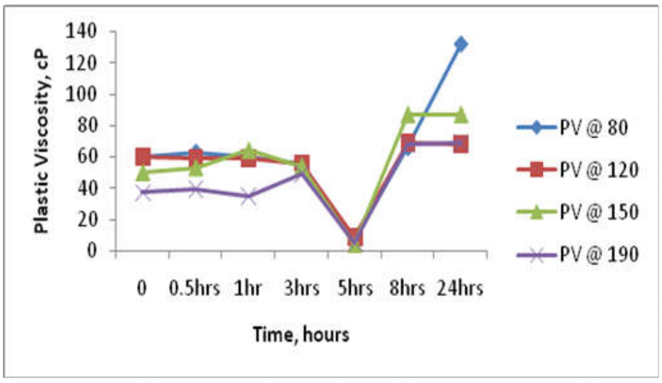

Figure 10. Plastic Viscosity as a function of time @ different temperature (°F)

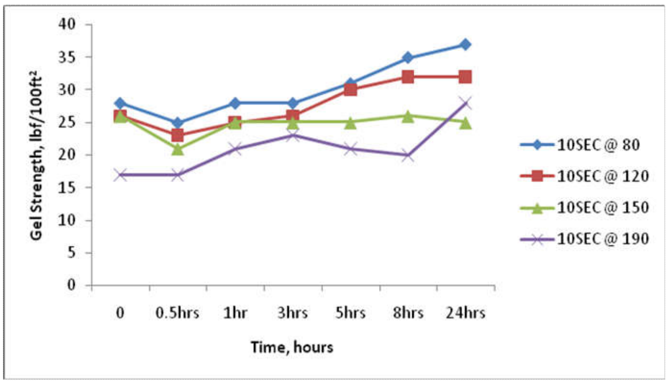

Figure 11. Gel Strength @ 10 Seconds as a function of time @ different temperature (°F)

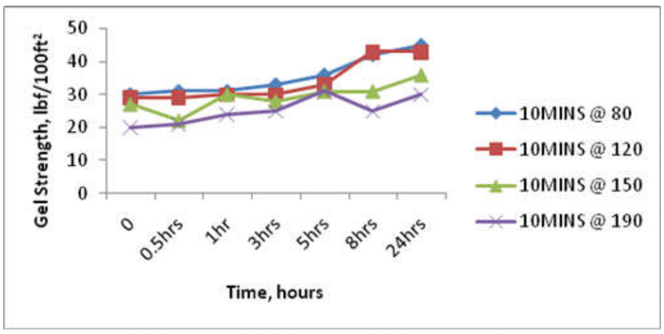

Figure 12. Gel Strength @ 10 Minutes as a function of time @ different temperature (°F)

Table 9. Multiple linear regression models for Water base mud

Shear Rate	Models	Goodness of Fit
600	Viscosity = 97.61456 - 0.21418*Temperature + 1.22516*Time	R^2 = 0.876 Adj. R^2 = 0.866 RMSE = 5.141
300	Viscosity = 79.01918 - 0.19011*Temperature + 1.68722*Time	R^2 = 0.792 Adj. R^2 = 0.775 RMSE = 8.291
200	Viscosity = 64.58447 - 0.16934*Temperature + 1.66712*Time	R^2 = 0.870 Adj. R^2 = 0.860 RMSE = 6.021
100	Viscosity = 52.75058 - 0.14912*Temperature + 1.34735*Time	R^2 = 0.761 Adj. R^2 = 0.741 RMSE = 7.211
6	Viscosity = 21.96346 - 0.08703*Temperature + 1.38559*Time	R^2 = 0.872 Adj. R^2 = 0.861 RMSE = 4.631
3	Viscosity = 8.48575 - 0.02736*Temperature + 0.45078*Time	R^2 = 0.698 Adj. R^2 = 0.673 RMSE = 2.577

Table 10. Multiple linear regression models for Pseudo-oil base mud

Shear Rate	Models	Goodness of Fit
600	Viscosity = 219.33855 - 0.41890*Temperature + 1.97570*Time	R^2 = 0.713 Adj. R^2 = 0.690 RMSE = 15.389
300	Viscosity = 159.43234 - 0.31363*Temperature + 0.80363*Time	R^2 = 0.255 Adj. R^2 = 0.195 RMSE = 25.582
200	Viscosity = 121.68886 - 0.26385*Temperature + 1.39187*Time	R^2 = 0.679 Adj. R^2 = 0.653 RMSE = 11.083
100	Viscosity = 95.33114 - 0.20890*Temperature + 0.47816*Time	R^2 = 0.369 Adj. R^2 = 0.318 RMSE = 12.758
6	Viscosity = 37.72601 - 0.06967*Temperature + 0.60859*Time	R^2 = 0.556 Adj. R^2 = 0.521 RMSE = 5.227
3	Viscosity = 31.98791 - 0.06341*Temperature + 0.27118*Time	R^2 = 0.635 Adj. R^2 = 0.606 RMSE = 2.667

Model Development

A predictive multiple linear regression model has developed that related viscosity with extended time and temperature for the different shear rate.

DISCUSSIONS

The water and oil-based fluids experience a significant increase in high viscosity readings, yield point, and gel strength when subjected under static time within a period of 24 hours at 80^{0}F, 120^{0}F, 150^{0}F and 190^{0}F respectively which means drilling fluids under static conditions had a detrimental effect on the rheological properties of the drilling fluids. The significant increase of the rheological properties could be as a result of the flocculation of clays and polymers present in the drilling fluids thus, this is in line with the observation made by Makinde F. A., et al (2011) which states that viscosity, yield point, and gel strength at a given temperature increase with extended static time. The results also agree with Bland et al., (2006) findings which say the effectiveness of drilling fluid will be reduced causing it to lose fluidity in during drilling. Also, Alderman et al., (1988) on water-based fluid observed shear viscosity decreases with increasing temperature in a similar manner for all drilling fluids.

Again, the increase in 10 seconds and 10minutes gel strengths with respect to static time is due to the increase in the attractive and large inter-particle forces. Rheological properties of the drilling fluids decreased significantly with increasing temperature as shown in Tables 1, 2, 3, 4, 5, 6, 7 and 8 respectively which is also the observation of Salimi *et al* (2011) which implies that temperature heavily influenced the viscosity of both oil and water based drilling fluids causing a reduction in carrying capacity and suspending ability of cuttings. This is in agreement with the observation made by Mohammed Shahjahan Ali (1990) and Makinde *et al* (2011) which also disclosed that the viscosity of most muds decreases on heating. The shear stress for a particular temperature increases with an increase in shear rate, but shear stress at a given shear rate decreases with an increase in temperature. This effect could be as a result of severe degradation of clays due to the application of heat as well as mechanical shearing and also the presence of polymers in drilling fluids. Furthermore, it was observed that there was an appreciable decrease in plastic viscosity with an increase in temperature as well as in the static time as shown in tables 1 through 8. These results are in good agreement with the study done by Shokoya *et al* (1997) where the plastic viscosities of the drilling fluid decreased with an increase in temperature. As the polymer degrades, the clay platelets start to dehydrate, the platelets dissociating each other resulting in a state of dispersion with edge-to-face contact of the platelets. Increase in temperature causes the platelets to disintegrate and ultimately leads to a state of dissociation and deflocculating resulting in low rheological properties. However, the high shear rate prevents the clay platelets from building structures like a house of cards and thus there is a gradual change in rheological properties. The results of the effect of temperature on the shear stress-shear rate relationship are similar to the findings made by Mohammed Sahjan Ali (1990). The results of the effect of temperature on the shear stress-shear rate relationship follow the same trend as found by Hiller (1963). He observed that shear stress for a particular temperature increases with shear rate, but shear stress at a given shear rate decreases with the increase in temperature. Models were developed for different shear rate for both the water base mud and the oil based mud, the goodness of fit of the model are shown in Table 9 and 10 for the water and oil base mud. From the table, it was observed that the water base mud model for all shear rate gave better R2 and Adjusted R2 value, this indicates that the water based model will give a better result when used for prediction than the oil base model.

Conclusion

Viscosity, yield point and gel strength of both oil and water based fluids significantly decrease with an increase in temperature whereas the parameters increased at a given temperature with an increase in extended static time.There was a clear reduction in plastic viscosities with an increase in extended static time for every temperature that was considered. It is essential to have an understanding of the drilling fluid rheological properties behaviour mitigate challenges associated with drilling operations owing to the fact mud rheology is of utmost importance because it influences penetration rate. Also, cutting slip velocity, for instance, correlates better with yield point than any other parameters. Proper gel strength is needed to keep the cuttings in suspension, and relatively low gel strength is better for a high penetration rate. Furthermore, if the drilling fluids become too viscous as a result of the extended static time, the amount of energy needed to rotate the drill stem and the drill bit will increase leading to an adverse effect. However, a lot of drilling problems can be avoided if the optimum values of these properties are maintained at a given temperature as well as kept in circulation drilling operations.

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