

EGS Propped Stimulation >300°C: From Design to Implementation Phase I

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Abstract

This paper provides an account of the design, implementation, and operational insights from a first-of-its-kind Enhanced Geothermal System (EGS) proppant stimulation targeting a dry rock setting with ~330 °C (626 °F) bottomhole temperature. It highlights the unique challenges of creating a high-temperature EGS and the innovative strategies employed to mitigate them, with the goal of advancing the scalability and viability of geothermal energy as a sustainable resource.

The demonstration project involved recompletion of an existing wellbore to facilitate advanced stimulation strategies aimed at enhancing rock permeability in extreme thermal and mechanical stress conditions. Tailored high-pressure stimulation techniques, supported by real-time monitoring, were employed to create a system of interconnected pathways between an injector and future producer well pair. Simulation models were used to predict fracture propagation and optimize stimulation parameters. A suite of diagnostic tools, including fiber optics, microseismic arrays, acoustic pulsing, and chemical/nanotracers, provided real-time and post-process insights into the engineered reservoir volume and fluid dynamics.

Initial results indicated that the project has created a reservoir with enhanced flow capability through propped fractures. The use of fiber optics yielded real-time data on temperature and microseismics, while microseismic mapping provided insights on subsurface dynamics and fracture orientation validation. Preliminary findings demonstrate the feasibility of high-temperature EGS development, while ongoing interpretations aim to refine understanding of reservoir behavior and optimize operational strategies. Currently, the drilling and stimulation of the twin well has been completed utilizing an optimized stimulation approach including but not limited to the implementation of the world's first sleeve above 300 °C for stimulation purposes, application of hybrid stimulation fluid for geometry creation and many more innovative approaches.

This project represents a pioneering effort in extreme-temperature EGS development, contributing invaluable data and operational insights to the geothermal sector. By addressing the unique challenges of high-temperature reservoirs, the paper offers insight and adaptive strategies that serve as a foundation for future EGS geothermal initiatives and enables the development of superhot rock (SHR) geothermal to support scalable, dense, lower-carbon intensity energy sources.

Newberry Volcano

Geological and Geophysical Evidence for High-Temperature EGS Development

Newberry Volcano, a large active volcanic system in central Oregon, represents a compelling SHREGS candidate. More than 40 years of geological and geophysical investigations have established the presence of a substantial conductive thermal anomaly, with temperatures exceeding 320 °C (608 °F) at 3,000-meter depth and projections of over 400 °C (752 °F) below 4000 meters. Importantly, this high-temperature resource occurs at relatively shallow depths and in a relatively well-characterized volcanic setting.

Located at the intersection of the cascade volcanic arc, Columbia Plateau, and Basin and Range province, Newberry Volcano has experienced a complex magmatic history. It has been active for over 600,000 years, erupting a mix of basaltic, andesitic, and rhyolitic material. The 50 × 30 kilometer elliptical edifice includes a nested caldera with numerous post-caldera features such as obsidian flows and maars. The flanks and interior of the volcano are cut by both caldera-related and regional faults, contributing to the structural complexity and potential for fluid pathways.

Subsurface characterization at Newberry Volcano incorporates lithologic data from well logs and cuttings, which reveal variable rock properties relevant to EGS development. Lava flows, welded tuffs, and intrusives are generally brittle and amenable to hydraulic stimulation, while volcanoclastic and clay-rich units tend to deform plastically. Structural and geomechanical inferences are supported by extensive geophysical data, including seismic, magnetotelluric (MT), gravity, and InSAR measurements. Legacy and recent datasets include:

- MT surveys from 2006, 2011, 2014, 2017 and 2022.
- Gravity surveys from 2006, 2007, 2011 and 2022.
- Earthquake catalogs.
- Seismic velocity tomography.
- Thermal models and updated extrapolations.
- 3D geologic models.

Several deep exploration wells have been drilled on the northwestern flank of the volcano—two by CalEnergy (CEE 86-21, CEE 23-22) and two by Davenport Newberry Holdings (NWG 46-16, NWG 55-29). NWG 55-29 displays a conductive thermal regime from ~+1700 meter elevation to total depth (TD) at -1,300 meters. While NWG 46-16 never equilibrated thermally to TD, extrapolation of its upper temperature gradient (~112 °C/kilometer) suggests bottomhole temperatures between 350 °C (662 °F) and 375 °C (707 °F). CalEnergy wells encountered temperatures greater than 315 °C (599 °F) below 2,740 meters, although insufficient permeability prevented classification as a conventional hydrothermal resource.

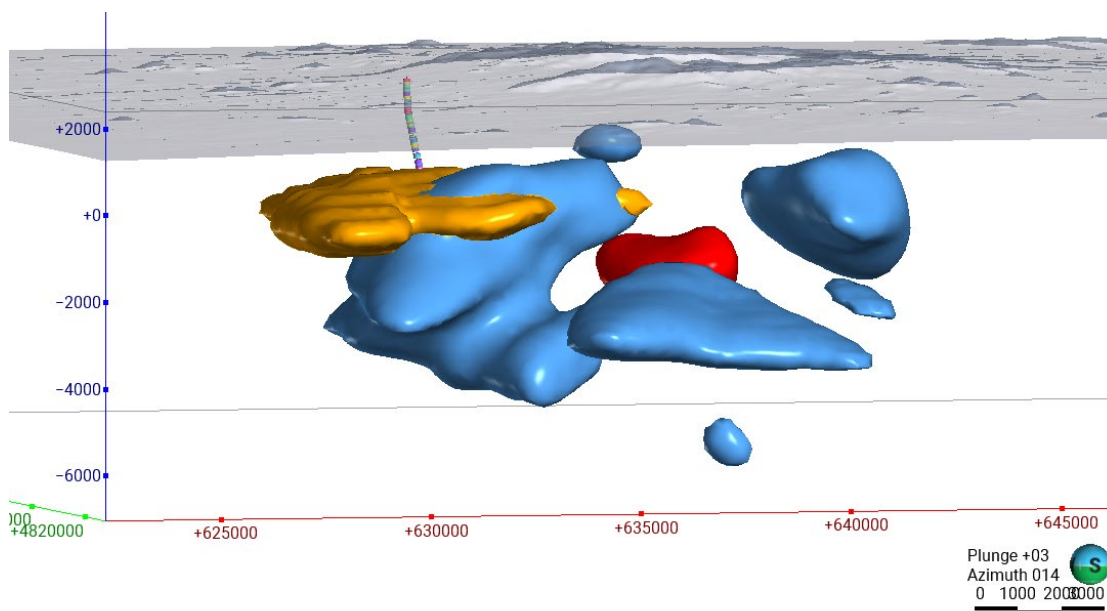


Fig. 1—Newberry Volcano Geodata Model

A robust 3D conceptual geologic model (**Fig. 1**) was originally developed during Phase 1 of the U.S. Department of Energy (DOE) FORGE initiative (Mark-Moser et al., 2016; PNNL, 2016). This model integrates temperature data from deep wells, thermal conductivity measurements, and thermal-hydrologic-mechanical-chemical (THMC) simulations constrained by porosity, permeability, and injectivity tests. It delineates target reservoir zones with superhot rock temperatures and suitable mechanical properties for EGS development. In 2022, new gravity and wideband MT data collection focused on under-characterized southern regions of the caldera and south flank. The resulting dataset was merged with legacy data in a joint inversion to update subsurface resistivity and density models, enhancing constraints on potential magmatic features, brittle-ductile transition depths, and reservoir targets.

Overall, the integration of geological, thermal, and geophysical data at Newberry Volcano provides a high-resolution understanding of subsurface conditions favorable for next-generation geothermal energy. With measured and projected temperatures exceeding 400 °C (752 °F) and an established framework for reservoir stimulation, Newberry Volcano represents one of the most promising SHR EGS sites in the continental U.S.

Well 55-29

NWG 55-29 was drilled in an area of the Newberry Volcano west flank away from any surface expressions of the caldera ring fractures mapped elsewhere. It is located on the edge of a gravity high anomaly first identified by Gettings and Griscom (1988) and confirmed by further gravity surveys. This gravity high is interpreted as the results of several high-density intrusions. The open-hole interval of NWG 55-29 extends between 1,903 meters to 3,066 meters total measured depth. The well first intersects microcrystalline granodiorite at a measured depth of 2,627 meters. This is the first of 12 granodiorite (with average thickness of 29 meters) or felsic (with average thickness nine meters) dikes or sills with alternating subvolcanic basalts to TD.

The lithologic column (**Fig. 2**) confirms the observations. It must be noted that induction, spectral density, dual-spaced neutron, temperature, natural gamma ray, and caliper logs were also obtained in NWG 55-29 during the drilling operation in the summer of 2008 using high-temperature, high-pressure, hostile slimhole logging suite.

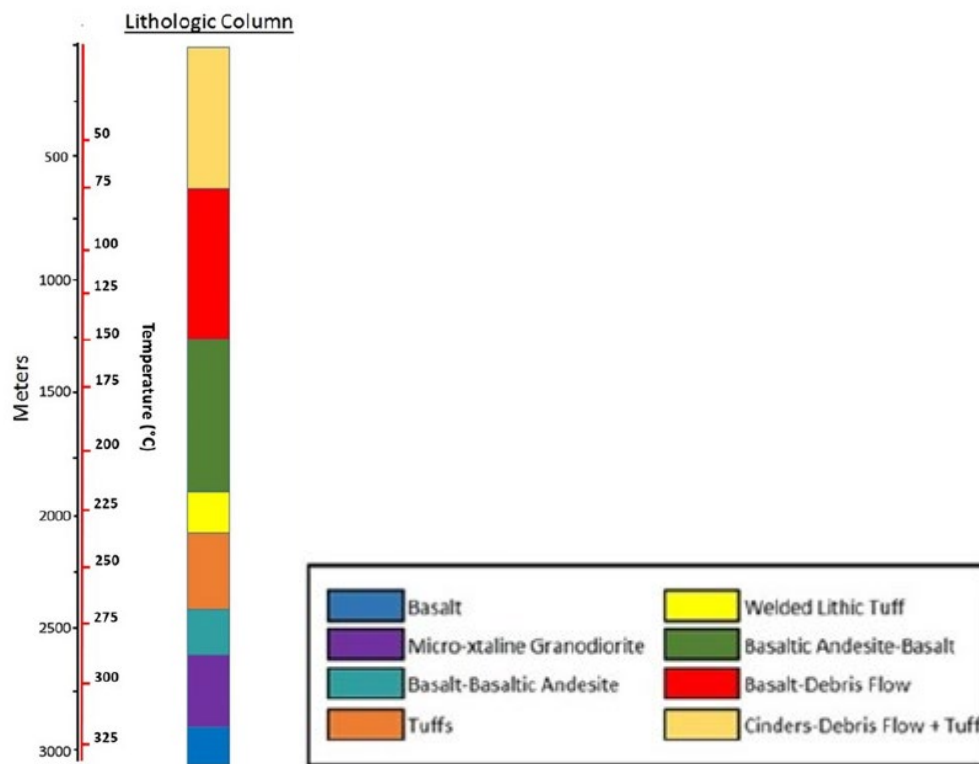


Fig. 2— Newberry Volcano Temperature and Lithologic Column from Mud Logging.

The Sandia National Laboratories Borehole Televier (BHTV) was run in October 2010 using a logging truck from the USGS in Menlo Park, California. The image log spans from the casing shoe at 1,970 meters to 2,701 meters ; the depth at which the tool stopped working due to high temperatures. The borehole breakouts seen in the BHTV showed a consistent azimuth, indicating that the minimum horizontal stress (S_{hmin}) is oriented at $092 \pm 16.6^\circ$ relative to true north (Davatzes and Hickman, 2011).

The completion approach of NWG 55-29 included a comprehensive design phase where each facet of the stimulation approach was analyzed and checked. From the concept of modelling fracture geometries and understanding surface area contact based on available data to choosing the stimulation fluid, proppant and conveyance methods downhole. The stimulation of this EGS well has been successfully completed and a twin producer well has been drilled and recently stimulated with the goal of connecting the wells and enabling heat harvesting. Innovative completion approaches have been a significant part of this work with some of the world's firsts in terms of pushing the boundaries in EGS. From the application of propped stimulation greater than 300°C (572°F) to running the world's first sleeve and successfully pumping through it in the producer well stimulation, the findings and results are an encouraging step to making SHR geothermal a scalable reality.

The diagram below (**Fig. 3**) conveys the technical approach and milestones during the stimulation of the injector well. The thought process was deliberate and diagnostic data, especially from fiber optics, enabled real-time applicability and technology transfer of conventional oil and gas technologies in this $>300^\circ\text{C}$ (572°F) EGS project.

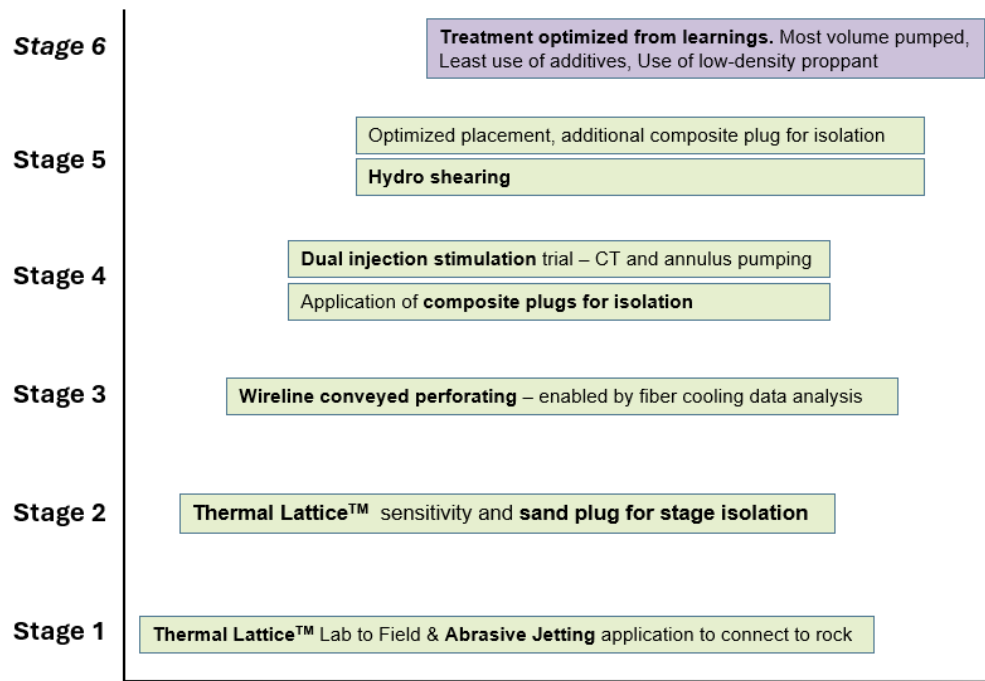


Fig. 3— The Technical Approach and Milestones During the Stimulation of The Injector Well.

Real-time data was incorporated into multiple fracture modelling softwares for NWG 55-29, and historical records were matched to infer geometries and coupled with microseismic data (**Fig. 4**). The NWG 55A-29 is the projected, recently drilled and stimulated producer well (**Fig. 4**). The main goal is to generate a fracture area that would enable a flow path between the injector and producer well and ultimately allow heat harvesting. This process includes iterations of hydraulic vs. propped half-lengths and their impact on heat harvesting potential, with propped half-lengths being the main drivers in terms of engineered reservoir volume.

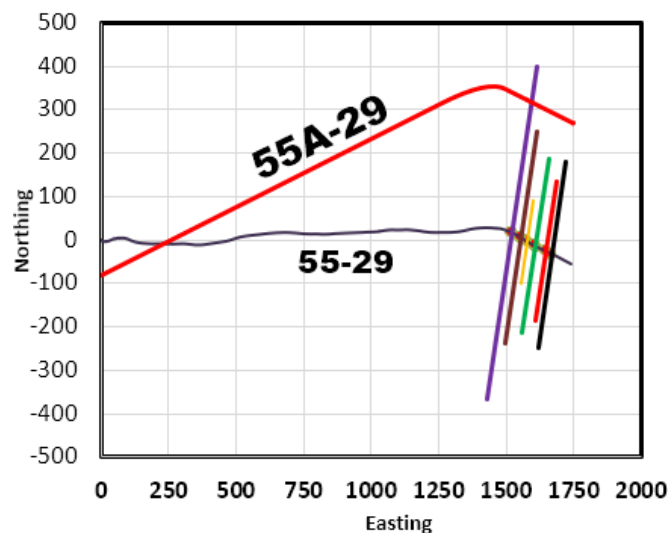


Fig. 4—Proposed Orientation for the Fractures Created During the NWG 55-29 Stimulation.

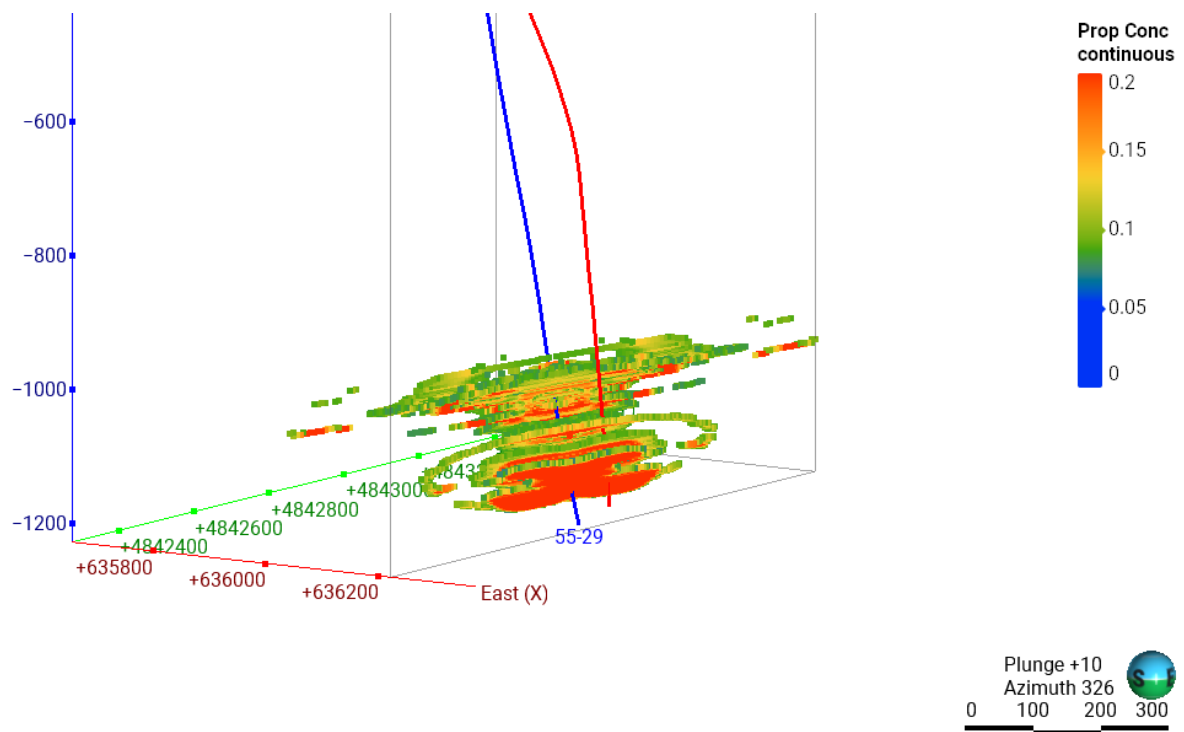


Fig. 5— Modeled Proppant Concentration in Fractures Created During the NWG 55-29 Stimulation.

Seismic monitoring

Permanent Seismic Network

Several seismic monitoring networks operate in the vicinity of the Newberry Volcano caldera and are maintained by the Cascade Volcano Observatory (USGS/CVO), the Pacific Northwest Seismic Network (PNSN), and Lawrence Berkeley National Laboratory (LBNL). Fig.6 shows the locations of all sensors within approximately 15 kilometers of the Newberry Volcano site, with the different network operators indicated by color. The LBNL network (network 2M in **Fig. 6**) was initially installed in 2012 to monitor the first phase of stimulation in NWG 55-29 (Cladouhos et al., 2016) and is therefore concentrated within five kilometers of the well. These sensors are installed in deep, steel-cased boreholes at depths up to 300 meters to limit the effect of attenuation from the loose surface deposits. The depth was also planned to ensure the sensors were installed beneath the water table, which helps to improve signal through better coupling.

There are two types of sensors in the LBNL network: six 2 Hz geophones installed in 2012, and two broadband, low-noise accelerometers installed in 2023. Data is recorded continuously at 250 or 500 samples per second, depending on the site, and sent over the cell network in real-time to LBNL and Earthscope for public access. One strong-motion accelerometer (NNVM; black triangle in **Fig. 6**) is installed in a Forest Service warehouse at Paulina Lake to record ground shaking at important nearby structures.

Seismic waveforms are scanned automatically in real-time to detect potential events represented by abrupt spikes in amplitudes across the network. If enough phase arrival picks can be automatically made, an event is located against a local, 1-D velocity model estimated during the 2012-2014 stimulations (Cladouhos et al., 2016). For located events, a magnitude is estimated, and if the resulting magnitude exceeds any of the thresholds defined in the Induced Seismicity Mitigation Plan (ISMP), an alert is sent via text and email to the relevant parties. Once an event has been reviewed by a scientist, the event is displayed in near-real-time on a public website.

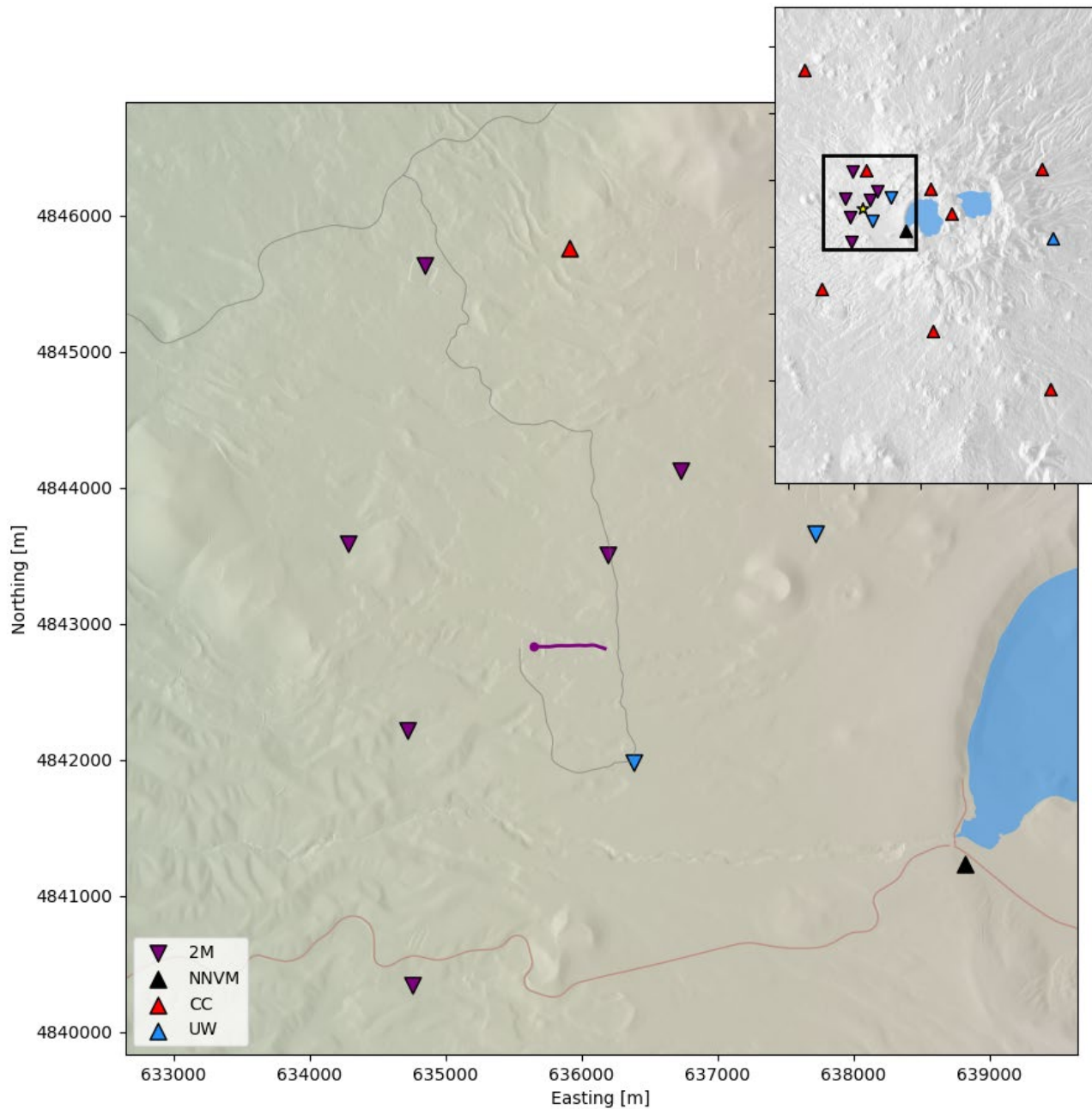


Fig. 6—Locations of Seismic Stations Surrounding the Newberry Volcano EGS Site. Stations are Colored by Network, and the Network Name is Included in the Legend. Inverted Triangles Show Sensors that are Installed in Boreholes. Upward-Pointing Triangles Indicate Sensors Installed at the Surface. NNVM is a Strong-Motion Accelerometer, and the NWG 55-29 is Indicated with a Dot at the Wellhead and a Line Showing the Surface Projection of the Trajectory at Depth. The Wellhead is Shown in the Inset with a Yellow Star.

Seismicity During 2012 and 2014 Stimulations

As mentioned above, the seismicity induced during the initial phases of injection was well-recorded and is reported in several publications (Cladouhos et al., 2016, Aguiar and Myers, 2019, Templeton et al., 2020). Over 300 events were reliably located during the 2012 to 2014 period, with 23 having a magnitude between 1.0 and 2.0 and two events exceeding magnitude 2.0 (Cladouhos et al.,

2016). Seismicity in 2012 was shallow and interpreted as the result of a casing leak. The initial analysis of 2014 data, after the leak was fixed, resulted in hypocenters that defined a cloud loosely centered on the bottom 3,000 feet of the well. Aguiar and Myers (2019) used a different method and showed that seismicity most likely occurred in distinct clusters at depths consistent with interpreted permeable zones at the toe of the well.

Seismicity During 2025 Stimulation

With the application of higher pressures comparable to 2014 stimulation, the 2025 operation in the injector well induced remarkably little seismicity. The few low-magnitude events that were detected – too small to be reliably located using the permanent seismic array – were corroborated by the distributed acoustic sensing data collected from the fiber optics in NWG 55-29. While the number of events were lower than expected, the stimulation application showed significantly reduced induced seismicity risks which is a critical operational benefit for all EGS projects. Crucially, the seismicity that did occur in NWG 55-29 and the newest stimulation of the adjacent producer aligns with prior interpretations of stress orientation and supports the expected fracture propagation geometry. This consistency strengthens confidence in the regional stress model and supports continued planning and optimization of future drilling and stimulation strategies.

Future of the Newberry Seismic Array

Regardless of the low level of seismicity induced during the stimulation of NWG 55-29 in 2025, improvements were made to the seismic monitoring at Newberry Volcano for the latest phase II stimulation. Incremental changes were made to the hardware for the permanent stations to allow them to operate more reliably in the winter months (e.g. new solar panels, additional batteries), and solutions to fully replace the old sensors are currently being explored. The simplest solution to bolstering the network is to add many more stations. This is being done by LBNL using patches of collocated nodal geophones that are combined into a single “sensor” to improve the signal-to-noise ratio at a given site. Additionally, hundreds of nodes were installed in an array centered on NWG 55-29 for the duration of the stimulation of the recently completed NWG 55A-29. The increase in the number of sensors coupled with the fiber optics DAS measurements improved the ability to detect seismic activity and improve reservoir characterization for all future activity at Newberry Volcano.

Induced Seismicity Mitigation Protocol (ISMP)

The Induced Seismicity Mitigation Protocol (ISMP), originally developed for the Newberry Volcano EGS Demonstration (NEGSD) conducted from 2011 to 2015, was updated in 2016 and again in 2022 for the current project. The results and lessons learned from the NEGSD have been integrated into the protocol’s seven steps, forming the foundation of the ISMP. This document specifically addresses the requirements outlined in the Induced Seismicity Screening (ISS) Worksheet, as implemented by the Bureau of Land Management (BLM) as part of the National Environmental Policy Act (NEPA) process.

The questions related to historical and contemporary seismicity, as well as Quaternary faulting in and around the project site, are addressed in the ISMP. There are no known seismogenic Quaternary faults within 10 kilometers of the site. However, background seismicity suggests that small-scale, buried crustal faults, capable of generating low-magnitude earthquakes ($M < 3$), are likely to exist within the project area. Both probabilistic and deterministic seismic hazard analyses have been conducted for the project. These analyses account for both natural tectonic activity and potential induced seismicity. It is not expected that significantly larger “triggered” earthquakes will occur, and the maximum magnitude of a potentially induced event is estimated to be around $M 3.5$.

This ISMP specifically outlines the communication and mitigation plan that was in place during the NEGSD and has been carried forward into the current project. A key component of this plan is seismic monitoring. (LBNL) initiated such monitoring in October 2022 to meet the requirements specified in the protocol.

The seismic monitoring network includes eight borehole seismic stations. A traffic light system, or decision tree, has been implemented during stimulation operations. This system is based on the magnitude of recorded seismic events, range and Peak Ground Acceleration (PGA) with each threshold triggering a defined set of actions related to both field operations and communication with local authorities.

Mazama Newberry 55-29 – Operational Considerations

The unique well history development of the NWG55-29 unconventional SHR geothermal well required several diverse stimulation and well intervention contingencies to be developed and mobilized for simultaneous deployment in a field environment (**Fig. 7**). The most prominent challenge was a casing-in-casing re-entry tubular condition requiring a perforating process that could effectively penetrate through the following well construction condition to access a formation composed of basalt, basaltic andesite, granite, and granodiorite:

- 4.5”-15.1# P-110 Liner.
- 4.5”x 7” Cement Barrier.

- 7"-29# P-110 Pre-Perforated Production Casing.
- 7" x 8.5" Openhole Cement Losses through a Legacy Pre-Perforated Tubular.

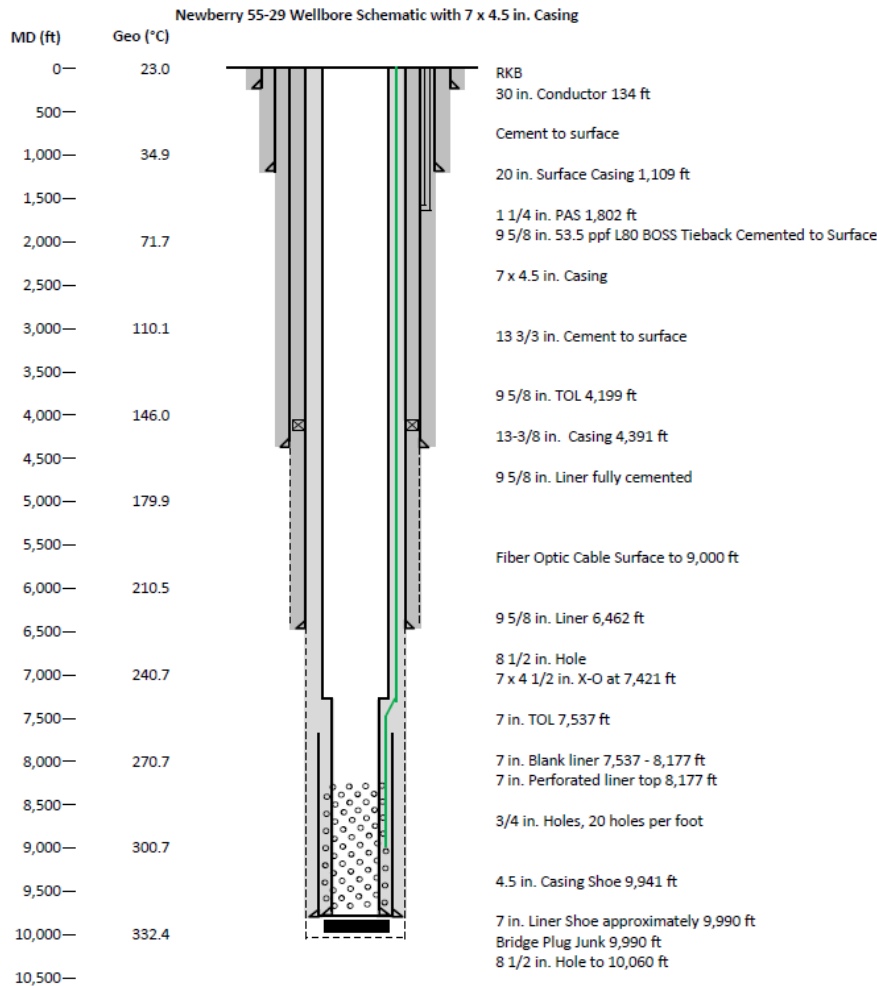


Fig. 7 55-29 Recompleted Completion Schematic Showing 7" x 4.5" Recompletion with the 7" Lower Slotted Liner in Place From Historical Completion. The Green Line Indicates the Installed Fiber.

A hybrid conventional and coiled tubing stimulation equipment spread was procured as a solution. This allowed for either dual injection pressure pumping utilizing abrasive perforating and dynamic diversion tools, or conventional plug and perforate intervention with bullhead stimulation. Both processes would facilitate multistage fracturing operations with a high degree of operational efficiency and energy transfer per unit of reservoir volume treated. Of note, the initial approach was to be the abrasive perforating and dynamic diversion treatment using coiled tubing. A permanently installed temperature and acoustic sensing fiber optic installation would be the arbiter of wireline-deployed intervention tools based on the physical validation of pre-treatment cooldown/warm back temperature modeling as well as assessing if the selected wireline tools could survive the residence time of intervention and pressure pumping duration.

To most effectively allow for on-location changes between stimulation and intervention processes, a simple dual injection approach was employed to ensure that separate clean fluid and proppant laden fluid flow paths could be maintained for both coiled tubing dual injection and conventional bullhead treatments. A simple valving change of one treating line to either the coiled tubing unit or the wellhead and an isolation change to two high-pressure pumping units could facilitate near-immediate cycle time changes between stimulation processes at a range of 20 to 40 bpm. An exaggerated view of the surface rig up and ultimate flow paths for each process is presented in **Fig. 8(a)** and **Fig. 8(b)**.

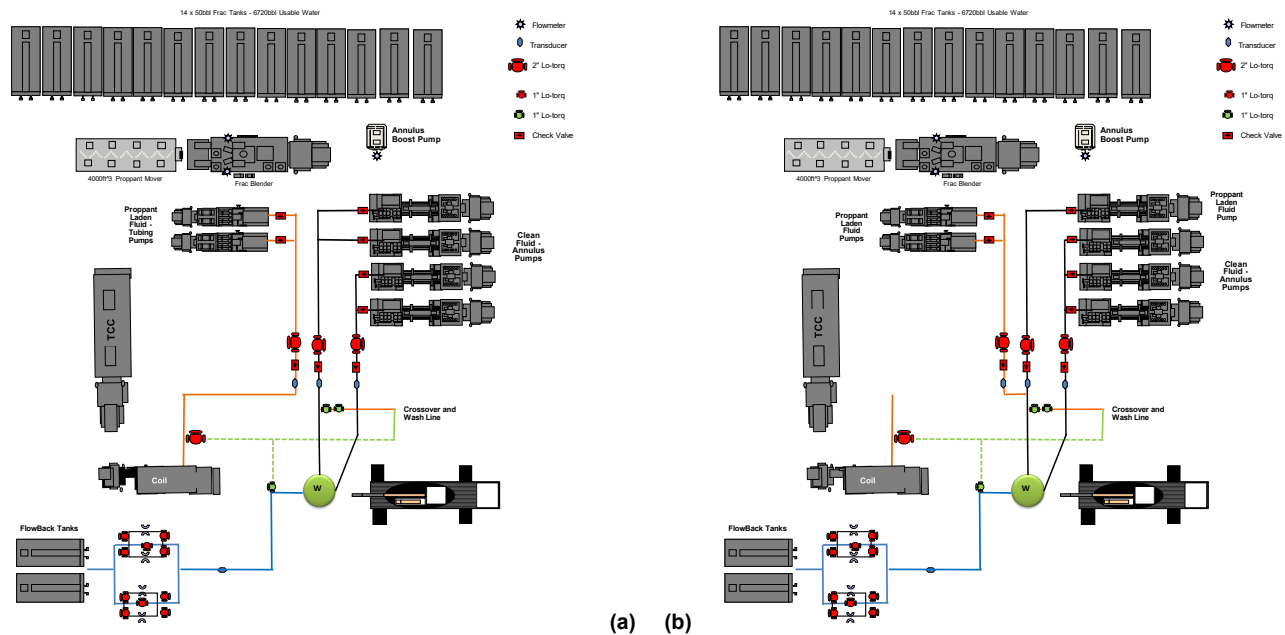


Fig. 8 (a)—Abrasive Perforating and Dual Injection Dynamic Diversion Stimulation Rig-Up; (b) Wireline Deployed Plug and Perforating and Bullhead Stimulation Rig-Up.

Abrasive Jetting Development and Testing

Given the challenging casing-in-casing re-entry tubular condition, extreme formation temperature, and significant amount of standoff between any perforating tools from the 4.5" liner to 8.5" open hole, physical testing of the abrasive jetting process with likely standoff conditions was executed in a controlled yard test environment. The testing included a well-rounded program including multiple velocities and target pressure drops across the jetting sub to provide a reasonable tolerancing framework that could be effectively translated to field implementation.

All abrasive jetting testing was setup with a single 0.1875" jet within a full tungsten carbide jetting sub aligned perpendicular to the face of a granite boulder with 4.0" standoff between the jet outside diameter and the granite face. A blast shield enclosure was then installed over the entire granite boulder, and a baseline rate of either 1.1 bpm or 1.3 bpm was established with a prepared 30cP guar based linear gel. After consistent rate and pressure was observed, 80 mesh mineral garnet was introduced at 1 lb/gal cutting media added per gallon of clean fluid. The abrasive jetting test was executed under steady state conditions for 30 minutes of abrasive exposure. A visual of the testing setup without the blast shield enclosure installed is provided in **Fig. 9**, and the average results from multiple runs of 1.1 bpm and 1.3 bpm total slurry jetting rates are provided in Table 1. Additional visuals of the perforation hole that was abrasively jettied from one of the 1.1 bpm test iterations is included in **Fig. 10**.



Fig. 9—Abrasive Jetting Test Setup with a Granite Boulder.

Test	Avg. 30 Min Rate	Pumping Interval	Observed Average Pressure Drop Across Jet	Standoff Pre-Test	Standoff Post-Test	Measured Cut Depth at 30min	Wear On Jet	Abrasive Perforation Size - Width x Height
(group)	(bpm)	(min)	(psi)	(in)	(in)	(in)	(in)	(in)
A	1.1	30	2633	4.0	4.0	7.83	None	1.5 x 0.85
B	1.3	30	3545	4.0	4.0	9.94	None	1.5 x 0.85

Table 1—Hydrajet Testing Results



Fig. 10 Abrasive Jetting Result from a 1.1 bpm Test.

Fluid System Development

Prior to operational planning for the 55-29 stimulation, an extensive effort in testing fluid systems was executed to aid in propped fracture modeling to design an optimized pumping schedule. The High Viscosity Friction Reducer (HVFR) additive selection process required a balance of targeting the best possible proppant transport potential, limiting the potential induced fluid damage in the downhole SHR environment, and focusing on environmentally-friendly chemistry given the sensitive wellsite location in the Central Oregon volcanics. Ultimately, a simple single additive HVFR system was employed to adequately address this trilemma.

Pressurized rheometer testing was executed utilizing equipment with a consistent and repeatable operational upper temperature limit of 243 °C (470 °F). Initially, rheology testing varying the HVFR concentration at the upper testing equipment temperature limit was executed to establish a baseline comparative rheological profile. It was concluded that significant thermal thinning began at roughly 107 °C (225 °F), and virtually no viscoelastic transport properties remained at the upper testing temperature threshold concentration of 10 gal/Mgal for the selected additive.

After the baseline rheology testing was completed (**Fig. 11**) and fluid system limitations were understood, preliminary cooldown modeling was completed. The cooldown investigation developed a range of likely temperatures that would be encountered during various stimulation material balance applications. This provided a temperature range where dynamic fluid properties would be tested at various shear rates to further optimize the pre-treatment propped fracture modeling and pumping design development.

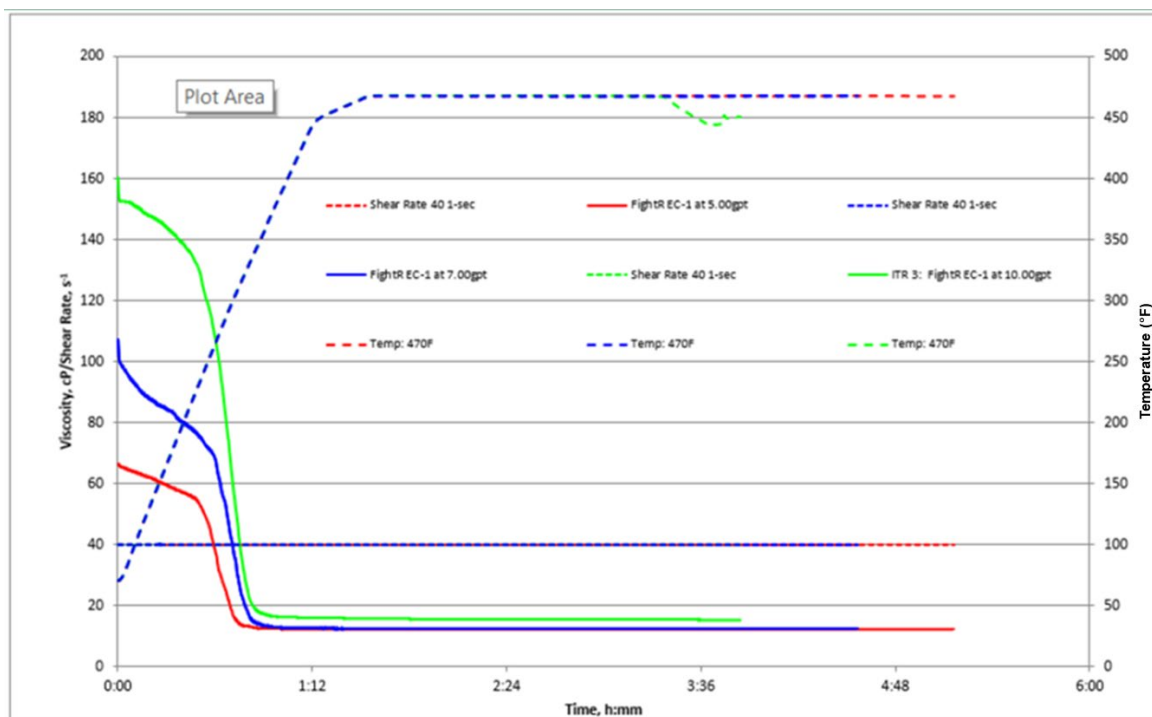


Fig. 11—Baseline Rheology Testing – Variable HVFR Loading at 243 °C (470 °F).

The critical Power Law Modeling fluid values n' (flow behavior index) and k' (flow consistency index) were obtained through shear rate sweep testing. For this testing, two sweeps were executed at the shear rates of 10-20-40-100-200-511-1000s⁻¹ for each test temperature of 100-150-200-225-250-275-300 deg Fahrenheit. The first sweep was completed when the sample initially achieved the target test temperature, and the second was executed at the maximum estimated pumping duration of three hours at the target temperature. In between the two sweep tests, a shear rate of 40s⁻¹ was held constant.

Clean data as well as the viscosity response were captured from the dual sweep testing, and the results were processed into the fluid portion of the stimulation modeling package (Fig. 12). The n' - k' results are presented in graphical and numerical format in Table 2 and Fig. 13.

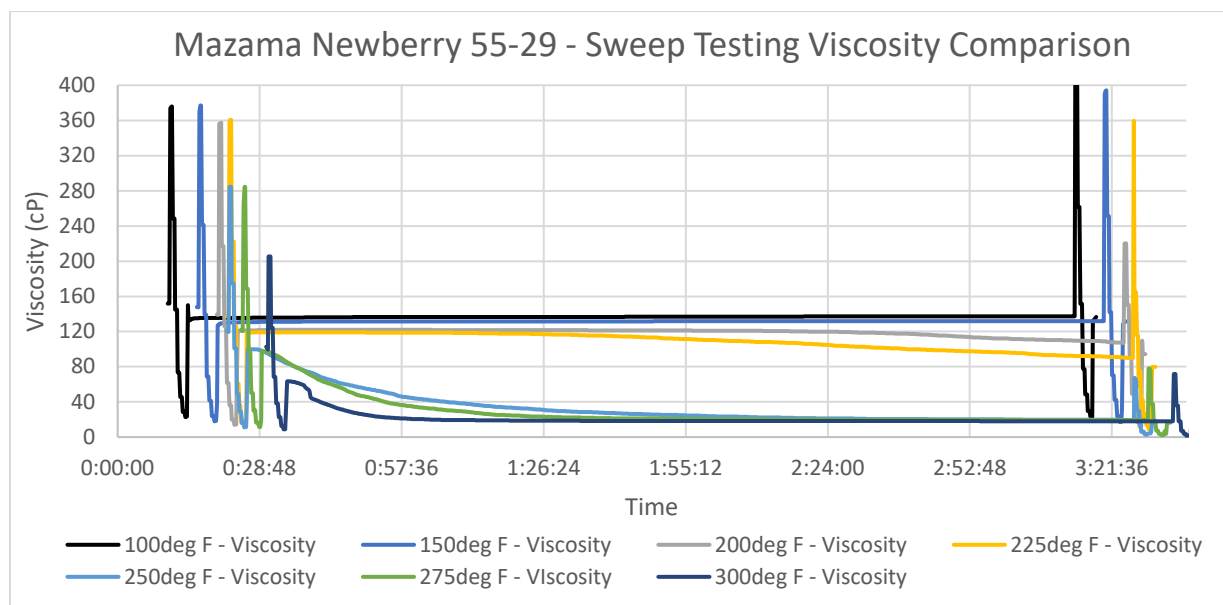


Fig. 12 Dual Sweep Shear Rate Testing – Viscosity Response.

Temperature (°F)	Temperature (°C)	Sweep 1(n')	Sweep 2 (n')	Sweep 1 (k')	Sweep 2 (k')
100	38	0.365	0.3535	0.0321	0.0352
150	66	0.3148	0.2954	0.0367	0.0405

200	93	0.2832	0.3461	0.0368	0.0213
225	107	0.2638	0.3794	0.0401	0.0151
250	121	0.2779	0.3612	0.0303	0.0039
275	135	0.2957	0.2988	0.0283	0.0056
300	149	0.3049	0.1129	0.02	0.0101
		Share Rate = s^{-1}			
		Shear Stress = (lb/ft ²)			

Table 2— Dual Sweep Shear Rate Testing – n'-k' Values.

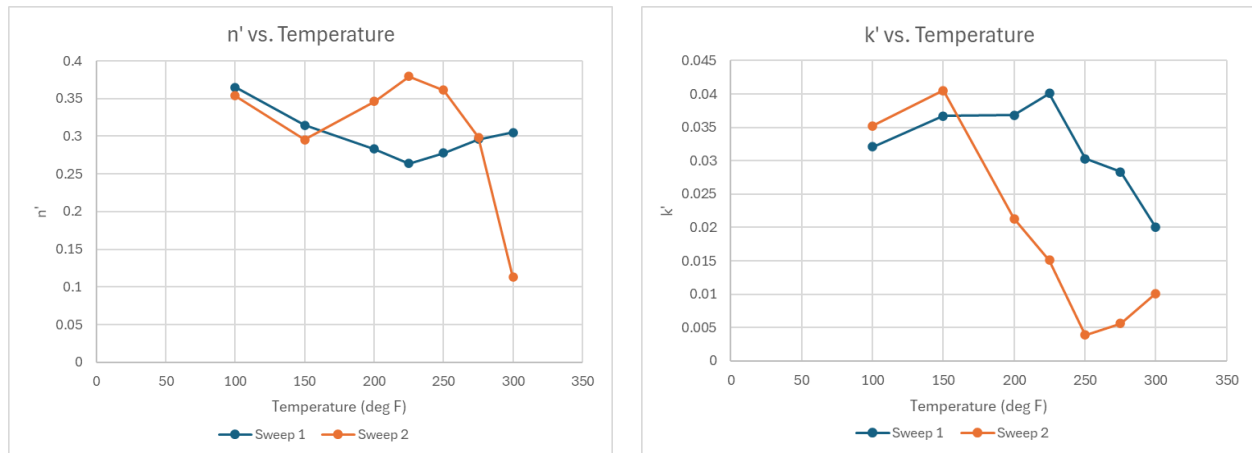


Fig. 13—n' and k' vs. Temperature

Pre-Treatment Testing Utility - Field Implementation

The fluid system and abrasive jetting development testing yielded the necessary results to effectively implement an operational program to facilitate the propped fracture stimulation pumping design. In the field implementation, a minimum of 7.8 bpm was executed through a 6 x 0.1875" jetting sub to average 1.3 bpm/jet to achieve a minimum 3,500 psi of pressure drop. This provided verified breakdown access to the formation as indicated by the treating pressure response as well as substantial directed dynamic diversion force to effectively commingle both tubing and annular rates into the developed hydraulic fractures. Additional in-treatment zonal isolation testing was executed to validate the efficacy of the dual injection dynamic diversion process. The competency of creating stimulation zonal isolation was tested by setting sand plugs between intervals and comparing injectivity conditions before and after sand plug isolation. If definitive treating pressure conditions were observed between the end of the previous treatment and the initial breakdown conditions of the subsequent treatment, the dynamic diversion process was qualified in creating competent treatment isolation without requiring discrete mechanical intervention for isolation. With these dual injection tactics applied at the targeted bottomhole assembly differential pressures, multiple coiled tubing targetted stimulation treatments were proficiently executed up to a total downhole rate of 20 bpm in the NWG 55-29 unconventional SHR geothermal environment.

Further field testing of stimulation processes included utilizing the fiber optic cooldown/warm back data to determine that formation access and wellbore isolation could be successfully achieved with wireline-deployed via plug and perforation utilizing a structured time phrasing plan. Multiple treatment intervals were successfully isolated, accessed, and propped-fracture stimulated at rates up to 40 bpm using wireline deployed multistage intervention.

An example treatment plot of stages 1 and 5 are shown in Fig. 14.

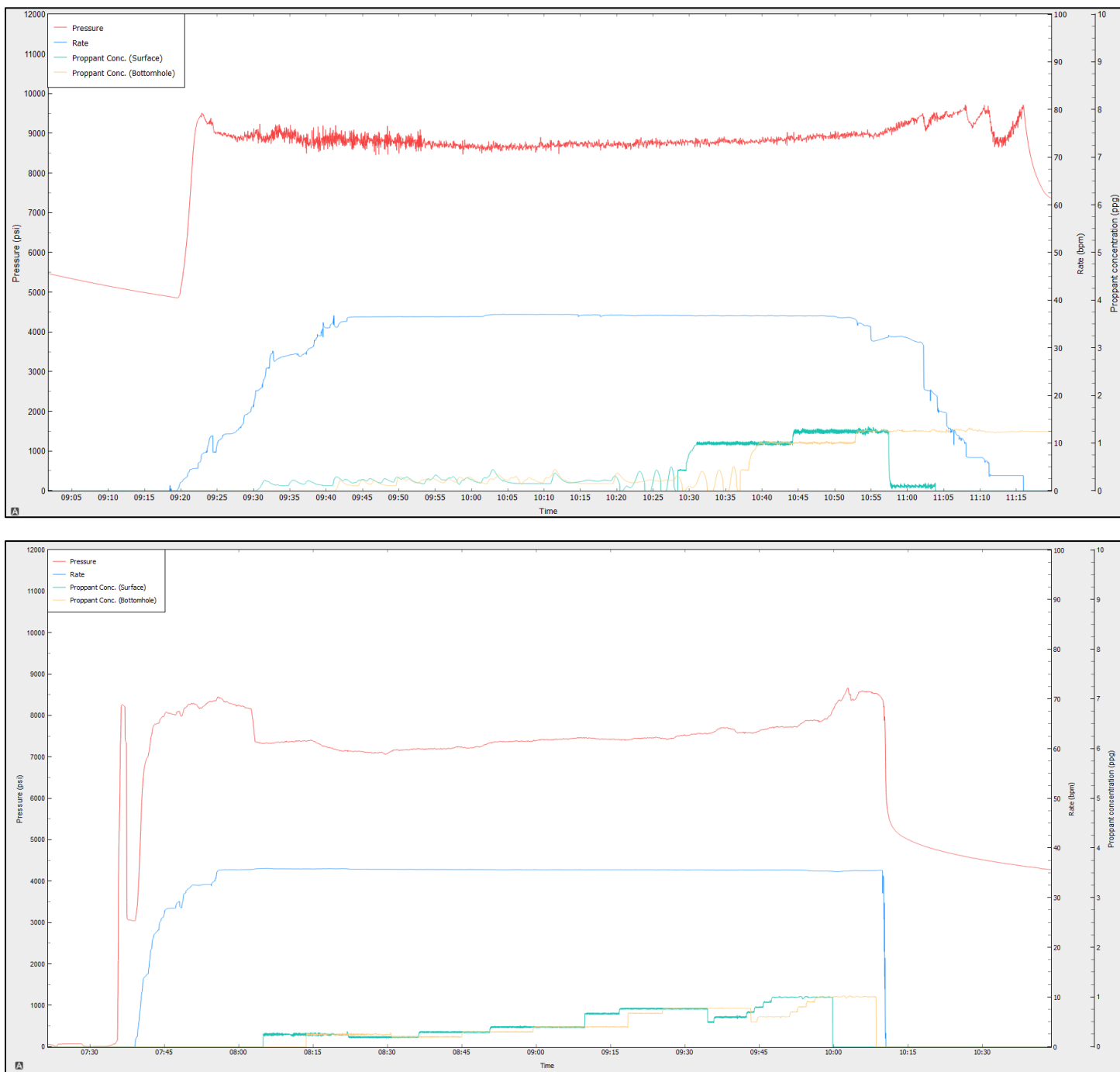


Fig. 14—An Example Treatment Plot of Treatment 1 (Basalt) and Treatment 5 (Granodiorite).

Installed Fiber Outputs

The fiber installed during the recompletion phase functioned as designed and did not suffer malfunctions during the NWG 55-29 stimulation as well as the latest Phase II stimulation of the twin well. Utilizing distributed temperature sensing (DTS) and distributed acoustic sensing (DAS) data critically helped streamline a decision flow through the completion phase and confirmed confidence in running wireline in the hole for perforating and setting the plug. Multiple cooldowns and warm back cycles were monitored to understand the delta of temperature change and implications of such changes on the ability to achieve desired stimulation goals (**Fig. 15**).

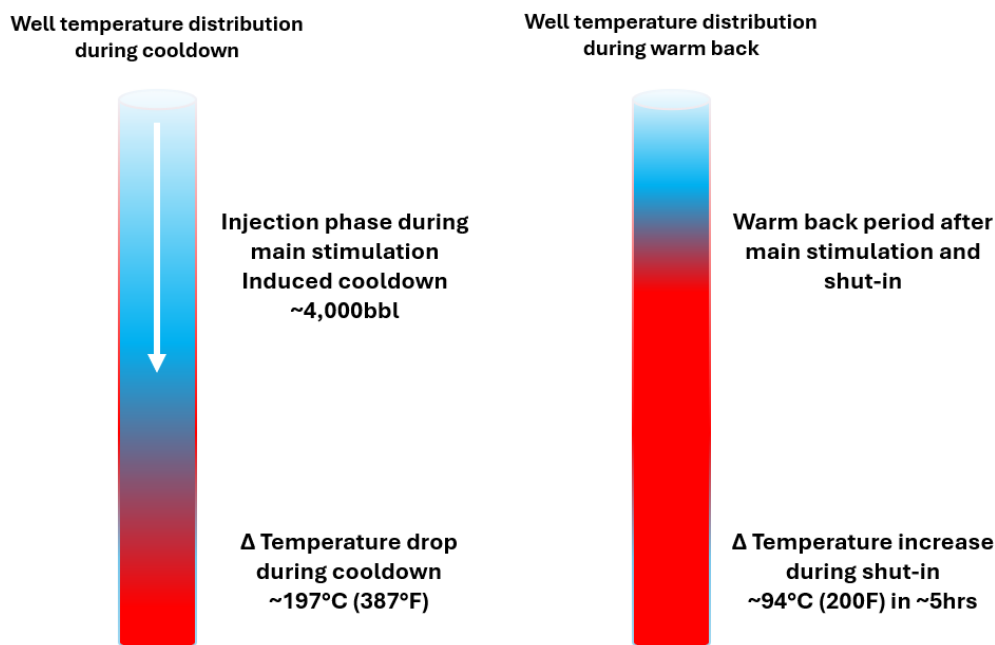


Fig. 15—An Example Temperature Change During Cooldown and Warm Back on Fiber Readings Plot of Stage 1 Main Stimulation.

Perforating Considerations

Perforating with explosive shaped charges in a geothermal environment presents several challenges. The high operating temperature requires selecting a suitable explosive based on the anticipated time at depth and the expected wellbore temperature (**Fig. 16**). Normally, deploying a hexanitrosilbeneHNS explosive with a maximum application temperature of 270 °C (520 °F) for one hour or less, is recommended for geothermal applications. Due to the tight mobilization timeline and limited availability of HNS charges, a cyclotetramethylene trinitramine (HMX) explosive charge was used. HMX explosives have a maximum application temperature of 205 °C (400 °F) for one hour or less which requires the wellbore to be cooled down between wireline conveyed perforating runs with circulating cooler fluid. Despite the temperature limitations of HMX explosives, it was observed that the HMX charges delivered a 15 to 20% improvement in overall perforating performance compared to an equivalent HNS loaded charge. Specifically, the HMX explosives provided a longer perforation length and larger entrance hole diameter.

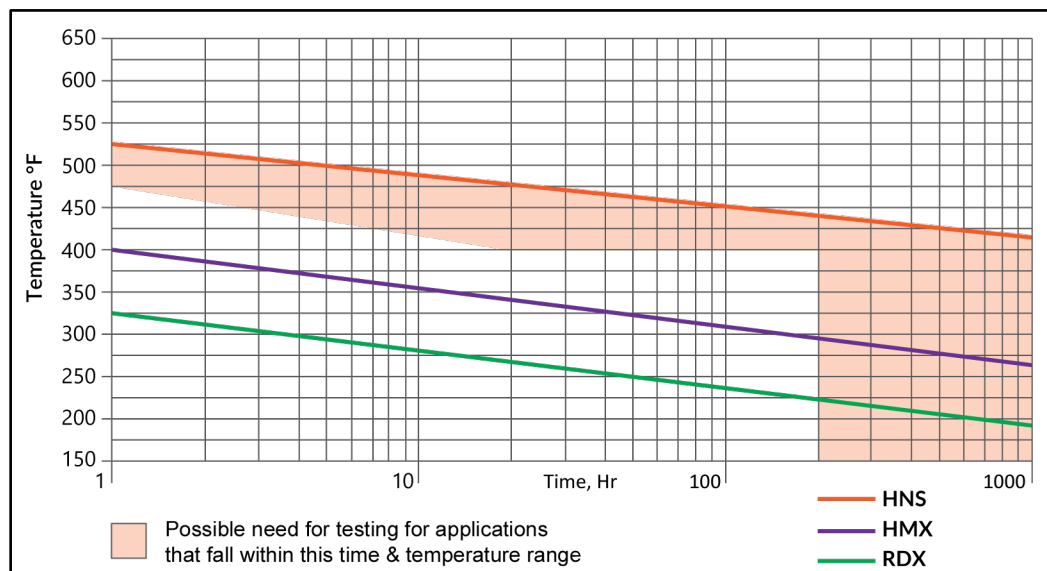


Fig. 16—Time Versus Exposure Temperature for Several Commonly Used Oilfield Explosives.

Shaped Charge Performance

Perforation penetration length is affected by several things, most notably the rock porosity, unconfined compressive strength (UCS), and the overburden stress. The targeted rock in this project is a granite formation with a approximately 2 to 4% porosity and an estimated UCS of 25,000 psi. The overburden gradient is estimated at 1.14 psi/ft at a true vertical depth (TVD) of about 9,750 feet with a resulting confining stress of 28,500 psi. These factors combined significantly limit the perforation tunnel penetration length into the formation. The existing completion had a 7" slotted liner and was covered with a 4.5" 11.6 lb/ft P-110 liner subsequent to recompletion for geothermal operations. The smaller diameter liner limited the diameter of the perforating carrier and the available mass of explosive to a 3 1/8" carrier loaded with a 22.7-gram shaped charge at six shots per foot (spf) and 60° phasing.

Perforating Operations

The initial plan was to run a shaped charge with a conventional powered metal; conical liner composed primarily of copper (**Fig. 17**). Pre-job modeling was performed to estimate entrance hole diameter in both strings of casing, the formation penetration, and the clear tunnel length (**Fig. 18**). Clear tunnel length is the portion of the penetration that is clear of plugging material like casing, cement, and shaped charge liner debris commonly known as the carrot. Formation penetration was modeled at approximately 4.60", clear tunnel length was estimated at approximately 1.33" and the entrance hole diameter through the outer string was calculated at approximately 0.32".

An alternative **reactive** shaped charge was proposed and selected for subsequent runs. The unique bimetallic liner in this charge generates a secondary reaction which partially begins upon jet initiation and then further develops during perforation tunnel formation. Given the confined conditions of the perforation tunnel, the process is highly exothermic and generates locally-applied radial mechanical energy. The application of this energy disrupts the formation of the damaged zone, resulting in a permeable, non-competent compacted region and limited or no tip plugging (**Fig. 19**). The **reactive shaped** charge performance was modeled, resulting in an estimated formation penetration of about 5.33", clear tunnel length of approximately 3.20" and an entrance hole diameter through the outer string of roughly 0.30" (**Fig. 18**). After switching to the reactive shaped charge, injectivity was established for each subsequent stage and the intervals were successfully stimulated.

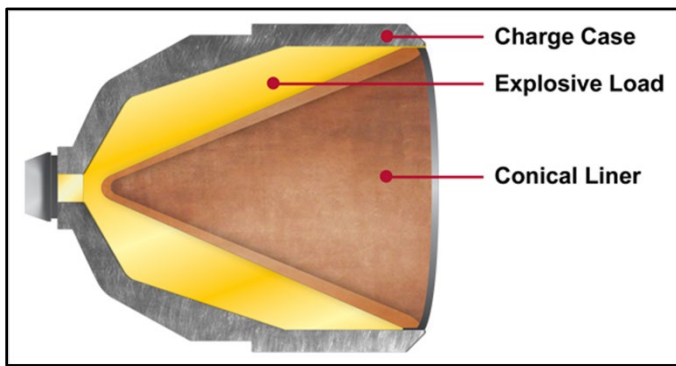


Fig. 17—Cross-section of Shaped Charge Illustrating Liner and Explosive Load Configuration.

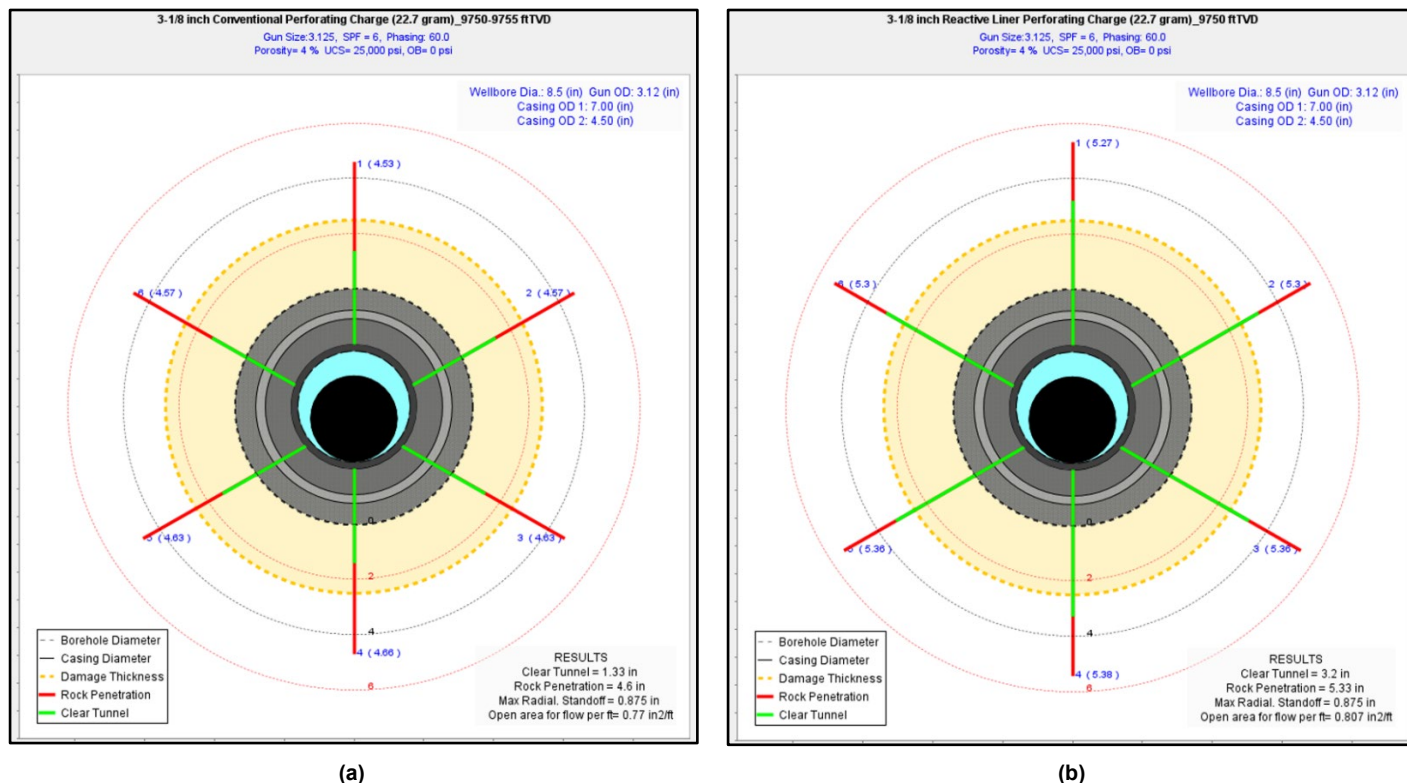


Fig. 18—(a) Modeled Conventional Shaped Charge Performance; (b) Modeled Reactive Shaped Charge Performance.

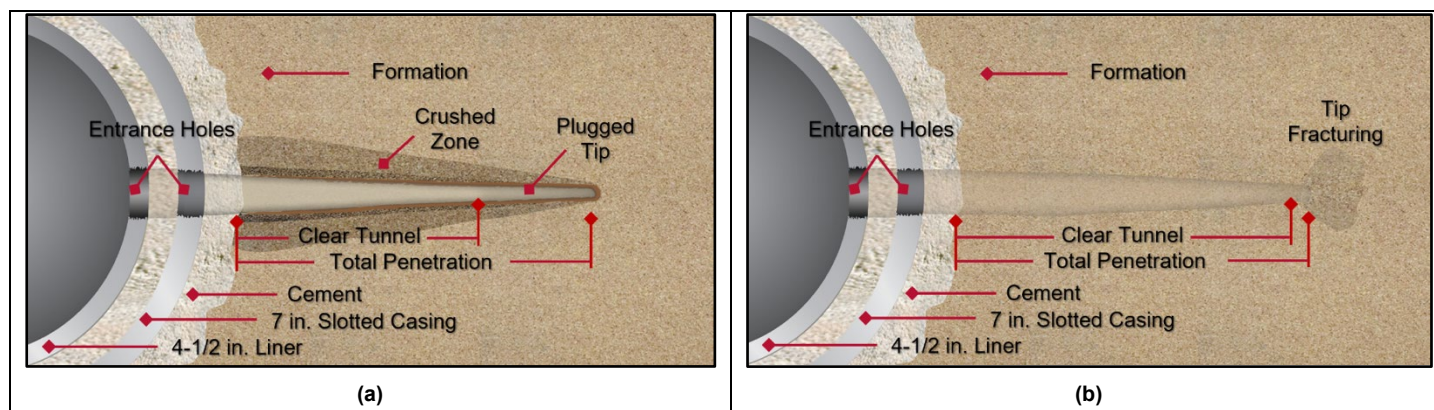


Fig. 19—(a) Conventional Shaped Charge Perforation Shows a Significant Crush Zone And Tip Plugging; (b) - Tunnel Created Using a Reactive Liner Perforating Charge Shows Limited Crushed Zone and No Significant Tip Plugging.

Frac Plug Selection

A composite frac plug was chosen to isolate a stage in the wellbore to ensure isolation between stages and provide the ability to remove the plug after completion with a Drillout Bottom Hole Assembly (BHA). A 3.500" High Pressure High Temperature (HPHT) frac plug was used based on its successful track record of performance in hotter applications up to 204.4 °C (400 °F).

Frac Plug Specifications

The frac plug exhibited the following characteristics:

OD: 3.500in (88.9mm)

ID: 0.625in (15.9mm)

Total Length: 26.3in (668mm)

Differential Pressure Rating: 15,000psi

Plug Components

The frac plug (**Fig. 20**) is comprised of a composite body made from filament wound S-type glass with a high-temperature resin and the isolation system is comprised of a rubber element. Due to high pressure at elevated temperatures, thermoplastic backup rings are used to provide the element mechanical support. Cast iron slips were used to anchor the plug into the casing wall, lock in the setting force when setting the plug, and to hold the force generated when differential pressure was applied. A 1.75" ball was used to isolate the inner diameter (ID) of the flow through frac plug. After setting the plug, the ball was launched from the surface to seat on the top of the plug and isolate the ID, ensuring pressure isolation from the stage below. This type of plug and ball drop methodology was applied to ensure a flow path for fluid pumping and to cool the plug if subsequent stage stimulation was delayed. Based on the fiber DTS data, it was possible to maintain a level of temperature dynamics supervision.

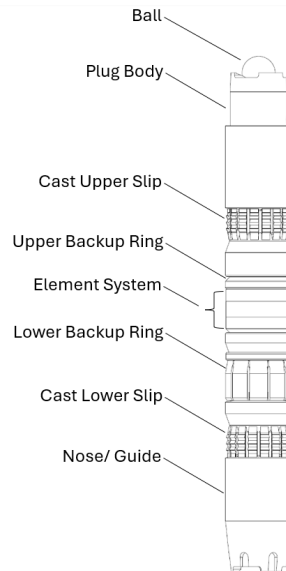


Fig. 20—Frac Plug Components Labeled.

Plug Design Validation

When validating the frac plug on the surface, a test chamber heated to 177 °C (350 °F) was used with the following procedure:

- The plug was set using a hydraulic setting tool to compress the plug and set the upper/lower slips and element before shearing off the plug to simulate the plug setting procedure during deployment.
- Pressure was applied above the plug in a cycling manner to simulate max allowable pressure and pressure cycles that occur during well operations.

During testing, the frac plug was exposed to temperature and pressure for 1.75 hours. Pressures applied to the plug were considered the differential pressure rating of the frac plug and was rated to 15,000 psi differential from the top.

Deployment

Due to the testing constraints of 177 °C (350 °F) and to reduce failure risks in the field, the well temperature was cooled to below 177 °C (350 °F) before setting by injecting cold fluid from the surface and monitoring the temperature with the installed fiber optics. The frac plug was deployed without the ball in place via wireline using a common setting tool. Once the plug was set, another wireline run was conducted to create the perforations above the plug to access the formation. Following this step, the isolation ball was pumped from surface to land on the plug, isolating the stage below. Upon completion of the well stimulation, coiled tubing with a mill out BHA was deployed to drill the plugs.

Proppant Selection

Proppant selection for EGS projects in SHR environments with temperatures exceeding 300 °C (575 °F) required rethinking traditional materials and design approaches. At these conditions, proppant transport, placement, and long-term performance face extreme mechanical, thermal, and chemical challenges.

Transporting proppant into deep, high-temperature fractures is fundamentally difficult. Fluid viscosity drops sharply at elevated temperatures, reducing carrying capacity. High thermal gradients, rapid fluid loss, and changing fracture geometries further complicate uniform placement and standard approaches often fail to capture these effects in SHR systems.

Even when placement is successful, proppants must survive conditions well beyond typical oil and gas operations. At temperatures exceeding 300 °C (575 °F), both conventional sand and resin-coated sand often fail due to crushing, dissolution, or chemical alteration. Long-term conductivity depends on thermal stability, resistance to closure stress, and chemical durability in reactive brines. Using inappropriate material leads to conductivity loss and degraded flow capacity between injectors and producers.

Selecting suitable proppant materials for the stimulation operation required considerable planning to determine the optimal type, size and application. Multiple iterations in terms of size, material, conductivity at varying conditions were also modelled with respect to fracture generation and post stimulation conductivity profiles.

Material Selection

Material selection was guided by the need to balance transportability, mechanical integrity, and thermal stability at SHR conditions. A forward-thinking approach was implemented to include materials that would help maximize the chances of stimulation treatment success as significant leak-off was expected. The selected materials included five types of proppant including natural sand, ceramic proppant, low-density ceramic proppant, micro proppant and 100 mesh.

The target formation environment of the NWG 55-29 was anticipated to have a significant amount of natural fissures and fractures, and a low fluid efficiency environment due to hard rock pressure dependent leak off (PDL) or transverse storage (TS) hydraulic fracture growth mechanisms. A pre-treatment diagnostic pumping program was planned for each interval to identify the PDL coefficient or TS ratio, and an active fluid loss mitigation plan would be deployed proportionate to the severity of the assessed conditions. To aid in fluid loss and reservoir conditioning control, a dry bulk amorphous silicate microparticle material with a non-API mean size distribution of approximately 300 mesh was utilized. For formation sections with a lower PDL signature, a front end microparticle treatment was sufficient for total fluid loss control. Where a high to extreme PDL condition was encountered, lead edge reservoir conditioning efforts were coupled with additional fluid loss treatments in the mid- and late portions of the pressure pumping operation. This resulted in consistent surface treating pressure reductions and building positive control of total bottomhole treating pressure. Larger amounts of high-conductivity stimulation materials ultimately were placed in the formation. The very high surface area to weight ratio amorphous silicate microparticle provided a positive net benefit to the success of the target treatment placement, and future production testing will indicate if any residual conductivity value is retained from connecting the low aperture natural fissure network with the principal propped hydraulic fracture system.

While natural sand is commonly used in wells operating below 93 °C (200 °F), it typically begins to degrade around 110 °C (230°F) which limits its use in SHR reservoirs. Nevertheless, natural sand was tested to understand its contribution to flow based on the tracer response. Brown sand loses over 80% of its conductivity as temperature increases from 66 °C (150 °F) to 177 °C (350°F) while white sand loses over 70% at 10,000 psi closure stress (**Fig. 21**). In contrast, lightweight ceramic proppants remain stable under the same conditions. The slight 2% conductivity reduction observed was primarily attributed to degradation of the Ohio sandstone cores used in API 19D conductivity testing rather than proppant failure. This performance gap reinforced the need for thermally stable, engineered proppants in SHR EGS applications to ensure longer term EGS flow efficiency and capacity.

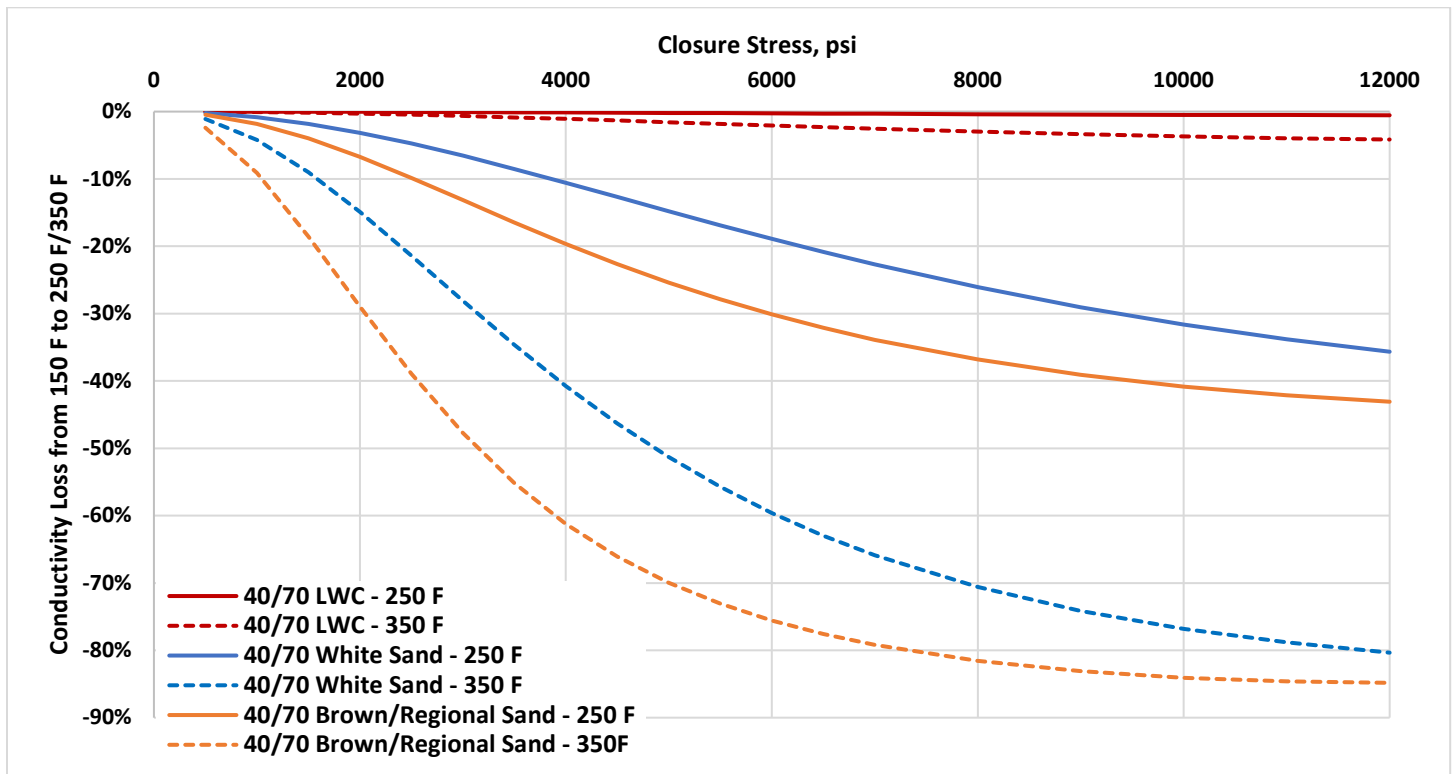


Fig.21—Conductivity Loss from 150F to 350F for Sands and Light Weight Ceramics (LWC), API 19D Long Term Conductivity Test at 66 °C(150 °F), 121 °C (250 °F) and 177 °C (350 °F), Data From Stim-Lab PredictK.

These trends are consistent with findings from Alcantar et al. (2025), which reported that natural sands degrade over time under SHR stress and temperature and conventional ceramic proppants maintain structural integrity while some experimental materials – despite high thermal resistance – lacked the mechanical strength needed for deployment. Based on this, ultra lightweight ceramic (ULWC SG 2.0) and a lightweight ceramic (LWC SG 2.71) were prioritized over natural sands and high-density ceramics to optimize transport and long-term conductivity.

The selected low specific gravity proppants aimed to enhance carrying distance from injector to producer and propped fracture length. Additionally, ceramic proppants ensured the thermal resilience and higher conductivity required for SHR conditions. **(Fig. 22).**

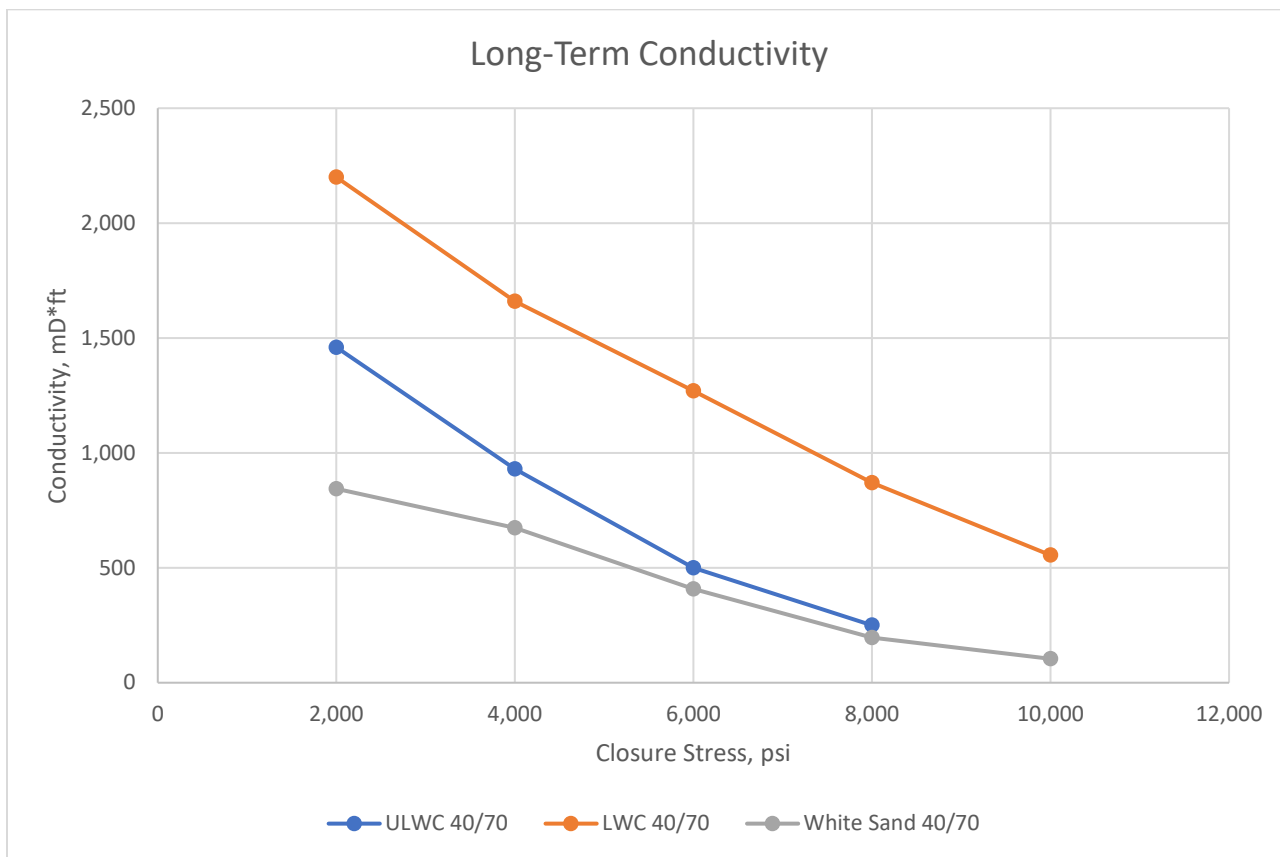


Fig. 22—API 19D Long-Term Conductivity at 250 °F of ceramic proppants vs. White Sand

Tracers Selection

Up until now, geothermal research, engineering, and development have primarily focused on strengthening metallurgical integrity and advancing technologies to improve drilling and well construction in high-temperature environments. With the recent shift to EGS projects with multi-stage geothermal wells, stimulation and completion strategies as well as flow dynamics optimization within targeted reservoirs are emphasized. Achieving maximum geothermal heat extraction depends on optimal and consistent connectivity between the injection well and each production well which significantly influences the injection strategy and overall project economics. One of the approaches in the current project focused on the use of nanoparticle tracers which complement diagnostic technologies in long-term and ultrahigh-temperature geothermal projects. Ultrahigh-resolution nanoparticle tracers consistently quantify the flow behavior of individual stages while narrowing the wide economic chasm that previously made stage-level flow mapping inaccessible to mainstream wells (Fig. 23).

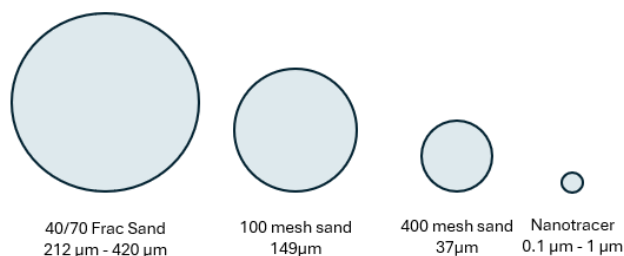


Fig. 23—The Non-Intrusive Nanoparticle Tracer in Relation to Conventional Frac Proppants.

For 55-29, 18 distinct ultrahigh-resolution and ultrahigh-temperature nanoparticle tracers were manufactured and nine were injected. The tracers were premixed in liquid form for occupational safety and accuracy and introduced across the stimulation stages. Stage 1 utilized three unique nanoparticle tracers distributed throughout the stage (from pad to flush), while Stages 2 and 3 each featured two unique nanoparticle tracers. Stages 4 and 5 each included a single unique nanoparticle tracer.

The nanoparticle recovery data revealed significant variations in flow contribution across the stimulated stages. All tracers were detected in the initial sample, with concentrations ranging from 0.71 to 1.53 ppb which demonstrated good communication between each frac and the wellbore – a critical factor for completion effectiveness and the injection process. While this information is critical and shows heterogeneity, there is sober technical awareness that vertical communication between fractures is possible allowing signatures of different pumped tracers to be seen in the fluid.

For Stages 1 and 2, the tracer concentration increased from pad to flush, suggesting good communication across the entire frac proppant length and increased fracture connectivity. The highest tracer concentration was detected in Stage 3, potentially indicating favorable reservoir and completion quality at this stage placement. Stage 4 exhibited intermediate tracer return levels, while Stage 5 showed the lowest recovery (**Fig. 24**). These initial results are encouraging, demonstrating effective frac and stage placement which are critical for the further development of the project and enabling a connection with the producer twin well.

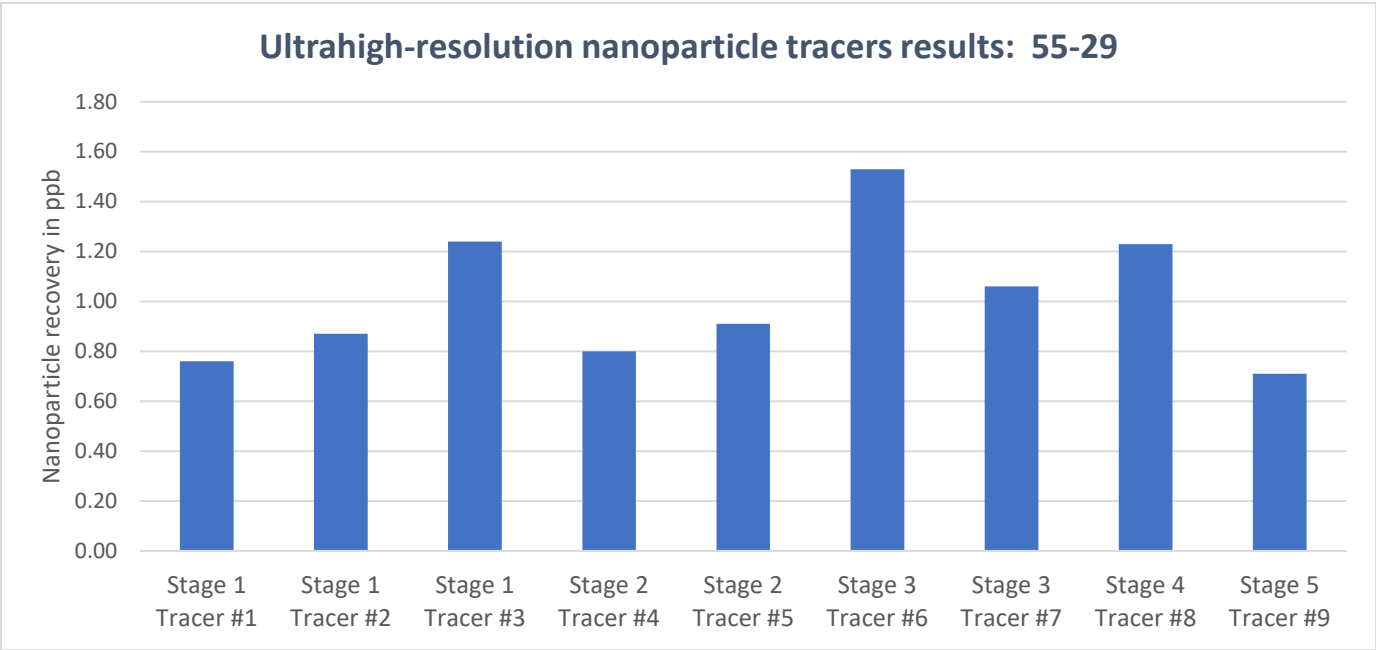


Fig. 24—The Non-Intrusive Nanoparticle Tracer in Relation To Conventional Frac Proppants.

Future analysis will include comparing long-term tracer recovery data with injection rates, pressures, and proppant volumes for each stage to identify and benchmark relationships between stimulation parameters and flow contribution. This analysis will include sampling from the producer and injector well. Long-term tracer monitoring will also be conducted to assess changes in flow profiles over time and evaluate the effectiveness of stimulation designs impacting the final heat harvesting process.

Measurements During Stimulation

Several non-invasive measurements were performed during the stimulation process. Acoustic friction analysis of water hammer signals supported the quantification of frictional pressure losses from flow in the well, through perforations and tortuosity in the near-wellbore region (Dunham et al., 2023, 2024). With additional assumptions regarding the perforation diameter, acoustic friction analysis also estimated the perforation efficiency at the time of the measurements. An active source was utilized to generate acoustic pulses from the surface before and after stimulation of most stages. Reflections from the stage, reported as near-field connectivity, infer the hydraulic connection between the well and fractures (Dunham et al., 2017). Finally, treatment pressure history and post-shut-in pressure decay were used to calibrate a 2D model of hydraulic fracture growth and leak-off, providing an estimate of hydraulic fracture dimensions (Rahimi-Aghdam et al., 2022). This approach was utilized as an additional tool to infer generated hydraulic lengths and enable comparisons with modelling and microseismic outputs.

The measurements confirmed the successful completion of all stages. It’s important to note that measurements were prevented in a few instances due to operational challenges, such as a frozen riser due to winter conditions. The perforation efficiency was consistently low, averaging around 15%, though higher efficiencies were also consistent with the acoustic friction analysis measurements if the perforation hole diameter used in the calculation was overestimated. Pressure losses from near-wellbore tortuosity were above 1000 psi at treating rates of approximately 30 bbl/min on all but one stage. Pipe and perforation friction were smaller in comparison, totaling just a few hundred psi as a consequence of the non-significantly high rates.

Acoustic Friction Analysis

Acoustic friction analysis is a method to quantify pipe friction, perforation friction, and near-wellbore tortuosity friction using the water hammer waveform generated by abrupt changes in the injection rate. The water hammer is a large amplitude tube wave that propagates through the fluid in the well, and is subject to attenuation by turbulent drag (pipe friction) as well as changes in sign and shape from hydraulic impedance changes. The latter includes changes in the inner diameter of the well and an open hydraulic connection through perforations and the near-wellbore region to the fractures in a stage. This approach isolates pipe friction from perforation and near-wellbore tortuosity friction. In particular, the wellhead pressure response following an abrupt change in injection rate depends only on wave propagation in the well, including pipe friction, prior to the arrival of the reflection from the stage. In contrast, step rate tests based on regressions to steady state pressure at various rates cannot uniquely separate pipe and perforation friction, which are both proportional to rate squared (Dunham et al. 2023, 2024) and validated against independent data (Cipolla et al. 2024). Acoustic friction analysis measurements were performed at the end of the stage, using the water hammer waveform generated when pumps were shut off and during stimulation.

Three measurements were taken from Stage 2 (**Fig. 24**). Acoustic friction analysis measurements from the end of each stage are summarized in Table 3.

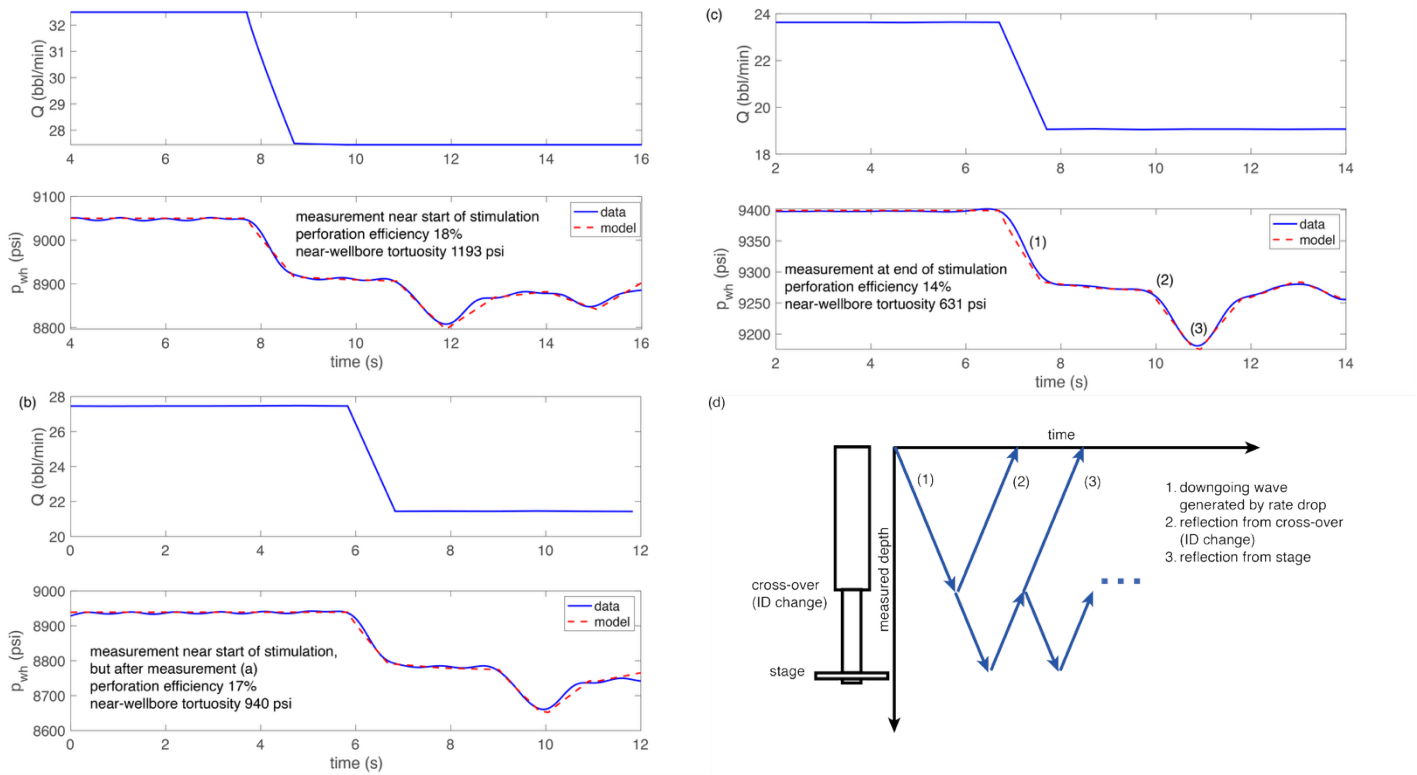


Fig. 24—Acoustic Friction Analysis for Stage 2. Measurements Were Performed Three Times, Twice Near the Start of Stimulation (A) and (B) and Again at Shut-In (C). Top Panels Show Wellhead Injection Rate, With Water Hammer Generated by Drops In Rate of a Few Bbl/Min. Bottom Panels Show Wellhead Pressure, Sampled at 20 Hz, with a Comparison Between Data (Blue) and Model (Red). Features in the Data Are Illustrated in (D). The Rate Drop at the Wellhead Produces a Proportional Drop In Wellhead Pressure, Marked As (1) in Panels (C) and (D). This Is Associated with a Down-going Tube Wave. The Wave Reflects a Change in Inner Diameter (ID) at the Cross-over. Because ID Decreases, the Reflection Coefficient is Positive, Manifesting as an Additional Pressure Drop Arriving at Time (2) in Panel (C). The Wave Reflected From the Stage Arrives Later, at Time (3) in Panel (C). The Reflection Coefficient is Negative, as Evidenced by the Pressure Increase Carried by This Wave. This Indicates an Open Hydraulic Connection to the Fractures in the Stage. Frictional Pressure Drops Are Measured as Follows: tDepressurization That Occurs Between (1) and (2) Is Proportional To Pipe Friction in the Upper Section of the Well Above the Crossover. Depressurization Between (2) and (3) is Controlled by Pipe Friction in the Lower Section of the Well Below the Crossover, as Wel as the Crossover Reflection. The Amplitude of the Reflection from the Stage, Marked (3), is Controlled Primarily by Perforation Friction, with Some Contribution from Near-Wellbore Tortuosity. The Stable Pressure Following the Water Hammer (Not Shown) Provides an Additional Constraint that Improves The Separation of Perforation And Near-Wellbore Friction. Parameter Values for Pipe, Perforation, and Near-Wellbore Friction are Determined by Minimizing the Misfit Between the Model Prediction and Wellhead Pressure Data. Perforation Efficiency and Near-Wellbore Tortuosity Both Decrease as Stimulation Progresses. The Higher Wellhead Pressure at the End of Stimulation In (C), as Compared to (A) and (B), Despite the Lower Rate and Smaller

Near-Wellbore Tortuosity, is Caused by the Increase in Hydrostatic Pressure and Pipe Friction Caused by Flushing the Well (Removing The Proppant Load) and Decreasing the Friction Reducer Concentration.

Treatment	Perf Efficiency (%)	Perf Friction (psi)	Pipe Friction (psi)	Near-Wellbore Friction (psi)	Rate at time of analysis (bbl/min)
1	13%	324	155	1494	30.6
2	14%	181	131	631	23.6
3	21%	136	132	1467	30.7
4	No data, operational issues				
5A	19%	175	140	1789	27.0
5B + 6	14%	580	202	1221	33.7

Table 3—Summary of Acoustic Friction Analysis Measurements at the End Of Each Stage.

Stimulation diagnostic and main stage summary

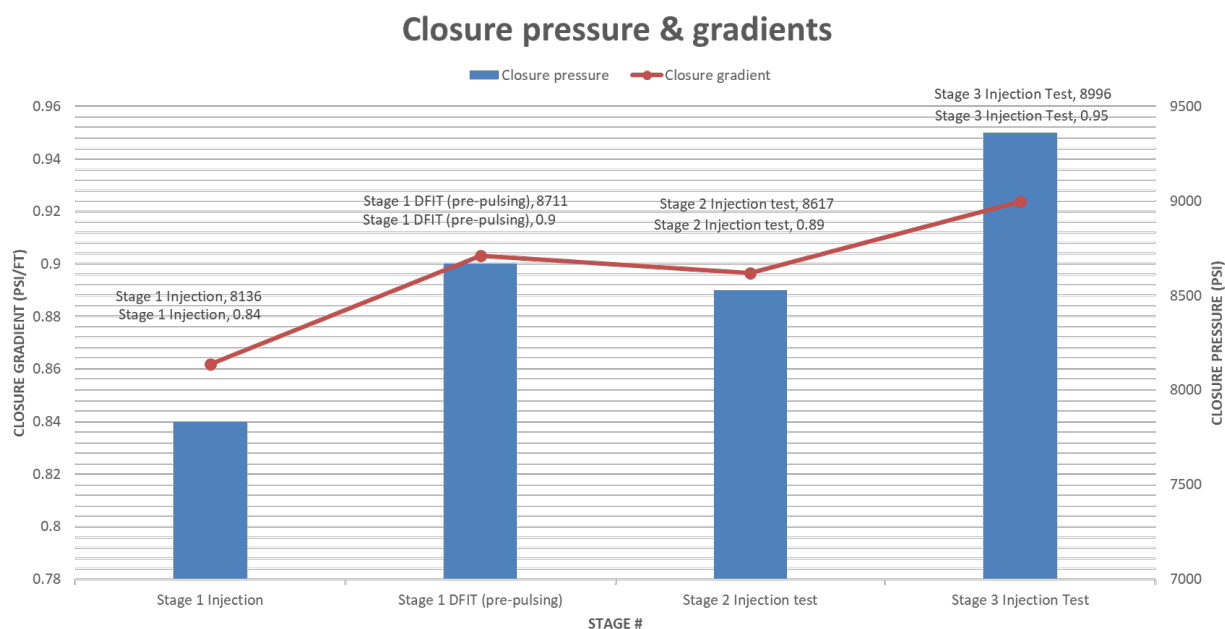


Fig. 25—Diagnostic Injection Findings on Select Stages.

Stage ID	Rock type	Slurry Volume (bbl)	Average Injection Rate (bpm)	Average WHTP (psi)
1	Basalt	3670	37	8895
2	Basalt	5840	25.5	8987
3	Basalt	3979	27	8287
4	Basaltic andesite	1115	9.9	8006
5	Granodiorite	19128	35	7537
		(2091 HS)		
6	Granodiorite	13,971	35-40	6798

Fig. 26—Main Stimulation Treatment Summary

Conclusion

To our knowledge, this paper showcases the completion of the world's first $>300^{\circ}\text{C}$ ($>572^{\circ}\text{F}$) EGS propped stimulation including the workflow and approach in implementation phase. With the ability to design for specific aspects of stimulation, the choice of stimulation fluid, proppants, conveyance methods of fluid downhole, perforating and abrasive jetting, to diagnostic technologies including fiber, tracers and micro seismic analysis, the stimulation of the injector has been successfully completed. The project showcased ability to push the boundaries in EGS stimulation and presents a first of its kind approach.

At this time, the twin well has been drilled and stimulated and an impending heat harvesting test that will follow in the near future. The application of stimulation has enabled the world's first sleeve $>300^{\circ}\text{C}$ (572°F) for propped stimulation and ability to create fracture geometries in $>300^{\circ}\text{C}$ (572°F) geothermal reservoirs utilizing proppants and hybrid stimulation fluids including high viscosity friction reducers and crosslinked fluid. Learnings from each segment in 55-29 stimulation has been carried over in the twin well design and implementation in a methodical manner to maximize chances of connectivity between the injector and producer.

This project demonstrates the ability to push the boundaries of EGS stimulation and presents a novel approach that can be replicated to help scale geothermal use.

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