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Non-polar Synthetic-Based Fluids Help Tackle Drilling Challenges in US Basins

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Abstract

The continuous drive for efficiency has been the main theme for drilling in US basins with the advancements in pad design, downhole tools, and directional drilling techniques. The utilization of synthetic-based drilling fluids has been a big contributor. Beyond their environmental advantages, the performance of synthetic drilling fluids has been proven in the field with increased lateral rates of penetration (ROP), casing run speed and better high temperature stability and compatibility compared to diesel based drilling fluids.

The benefits of synthetic base fluid stem from its pure, non-polar chemical composition, which contains low levels of naphthenics, and ultra-low aromatics including nearly zero BTEX compounds. The physical properties makes it well-suited for drilling in the US shale basins. The high non-polarity fosters a more compatible fluid-formation interface, resulting in lower friction and increased wellbore integrity. In the Haynesville play, the high aniline point enhances elastomer compatibility, significantly reducing mud motor failures.

A series of scientific techniques, including BET, TGA-IR, and XPS, were employed to investigate the interactions between the formation and base fluids to help understand the field performance such as less fluid dilution. Although non-aqueous fluids are generally not reactive with shales, it was observed that organics migrated to the surface following treatment with diesel, leading to decreased pore volumes. The presence of aromatics can effectively dissolve organic matter, contributing to solid degradation. Laboratory tests with shale cuttings revealed a more pronounced effect on diesel-based fluid properties. By combining interface analysis with fluid property assessments, the field performance was quantitatively evaluated.

Introduction

The evolution in US shale drilling is the quick adaptation of various new technologies and creation of efficient assembly lines to produce wells with elongating laterals. Records of 24-hour footage are replaced frequently. The total rig count has dropped since 2022 while the number of wells drilled each year remains steady. Considering the increase in total depth, the footage drilled per rig per month has increased, which represents an approximately 5-10% efficiency gain each year. Upgrades in drilling practices, measurements, downhole motors, bits and rig equipment are all contributing to the efficiency increase; however, the role of drilling fluids is often underestimated especially the use of synthetic-based drilling fluids or muds (SBM) since 2020.

The industry has practiced and mastered the use of Non-Aqueous Drilling Fluids (NADF) for almost a century since it was introduced in 1930’s. (Patel et al., 2011). Nowadays, most of the curve and lateral sections in US basins are drilled with NADF for the shale inhibition, stable fluid properties and lubricity. Due to the long history and large inventory of used mud, Diesel Oil-Based Mud (DOBM) still dominates several US basins, although it may become the bottleneck for drilling efficiency besides the health, safety and environmental (HSE) concerns.

One noticeable challenge is the amount of drill solids produced due to the fast drilling rate. The low gravity solids build up at an increased speed, especially fine solids in DOBM, which in turn requires more chemical treatment and dilution. On the other hand, SBM has become the preferred system in DJ and Haynesville basins as it not only alleviates the HSE concerns but also provides improved drilling performance. The synthetic base fluid used is a Gas-to-Liquid (GTL) product. It is manufactured from natural gas via the Fischer-Tropsch synthesis process and has a chemical composition of over 98% slightly branched iso-paraffins and n-paraffins. For comparison, diesel can have over 25% aromatics including a considerable amount of BTEX. Although there are many grades of GTL products, there is one specific grade optimized for drilling. This drilling grade is referred herein as synthetic paraffin (SP) fluid which forms the base for GTL synthetic paraffin-based mud (GTL-SBM).

SBM was introduced in the 1990s for offshore applications due to the environmental restrictions on drill cuttings discharges. SBM was initially referred to as “pseudo oil mud” because it was designed to mimic the drilling performance of mineral oil-based mud. However, the higher cost for the esters, polyalphaolefins (PAO), linear and internal olefins limited their use to regions where they were mandated by local legislation. Effectively, internal olefin is the only base oil used by operators offshore in the Gulf of Mexico (now Gulf of America).

When used for land drilling, there seems to be confusion or misuse of the definition of SBM. The U.S. EPA (EPA Region 6 Fact Sheet) has clearly defined "Synthetic Material" as fluid that is produced by the reaction of purified chemical feedstocks as opposed to the traditional base fluids such as diesel and mineral oil that are derived from crude oil through physical separation processes. The International Association of Oil and Gas Producers (IOGP) differentiates drilling base oils according to their aromatic hydrocarbon content, with Group I having >5% aromatics, Group II between .5 and 5%, and Group III <.5% (Oil and Gas Producers, 2003). Notably, lightly hydrotreated mineral oils and straight run gas oils used in drilling fit into the same IOGP group as diesel, even though they are sometimes incorrectly referred to in the industry as "synthetics" with the rationale that they are not traditional diesel fuel.

Certainly, the definition does not dictate the actual downhole performance. The most important factor is chemical composition. Synthetic processes virtually eliminate the presence of aromatics. Additionally, they produce consistent chemical fingerprints as compared to refinery processes that make diesel or mineral oils from crude that vary widely depending on the local production from oil and gas wells that are the source of feedstock to refineries. For instance, the kinematic viscosity of diesel varies from 1.9 to 4.1 cSt, while synthetic paraffin only varies by +/- 0.1 cSt. Aniline point, flash point, pour point and density are also more consistent with synthetic paraffin. The potential blending of diesel with biodiesel can be even more detrimental as biodiesel degrades more under HT conditions.

The aromatics not only cause health, safety and environmental concerns but also impact the drilling fluid properties negatively. One of the fundamental aspects is the affiliation to solid surfaces. As aromatics are less hydrophobic than olefins or paraffins, they are more attracted to the surface of formation solids or drill pipe/casing, which are hydrophilic in general. In addition, aromatics have a higher solvency than paraffins, which partially dissolves the organic materials in formations. Cycloparaffins (naphthenes) in mineral oils are saturated ring-containing compounds converted by the hydrogenation of unsaturated aromatics in refinery processes. These non-synthetic cycloparaffins have an affiliation to solids that is between that of aromatics and linear synthetic paraffins. The surface affiliation, hydrophobicity, and polarity/solvency of all drilling base oils can be quantified by the aniline point, which has proven to be an important indicator. The aniline point is also influenced to a lesser degree by the average hydrocarbon chain length, as lower chain length increases solvency.

As shown in Figure 1, synthetic linear paraffins are the most non-polar of the components in drilling base oils, followed by cycloparaffins (naphthenes) and then aromatics which are the most polar having the highest attraction to solids and chemicals in the drilling fluids. It is the purpose of this study to investigate the role of non-polarity of the base oils on subsequent drilling fluid properties and field drilling performance. To investigate the mechanism of interaction between drilling base oils and shales, a series of advanced chemical analyses were conducted.

TGA-IR

Thermogravimetric analysis and infrared spectroscopy (TGA-IR) is a powerful combination of techniques to characterize materials. TGA measures weight loss as a function of temperature or time but it does not identify the compound that is lost at certain temperatures. The combination of TGA and IR can measure the evolution of gases caused by thermal decomposition and provide information on the specific components. The IR spectra at various temperatures provides a map to how the base oil molecules leave the shale sample and in turn provide information on the affiliation to the surface. The lab experiments were conducted at PTG Eindhoven. The TGA-IR measurements were carried out with a PerkinElmer TGA 4000 coupled to a gas cell in a PerkinElmer Frontier FT-IR spectrometer.

In the lab tests, Wolfcamp shale samples were ground and sieved to <150 microns. The sieved shale was mixed with diesel or synthetic paraffin with occasional shaking for 3 days at room conditions, then filtered to remove excess liquid and the solids were spread to dry for 7 days at room conditions. Two Wolfcamp core samples were investigated. Wolfcamp 1 has <1% organic matter while Wolfcamp 2 has ~3%. The results on Wolfcamp 2 are reported here as it is more representative.

TGA-IR analysis can characterize the adhesion strength of the liquids onto the mineral surfaces. This is accomplished by measuring the activation energy of the liquid deposited on the minerals and comparing it to that of the bulk liquid. The difference in activation energy ($E_a – E_{a,liquid}$) due to contact with Wolfcamp 2 shale is shown in Figure 2. This difference is higher with diesel, indicating stronger interaction with shale. The C-H peaks from Wolfcamp 2 show an interesting trend in Figure 3. GTL synthetic paraffin leaves at a lower temperature (earlier) than diesel with narrower decomposition, indicating weaker interaction with Wolfcamp 2 shale. This may be an indication that diesel forms not only a bulk film but also a tight bond with the mineral surface or in deeper pore spaces.

The findings agree with the previously reported (Lu et al., 2023) experimental results. In those tests, DOBM showed a more aggressive impact on shale solids than GTL-SBM. The penetration of diesel in drill solids dissolved the organic matter and thus caused the solids to break down. This directly impacts the solid removal efficiency during drilling and the increase of fine LGS in the fluids and negatively affects overall fluid properties. Similarly, drilling simulations (Lu et al., 2024) with

Wolfcamp B shale showed finer, darker and wetter drill cuttings with diesel compared to synthetic paraffin.

XPS Surface Analysis

X-ray photoelectron spectroscopy (XPS) is an analytical technique that measures the surface chemical composition. The chemical composition provides a quantitative measurement of the affiliation of the base oil molecules to the shale surface. XPS assesses the adhesion/adsorption of the liquids on the minerals. This is only the liquid which does not get removed from the surface during high-vacuum sample evacuation before the XPS measurement. The results on Wolfcamp 2 are shown in Figure 4, indicating treatment with diesel brings more aliphatics up to the surface than treatment with synthetic paraffin.

BET Surface Area Measurement

Brunauer-Emmett-Teller (BET) measurement is utilized to investigate if the affiliation of base oil causes changes in the microstructure of the shale. Similar to the TGA-IR analysis, shale samples were ground and sieved to 125 to 250 microns. The tests were performed on Eagle Ford shale at Stony Brook University using a Quantachrome Nova 2000 instrument with nitrogen as adsorbate.

The powders were mixed with diesel or synthetic paraffin and then dried for BET analysis. The results are shown in Table 1. A decrease in total pore volume was observed after the shale interacted with diesel. It is speculated that diesel imbibes in the pores and dissolves some of the organic matter and thus causes blockage in the pores. It is additional evidence showing the higher affiliation of aromatic molecules to the shale surface in comparison to synthetic paraffins.

Drilling Fluid Properties with Wolfcamp Solids

NADF samples were made with the identical formulation except for the base oils to quantify the impact of non-polarity on fluid properties in the presence of drill solids. A Wolfcamp core 3 sample with 6.4% TOC was utilized in the study. The core sample was ground and sieved. The sub 100 mesh powder was collected and added to the fluids as LGS contaminations.

The fluids are 12 ppg density with 55 ppb of fine solids. The rheological properties were measured before and after hot rolling at 250 °F for 16 hours. The results are shown in Figure 5. With the exact same formulation and chemical packages, GTL-SBM shows a lower viscosity. The yield point of the DOBM almost doubles that of the SBM, although the difference became smaller after hot rolling. The difference in rheological properties is a direct result of the base oil and solid interactions. Aromatics in diesel have a quick reaction with drill solids and can degrade the solids into finer LGS, which has detrimental effects on fluid properties.

Although the study is in a simulated lab environment, it provides a direct comparison on the base oil effects. In practice, this means more maintenance is required for DOBM. When more fine solids are generated, it often requires more dilution to keep the rheological properties within the targeted ranges. This was proven to be case with the field data collected.

High Temperature (HT) Drilling Fluid Properties

NADF is a complex invert emulsion system containing a large amount of solids. When the bottom hole temperature (BHT) exceeds 250 °F, it becomes more challenging to understand and maintain the fluid system. During drilling, the fluid is being circulated and sheared, goes through a temperature cycle from surface to downhole and then back up to the surface. New drill solids are entering the system, which consumes emulsifiers and/or wetting agents. Base oil is regularly added for dilution to maintain the rheological properties in the targeted range. The balance between the amount of emulsifiers/wetting agents and total surface/interfaces determines the stability and rheological properties. With an increased lateral length, the fluid is being heated at HT for even longer. At the same time, the mud checks are done at only 150 °F, which does not emulate the downhole conditions.

There are two type of lab tests to investigate the HT fluid properties. One is to measure the properties at 150 °F and atmospheric pressure before and after hot rolling at high temperature. The other one is to directly measure the rheological properties under high temperature and high pressure with a HTHP rheometer. Hot rolling poses a stress to the fluid system as the chemical additives may degrade and become less effective. It also affects the performance of organophilic clays. When LGS are present, the solids can break down and thus create new surface area, which requires more additives to stay oil-wet and dispersed.

Aromatics are expected to accelerate the thermal effect on the fluid system as the molecules penetrate the solids deeper and quicker. It is also speculated that aromatics affect the stack structure of organoclays as the amine coating can be interrupted. To evaluate the role of chemical constituents in base oils, DOBM and GTL-SBM were formulated in the lab.

To quantify the impact of non-polarity on fluid loss properties in the presence of drill solids, NADF samples were mixed with otherwise identical formulations except for the base oil. Field drill cuttings from the Haynesville were ground and sieved to <100 mesh to simulate low gravity solids contamination at 55 ppb concentration. The fluid density was 15 ppg. The fluid loss properties were compared after hot rolling at 250 ºF for 16 hours and after hot rolling at 350 ºF for 16 hours. The results are shown in Figure 6. With the same formulation and additive packages, GTL-SBM shows a stable fluid loss and filter cake thickness with no water in the filtrate. DOBM shows a nearly three-fold increase in fluid loss, doubling of filter cake thickness and presence of water in the filtrate. Although shale formations are relatively impermeable, the fluid loss test is an indicator that polar aromatics in DOBM accelerate the degradation of additives at HT conditions.

In another set of tests, properties were measured after hot rolling at 400 °F and under HTHP conditions from 150 ºF to 400 ºF. The fluid density was 15 ppg with 55 ppb of fine ground Haynesville cuttings to represent drill solids in the field. The fluids had identical formulations except for the base oils.

The effects of hot rolling are shown in Figure 7. It shows the yield point of both fluids at 150 °F before and after hot rolling at 400 °F. The YP dropped from 14 to 1 in the case of DOBM, which indicates the chemical forces within the system are weakened. A low yield point can lead to hole cleaning or other drilling issues. In addition to yield point, the low shear rate yield point (LSYP) dropped from 8 to 1. On the other hand, the properties of GTL-SBM were found to be maintained in the expected range.

A Grace M7500 HPHT Rheometer was used to study the rheological property changes over temperature and pressure from 150 to 400 °F and ambient to 12,000 psi pressure. The changes in PV, YP and LSYP are plotted in Figure 8. The values were calculated by subtracting the readings at the temperature and pressure from the readings at 150 °F and atmospheric pressure. The difference in PV increases but it reaches a plateau above 250 °F. The YP and LSYP show a different trend. The changes are minimal up to 300 °F, while becoming more evident above 300 °F. It indicates the effects on internal chemical forces are more critical when above 300 °F. More importantly, GTL-SBM shows a smaller change than DOBM especially in the temperature range above 300 °F. As identical formulations were used, the difference is attributed to the chemical composition of the base oil. A similar trend was reported in a study published by Aramco Houston Technology Center (Jian et al., 2023). DOBM was shown to have a much larger drop in rheological properties than GTL-SBM when the temperature was increased from 150 °F to 350 °F in an HTHP rheometer.

One of the concerns in the field when switching from DOBM to GTL-SBM is the availability of emulsifier packages and their compatibility, which can impact the fluid properties. Various emulsifier packages were tested in GTL-SBM, with the results shown in Figure 9. All emulsifiers were used at the same dosage in an otherwise identical 15 ppg formulation. Most of the fluids show a stable YP before and after hot rolling at 350 °F. Although the selection and dosage of emulsifiers can be further optimized, the combinations tested worked well with synthetic paraffin. The consistency can be attributed to the pure chemical composition of synthetic paraffin, which minimizes interaction with mud additives.

Although it is not the focus of this study, the solvency effect of aromatics has been shown in laboratory tests to be detrimental to elastomers especially under elevated temperature such as Haynesville and pockets in Eagle Ford. The elastomer failure can be very costly for downhole tools including mud motors. DOBM is shown to have more swelling effect on elastomers as diesel can dissolve and/or penetrate some of the elastomer compounds.

Field Performance – DJ Basin

As drilling is a complicated process, it is often difficult to compare the performance of a fluid system with only one or a few wells as the downhole tools and formation characteristics can dominate the ROP or overall drilling efficiency. Fortunately, drilling data from over 400 US wells were collected. All the wells were drilled from 2022 to 2024. About a quarter of the wells were drilled with diesel or another Group I base oil, and the rest were drilled with GTL synthetic paraffin. The rigs that used the Group I base oil D switched to GTL in the second half of 2023. As the rigs stayed in the same areas with the same operator, it provided a fair comparison of the performance of the base oils. The improvement due to the use of GTL was evident when the drilling performance was quantified.

Direct comparisons in ROP, dilution rate and casing run speed are shown in Figure 10. The data are organized by each rig. The performance of GTL-SBM is plotted on the left of each chart while the Group I base oil D is on the right. The average ROP was calculated as the total depth divided by the actual drilling time. Rigs running GTL-SBM saw a ROP improvement of +97, +37, and +6 feet/hour which represents gains of +30.3%, +11.1%, and +1.9% respectfully compared to the same rigs running Group I base oil D. Data were not available for rig C running base oil D. For an 18,000 ft well, performance improvement means 13, 5, and 1 hour reductions in drilling time for Rig A, B and D, respectively. At 300 – 400 ft/hr drilling rate, the 24-hour footage can be easily over 10,000 ft. In 2024, new 24-hour drilling records were made several times in the DJ basin with GTL as the drilling fluid system.

The base oil consumptions were also provided from this group of wells. The dilution rate was calculated as gals/ft. The base oil D consumption rate was not available for Rig A or Rig C. Rigs B and D saw an average fluid usage reduction of 0.16 to 0.37gal/ft. This equates to 69 to 159 barrels less usage per well. As base oil is only ~60% of the fluid system volume, the drilling fluid reduction is more like 115 or 265 bbls, which means not only less product consumption but also less drilling waste to haul off.

In addition to ROP and base oil dilution rate, the casing run speeds were summarized in Figure 10C. As presented in the previous AADE paper (Lu et al., 2024), GTL-SBM can generate a better lubricity than DOBM. Casing run speed is influenced by the friction, the rheological properties and the quality of hole cleaning. The results from Rigs A, B, and D clearly show an improvement. The average enhancement is over 300 ft/hr in casing run speed, which can be over 2.5 hours reduction in rig time. In addition to ROP, dilution rate and casing run speed, a reduction in trip time was also observed. With all the factors combined, an estimated of $90k/well saving was achieved with the time reduction when the rig switched from the Group I base oil D to GTL synthetic fluid.

It is worth mentioning the initial incentive for use of GTL synthetic paraffin in the DJ basin was to meet the HSE and environmental restrictions, which is normally interpreted as a cost increase. However, the utilization of GTL synthetic base fluid not only meets the regulatory requirements but also helps lower the cost. More importantly, it provides a reliable fluid system that enables the operator to be ahead of the drilling schedule. In Dec 2024, Colorado regulatory agency mandated Group III base oil in the new ECMC rules.

Field Performance – Haynesville

Haynesville is the deepest and hottest shale formation among all the US basins. It certainly poses drilling challenges. The average drilling days per well is much longer than other basins and the average ROP is also lower. As discussed in the previous section, HT down hole environments require a more stable and predictable fluid system and aromatics can accelerate the thermal degradation of additives and thus the fluid properties. GTL synthetic base fluid is virtually free of aromatic hydrocarbons, and it provides a reliable continuous phase for formulating drilling fluids. After the adaptation, the drilling time for laterals has been reduced by days in the Haynesville. With one specific set of wells, the average reduction is 12.1 days.

A couple of examples are presented here for comparison. Figure 11 shows two well profiles, and corresponding ROPs are plotted in Figure 12. GTL-SBM generated a one-run lateral with no extra trips while the DOBM well had 4 trips before reaching TD. The in-situ ROP nearly doubled with GTL-SBM. Considering the rig spread cost, the saving is remarkable. There are many reasons for the undesired trips, but the leading cause is due to mud motor failures, which are tied to the swollen elastomer caused by aromatics.

In addition to reduction in drilling days, the use of GTL synthetic fluid also reduces the consumption of mud chemicals. This is in line with the laboratory findings. The excellent performance of GTL-SBM under HT environments has long been proved in offshore south Asia where the BHT exceeds 425 °F. The selection of synthetic fluid was a critical part of the drilling operations (Callahan et al, 1997 and Witthayapanyanon et al, 2014). Overall, GTL synthetic paraffin has become the fluid choice for Haynesville drilling.

Discussion

Beside DJ and Haynesville basins, the synthetic paraffin base fluid is spreading to other basins including Uinta, Appalachian, Eagle Ford and Permian. Performance enhancements were reported from field experience. For instance, the high wax content in the Uinta basin poses a challenge for maintaining the desired drilling fluid properties. The field data show significant improvement in trips and casing runs, which can be tied to the non-polar chemistry of the base fluid. The high temperature performance is expected to help the drilling operations in the Eagle Ford as well.

Upgrading the fluid system along with other advancements in technologies is essential to maximize drilling efficiency. Having a steady rheological profile through a temperature and pressure range is needed. The aromatics in DOBM can become a bottleneck for drilling long laterals, especially with more challenging formations and well designs. The aromatics have more interaction with formation and drill solids due to the high solvency. The degraded solids can become ultra fines, which cannot be removed with regular solid control equipment. With an increased drilling rate, more solids are being introduced to the drilling fluid system, which requires a more compatible fluid system. One observation in the field is the increased hole cleaning time when DOBM is used.

The perception of synthetic drilling fluids is that they are solely needed for HSE and environmental reasons, which is true for offshore drilling. The evolution in US shale drilling has pushed the requirements for drilling fluids. Synthetic base fluid certainly meets the extended requirements and has promoted the development of shale drilling, especially in DJ and Haynesville basins. The pure chemical composition of GTL base fluid does not only meet the stringent environmental regulations and enables the onsite disposal of cuttings but also provides a boost in drilling efficiency with a better compatibility due to the non-polar nature.

Conclusions

The non-polar chemistry in synthetic paraffin base fluid is the fundamental reason for its recent success in US basins. In addition to the HSE benefits, it also significantly improves the drilling efficiency and thus generates cost savings. Furthermore, it provides a reliable and consistent fluid system to maximize other drilling upgrades to help tackle longer and hotter laterals.

- GTL paraffin is a true synthetic Group III base oil. The chemical composition comprises mainly iso and normal paraffin, which are the most non-polar base oil components.
- Scientific investigations with TGA-IR, XPS and BET revealed the direct connection between

surface interaction and non-polarity of the base oils.

- Laboratory measurement show the detrimental role of aromatics on the drilling fluid performance especially at elevated temperature range.
- With over 2000 wells drilled with GTL synthetic base oil in US basins, the performance is proven in the field and generates cost savings.
- Non-polar synthetic base oil is recommended for all US basins as it provides a better compatibility and reliability to meet requirements with the trend for longer laterals and faster drilling speed.

Acknowledgments

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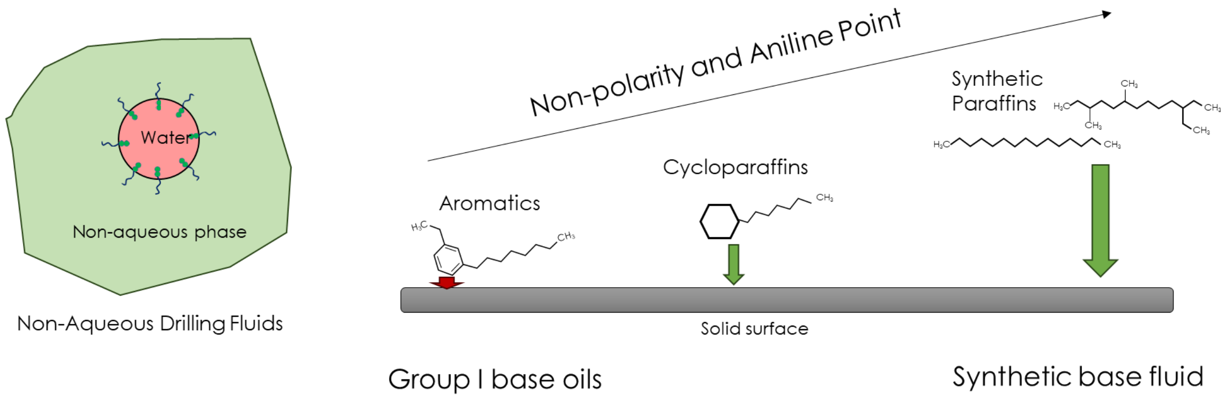

Figure 1 –Non-polarity and chemical compositions of base oils for non-aqueous drilling fluids

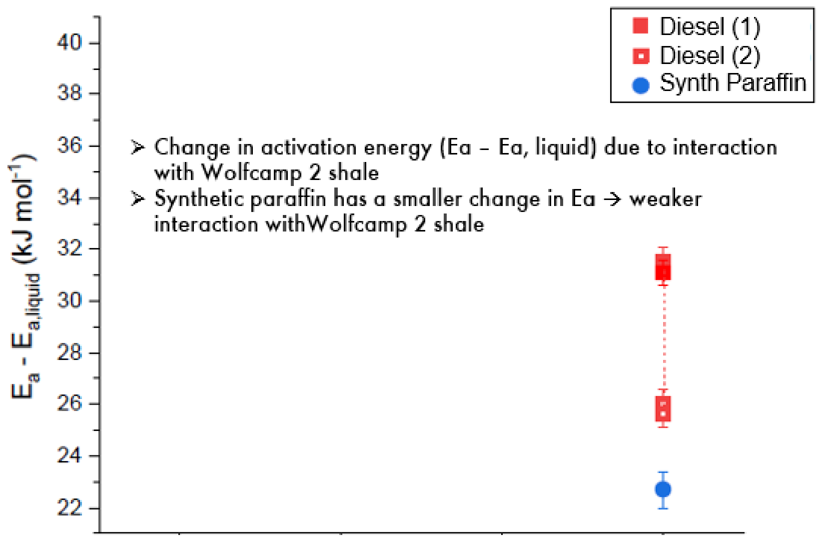

Figure 2 – TGA Activation Energy comparison with Wolfcamp 2 shale

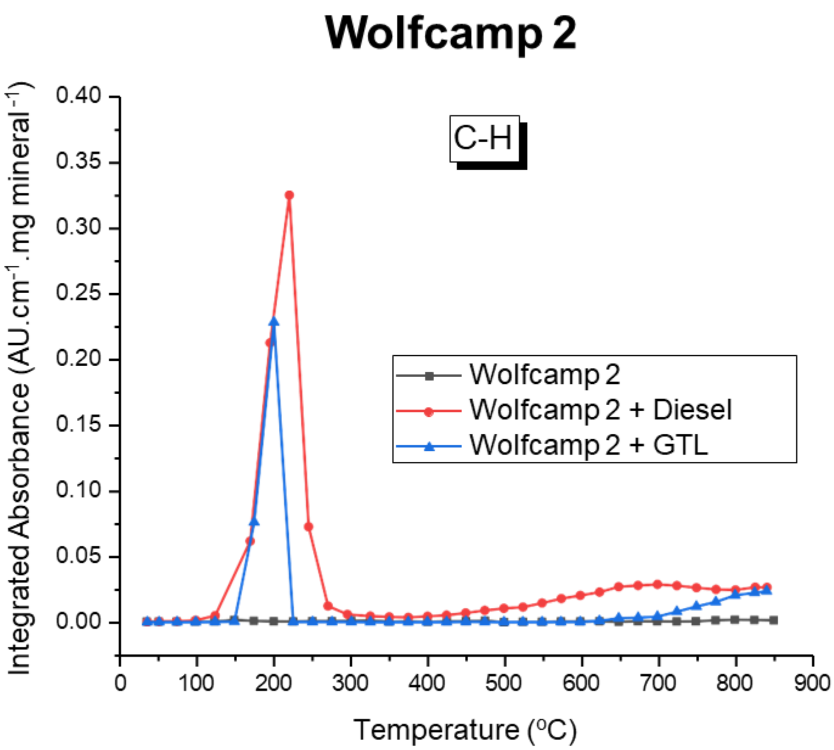

Figure 3 – TGA-IR absorbance of C-H peak – Wolfcamp 2

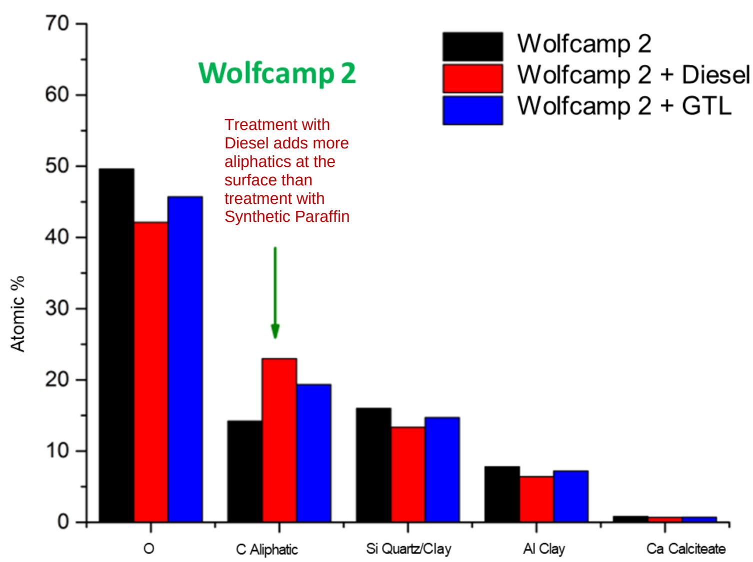

Figure 4 – XPS results of Wolfcamp 2 shale

Sample	BET Surface Area (m^2/g)	Total Pore Volume (cc/g)	Average Pore Radius (nm)
Eagle Ford Shale	8.814	3.12×10^{-3}	0.70
Eagle Ford Shale + Diesel	6.717	0.42×10^{-3}	0.86
Eagle Ford Shale + GTL	7.652	2.65×10^{-3}	0.69

Table 1 – BET measurement of shale sample after interacting with Diesel or GTL Synthetic Paraffin

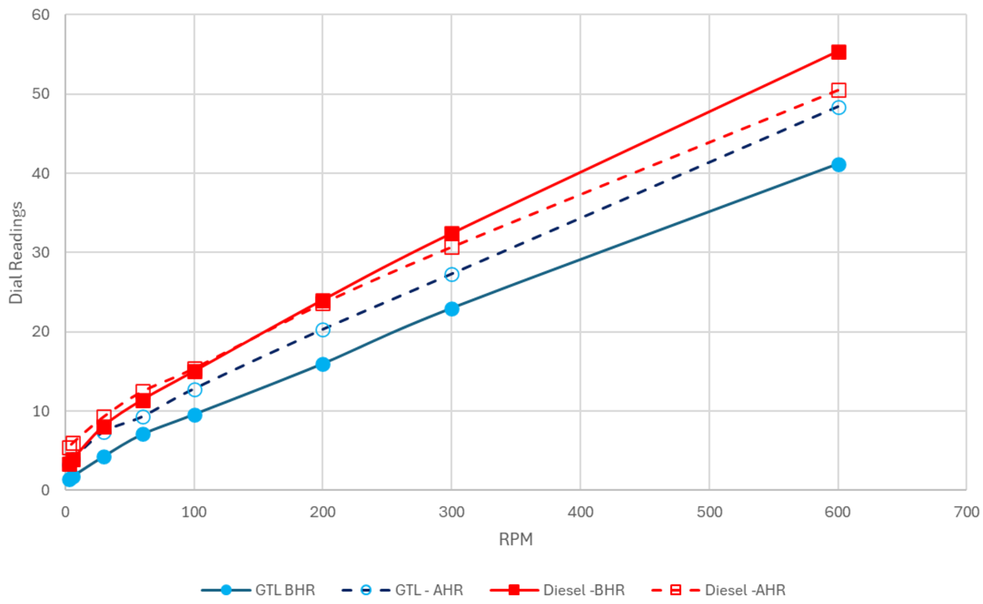

Figure 5 –Consistency curve after hot rolling 12 ppg muds containing ground Wolfcamp core for drill solids

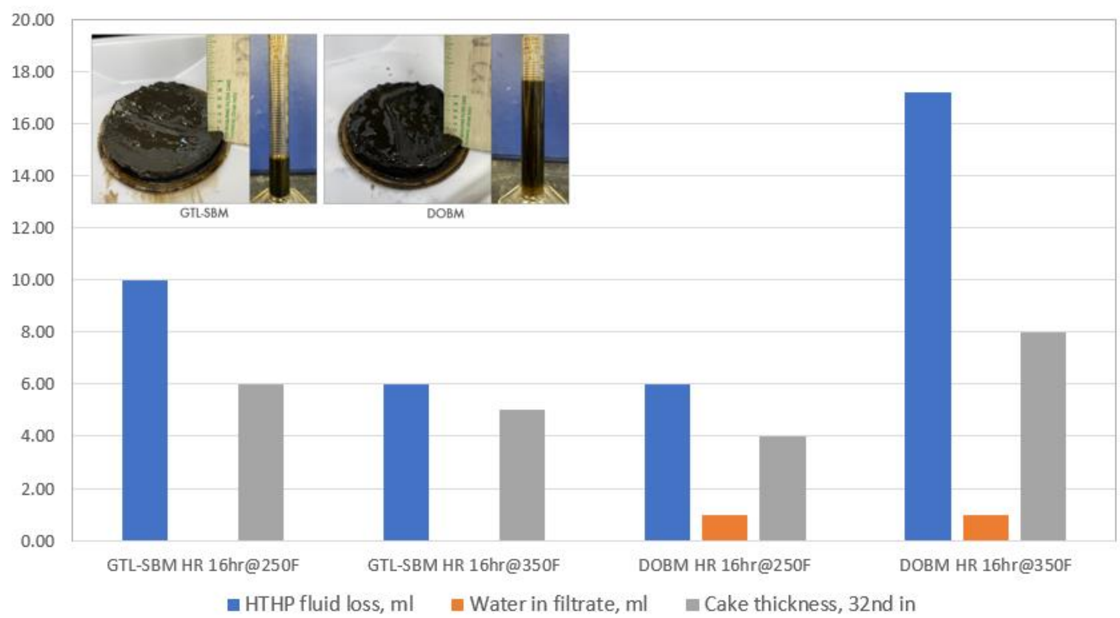

Figure 6 –HTHP fluid loss results after hot rolling 15 ppg muds containing ground Haynesville cuttings for drill solids

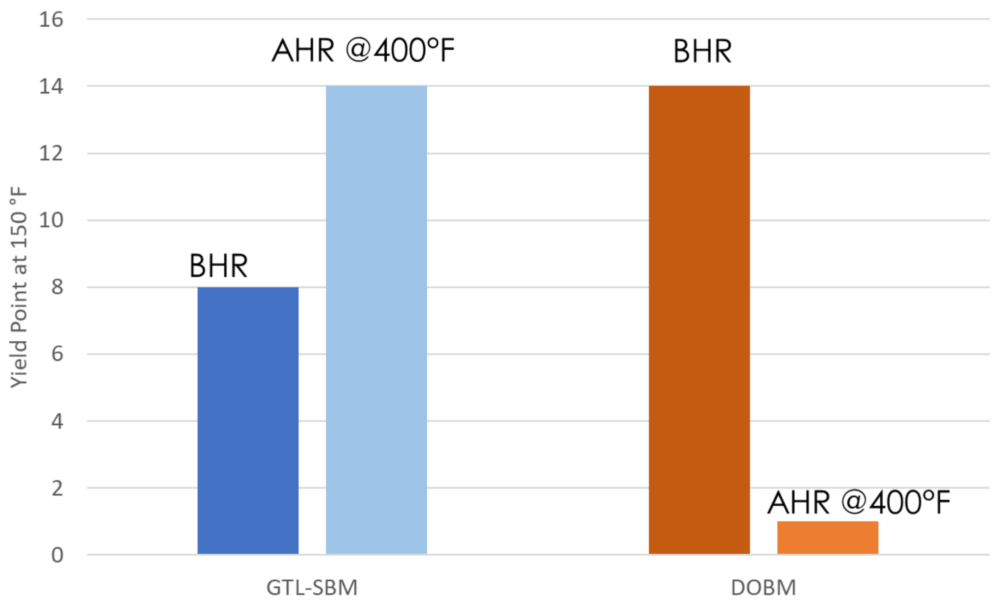

Figure 7 – Drilling fluid stability at 400 °F: GTL-SBM vs. DOBM

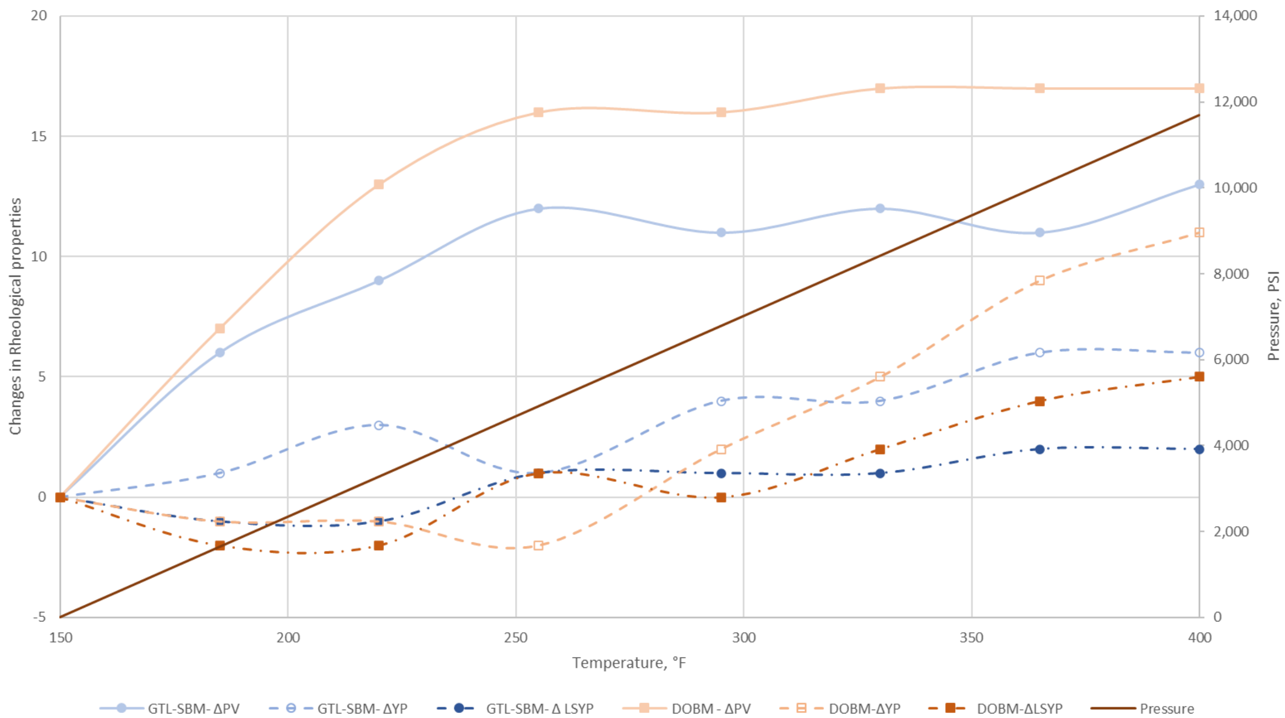

Figure 8 – Drilling fluid property changes with temperature and pressure for GTL-SBM and DOBM

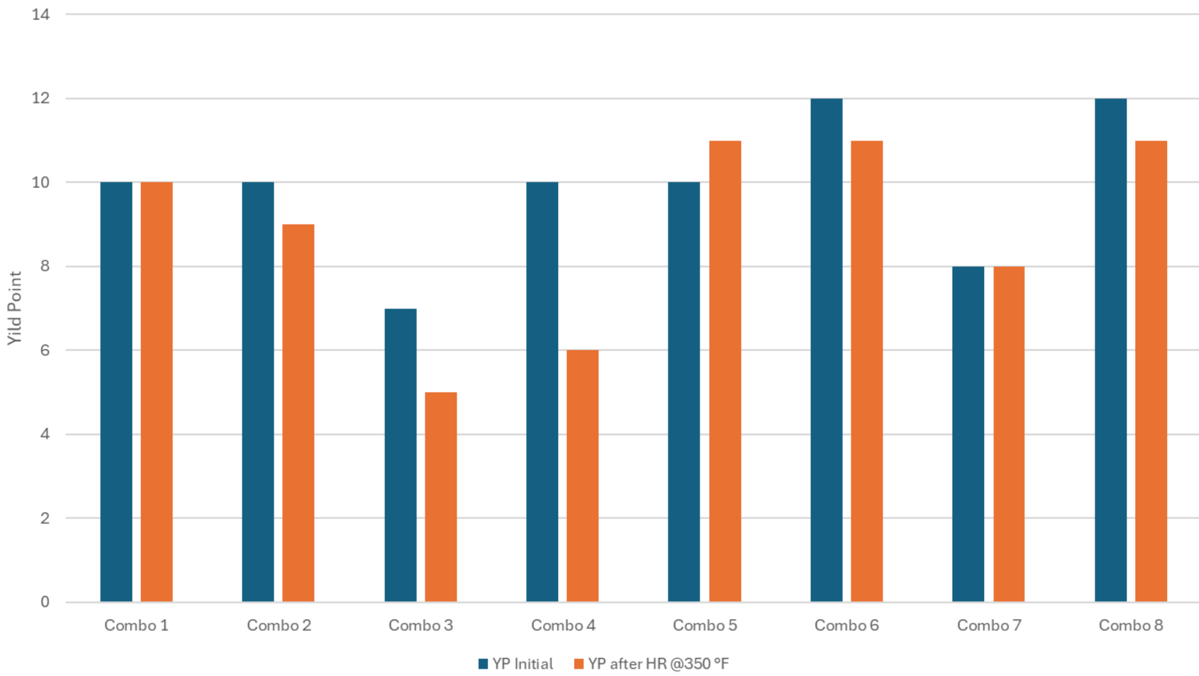

Figure 9 – GTL-SBM with various emulsifier combos

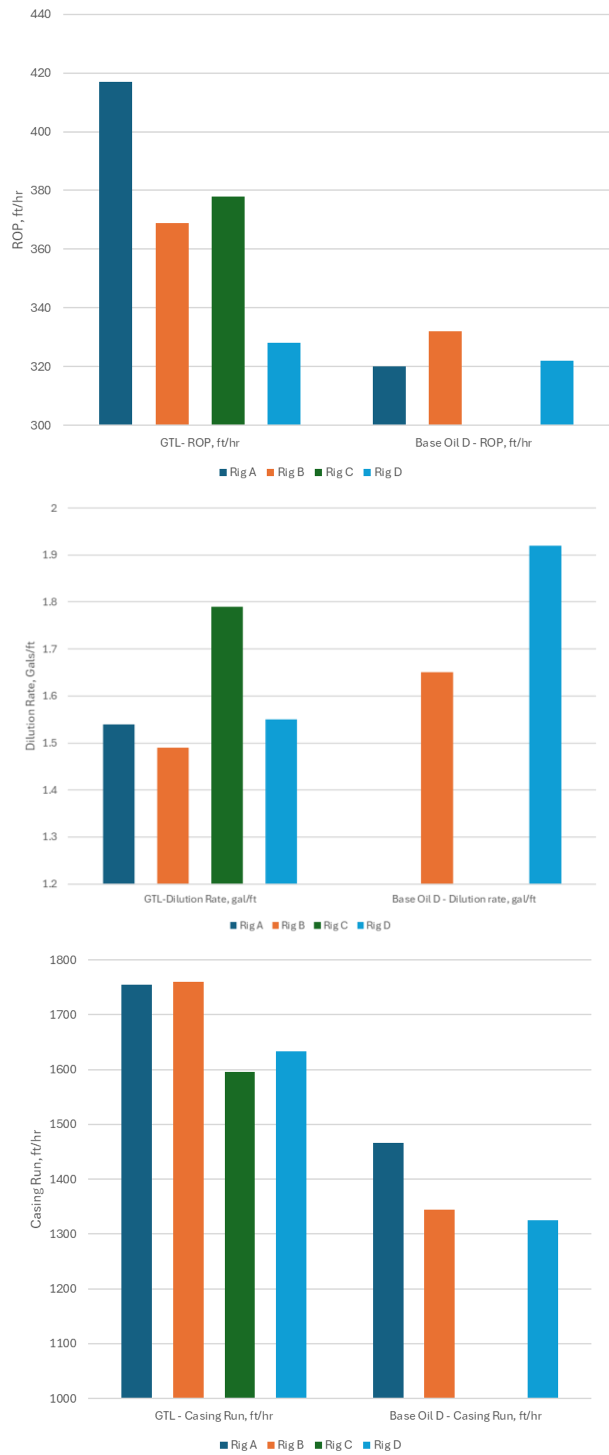

Figure 10 - Drilling performance comparison between GTL and Group I base oil D. A, ROP, B, Dilution rate, C Casing run speed

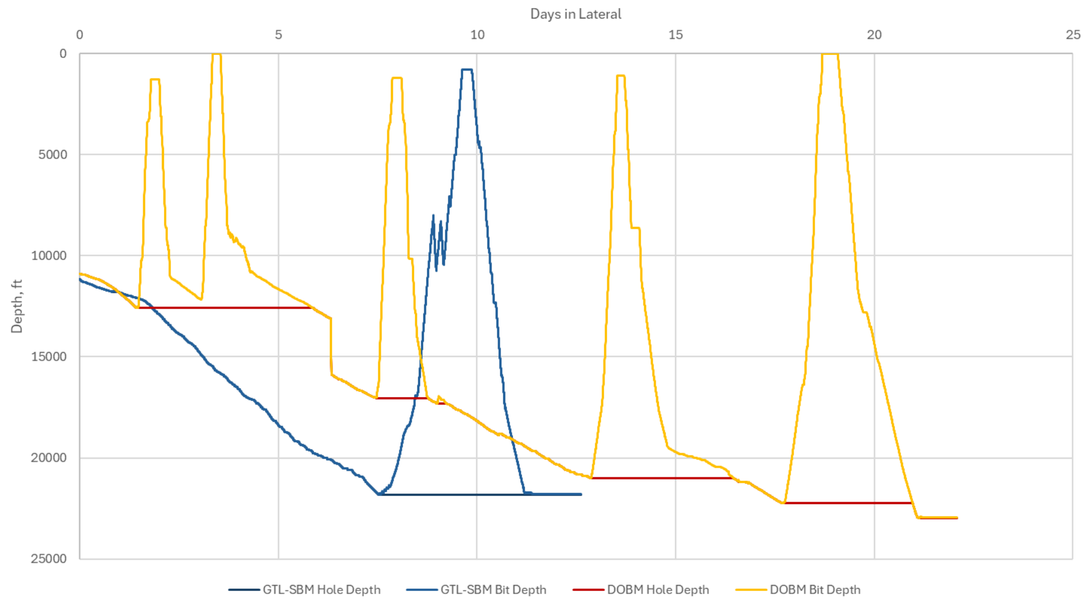

Figure 11 - Laterals in Haynesville. GTL-SBM vs. DOBM

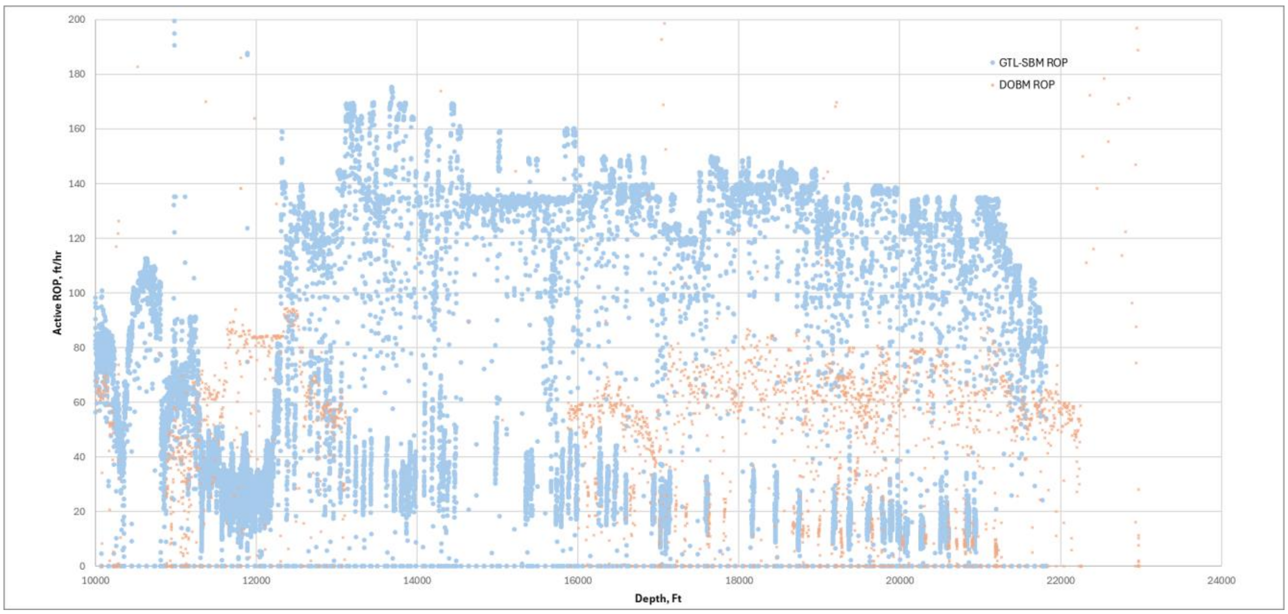

Figure 12 - Active lateral ROP in Haynesville wells. GTL-SBM vs. DOBM