

# Redefining HPHT Drilling Fluids: Enhanced Oil-Based Drilling Fluid System for Deepest & Highest Temperature Exploration Well in Mahakam Block, Indonesia

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## Abstract

Over the decades, Mahakam Block has reached its maturity with declining production. Exploration needs to be conducted to sustain production. In 2024, Pertamina Hulu Mahakam drilled the deepest and highest temperature exploration well in the history of Mahakam Block. With maximum Bottom Hole Static Temperature (BHST) of 184.4degC and depth of 5206mMD, drilling fluid design has been challenging.

Enhanced oil-based high-temperature drilling fluid system was formulated to maintain stability throughout the construction and evaluation of the well. Due to logistics constraints, the fluid system from previous section will be conditioned with specialized additives to withstand the high-temperature condition, instead of building new whole system. Comprehensive laboratory tests were conducted to evaluate fluid's thermal stability, including rheological properties, fluid loss, sag index, electrical stability, solids analysis, and alkalinity. Properties were measured at the temperature of 184degC for 7-day duration. The results were compared to desired properties to identify the adjustments needed, until acceptable properties were achieved. Simultaneously, hydraulics simulations evaluated downhole pressure management, wellbore stability, and hole cleaning. This is crucial particularly when mud weight is adjusted to for operational requirements.

The engineered fluid system demonstrated its ability to maintain wellbore integrity under prolonged high-temperature exposure. Fluid remained stable despite multiple mud weight adjustments as operationally required. The success of this challenging well drilling establishes benchmark for High-Pressure, High-Temperature (HPHT) drilling in the Mahakam Block and provides valuable insights for future exploration wells in similar environments.

## Introduction

Mahakam Block is one of oil and gas resources in Mahakam Delta, East Kalimantan, Indonesia. This area was explored since 1970 and was become the largest gas production in Indonesia (Suripno et al., 2024). However, it has been facing

natural decline from 2010 to the current date. Several strategies have been implemented to maintain the production rate, and one of them is discovering new hydrocarbon reservoirs in challenging areas, including HPHT fields.

Robust well architecture and enabling HPHT technologies such as thermally stable drilling fluid, are critical for the successful delivery of these wells. While high pore pressures necessitate high-density fluids laden with weighting agents to maintain well control, these high-solids systems often suffer from excessive rheology. Consequently, this leads to unmanageable Equivalent Circulating Densities (ECDs), induced losses, and compromised Rate of Penetration.

Developing thermally stable fluids that perform effectively at high temperatures is further complicated by the limitations of conventional invert-emulsion systems, which utilize amine-based emulsifiers. These emulsifiers are prone to thermal degradation around 175°C, resulting in the release of ammonia (NH<sub>3</sub>), increased rheology, and high-temperature gelation. As a result, the development of a novel drilling fluid design was essential to efficiently and safely drill this well.

Finally, maintaining a consistent fluid density under extreme borehole conditions is vital for effective well control. As such, monitoring and mitigating barite sag remains a critical aspect of HPHT drilling fluid design and evaluation.

## Well Background

The well was the highest temperature exploration well in Mahakam Block. It was planned to drill using jack-up rig located offshore from the Mahakam Strait with water depth of 71.98 m. The well was planned as a vertical hole with planned total depth of 5,206 meters TVD. It was expected that the well could reach pressure of 16,994 psi and bottomhole temperature (BHT) 184°C. According to SLB HPHT classification system (Figure 1), this well was considered a HPHT well. The operational goal was to test, permanently plug and abandon after obtaining necessary data.

The objectives of the drilling fluid design for this well were:

- No Non-Productive Time (NPT) associated with

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- drilling fluid
- Stable drilling fluid at BHT
- No excessive ECD associated with drilling fluid at BHT

This paper discusses the laboratory evaluation, hydraulics simulations, and field execution of a HPHT drilling fluid design for HPHT well in Mahakam Block. The objective was to select a high-density, thermally stable HPHT fluid formulation with low rheological properties (low Plastic Viscosity, low ECD) and minimal barite sagging.

### Drilling Fluids Design

The surface and upper section of this well was planned to be drilled using High-Performance Water-based Mud (HPWBM). The synthetic-based mud (SBM) was used in the lower sections of the well. This paper focuses on the design and evaluation of HPHT SBM design that was used for the last two (2) sections of this well.

Multiple mud formulations were formulated and evaluated through numerous lab tests to ensure thermal stability and desirable fluids properties. The fluids were tested before and after 16 hours of dynamic aging at the maximum BHT. Furthermore, to qualify the system for prolonged static periods, specifically during wireline logging operations, static aging tests were extended to 168 hours (7 days). Following these tests, the fluids were analyzed for rheological profile and barite sag tendency. The formulation underwent iterative adjustments until the system demonstrated acceptable results.

### Laboratory Testing

Prior to entering HPHT zone, conventional SBM had already been used to drill the intermediate sections. Conditioning from conventional SBM to HPHT SBM is preferred to minimize cost and logistics issue. As most conventional mud products do not tolerate high temperature environment and exhibit high rheology and high temperature gelation, specialized mud products that are designed for high temperature environment were used. These products are added to conventional SBM to achieve thermal stability.

To ensure the lab results were representative of field conditions, the preliminary testing utilized centrifuged SBM from the other wells as 'seed mud.' This approach accounted for the presence of drilled solids and pre-existing chemical concentrations. The HPHT SBM formulation is detailed in Table 1.

The laboratory results are summarized in Figure 2. Rheological profiles were characterized at three temperature points (120°F, 150°F, and 180°F) to map the fluid's behaviour across the circulating temperature gradient. The data confirms that the fluid maintained a stable rheological profile even after 168 hours (7 days) of static aging.

The recorded Sag Factor remained below 0.53, indicating a negligible potential for barite settlement during prolonged static periods. Furthermore, no free oil or internal phase separation was observed, confirming superior emulsion stability.

To further validate performance under downhole conditions, an HPHT viscometer was utilized to model the simultaneous

effects of high pressure and high temperature on fluid viscosity (Figure 3). These comprehensive test results demonstrate that the formulation is thermally stable.

### Hydraulics Simulation

During the planning phase, hydraulics simulations were conducted to predict ECD, ESD, temperature, hole cleaning, tripping profiles, and overall fluid characteristics under simulated downhole conditions and planned drilling parameters. Sensitivity analysis of various operating parameters including flowrate, rotary speed and rate of penetration (ROP) was run and used to develop the hydraulic drilling window for each hole section. This is to determine the operating window between downhole pressures of the fluid system and fracture gradient & pore pressure of the wellbore.

Figure 4 presents a simulation snapshot at anticipated drilling parameters for the 10.625 in. x 12.25 in. hole section: pump rate of 1,900 L/min, ROP of 10 m/hr, and rotary speed of 150 rpm. Applying the rheological profile for 2.14 SG HPHT SBM, the calculations estimated a maximum ECD at total depth (TD) of approximately 2.162 SG. This remains below the fracture gradient of 2.27 SG.

Figures 5, 6, and 7 present the parametric analysis of ECD at the casing shoe, ECD at TD, and Hole Cleaning Index (HCI) as functions of flow rate and ROP. Simulation results indicate that the ROP should be limited to 10 m/hr, as higher ROP values reduce HCI and increase the risk of cuttings bed formation.

For 8.5 in. x 9.5 in. hole section, simulation results are presented in Figure 8. At the planned drilling parameters, with the pump rate of 1,850 L/min, ROP of 10 m/hr, and rotary speed of 120 rpm, using a 2.2 SG SBM, the ECD at TD was simulated at 2.298 SG. This value is very close to the fracture gradient of 2.30 SG. Therefore, it is recommended to use lower unless additional formation pressure data justifies otherwise. Consequently, a follow-up simulation was conducted with a 2.16 SG SBM, resulting in an ECD at TD of 2.248 SG (Figure 9). As the pore pressure is 2.18 SG, managed pressure drilling (MPD) will be utilized to maintain a safe operating window and ensure well control throughout the drilling operation.

Figures 10, 11, and 12 provide a parametric analysis of ECD at the casing shoe, ECD at TD, and HCI with respect to variations in flow rate and ROP. Given the high BHST anticipated in these intervals, mud density will be adjusted progressively during drilling to compensate for temperature-induced changes in mud weight and to ensure that minimum equivalent static density ESD is always maintained. A temperature correction was also applied in the simulations, as depicted in Figure 13, with the reference temperature for the corrected mud weight standardized at 49°C.

### Field Execution

Prior to drilling the HPHT sections, the actual SBM sample retrieved from the previous section was tested and conditioned in the laboratory to determine the optimal formulation for subsequent treatments. The final formulation is presented in Table 2, and laboratory test results are shown in Figure 14. With the appropriate treatment, the fluid demonstrated the ability to

withstand anticipated drilling conditions, including 7 days of static aging without significant barite sag.

The 10.625 in. x 12.25 in. section began with 2.02 SG SBM carried over from the previous interval. The system was conditioned to achieve the target mud weight of 2.14 SG, which served as the starting density for drilling to 4,401 mMD. Initial drilling progress was hindered by a notably slow ROP, averaging 0.3–0.5 m/hr, with pumping rates of 1,600–1,700 L/min. To enhance drilling efficiency, the mud weight was reduced to the 2.08–2.10 SG range, permitting an increase in flow rate to 1,800 L/min. As a result, the ROP improved to between 0.7 and 1 m/hr.

Between 4,420 mMD and 4,438 mMD, the hole was reamed from 10-5/8" to 12-1/4", and the mud weight was adjusted upward from 2.10 SG to 2.12 SG. At 4,472 mMD, increased mud weight to 2.12–2.15 SG, ahead of drilling to section TD at 4,556 mMD. After reaching TD, wireline logging was performed and casing was run to bottom. The mud was conditioned to 2.12 SG to minimize the risk of losses or fracturing during cement job.

Table 3 provides a summary of actual fluid properties observed while drilling the 10.625 in. x 12.25 in. section. Rheological properties were continuously optimized to control ECD, and, while excess lime was monitored to ensure stable emulsion was achieved with no issues encountered.

Before commencing the 8.5 in. x 9.5 in. interval, the mud weight was increased from 2.12 SG to 2.16 SG. After drilling 3 meters of new formation, a Formation Integrity Test (FIT) was performed, followed by mud conditioning to reduce both rheology and mud weight back to 2.14 SG. During drilling, losses were encountered at a rate of 3–5 m<sup>3</sup>/hr. Bridging agents (Calcium Carbonate Fine and Medium) were added to mitigate formation loss. Mud coolers were run to stabilize mud temperature in response to elevated downhole temperatures.

As drilling advanced to 4,785 mMD, the mud weight was increased to 2.19 SG. Long Circulation Test (LCT) results prompted a further increase in mud weight to 2.21 SG before pulling out of hole (POOH) the bottomhole assembly (BHA). Mud weight was again reduced to 2.14 SG and run-in-hole (RIH) rotary BHA for continued drilling to 5,055 mMD. A Dynamic Pore Pressure Test (DPPT) was then conducted, leading to a mud weight increase to 2.22 SG prior to POOH BHA. Wireline logging indicated opportunity for deepening. Upon RIH BHA to TD, mud weight was reduced to 2.14 SG before drilling ahead to 5,206 mMD and performing another DPPT. Mud weight was increased to 2.23 SG, followed by a wiper trip and gas circulation as required.

Logging operations was performed again for 7 days, after which a 3.5" tubing stinger was run into the well. Notably, no barite sag was observed, despite a total of nine days in static conditions. Prior to plug and abandonment, the mud weight was reduced to 2.16 SG. The summary of actual fluid properties observed while drilling the 8.5 in. x 9.5 in. section is shown on Table 4.

Given the narrow drilling margin in both sections, precise mud weight control was critical. This required vigilant monitoring of shaker screens, prompt replacement of damaged

screens, strict addition of barite, and dilution rates. The yield point and LSRYP were maintained within the specification range by adjusting the concentrations of Flat Rheology Modifier and High-Temperature Viscosifier as required by downhole conditions. While rheological parameters such as yield point, LSRYP, and gel strength (GS) play a crucial role in preventing solids settling during static or low shear conditions, relying solely on these profiles in HPHT environments can lead to overtreatment. This may result in increased pump pressure, higher ECD, and reduced ROP, ultimately slowing down the drilling operation. Prior to static state, the actual mud sample was tested at the rigsite to ensure that the sagging potential is low.

### **Lesson Learnt and Recommendations**

- Continuously monitor and validate the hydraulic simulation to ensure alignment between the planned parameters and actual drilling conditions.
- Always utilize all mud coolers and designate a dedicated tank as a water coolant located adjacent to the active tank to aid in transferring heat from the hotter mud returning from the wellbore, maintaining the suction temperature below 75°C. When the water in the dedicated pit reaches 40°C, it should be dumped and refilled with fresh seawater.
- An excess lime concentration of 2 kg/m<sup>3</sup> has been adequate for maintaining emulsion stability; however, due to possibility of encountering gas influx, aim to increase the excess lime level to above 5.7 kg/m<sup>3</sup> in the mud system.
- Pre-treat active with a wetting agent before adding barite when increasing the MW. Add 1ppb of wetting agent every 10 MT of barite. For daily treatment, maintain 1.0-2.5 ppb of wetting agent in active system.
- Utilize finer screens to avoid coarse particles mixed into the active system. Emulsion stability will be maintained with finer particles in the system.
- Solid removal with a centrifuge is not effective for heavy mud, except when the centrifuges are run with barite recovery system.
- Bleeding from reserve pit to maintain properties and prevent inhomogeneity in the system.
- Install finer shaker screens (140-220 mesh) whenever possible to minimize intrusion of finer solids into the mud system.
- To maintain ECD, minimum mud yield stress while drilling is required to provide adequate barite suspension. Based on available data the minimum yield stress (based on Fann 3 and 6 rpm) should be in the range 7 - 10 lb/100 sq.ft. (for vertical well).

### **Conclusions**

- Effective mud weight management within a narrow drilling window ensured wellbore stability and

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prevented both formation influxes and losses during HPHT operations.

- Monitoring of solids control equipment, particularly shaker screens, minimized drilled solids accumulation and maintained optimal mud properties throughout each interval.
- Continuous adjustment of rheology by using Flat Rheology Modifier and High-Temperature Viscosifier, optimized hole cleaning, cuttings suspension, and minimized sag risk during static and dynamic conditions.
- Strategic density reductions and flow rate increases enabled improvements in ROP while retaining ECD within fracture gradient limits.
- The timely application of bridging agents successfully reduced formation losses.
- Regular mud checks and conditioning before static periods, prevented barite sag despite prolonged suspension times.
- The drilling program was completed safely and efficiently, with no significant well control incidents or fluid-induced borehole instability, confirming the success of the mud system and operational strategy.

High-Temperature Emulsifier, lb/bbl	14
Secondary Wetting Agent and Emulsifier, lb/bbl	4
Lime, lb/bbl	6
High-Temperature Filtration Control Additive 1, lb/bbl	1.5
High-Temperature Filtration Control Additive 2, lb/bbl	16
Barite, lb/bbl	567.04

Table 2. HTHP SBM Formulation (Field Execution)

Base Oil, lb/bbl	20.09
Seed Mud, lb/bbl	728
High-Temperature Viscosifier, lb/bbl	1.00
Flat Rheology System Modifier, lb/bbl	2.00
High-Temperature Emulsifier, lb/bbl	7.00
Secondary Wetting Agent and Emulsifier, lb/bbl	6.00
Barite, lb/bbl	132.31

Table 3. Fluid Properties Summary for 10.625 in. x 12.25 in. Section

Fluid Properties	Program	From (Actual)	To (Actual)
Mud Weight (SG)	2.14-2.17	2.08	2.16
Plastic Viscosity (cP)	ALAP	66	100
Yield Point (lb/100ft <sup>2</sup> )	20-32	22	31
LSRYP (lb/100ft <sup>2</sup> )	10-14	7	11
10s & 10m Gel Strength (lb/100ft <sup>2</sup> )	11-20 / 18-30	13 / 25	19 / 44
HTHP Fluid Loss (150°C, 500psi)	≤ 4.0	3.2	3.6
OWR	85/15 – 90/10	86/14	90/10
WPS (g/L)		298	356
Excess Lime (kg/m <sup>3</sup> )	> 10	5.18	8.88
LGS (%)	< 5	3.03	4.55

Table 4. Fluid Properties Summary for 8.5 in. x 9.5 in. Section

Fluid Properties	Program	From (Actual)	To (Actual)
Mud Weight (SG)	2.16 – 2.20	2.13	2.23
Plastic Viscosity (cP)	ALAP	67	112
Yield Point (lb/100ft <sup>2</sup> )	20 – 35	21	34
LSRYP (lb/100ft <sup>2</sup> )	10 – 14	7	11
10s & 10m Gel Strength (lb/100ft <sup>2</sup> )	11 – 20 / 18 – 30	10 / 23	18 / 44
HTHP Fluid Loss (150°C, 500psi)	< 4.0	3.0	3.8
OWR	85/15- 90/10	89/11	90/10
WPS (g/L)		291	479
Excess Lime (kg/m <sup>3</sup> )	> 10	6.29	8.14
LGS (%)	< 5	3.12	5.88

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**Nomenclature**

- BHA* = Bottomhole Assembly
- BHST* = Bottom Hole Static Temperature
- BHT* = Bottom Hole Temperature
- HPHT* = High-Pressure and High- Temperature
- ECD* = Equivalent Circulating Density
- ESD* = Equivalent Static Density
- NPT* = Non-productive Tive
- SBM* = Synthetic Based Mud
- ROP* = Rate of penetration
- TD* = Total Depth
- HCI* = Hole Cleaning Index
- YP* = Yield Point
- LSRYP* = Low Shear Rate Yield Point
- GS* = Gel Strength
- LCT* = Long Circulation Test
- FIT* = Formation Integrity Test
- DPPT* = Dynamic Pore Pressure Test
- RIH* = Run-in-hole

**Tables**

Table 1. Preliminary HTHP SBM Formulation

Base Oil, lb/bbl	83.82
Centrifuged Mud, lb/bbl	75.78
High-Temperature Viscosifier, lb/bbl	2.25
Flat Rheology System Modifier, lb/bbl	6

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Figures

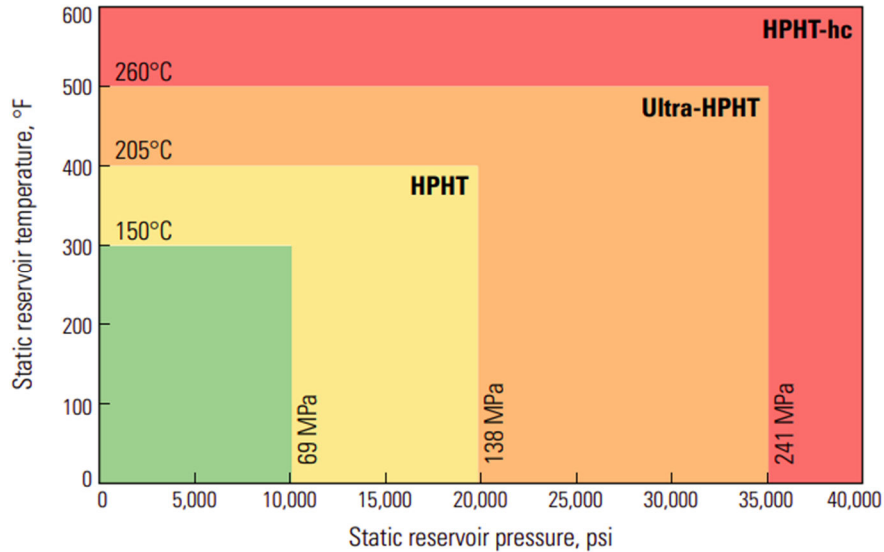


Figure 1 – SLB HPHT Classification System.

LR-KAL - 2022-207PHM 2.25 SG	20 (SG.2.22) 90/10.SWR														
Date	24-Aug-23			25-Aug-23			2-Sep-23			4-Sep-23			4-Jun-23		
Heat Aging Temp, °C:	Initial			184			184			184			184		
Heat Aging, Hours:	Initial			16			72			120			168		
Initial (I)/ Static (S)/ Rolling (R):	Initial			R			R + S			R + S			R + S		
Mud Weight @ Room Temp.	2.22			2.22											
Rheology Temperature	deg F	120	120	150	180	120	150	180	120	150	180	120	150	180	
600 PPM		342	332	246	189	329	236	181	325	222	170	440	282	215	
300 PPM		184	180	132	102	178	129	98	175	123	93	236	155	121	
200 PPM		129	128	93	72	125	89	70	123	87	66	166	118	87	
100 PPM		73	69	53	42	71	64	40	70	50	38	95	68	51	
6 RPM		13	12	10	8	12	10	8	12	10	8	17	14	11	
3 RPM		10	9	7	6	10	8	6	10	8	6	13	11	9	
L.SYP		7	6	4	4	8	6	4	8	6	4	9	8	7	
Plastic Viscosity	cP	158	152	114	87	151	107	83	150	99	77	204	127	94	
Yield Point	Lb/100 ft <sup>2</sup>	26	28	18	15	27	22	15	25	24	16	32	28	27	
10 sec Gel	Lb/100 ft <sup>2</sup>	13	11	9	8	12	8	7	12	9	8	15	13	11	
10 min Gel	Lb/100 ft <sup>2</sup>	17	14	12	10	15	12	10	14	12	10	19	15	13	
30 min Gel	Lb/100 ft <sup>2</sup>	18	15	13		17	14	12	15	13	11	20	16	14	
Electrical Stability	Volts	1,554		1,017		922			886			824			
Sagging Test															
Top	sg					2.10			2.09			2.07			
Middle	sg					2.20			2.19			2.17			
Bottom	sg					2.33			2.35			2.36			
Sag Factor						0.53			0.53			0.53			
Retort Solids (Uncorrected)	% Volume			40		40			40			40			
Retort Oil	% Volume			54		54			54			54			
Retort Water	% Volume			6		6			6			6			
Oil Fraction				0.90		0.90			0.90			0.90			
Oil Water Ratio				90/10		90/10			90/10			90/10			
H2SO4	ml			0.10		0.00			0.00			0.00			
Exces Lime	ppb			0.13		0.00			0.00			0.00			
AgNO <sub>3</sub> 0.282 N (PNP)	cc			1.40		1.40			1.40			1.40			
WPS as CaCl <sub>2</sub>	%			26.75%		26.75%			26.75%			26.75%			
HTHP @ 184 °C/ 500 PSI	cc/30 min			3.2		2.0			2.0			2.4			
HTHP Water	cc/ 30 min			0.0		0.0			0.0			0.0			

Figure 2 – Preliminary HPHT SBM Lab Test Result

Fann Degrees at Shear Rate															
Num	Temp F	Temp C	Pressure psi	Pressure bar	600 rpm	300 rpm	200 rpm	100 rpm	6 rpm	3 rpm	Gel 10 sec	Gel 10 min	PV cp	YP lb/hsf	Ty/YP
1	66	19.0	0	0.0	473	286	217	139	43	36	40	65	187	99	0.29
2	66	19.0	2000	136.0	687	400	294	179	49	41	41	66	287	113	0.29
3	66	19.0	3000	204.0	828	473	343	204	52	44	42	67	355	118	0.31
4	80	27.0	0	0.0	419	248	185	115	33	26	27	41	171	77	0.25
5	80	27.0	3000	204.0	665	374	269	159	38	31	28	42	291	83	0.29
6	80	27.0	4000	272.0	776	430	305	177	40	32	28	42	346	84	0.29
7	100	38.0	0	0.0	354	203	149	90	23	17	18	25	151	52	0.21
8	100	38.0	1000	68.0	401	227	165	98	24	18	18	25	174	53	0.23
9	100	38.0	2000	136.0	453	254	182	107	25	19	18	25	199	55	0.24
10	120	49.0	0	0.0	301	169	122	72	16	12	13	17	132	37	0.22
11	120	49.0	4000	272.0	455	244	170	96	19	14	14	18	211	33	0.27
12	120	49.0	7000	476.0	619	321	219	119	21	16	14	18	298	23	0.48
13	150	66.0	0	0.0	239	131	93	54	11	8	9	12	108	23	0.22
14	150	66.0	6000	408.0	392	210	139	76	13	9	10	12	182	28	0.18
15	150	66.0	10000	680.0	545	289	182	96	15	11	10	13	256	33	0.21
16	185	85.0	0	0.0	186	100	70	41	8	6	7	9	86	14	0.29
17	185	85.0	7000	476.0	297	157	103	56	9	7	8	9	140	17	0.29
18	185	85.0	12000	816.0	409	215	135	71	10	7	8	10	194	21	0.19
19	203	95.0	8000	544.0	268	141	92	50	8	6	7	9	127	14	0.29
20	203	95.0	12000	816.0	339	178	113	60	9	6	7	9	161	17	0.18
21	212	100.0	9500	646.0	270	142	92	50	8	6	7	8	128	14	0.29
22	230	110.0	10000	680.0	237	124	82	45	7	5	7	8	113	11	0.27
23	266	130.0	12000	816.0	194	103	69	39	7	6	6	8	91	12	0.42
24	285	141.0	13500	918.0	179	95	65	38	7	6	6	8	84	11	0.45
25	311	155.0	14500	986.0	155	83	59	36	7	6	6	8	72	11	0.45
26	338	170.0	16000	1088.0	136	73	55	35	6	5	7	8	63	10	0.40
27	365	185.0	17500	1190.0	121	65	53	36	6	5	7	9	56	9	0.44
28	375	191.0	20000	1361.0	124	66	55	38	5	4	7	9	58	8	0.38
29	383	195.0	20000	1361.0	118	63	54	39	4	3	7	10	55	8	0.25

Figure 3 – HPHT Rheology

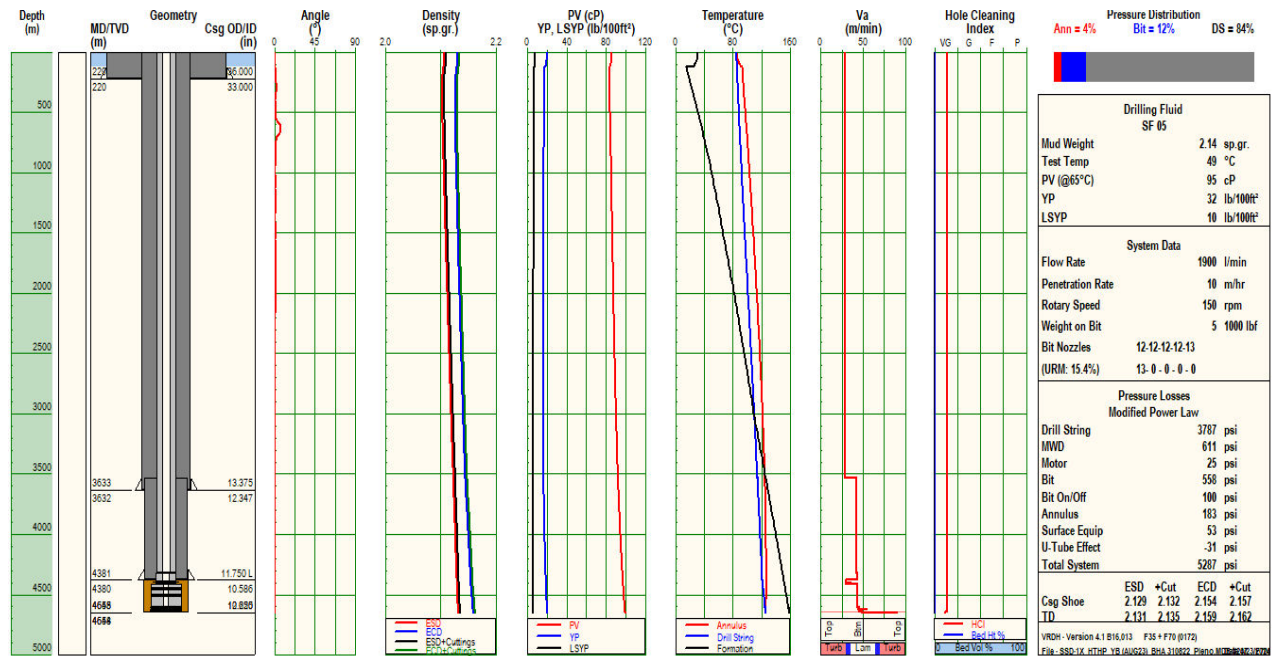


Figure 4 – Hydraulics Simulation for 10.625 in. x 12.25 in. Section

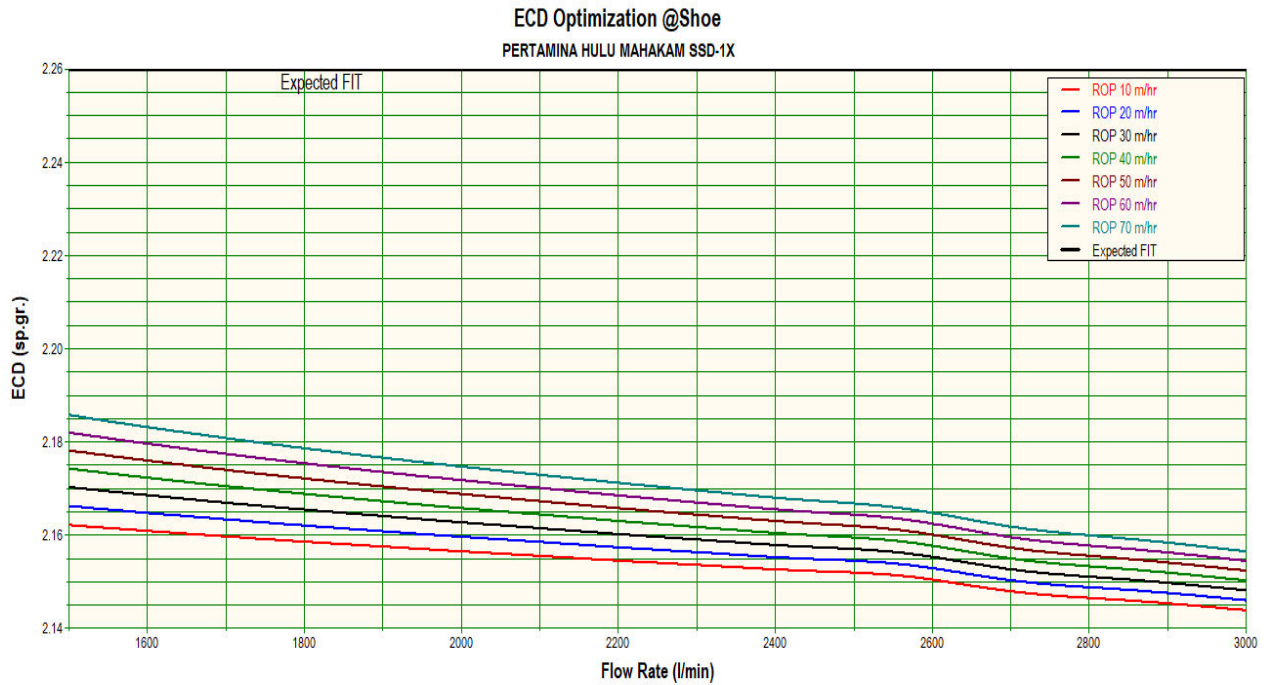


Figure 5 – Sensitivity Analysis for ECD at Casing Shoe (10.625 in. x 12.25 in. Section)

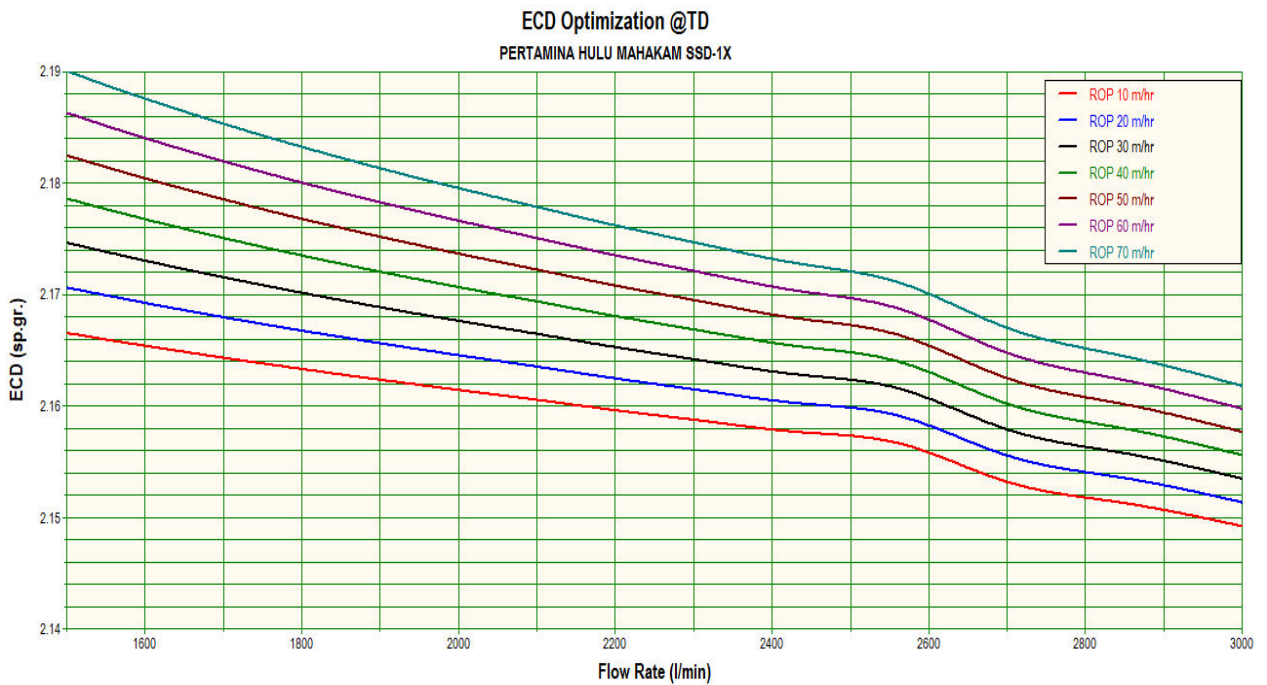


Figure 6 – Sensitivity Analysis for ECD at TD (10.625 in. x 12.25 in. Section)

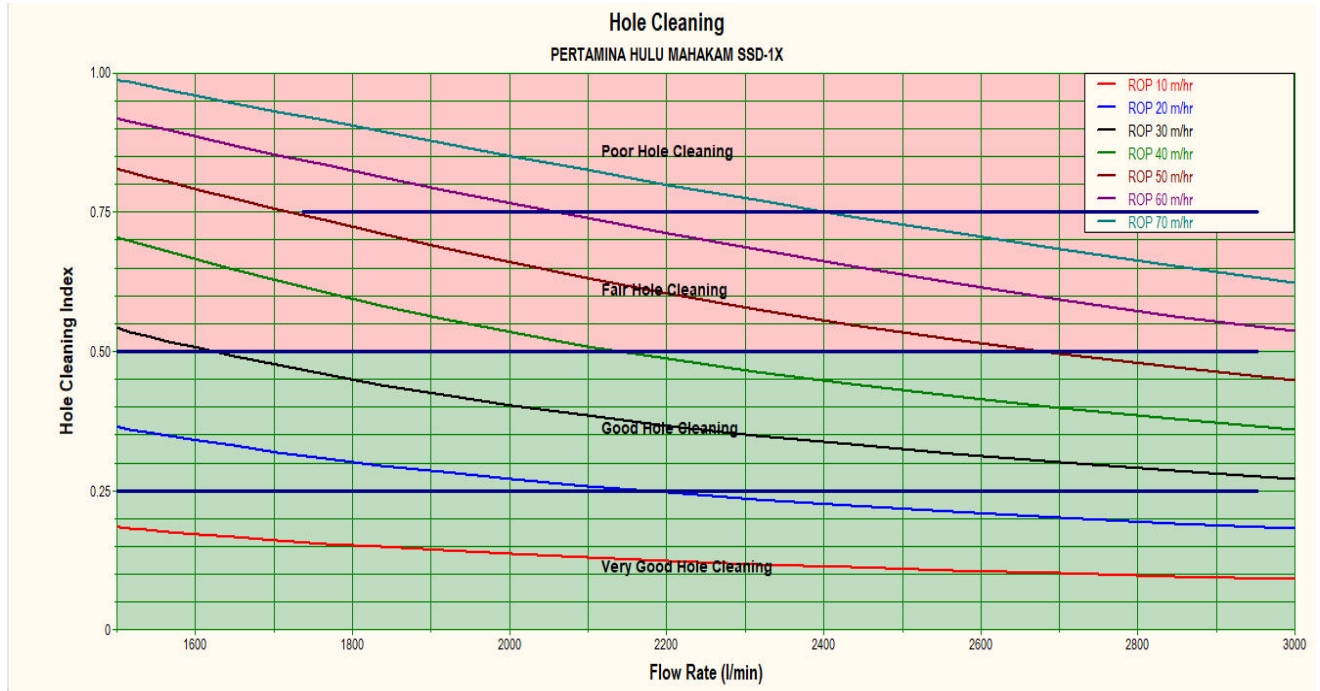


Figure 7 – Sensitivity Analysis for Hole Cleaning (10.625 in. x 12.25 in. Section)

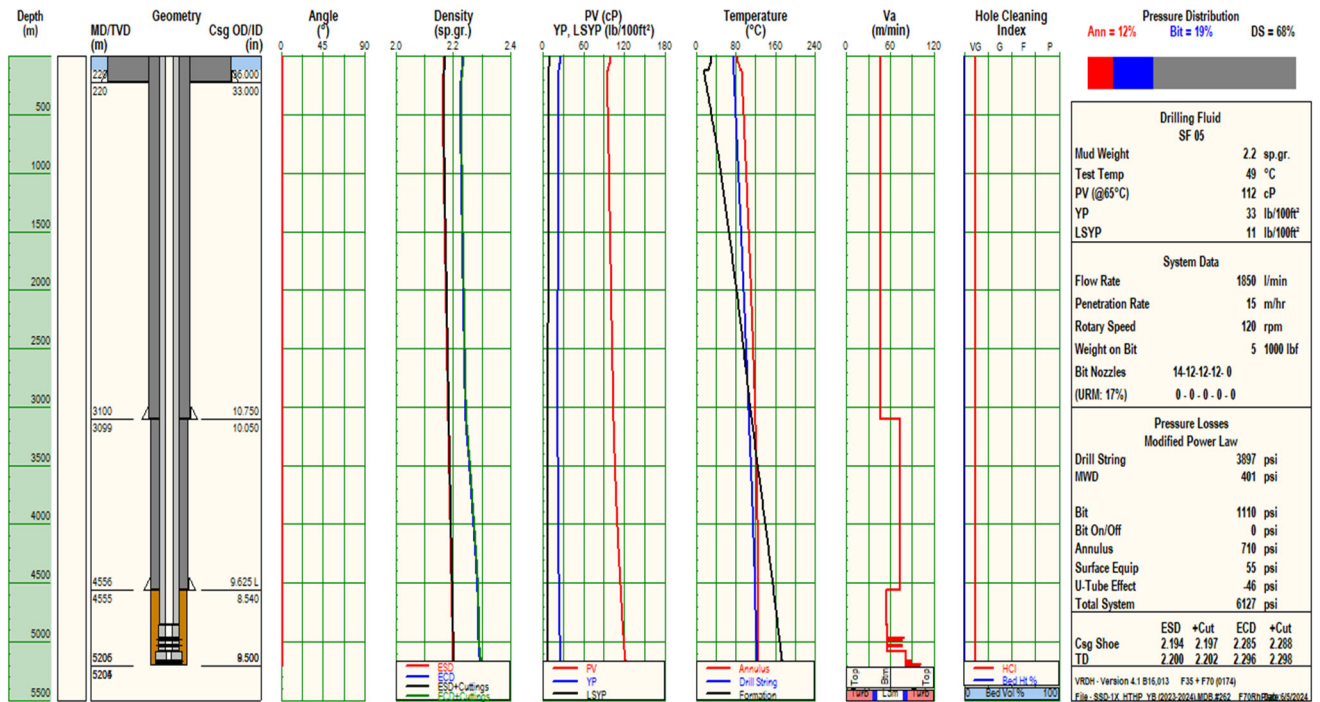


Figure 8 – Hydraulics Simulation for 8.5 in. x 9.5 in. Section (2.20SG SBM)

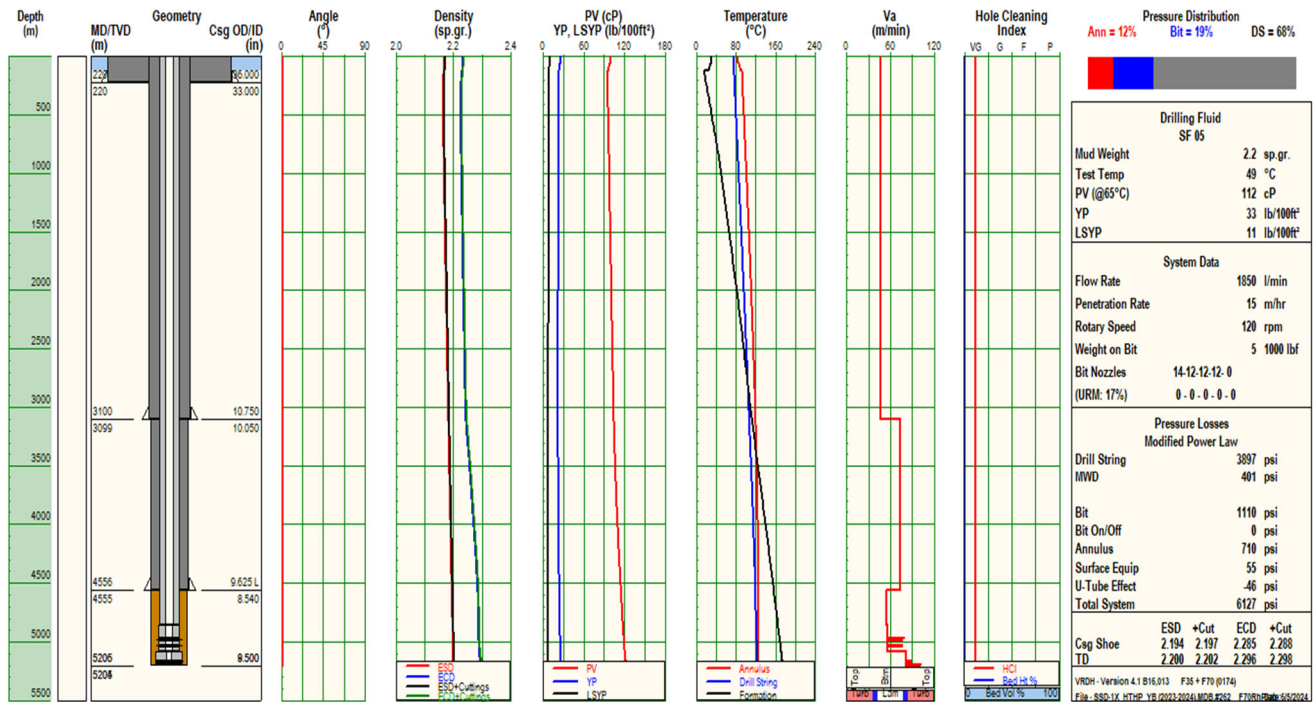


Figure 9 – Hydraulics Simulation for 8.5 in. x 9.5 in. Section (2.16SG SBM)

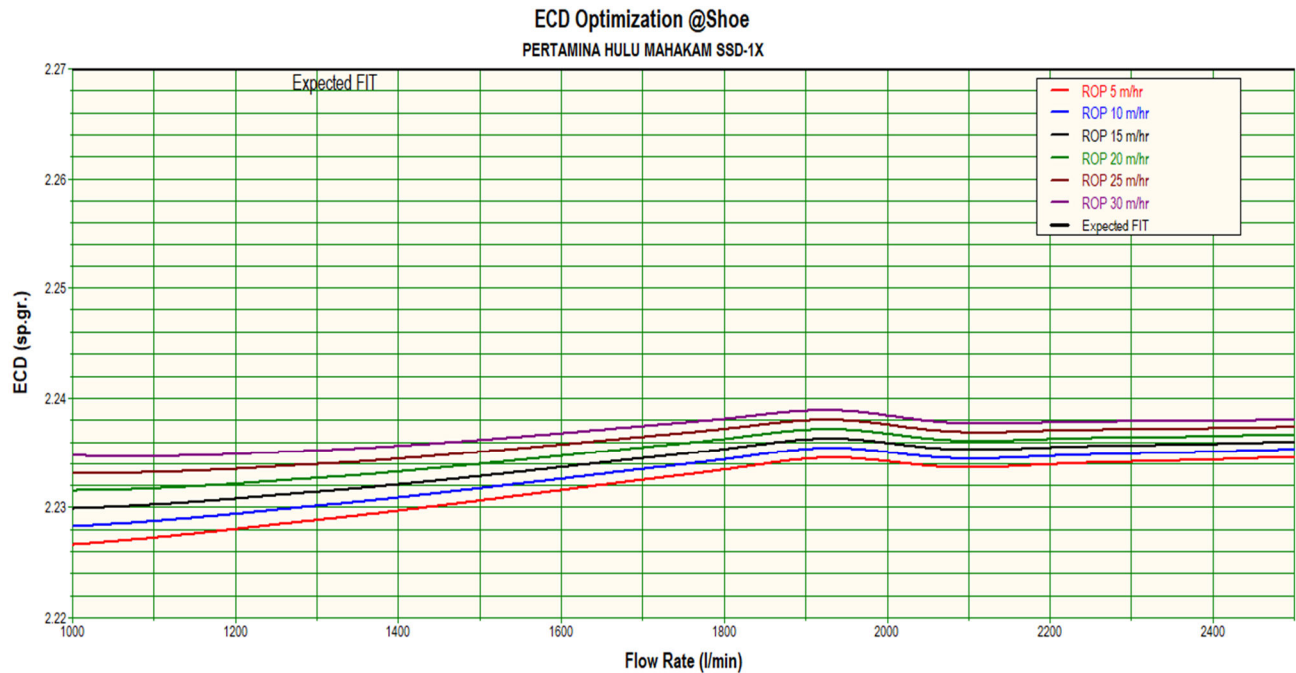


Figure 10 – Sensitivity Analysis for ECD at Casing Shoe (8.5 in. x 9.5 in. Section)

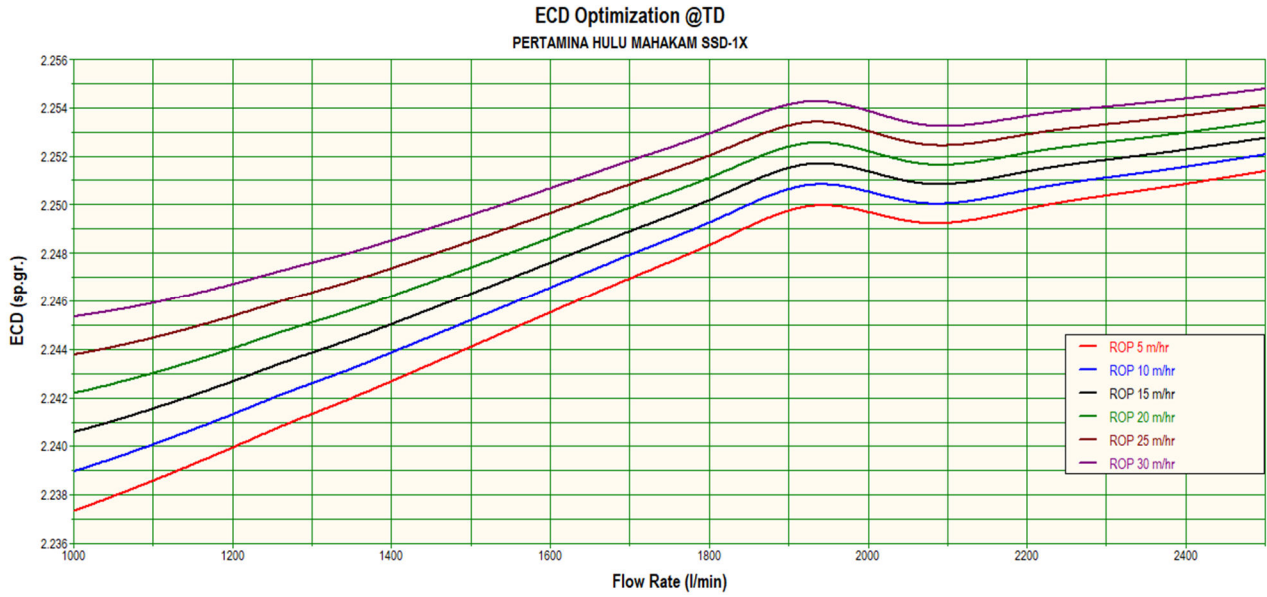


Figure 11 – Sensitivity Analysis for ECD at TD (8.5 in. x 9.5 in. Section)

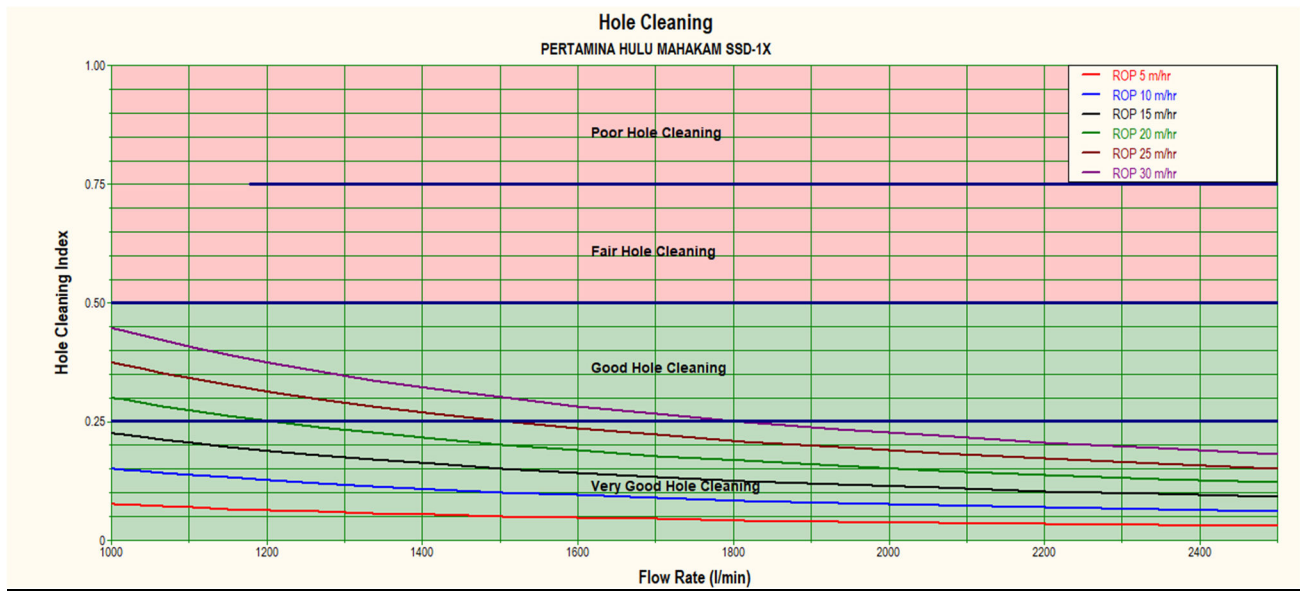


Figure 12 – Sensitivity Analysis for Hole Cleaning (8.5 in. x 9.5 in. Section)

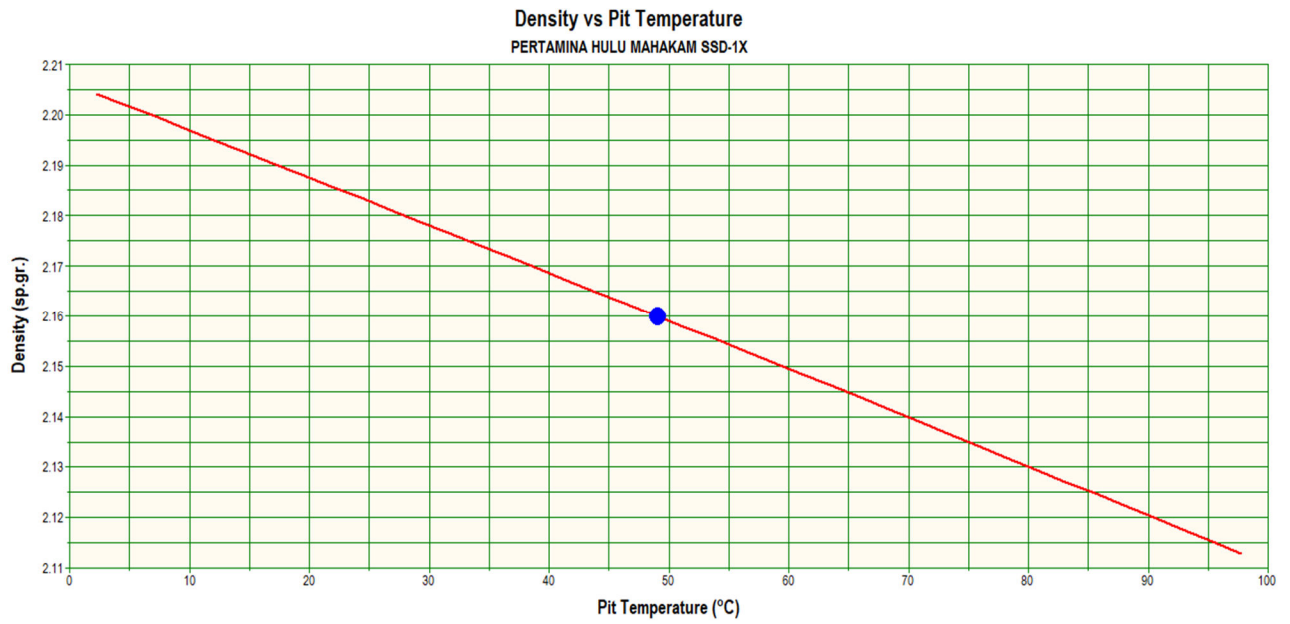


Figure 13 – Density vs Temperature Simulation

Heat Aging Temp, oF:			335	335	335	335
Heat Aging, Hours:			16	72	120	168
Initial (I)/ Static (S)/ Rolling (R):		Initial	R	S	S	S
Mud Weight @room temperature	SG	2.17	2.17	2.17	2.17	2.17
Rheology @150F	600 RPM	215	200	216	208	210
	300 RPM	126	110	116	111	113
	200 RPM	87	79	78	77	78
	100 RPM	54	46	44	43	44
	6 RPM	15	10	7	6	7
	3 RPM	13	8	5	4	5
LSRYP	lb/100 Ft <sup>2</sup>	11	6	3	2	3
Plastic Viscosity	cP	89	90	100	97	97
Yield Point	lb/100 Ft <sup>2</sup>	37	20	16	14	16
10 sec Gel Strength	lb/100 Ft <sup>2</sup>	18	13	10	8	7
10 min Gel Strength	lb/100 Ft <sup>2</sup>	32	33	36	32	31
Electrical Stability	volts	1770	1455	1357	1280	1064
% Water		6.0	5.0			
% Oil		50.0	47.0			
% Solid		44.0	48.0			
Oil/ Water Ratio		89/11	90/10			
H2SO4 N/10	cc	1.0	0.5			
AgNO3 0.282N	cc	1.5	1.5			
Excess Lime	ppb	1.30	0.65			
Salt, CaCl2	%wt	28.12	31.95			
CaCl2 (Brine phase)	g/l	355.57	417.37			
ASG	%v	3.87	3.62			
LGS	%v	8.41	16.22			
HGS	%v	34.98	31.15			
Water Phase Salinity	mg/L	440K	440K			
HPHT '@335 °F/ 500 Psi	cc/30 min	2	2.8			
Static Sag Test	Free Fluid	ml		7	15	21
	Top	sg		2.194	2.199	1.978
	Mid	sg		2.223	2.22	2.038
	Bottom	sg		2.264	2.378	2.245
	Index Sag	%		0.5079	0.5196	0.5316

Figure 14 – Lab Test Result during Field Execution