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Mineralogy and Rock Response Analysis Approach to Mitigate Wellbore Stability Issue in "B" Cluster of East Java Field

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ABSTRACT

The instability of shales in drilled formations leads to serious operational problems with major economic consequences for petroleum exploration and production. It is generally has agreed that the nature of the clay minerals in shale formations is a primary causative factor leading to their instability, although the exact mechanism involved is more debatable. Currently, the principal cause of shale instability is considered to be volume expansion following the osmotic swelling of sodium smectite. However, illitic and Kaolinite shales may also be unstable, so that interlayer expansion cannot therefore be consider as a universal causative mechanism of shale instability. This review considers alternative scenarios of shale instability where the major clay minerals Kaolinite suspected to be a key success to mitigate the wellbore stability. It is found from the literature that the inhibited by the use of more concentrated Potassium-based fluids which is effectively shrink the thickness of the clay mineral surfaces in the pore walls but may differently responded by Kaolinite dominant clay. The use of soluble polymers would also encapsulate these clay mineral surfaces and so inhibit their hydration. In this scenario, the locus of action with respect to shale instability and its inhibition is moved from the interlamellar space of the smectic clays to the charged external surfaces of the various clay minerals bounding the walls of the shale pores.

Keywords: shale instability; smectic shale; illitic shale; kaolinitic shale

I. INTRODUCTION

The high cost and risk of investing in the oil and gas industry is a major challenge for an oil and gas company. Planning for drilling operations is the key to success in developing an oil and gas field. As part of the design of an oil and gas well, the stability of the wellbore starting from the aspect of pore pressure analysis is an important thing which is then translated into a safe limit of drilling fluid density which is known as the mud windows. The minerals that make up the rock to be drilled are key in mitigating for the next challenges and successful design of a drilling fluid program. The purpose of this research is to minimize the problems due to the instability of the wellbore which is suspected to be caused by the chemical character of a dominant rock-forming mineral. Smectite, Illite and Kaolinite have different characters and require different handling as well. Ignorance of the minerals that make up the shale rock ultimately has the potential for inappropriate ways to mitigate the problem and result in constrained drilling operations.

1.1. Drilling Challenge

After evaluating the pore pressure, rock collapse pressure, and fracture pressure, which is known as a Geo-Mechanical study and then translated into a well construction design, the next step as part of the optimization and correction of the well construction design is to analyze the rock properties. Neglecting steps due to time constraints in presenting data often ends up being detrimental in terms of costs and even the safety of people directly involved in operations. The availability of sufficient rock samples for analysis is often the main reason for omitting an important step in mitigating wellbore stability risks. With the limited number of samples, XRD analysis more makes sense because it does not require a large number of samples in the analysis process. The data obtained in this analysis process can then be evaluated which includes:

- What are the minerals that make up the rock?
- How does the dominance of rock minerals affect the stability of the wellbore?
- How effective the drilling mud in reducing wellbore stability problems?
- How does the type of drilling mud affect the dominance of rock minerals?
- What is the effect of temperature, pressure and inhibition method on wellbore stability?

After knowing the type of mineral, the next step is to formulate a mud that is used to see the response of rocks to drilling mud that is close to subsurface conditions through erosion testing and expansion testing. There is a lot of literature that

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in rocks that are high in Smectite domination, the use of the potassium ion is really helps reduce the problem of expanding the rock, higher concentration of the potassium ion in the drilling mud, the better the mud system will maintain the stability of the smectite-rich rock.

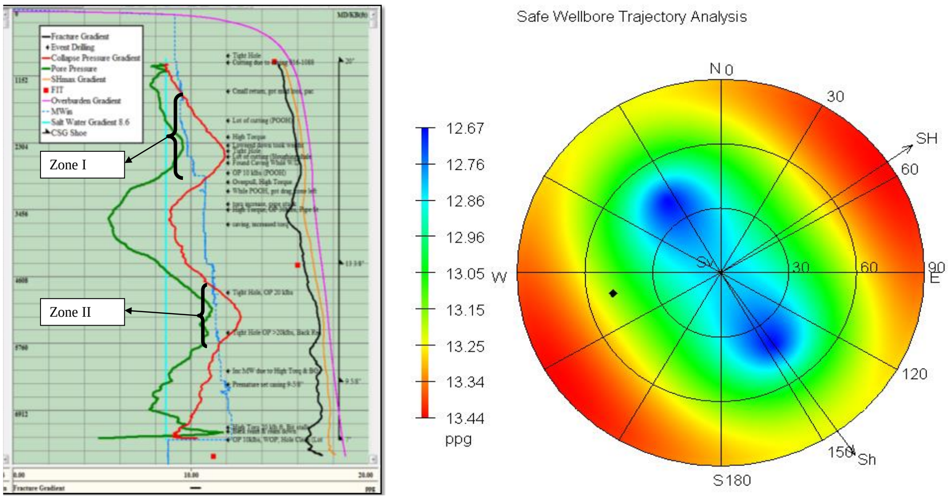

Figure 1. PPFG from Geomechanics Study

Figure 2. Cutting Sample

II. METHODS

Cuttings sample and Mud logs are the importance data used in the study, both of data are used to the rock selection. CEC and XRD analysis are the next step evaluation to initial of reactivity mitigation methods. According to the well construction design, the sample data collected for erosion tests and swelling potential tests.

III. RESULTS AND DISCUSSION

3.1. X-Ray Diffraction

Mineralogical composition analysis was determined using X-ray diffraction methods. A Quartz Minerals are very dominant from top to bottom formation followed clay and Calcite. The analysis results for all samples show that the surrounding clay minerals are Smectite with a peak of 15A, and Kaolinite minerals with a peak of around 7A. Kaolinite minerals include minerals that are unlikely to swell in wet conditions. The mineral Smectite may swell in wet conditions.

Table 1. The Mineralogical Bulk Composition of Cutting Sample Well X24

Sample Depth (ft)	Quartz (%)	Clay (%)	Calcite (%)

930 -950	40.1	31.6	16.2
1130 - 1150	49.3	32.7	8.8
1310 - 1330	75.8	13.7	7.3
1490 - 1510	61.9	26.4	6.4
1690 - 1710	70.9	11.1	14.8
1890 - 1910	65.4	22.8	7.4
2090 - 2110	69.1	19.8	6.4
2290 - 2310	66.6	23.2	5.9
2490 - 2510	66.9	27.1	
2990 - 2710	33.5	18.9	18.6
2890 - 2910	20.6	8.1	65.4
3090 - 4010	30.7	14.9	41.2
3290 - 3310	28.1	6.5	47.2
3490 - 3510	19		56.3
3690 - 3710	11.2		73.8
3870 - 3890	22.2		54.7
4070 - 4090	19.8	12.2	32.9
4270 - 4290	43.8	11.8	28.6
4450 - 4470	50.2	17.7	22.6
4610 - 4630	37.6	19.6	30.4
4820 - 4840	53	22.1	20.2
5040 - 5060	30.5	14.3	35.8
5240 - 5260	54.9	23.9	11.2
5440 - 5460	56.2	29.5	8.6
5640 - 5660	54.4	19.9	14.6
5840 - 5860	45	18	9.6
6040 - 6060	37.4	15.8	8.1
6100 - 6120	56.5	14.8	3.9
6240 - 6260	53.9	25.1	12.2
6300 - 6320	57.2	18.3	11.1
6600 - 6620	57.4	20.2	8.2
6660 - 6680	57.3	20.1	8.6
6800 - 6820	61	13.8	8.1
6860 - 6880	53.9	22.5	5.6
7080 - 7100	68.5	8.4	10.9
7280 - 7300	55.5	14.6	10.2
7460 - 7480	61.9	15.8	10.8
7640 - 7660	50.7	11.2	18.9
7860 - 7880	52.6	12.4	16.8
8060 - 8080	47.6	7.9	22.1
8260 - 8280	50.4	17.2	9
8400 - 8420	63.2	7.8	16.8

Table 2. The Mineralogical Bulk Composition of Cutting Sample Well X36

Sample Depth (ft)	Quartz (%)	Clay(%)	Calcite(%)
1968.5 - 2296.6	67.6	11.1	16.1
2952.8 - 3280.8	25.4	9.2	52.5
3280.8 - 3608.9	26.8	13.8	46.9
3608.9 - 3937.0	12.5	6.2	54.9
5249.3 - 5577.4	56.2	15.4	12.1
6233.6 - 6561.7	62.2	11.4	8.1
6561.7 - 6889.8	58.8	11.3	12.7
7217.8 - 7545.9	33.6	11.3	40.8

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Table 3. The Mineralogical Clay Oriented Composition of Cutting Sample Well X36

					Mixed Layer		
Sample Depth, (ft)	Kaolinite (%)	Illite (%)	Smectite (%)	Chlorite	I/S R1 (Nat) - Regular (%)	I/S R1 (Nat) - Irregular (%)	Total (%)
1968.5 - 2296.6	33	19	24			24	100
2952.8 - 3280.8	30	17	53				100
3280.8 - 3608.9	30	25	45				100
3608.9 - 3937.0	33	12	40			14	100
5249.3 - 5577.4	49	21	10		6	13	100
6233.6 - 6561.7	73	12	3		4	7	100
6561.7 - 6889.8	71	11	4		3	10	100
7217.8 - 7545.9	79	6	2		6	6	100

Table 4. The Mineralogical Clay Oriented Composition of Cutting Sample Well X24

					Mixed Layer		
Sample Depth, (ft)	Kaolinite (%)	Illite (%)	Smectite (%)	Chlorite (%)	I/S R1 (Nat) - Regular (%)	I/S R1 (Nat) - Irregular (%)	Total (%)
1170 - 1190	30.41	16.64	29.36		10.06	13.53	100
1670 - 1690	23.39	14.47	28.02	13.04	7.78	13.3	100
1850 - 1870	30.33	13.18	36.25		6.34	13.9	100
2030 - 2050	24.08	11.38	36.3	6.42	9.74	12.08	100
2210 - 2230	26.06	9.79	34.52			29.63	100
2390 - 2410	40.09	19.68			8.24	31.99	100
2570 - 2590	25.87	10.71	27.5		7.56	28.36	100
2750 - 2770	23.3	14.59	62.11				100
3050 - 3070	25.3	18.31	18.16		9.84	28.39	100
3170 - 3190	21.99	12.54	31.06		5.75	28.66	100
5400 - 5420	34.3	12.3	25.6		6.93	20.87	100
5800 - 5820	32.39	12.03	28.54		5.49	21.55	100
6000 - 6020	39.09	12.26	21.16		5.21	22.28	100
6140 - 6160	56.41	12.23	10.15		7.29	13.92	100
6520 - 6540	60.97	13.19	6.58		5.51	13.75	100
6640 - 6660	60.19	14.8	7.48		4.49	13.04	100
6720 - 6740	61.25	12.47	10.64	15.64			100
7120 - 7140	55.85	16.29	8.27	19.59			100
7320 - 7340	62.86	13.56				23.58	100
7620 - 7640	50.84	12.49	3.91	6.35	9.34	17.07	100

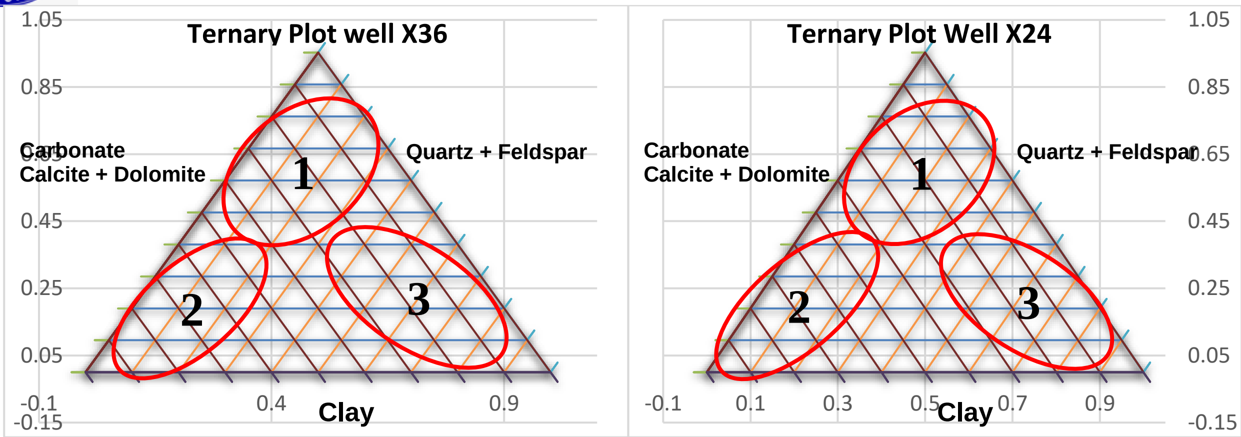

Figure 3. Ternary Plot (Modified from Bai, 2016; after Rickman et al., 2008)

- Zona 1, Brittle quarts rich
- Zona 2, Brittle carbonate rich
- Zona 3, Ductile

3.2. Cation Exchange Capacity

The cation exchange capacity (CEC) of the cutting sample was measured by API standard method. In detail, the results of the CEC test from the cutting samples in each of these formations are shown in figure 4 and figure 5. It can be concluded that the results of the CEC analysis of the cutting samples from the well X24 and well 36 were dominated by class B with firm texture with mixed layer clay, Montmorillonite and illite. Shale with class B has the characteristics of Soft and fairly high dispersion so that it has the potential to expand or swell, especially at the top, while in the lower zone it tends to be brittle.

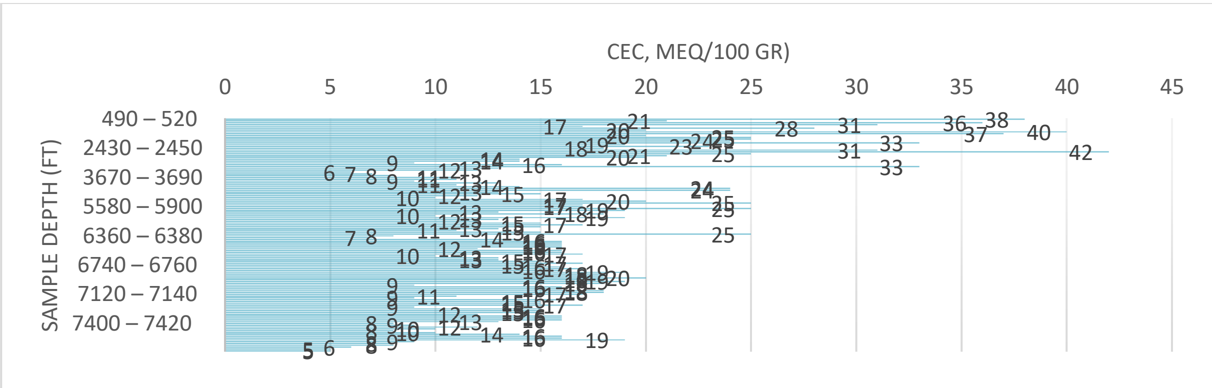

Figure 4. MBT Value Cutting Sample Well X24

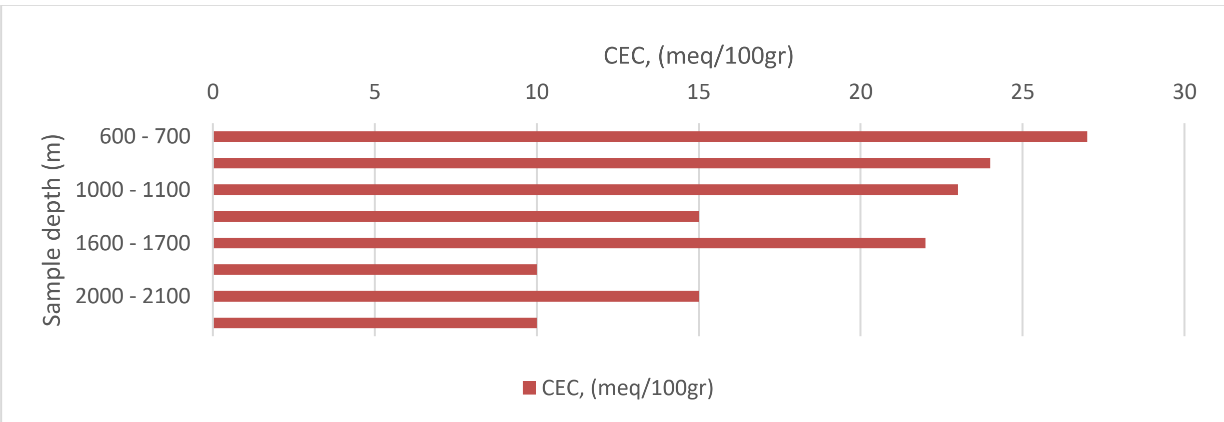

Figure 5. MBT Value Cutting Sample Well X36

3.3. Dispersion Test

This test is measuring the dispersion tendency of the cutting sample during exposed to testing fluid. Table 4 shown that the cutting recovery of well X24 and well X36 at various fluids are low tendency at the top of formation. Increasing the sample depth, the tendency of recovery behaves a decrease trend. Overall, the shale cuttings of the formation are water sensitive.

Table 5. Cutting Sample Recovery of Well X24 & X36

Remark	**X36**								**X24**	
Sample depth (m, ft)	600 – 700	900 – 1000	1000 – 1100	1100 – 1200	1600 – 1700	1900 – 2000	2000 – 2100	2200 – 2300	1010' – 3070'	4450' – 7440'
Initial weight samples (gr)	20	20	20	20	20	20	20	20	20	20
Recovery (gr)										
Formula 8	19.55	14.6	19.9	19.07	18.17	18.08	13.54		19.81	15.94
Formula 2				19.18						
Formula 4	19.64	12.28	19.74	18.64	19.15	16.4	3.55		17.37	16.08
Formula 5	18.61	14.22	19.01	19.65	19.14		8.77		14.39	16.64
Weight loss (%)										
Formula 8	2.25	27.00	0.50	4.65	9.15	9.60	32.30		0.95	20.30
Formula 2				4.10						
Formula 4	1.80	38.60	1.30	6.80	4.25	18.00	82.25		13.15	19.6
Formula 5	6.95	28.90	4.95	1.75	4.30		56.15		28.05	16.80

3.4. Swelling Test

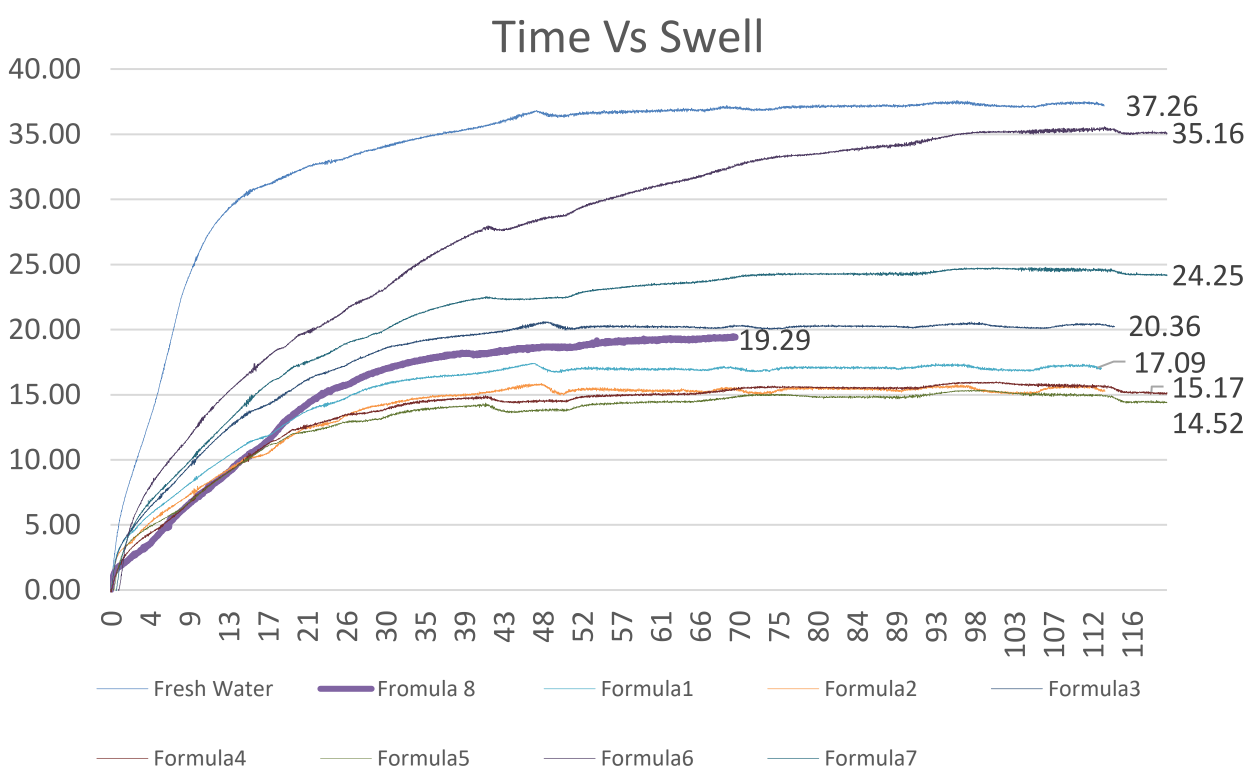

Figure 6. LSM Test Lower Formation Well X24 (4450' – 7440')

3.5. Principle of Drilling Fluid Design

Based on the shale characteristic test and geo-mechanics evaluation, understanding of the formation can be obtained. For the upper formation smectite dominant clay even the bulk dominant is quarts, the mainly problem is the reactivity of the shale which is water absorption create swelling on the clay. For lower formation bulk mineralogical test still dominated by Quartz and for clay-oriented test Kaolinite is the main mineral. Kaolinite minerals are minerals that do not to swell in wet conditions.

Based on the characterization of the typical formation obtained from different well depth, the strategies to design the drilling fluid were proposed as follows. For Water based system, inhibitive properties are the primary consideration due to different minerals are different response to the inhibition methods. For the upper formation, in order to minimize hydration and drilling problem, water-based fluid system with encapsulation, pickling, sufficient the wellbore cleaning is recommended. For lower part of the formation, Kaolinite is sensitive to water, pickling and pH, water-based fluids system is not recommended in this similar well. Drilling to deeper depth, the formation tendency is hard and the rate of penetration will also decrease, time dependency wellbore integrity formation is mainly problem on this.

3.6. Fluids Pilot Test

High inhibition water-based drilling fluid system was developed in recent year with the amine base as the superior inhibition component. This method is the amine will be positively charged after protonation and absorbed onto the negatively charged clay surface through electrostatic interaction. This condition is applicable for clay with smectite dominant and laboratory test shows different response when the clay dominated by kaolinite. Sample Recovery on dispersion test are very significant different also the swelling test result even the inhibition method was combined with polymer encapsulation, Potassium and surfactant.

3.7. Drilling Fluid Design for Upper formation

According to the characteristics of the upper formation, hydraulics design, fast ROP, Low angle and short trajectory interval, water-based drilling fluid system with amine based combined with polymer encapsulation and pickling method still effective to minimize wellbore reactivity which is the clay dominated by smectite. Amine inhibition should be maintained due to the concentration will be decreased caused carried away by cutting and the same condition with potassium by the different method. Drilling fluid formula was optimized by different dose to know the response of cutting sample, which is amine base inhibitor >3% (formula 8), Potassium base inhibitor 1 %– 12 %, Polymer encapsulation 2 ppb and also rheology and filtration was controlled to meet the hydraulics design. The drilling fluid was passing the stress test for 16 hours rolling at 230°F.

Table 6. Optimized Drilling Fluid Properties

Testing Sample	***Remark***	*MW*	*PV*	*YP*	*pH*	*API*	*K+*	*Cl-*	*MBT*
Optimized Fromula 1	Stress test 16 hrs @220°F	12.4	26	37	11	2	28400	1400	3
Optimized Fromula 2		12.1	27	37	11	2	28560	6700	4
Optimized Fromula 3		12.1	23	32	11	2.6	28620	6100	4
Optimized Fromula 4		12.2	24	34	7	3	91000	68600	5
Optimized Fromula 5		12.1	23	33	7	1.8	1100	67900	5
Optimized Fromula 6		12.1	24	32	7	2.2	1100	1300	5
Optimized Fromula 7		12.2	26	32	10	2.2	6200	12900	5
Optimized Fromula 8		13.0	28	33	10.64	4.0	34,667	38,000	3

Cuttings sample dispersion test for different sample depth shows the result of this test in comparison to get the optimum drilling fluid formula, the upper formation was good integrity while test by combined inhibition in water-based drilling fluid system.

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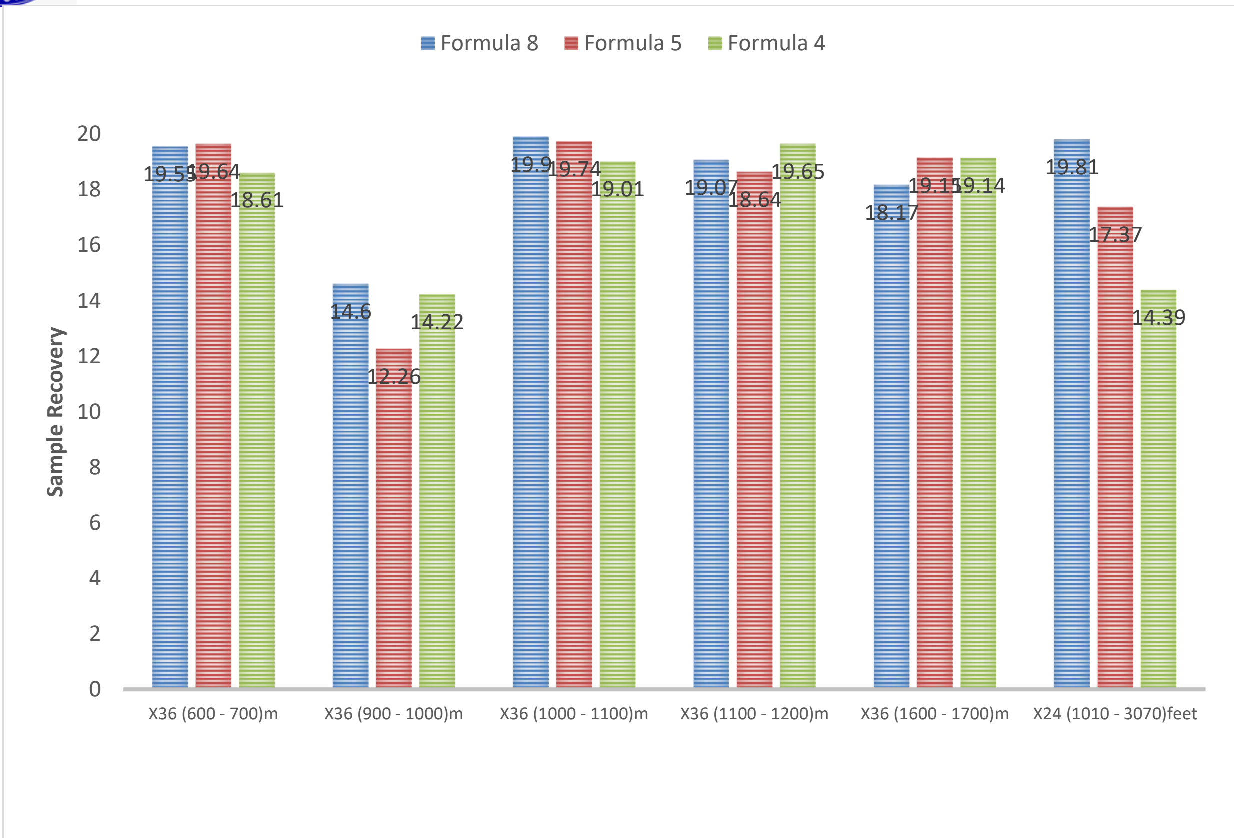

Figure 7. Weight Loss (%) Erosion Test Upper Formation

3.8. Drilling Fluid Design for Lower formation

According to the characteristics of the deeper formation, limitation hydraulics design, low ROP on hard formation, high angle and long trajectory interval, water-based drilling fluid system with amine based combined with polymer encapsulation and pickling method shows not effective to minimize wellbore reactivity which is the clay dominated by kaolinite.

Drilling fluid formula was optimized by different dose to know the response of cutting sample, which is amine base inhibitor >3% (formula 8), Potassium base inhibitor 1 %– 12 %, Polymer encapsulation 2 ppb and also rheology and filtration was controlled to meet the hydraulics design. The drilling fluid was passing the stress test for 16 hours rolling at 230°F.

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Optimized Fromula 3		12.1	23	32	11	2.6	28620	6100	4
Optimized Fromula 4	Stress test 16 hrs @220°F	12.2	24	34	7	3	91000	68600	5
Optimized Fromula 5		12.1	23	33	7	1.8	1100	67900	5
Optimized Fromula 6		12.1	24	32	7	2.2	1100	1300	5
Optimized Fromula 7		12.2	26	32	10	2.2	6200	12900	5
Optimized Fromula 8		13.0	28	33	10.64	4.0	34,667	38,000	3

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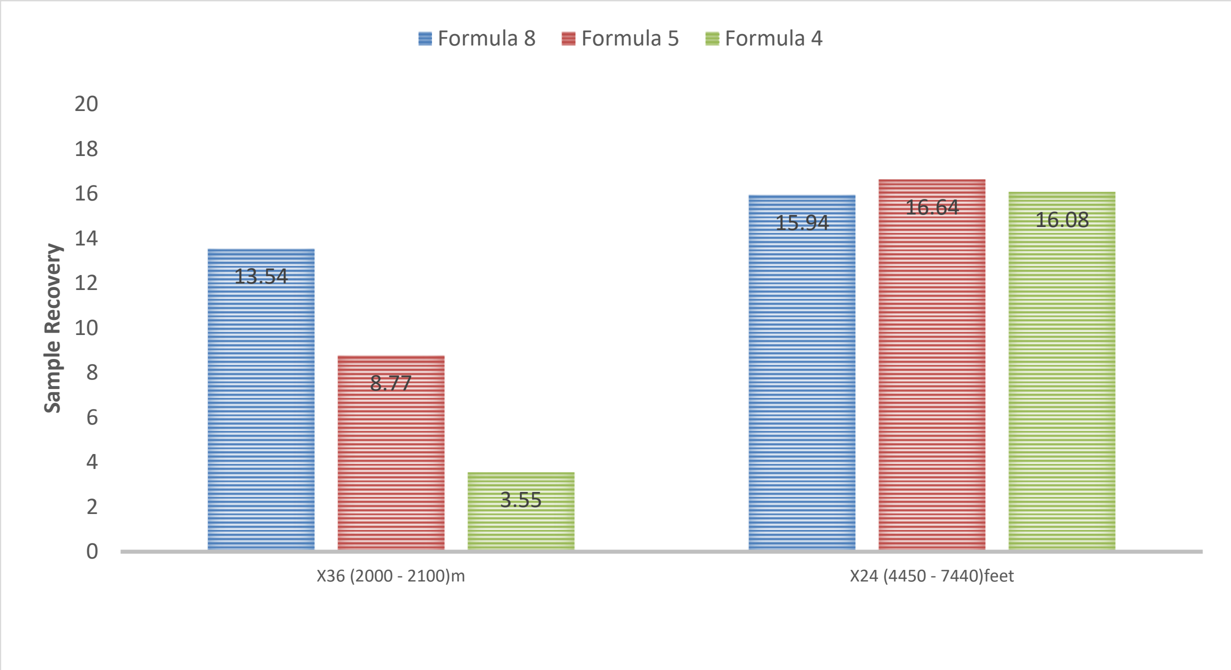

Figure 8. Weight Loss (%) Erosion Test Lower Formation

IV. CONCLUSION

1. The availability of sufficient rock samples for analysis is an important step in mitigating wellbore stability risks.
2. With the limited number of samples, XRD analysis is the best idea for formation stability assessment.
3. Based on the characterization of upper formation well X24 and X36 with smectite domination mineral on clay-oriented analysis, short open hole section, water-based mud with potassium, polymer and amine-base inhibition was optimized to minimize wellbore instability issue. For lower formation, water-based fluids system was different responded by the formation, character of clay with kaolinite domination was not compatible for this inhibition method. The sample recovery is very low on erosion test, indicated high swelling by linear swelling test. The deeper formation tends to time dependency wellbore stability. The deeper formation in this cluster well with long trajectory, low rate of penetration and higher bottom-hole temperature and pressure is recommended to apply non-aqueous-based fluids system to drill the well.

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