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# Evolution of Drilling Fluids for Enhanced Geothermal Systems

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## Abstract

Over the past two decades and coinciding with the onset of the Green Energy Transition, geothermal drilling has experienced increasing demand. This has driven the development of more complex well profiles and the advancement of Enhanced Geothermal Systems (EGS), operating under extreme temperature conditions and opening new frontiers in recovering geothermal energy from hot, dry rock.

Efforts to develop drilling fluids for supercritical temperatures began several years ago with the design of a water-based fluid that was initially deployed successfully in Europe. This fluid withstood temperatures up to 842 °F and set a new benchmark in fluids evaluation and performance. The formulation incorporated a combination of novel and conventional additives, such as synthetic polymers, thinners, weighting agents, and a specific clay to deliver exceptional field performance around hole cleaning, fluid loss control and rheological stability while drilling through harsh volcanic formations.

The geothermal energy industry has progressed rapidly since that time, when the focus of geothermal drilling was largely upon harvesting steam energy from traditional (hydrothermal) reservoirs, with their abundant reserves of aqueous resources. Today, the development of hot, dry rock (petrothermal) resources, enhanced by fracturing the geothermal system (EGS), has opened opportunities for new regions with formations whose only resource is heat alone. Such extreme conditions have introduced significant thermal, chemical, and mechanical challenges that push existing polymeric fluid technologies to their performance limits. As a result, laboratory testing protocols and fluid technologies have advanced to perform under supercritical conditions of 716 °F, extending the high-temperature water-based mud operational envelope.

This paper describes the evolution of water-based drilling fluid design, including testing and validation protocols, as well as changes in chemistry, composition, properties, and formulation to address these different conditions.


## Introduction

Geothermal energy production is, in the collective imagination, commonly linked with the possibility of getting water or steam at high temperature and pressure on surface to drive turbines for electricity production, and then to be pumped into a surface piping network to feed civil building heating systems. In reality, geothermal power production can fit various needs, depending on the temperature of the geothermal reservoir. It may be used in agriculture and aquaculture, as well as industrial applications, such as cement and aggregate drying. Geothermal energy can also be used to feed the heating and cooling systems of residential and commercial buildings in addition to the more commonly known function of electricity production (Figure 1).

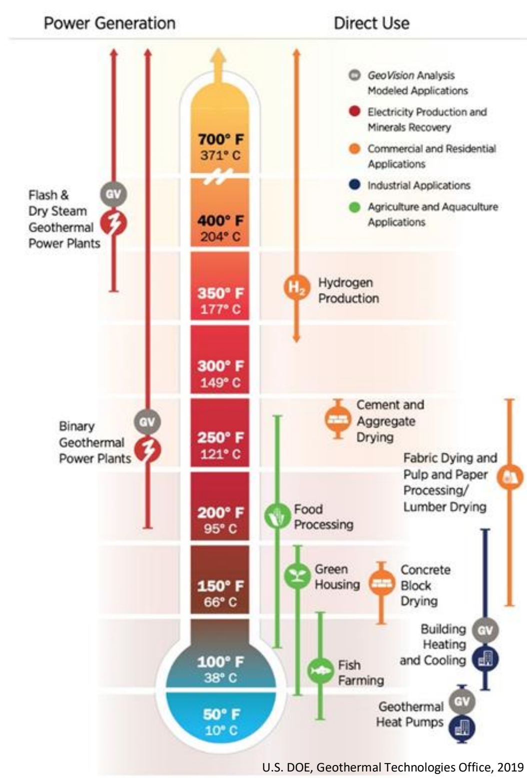


**Figure 1: Application for Geothermal production water at different temperatures**

In recent years, in different parts of the globe, geothermal drilling and water production is also associated with minerals recovery, in particular lithium extraction production projects.

The time to recover capital deployed in the geothermal energy industry is significantly longer when compared with hydrocarbon production, and this, consequently, has historically led to less investment from the market, which has resulted in lower drilling activity. However, as a "green" source of energy, geothermal has been included as one of the sources to contribute to the "Green Energy Transition" process ongoing worldwide in the drive to decrease carbon emissions, particularly in the most developed countries. Unlike other green energy sources, such as solar and wind, geothermal has the advantage of being consistently available, independent of weather conditions. This energy source has been linked in the past only to regions characterized by volcanic activity and consequently, production of water or steam at high temperatures. But now, different applications are able to generate water at low or medium temperatures, enabling new development in non-volcanic regions.

The geothermal industry, targeting greater economic returns, has been pushed recently to develop existing fields and explore fields in new regions characterized by a critical high-temperature (Finger and Blankenship (2012)), applying innovative geothermal well solutions, such as the network of U-tube shaped wells found in North America and Central Europe. All these activities have stimulated private investment, and in many cases these private investors are Petroleum E&P companies, adjusting their focus from being exclusively hydrocarbon producers to all-energies producers.

The growth in geothermal drilling activity in the last fifteen years, with developments from a hydrothermal system (Figure 2) to a Supercritical Petrothermal Enhanced Geothermal System (Figure 3), has also increased the challenges faced from a drilling perspective, specifically in terms of well design and maximum downhole temperatures that have not yet been experienced in the oil & gas industry.

Drilling activity within countries situated on the famous "Ring of Fire", the border of the Pacific boundary with the highest production of geothermal energy, have recorded growth. Activity has also increased in countries outside of this region, as new developments of low and medium enthalpy energy have increased, particularly in continental Europe. Furthermore, thanks to the interest from major oil & gas producer countries historically linked with hydrocarbon production have begun to investigate the development of geothermal resources, including in the Middle East. These companies are trying to diversify their energy production portfolio, and they have started studying and actively supporting, directly or indirectly, activities related to this new generation of geothermal drilling applications.

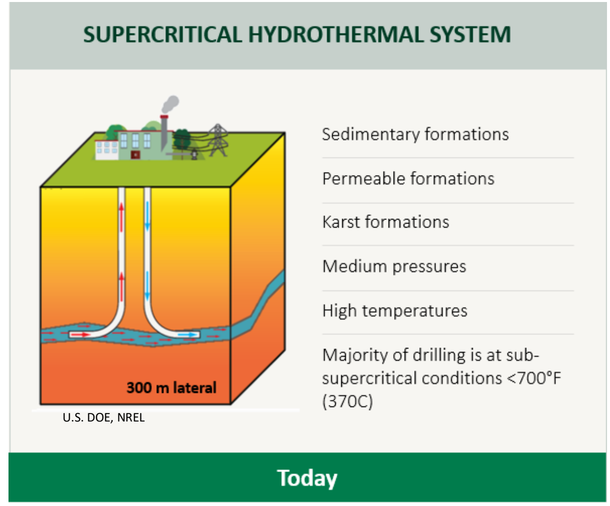


**Figure 2: Example of Hydrothermal system**

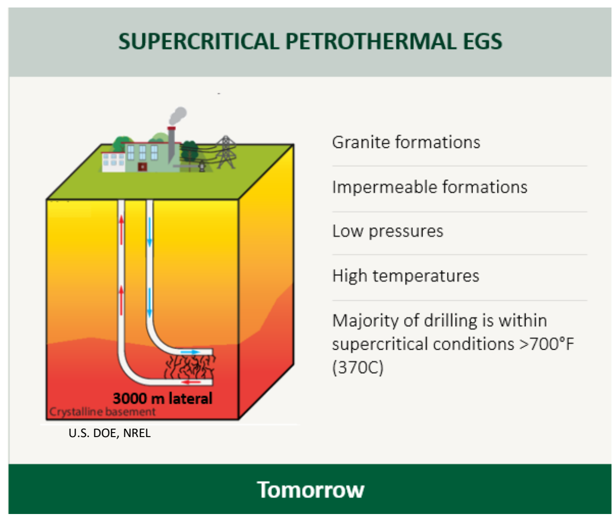


**Figure 3: Example of Petrothermal EGS system**

The development of these petrothermal fields, characterized by extreme high temperature, have pushed the whole drilling industry into technical development rarely seen in the last decades, to provide applicable solutions to deal with such critical environments from downhole tools, cementing, piping, casing, and drilling fluids, to enhance drilling performance and production rates in this "Green Energy Transition" era.

## Geothermal Drilling Fluids Development

The enthalpy of a geothermal reservoir is a thermodynamic property describing the total heat content of a system and practically refers to the temperature of the reservoir and consequently of the production water. This level has been historically considered the main relevant while designing drilling fluids.

There are three main levels of enthalpies in a geothermal reservoir, the classification of which has varied significantly over last fifty years, as described in the figure below (Figure 4):

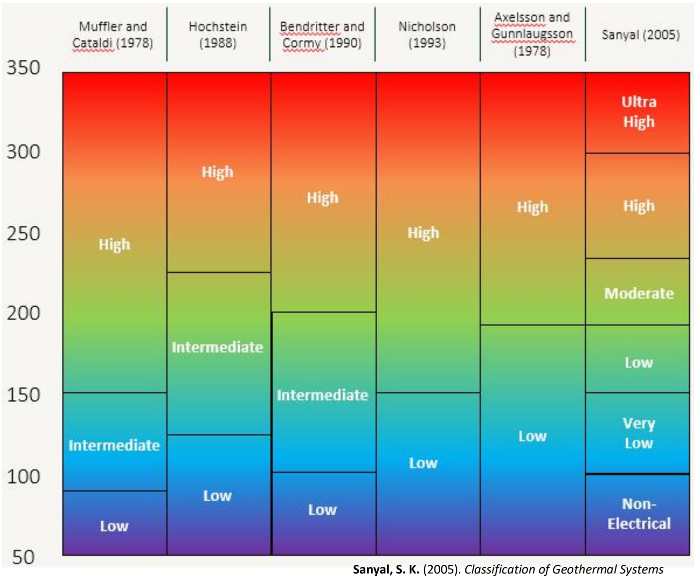


**Figure 4: Different definitions of level of Enthalpy in a Geothermal Reservoir (y axis denotes temperature in deg C)**

Geothermal drilling fluids have been commonly associated with the utilization of water-based drilling fluids systems for a various number of reasons: from the need to provide "Green" tools to drill their wells, to the severe loss rates expected while drilling reservoir, from a cost stand point and also looking to the fact that geothermal drilling is sometimes carried out in remote locations, with limited logistic options. This led the drilling fluids community to set the limits of low and medium enthalpy in line with the maximum operating temperature of common biopolymers in the market (without the use of temperature extenders), which is in the range of 130 to 150 °C (266 to 302 °F). If a geothermal reservoir has a maximum downhole temperature in this range, drilling fluid design is pretty similar to that of a common hydrocarbon well, as the systems and individual products, such as polymers, inhibitors etc., function in this environment. Moving into a higher level of enthalpy, (i.e. increasing the maximum downhole temperature expected) to around 250 °C (480 °F) the design of the drilling fluid changes significantly, as most of the components have to be substituted. Different types of clay are utilized to provide viscosity, while fluid loss is mainly related to the use of products based on lignite, which has the additional effect of reducing the risk of fluid gelation when exposed to high temperature for longer periods. High enthalpy reservoirs are commonly composed of inert formations characterized by a network of karst fractures that lead to severe losses of fluid downhole. In such cases a key consideration for fluid design is that new fluid is easy and quick to mix in case of losses, preferably with a low cost per barrel (Cole and Young (2020)) (Saleh and Teodoriu (2020)) (Lowry and Nielson (2018)) (Williams and Reed (2008)). In some cases, the reservoir is characterized by a hydrostatic, or even sub-hydrostatic gradient. This can lead operators to drill ahead with drill water and high viscosity sweeps once losses occur, to move cuttings into fractures, thereby decreasing the cuttings load in the annulus and consequently reducing the risk of stuck pipe events.

The latest developments are leading some operators to move from a Hydrothermal System to a Petrothermal Enhanced Geothermal System, characterized by reservoir temperatures above 350 °C (660 °F), hard rock drilling, with no aquifer or downhole fractures. Drilling fluids designed with common additives have been already proven to be ineffective due to thermal degradation, resulting in challenges such as gelation, flocculation and sag (Zilch and Otto (1991)). Designing effective drilling fluids for a high enthalpy application in a Hydrothermal System requires a detailed protocol and several iterations to identify chemistries that will provide desired properties and avoid drilling issues due to poor fluid performance. The first challenge to deal with when designing drilling fluids for Petrothermal EGS applications is the temperature limitations of the laboratory equipment. Laboratory equipment providers have recognized these limitations and are working to address this, however, currently replicating downhole conditions in laboratory is not always feasible. The laboratory fluid design and validation process is crucial to avoid undesired fluid behavior in such hostile conditions. When designing fluids for these environments, it is necessary to define first the harshest condition that the drilling fluid will be exposed to and design the fluid to be resilient to these conditions. Typically, this is when the fluid is left static in the well for an extended period of time, for example during a trip out of the hole.

### *Geothermal drilling application in Tuscany*

Larderello field, located in Tuscany, Italy (Figure 5), is known as the oldest developed geothermal field in the world thanks to the produced steam at high temperature coming from a high enthalpy reservoir (Bargiacchi and Conti (2020)). This led Italy to become a leader in terms of drilling knowledge and for geothermal production volume, driving Italy into the top ten countries in the world for electricity production (Bertani (2016)) and top twenty for general thermal application (Lund and Boyd (2016)) linked with geothermal. In fact, the steam produced is utilized to power the turbines to generate electricity and to heat houses and greenhouses.

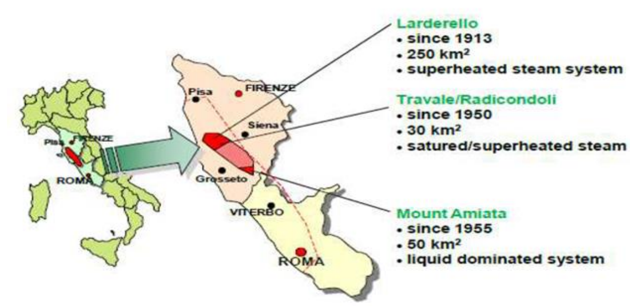


**Figure 5: Traditional geothermal areas in Tuscany, Italy**

In 2017, following a geological study by a consortium formed by a European Union Agency, the Italian National Council of Research decided to restore an unproductive and already plugged well in Larderello field, in Tuscany, Italy. Larderello field sits in a tectonically active region (Santilano and Manzella (2015)), and the plan was to drill deeper to and perform studies and analyses on formation behavior in this critical temperature environment.

The existing well was already drilled and cased off with a 9 5/8in casing to 2,468 m (vertical). At this depth a downhole temperature of 340 °C (644 °F) was recorded during the drilling phase, however, as productive wells in the area often encounter fractures and subsequent high fluid losses below this depth, the well was classified as unproductive and plugged and abandoned. This new development project planned to drill two new deeper intervals, an 8 1/2in and a 6in hole to a final depth of 3,500 m TVD in order to penetrate an unexplored lower formation predicted to have a final Bottom Hole Static Temperature (BHST) of 450 °C (842 °F). Furthermore, these new intervals were expected to be pressurized, adding another challenge. An Equivalent Mud Weight (EMW) of 1.50 sg (12.5 ppg) was expected to be necessary to drill the 6in interval. As this project was considered extremely challenging, the Italian National Geothermal Drilling Company was appointed by the consortium as Operator and Rig Contractor, who quickly arranged a brainstorming session with different service companies to provide innovative solutions as to how to manage such temperatures, including drilling fluid design.

When designing the drilling fluid, the test temperature of 204 °C (400 °F) was set in recognition of the limitations of the laboratory test equipment. The maximum exposure time at temperature was agreed at 24 hours to reflect the time that fluid would remain static while tripping in and out of hole.

The parameters below were set as benchmarks for the testing protocol:

- Design a water-based drilling fluid at a density of 1.50 sg (12.5 ppg) to control formation pressure
- Sag, flocculation and gelation properties must be minimized when exposed to 24 hours of static aging
- Provide stable rheology and an acceptable fluid loss performance after static aging at 204 °C (400 °F).

Almost two years of intensive lab testing were performed to achieve the goal of designing a drilling fluid capable of exhibiting minimal thermal degradation but also easily and quickly treated to return to the initial properties.

The laboratory testing for this project was conducted in the fluid provider's Technology Center in Rome, Italy, due to proximity to the field and the skill and extensive experience of the personnel with geothermal applications. Testing began by submitting the commonly used gel-lignite geothermal formulation tailored for high enthalpy to the agreed protocol, as this gives first indications on how to adjust fluid design to deal with these extreme high temperatures. These gel-lignite water-based fluids do not require a weighting agent, as high-enthalpy reservoirs are characterized by a hydrostatic or sub-hydrostatic gradient. The requirement to add a weighting agent introduced an additional challenge of avoiding the occurrence of sag during static aging.

The main conclusions from the testing can be summarized thus:

- API gel (bentonite), commonly used as suspending agent, was removed from the formulation due to its gelation behavior while aging and substituted with a different clay that yields at a temperature over 100 °C (212 °F) and provides stable rheological properties after heat aging
- Consequently, common xanthan gum biopolymer was kept in the formulation as primary viscosifier and suspending agent while mixing and displacing the cold new drilling fluid in hole
- To keep an acceptable fluid loss value, different synthetic polymers were tested to select one with the best performance under high-temperature conditions
- Different types of lignite were assessed as fluid loss agent and thinner. In addition to identifying the best performer, the decision also took into consideration the HSE characteristics of the different lignites
- A resinated lignosulfonate was utilized to stabilize rheology at high temperature and further improve fluid loss control
- Gelation due to thermal degradation was prevented thanks to addition of a synthetic thinner
- Sized ground marble was added to the formulation to reduce fluid loss and strengthen the filter cake. The bridging package was designed based on formation pore sizes using products with various particle size distributions
- Micronized weighting material was included in formulation to provide density. Moreover, thanks to its lower particle size distribution, it displays some auto-suspension behavior that reduces the risk of solids sag during aging

The results of this testing protocol defined the High Temperature Water Based Fluid (HT WBF) formulation for this project (Table 1).

**Table 1: Water-Based HT Formulation**

| Products | Concentration (ppb) | Concentration ($Kg/m^3$) |
|---|---|---|
| Base Fluid | 0.756 bbl. | 756 lt |
| Alkalinity | 0.5 | 1.4 |
| HT Clay | 10.5 | 29.9 |
| Biopolymer Viscosifier | 1.0 | 2.9 |
| Synthetic HT Thinner | 9.0 | 25.7 |

| | | |
|---|---|---|
| HT lignite thinner / FL reducer | 9.0 | 25.7 |
| HT Mud stabilizer | 10.5 | 29.9 |
| Synthetic HT FL reducer | 5.5 | 15.7 |
| Bridging agent | 28 | 79.8 |
| Micronized Weighting agent | 188 | 535.8 |

Table 2 presents the fluid properties Before Hot Rolling (BHR) and After Hot Rolling (AHR) at 204 °C (400 °F) for 24 hours.

**Table 2: HT WBF fluid properties before and after aging**

| Parameters | Unit | BHR | ASA @ 204 °C for 24 hrs |
|---|---|---|---|
| Density | sg | 1.50 | 1.50 |
| pH | - | 9.3 | 8.9 |
| Rheology Temperature | °F | 120 | 120 |
| 600 rpm | lbs/100 ft$^2$ | 77 | 22 |
| 300 rpm | lbs/100 ft$^2$ | 56 | 17 |
| 200 rpm | lbs/100 ft$^2$ | 48 | 15 |
| 100 rpm | lbs/100 ft$^2$ | 37 | 12 |
| 6 rpm | lbs/100 ft$^2$ | 18 | 9 |
| 3 rpm | lbs/100 ft$^2$ | 15 | 9 |
| PV | cP | 21 | 5 |
| YP | lbs/100 ft$^2$ | 35 | 12 |
| Gels 10"/10' | lbs/100 ft$^2$ | 17/44 | 13/35 |
| API fluid loss | ml/30 min | 3.5 | 5.0 |
| Gelation | Visual | - | None |
| Flocculation | Visual | - | None |
| Sag Factor* | - | - | 0.515 |

*Sag Factor = Density Bottom / (Density Top + Density Bottom)

In addition to standard fluid rheology measurements, HPHT rheology was performed at 200 °C (392 °F) and a pressure of 8,000 PSI to better understand fluid behavior under downhole conditions (Table 3).

**Table 3: HTHP Rheology @ 200° C and 8000 PSI**

| Parameters | Reading (200 °C, 8000 psi) |
|---|---|
| 600 rpm | 10 |
| 300 rpm | 9 |
| 200 rpm | 5 |
| 100 rpm | 3 |
| 6 rpm | 2 |
| 3 rpm | 2 |
| PV (cP) | 1 |
| YP (lbs/100 ft$^2$) | 7 |
| Gels 10"/10' (lbs/100 ft$^2$) | 3/6 |

Fluid design was completed and approved for use before the start of the project. Downhole conditions during drilling were found to be as harsh as predicted, however the fluid performed well, underlining the robustness of the fluid design testing protocol. The 8.5in interval was completed shallower than planned at a depth of 2,602 m due to the higher-than-expected thermal gradient and a 7in Liner was run and cemented. At this depth a Bottom Hole Static Temperature (BHST) of 360 °C (680 °F) was recorded. The 6in hole was drilled with a weighted drilling fluid to 2,721 m where a BHST of 380 °C (716 °F) was recorded. At this depth, a network of karst fractures was encountered. After two successful deployments of a new technology Lost Circulation Material, drilling continued until new fractures were met. The decision was taken at this point to drill ahead blind with drill water and HiVis sweeps until well TD was called at 2,909 m, where a BHST between 480 and 600 °C (896 – 1,112 °F) was recorded with a color thermometer provided by the Italian Council of Research. The performance of the drilling fluid during this project is summarized below:

- Stable and robust rheology was recorded throughout the drilling program
- Fluid Loss control was almost lost when downhole temperature increased over 300 °C (572 °F). However, no issues were observed due to inert nature of the formation drilled
- The main concern of the operator during the lab testing was to avoid sag and keep a stable fluid column. No sag events were recorded, even after two days of tripping for a bit change due to the higher than planned temperature environment
- Fluid exposed to BHST for extended periods was easily reconditioned and properties always quickly restored
- A number of gas influx events were recorded, particularly through the 6in interval. The presence of $H_2S$ and $CO_2$ was managed effectively with no recorded negative impact on fluid properties.

Overall, the project was considered a success (Pallotta, Dei et al (2020)). From a drilling fluid perspective, only the Fluid Loss control was out of specification, but this did not affect drilling operation. This well also presented the opportunity to field-test a new type of Lost Circulation Material (LCM), that was successfully deployed at critical temperature.

### *Progress after Tuscany application*

Around 2020 and the COVID-19 pandemic period was the time when it could be argued that many governments and public entities started to revisit and define their long-term energy plan. During this period, we have seen how the "Green Energy Transition" became one of the topics of most interest, and geothermal energy was able to capture and attract part of the financial resources dedicated to the transition. Thanks to these new economic resources, geothermal operators had the opportunity to start planning more challenging projects, like the closed-loop system that is currently ongoing in Central Europe after some applications in North America. This kind of project has the goal to drill simultaneously with two rigs, separated by few kilometers, two different vertical wells, then a network of horizontal laterals to intercept and connect those drilled by the other rig. The objective is to create a network of U-tube shaped wells in a loop that allows cold water to be circulated from the inlet well, through the parallel wellbores, extracting heat by conductive heat transfer with the rock, resulting in higher temperature water at the outlet wellbore (Figure 6)

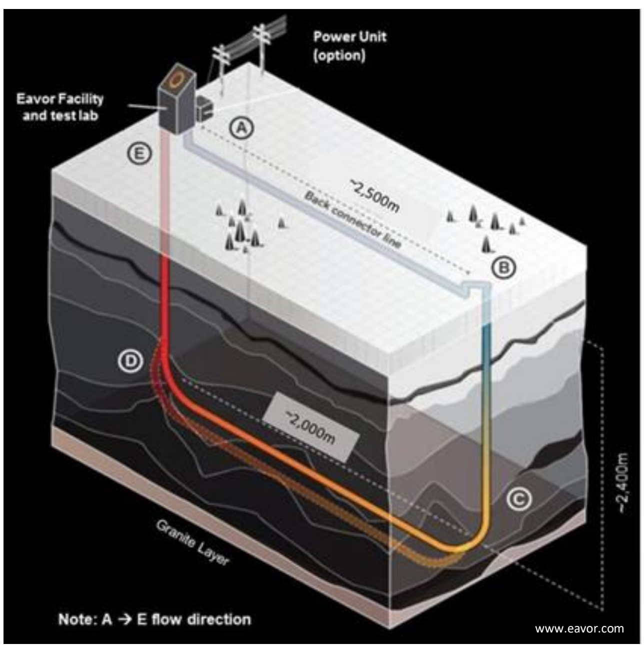


**Figure 6: An example of U-tube network of wells**

The aim of these projects is to show that geothermal energy production can be applied in reservoir formations without presence of aquifers, independently of its geological composition, without fracking and minimal land and water requirements. This kind of application unlocks the possibility to produce clean energy in places where the geothermal industry could not be deployed before. Achieving the result of completing a network of U-tube wells is best achieved with the additional capital investment and engineering expertise available when partnering with National and International Oil and Gas Operators. Some operators, including those well known to be single player developers of hydrocarbons in the most productive areas of the globe, are also looking to the future with geothermal investment in challenging applications.

### *HT WBF Development for a field of study in new area of interest*

Starting from the formulation successfully designed and deployed for the Tuscany application, further enhancement to the high-temperature, water-based drilling fluid was undertaken for a geothermal application in a new field of study. The laboratory testing campaign had the goal to confirm fluid suitability and improve performance when exposed to chemical contamination at elevated downhole temperatures for longer periods of time than required for the Tuscany Project.

These tests were performed by the same fluid provider, this time in its Technology Center in Houston. A more robust hydrogen sulfide ($H_2S$) test was also performed by a third-party laboratory. The fluid design and validation process included evaluation of fluid behavior under static aging, thermal degradation, weighting material suspension, and chemical contamination by acid gasses, such as $CO_2$ and $H_2S$. Although higher bottom hole temperatures were anticipated on this project, laboratory testing was limited to a maximum temperature of 204°C (400°F) to comply with the safe operating temperature limits of the test equipment.

Laboratory testing of the new fluid design was performed in incremental steps to fully assess the performance of new additives to the formulation. For this reason, in Table 4 below, static aging temperature was increased gradually and, once a formulation resistant to the temperature was achieved, the aging time was prolonged from 16 to 48 hours and solids load increased to achieve a mud weight higher than 1.57 sg (13.1 ppg).

The following key components were included in the design of this high-temperature, water-based fluid:

- A new kind of gel was introduced to provide a stable and robust rheology profile over high temperature to improve hole cleaning while avoiding gelation
- Engineered synthetic polymers were selected to provide adequate rheology and improve fluid loss control
- Modified lignite-based additives were included to improve fluid loss control and stabilize rheology, further reducing the risk of gelation
- As thermal degradation resulted in a reduction in pH, consequently impacting on the performance of all other components, alkalinity buffers were included in the formulation
- The bridging package was designed and tested to fit

with formation porosity and permeability. This was composed of a sized ground-marble calcium carbonate with a dedicated Particle Size Distribution for optimum bridging

- API Barite was chosen as weighting agent for this fluid

### *Laboratory Test Results*

A series of tests was conducted in the laboratory. The work is summarized in Table 4 below. Each test is represented by a unique sample ID (i.e. B1, C2, etc.), where the letter corresponds to the fluid formulation and the number indicates the test performed. Key points from the testing are noted below:

- Formulation A gave reasonable results for fluid rheology and fluid loss after ageing for 16 hours at 370 °F. Although gel strengths were recorded as flat after ageing, no signs of barite settlement were observed in the ageing cell.
- Formulation B (13.9 ppg) exhibited a more stable rheological profile after ageing at 400°F, however after 24 hours aging the fluid showed some signs of gelling up (progressive gel strengths). HPHT fluid loss results were higher than was considered acceptable.
- Formulation C exhibited good, consistent rheology and fluid loss results when aged at 400°F for up to 48 hours. A low sag factor (0.51) was recorded for all samples, confirming fluid stability.
- Based on the results of tests conducted, Formulation C was identified as the optimized formulation.

**Table 4a: HT WBF Lab Summary – Fluid Properties**

| Sample ID | A1 | B1 | B2 | B3 |
|---|---|---|---|---|
| **Temp.** | 188 °C (370 °F) | 204 °C (400 °F) | 204 °C (400 °F) | 204 °C (400 °F) |
| **Notes** | Baseline | Baseline | Extended aging | Extended aging |
| **Aging Duration** | 16 hr. | 16 hr. | 24 hr. | 48 hr. |
| **Density (ppg)** | 9.5 | 13.9 | 14.6 | 14.6 |
| **PV(cP)** | 31 | 47 | 76 | 36 |
| **YP(lb./100ft$^2$)** | 31 | 21 | 64 | 12 |
| **Gel Strengths (10 sec/ 10 min)** | 4/4 | 5/13 | 16/54 | 3/8 |
| **Fluid Loss (mL)** | 22.8 @ 149 °C (300 °F) | 38 @ 204 °C (400 °F) | 44 @ 204 °C (400 °F) | 48 @ 204 °C (400 °F) |
| **Barite Sag (Δ** Density, ppg) | Not reported | 0.4–0.7 | 0.4–0.7 | 0.4–0.7 |

**Table 4b: HT WBF Lab Summary – Fluid Properties**

| Sample ID | C1 | C2 | C3 |
|---|---|---|---|
| **Temp.** | 204 °C (400 °F) | 204 °C (400 °F) | 204 °C (400 °F) |
| **Notes** | Baseline | Static aging | Extended aging |
| **Aging Duration** | 16 hr. | 24 hr. | 48 hr. |
| **Density (ppg)** | 13.1 | 13.3 | 13.6 |
| **PV (cP)** | 47 | 47 | 39 |
| **YP (lb./100ft$^2$)** | 25 | 25 | 33 |
| **Gel Strengths (10 sec/ 10 min)** | 3/4 | 3/5 | 5/8 |
| **Fluid Loss (mL)** | 19.6 @ 204 °C (400 °F) | 19.2 @ 204 °C (400 °F) | 18.4 @ 204 °C (400 °F) |
| **Sag Factor** | 0.51 | 0.51 | 0.51 |

While the field trials are still pending, the laboratory results demonstrated the reliability and consistency of the Enhanced HT WBF across a range of high-temperature tests in the laboratory and its readiness to be deployed in new challenging Geothermal projects, in support of developing broader applications in Hydrothermal and Petrothermal systems.

## CONCLUSION

The evolution of the geothermal drilling industry is characterized by higher temperatures and densities, elevated chemical contaminations, and more complex well designs. These challenges have led to a similar evolution of geothermal drilling fluids to address downhole requirements for safe and efficient drilling. The last generation of HT WBF dedicated to geothermal activity enables reliable operations at all temperatures.

This paper discussed the evolutionary development of a water-based drilling fluid system, starting from the common gel-lignite formulation tailored to deal with a low-to-medium enthalpy applications in a hydrothermal system, to the first development as a HT WBF tested in the lab at 200 °C (392 °F) and field proven at 450 °C (842 °F), to supercritical temperature enhanced formulations incorporating nanomaterials and synthetic polymers, capable to withstand 96 hours static aging at 200 °C (392 °F) and able to maintain a low fluid loss as well.

Past field experience in Tuscany demonstrated that an engineered fluid could maintain stable rheological properties to avoid sag and gelation problems, and to be easily reconditioned after thermal exposure to simplify drilling operations and minimize waste. Further enhancements were applied to this formulation in lab, through another extensive testing campaign which confirmed the fluid system's resilience under simulated geothermal conditions. These upgrades in fluid properties and characteristics will be a key factor of the development of deeper and hotter sources characterized by granitic formations.

Looking forward to the fluids that will be developed in the future for even more challenging environments, we note the following emerging trends:

- AI driven fluid optimization, providing predictive modeling and real time fluid properties adjustment
- Nanomaterial-enhanced formulations by improving thermal conductivity and chemical resilience.
- Improvements to fluid loss control at ultra-HTHP conditions, an area of our R&D focus.

As the transition towards cleaner forms of energy continues, it is to be expected that geothermal projects will continue to grow in popularity, scope and complexity. Robust fluid design and execution play a major part in the success of any drilling operation, the laboratory and field experience presented here underlines how drilling fluids will evolve to meet these challenges and with the development of new lab testing equipment, able to meet harshest conditions in terms of pressure and temperature applied to the fluid, its behavior in critical environment may be further investigated and improved.

Future laboratory investigations of drilling fluids at temperatures exceeding 230 °C (446 °F) will require significant advancement of the equipment typically found in conventional drilling fluids laboratories. These conditions generally exceed the design and safety limits of most purpose-built oilfield laboratory instruments, including pressure aging cells, ovens, fluid-loss measurement devices, and rheometers, with only a limited number of systems rated to operate up to approximately 260 °C.

Although certain testing requirements can be partially addressed using equipment adapted from the chemical processing industry, these solutions are not optimized for oilfield-specific fluids, pressure regimes, or testing methodologies. The development and deployment of a dedicated, ultra-high temperature, oilfield specific laboratory testing suite would offer to accelerate geothermal drilling fluids research and more effectively support the evolving demands of future geothermal applications.

## Nomenclature

°C = Temperature, Degree Celsius
°F = Temperature, Degree Fahrenheit
AHR = After Hot Rolling
ASA = After Static Ageing
bbl = Volume, Barrel
BHA = Bottom Hole Assembly
BHR = Before Hot Rolling
BHST = Bottom Home Static Temperature
cP = Viscosity, Centipoise
EGS = Enhanced Geothermal System
EMW = Equivalent Mud Weight
hr = Time, Hours
HT = High Temperature
Kg/m$^3$ = Concentration, kilogram per cubic meter
lb./100ft$^2$ = Pressure, Pound per hundred square feet
lt = Volume, liter
m = Length, meter
min = Time, minute
ml = Volume, milliliter
ppb = Pounds per barrel
ppg = Density, Pound per Gallon
PSI = Pressure, pound-force per square inch
PV = Plastic Viscosity
rpm = Revolutions per minute
sec = Time, Second
sg = Density, Specific Gravity
TVD = True Vertical Well
WBF = Water based fluid
YP = Yield Point

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